

## Strathcona Resources Ltd. 2025 Shareholder Letter – March 11, 2026

Fellow Shareholders,

2025 was a transformative year for Strathcona. In May we transitioned into a pure-play heavy oil company through the sale of our Montney business, and shortly thereafter spent the better part of six months looking to roughly double in size by acquiring MEG Energy. While our MEG bid proved unsuccessful, it allowed us to purchase the Vawn project and other undeveloped thermal lands in a transaction which (though substantially smaller than MEG on an absolute basis) we believe will end up being even more impactful *per share*. The year concluded with Christmas coming three days early on December 22 when we paid a special distribution of \$10.00 / share on a tax-efficient basis.

Strathcona's 2025 was long on eye-catching M&A headlines which might make it easy to overlook the actual operational and financial results for the year. The purpose of this shareholder letter (our third since going public) is therefore to give our shareholders a straightforward and accurate reporting of how their business performed in 2025. In doing so, our aim is to first explain *what* we view as the important measures of success, followed by *how* we think we did against them. Playing the role of a baseball umpire, we believe 2025 included both home runs, strikeouts and a few base hits, each of which will be discussed herein.

### 2025 Financial Summary<sup>1</sup>

(\$ millions, unless otherwise indicated)	Year Ended	
	December 31, 2025	December 31, 2024
WTI (US\$/bbl)	\$64.81	\$75.72
WCS Hardisty (C\$/bbl)	\$75.06	\$83.53
AECO 5A (C\$/gj)	\$1.59	\$1.38
<b>Production (boe/d)</b>	<b>152,163</b>	<b>183,080</b>
% Liquids	86%	78%
Field operating income, incl. other income <sup>1</sup>	\$1,925	\$2,203
General and administrative	(\$98)	(\$101)
Depletion, depreciation and amortization	(\$697)	(\$874)
Interest and finance costs	(\$200)	(\$258)
Current Income Tax Expense (Recovery)	\$0	\$0
<b>Operating Earnings<sup>1</sup></b>	<b>\$930</b>	<b>\$970</b>
Funds from Operations <sup>1</sup>	\$1,594	\$1,937
Capital expenditures	(\$1,186)	(\$1,296)
Decommissioning costs	(\$44)	(\$36)
<b>Free Cash Flow<sup>1</sup></b>	<b>\$364</b>	<b>\$605</b>
Debt	\$2,095	\$2,462
Common shares (millions)	214.2	214.2

### 2025 Reserves Summary

	Oil	Natural Gas	Total	After-Tax PV-10
	(MMbbls)	(Bcf)	(MMboe)	(\$mm)
Developed Producing (PDP)	241	2	241	3,773
Developed Non-Producing (PDNP)	1	0	1	9
Undeveloped (PUD)	983	2	984	5,178
<b>Total Proved (1P)</b>	<b>1,225</b>	<b>5</b>	<b>1,226</b>	<b>8,960</b>
Probable (PROB)	940	2	940	3,732
<b>Total Proved plus Probable (2P)</b>	<b>2,165</b>	<b>7</b>	<b>2,166</b>	<b>12,692</b>

## 1. Production and Operations

Strathcona is organized across three semi-autonomous business units – Cold Lake, Lloydminster Thermal and Lloydminster Conventional – each with a President with autonomy over, and accountability for, day-to-day operations. These businesses are supported by a limited corporate function, providing administrative services and overseeing capital allocation. On a combined basis production from continuing operations was 115 Mbbls / d in 2025 (up 3% year-over-year), or approximately 152 Mboe / d including our divested Montney business unit.

	<b>Cold Lake</b>	<b>Lloydminster Thermal</b>	<b>Lloydminster Conventional</b>	<b>Montney</b>	<b>Total</b>
	<i>(Mboe / d)</i>	<i>(Mboe / d)</i>	<i>(Mboe / d)</i>	<i>(Mboe / d)</i>	<i>(Mboe / d)</i>
2017	0	0	17	5	23
2018	0	0	15	16	32
2019	0	1	13	20	34
2020	15	1	10	26	52
2021	24	1	12	32	68
2022	47	13	22	34	114
2023	56	30	23	46	155
2024	60	27	24	72	183
<b>2025</b>	<b>61</b>	<b>30</b>	<b>23</b>	<b>38</b>	<b>152</b>

Our Cold Lake business, led by Kim Chiu, had a strong year with production of 61 Mbbls / d, up 3% versus 2024. Kim and his team manage a portfolio of four thermal projects (three on-stream today, one to be developed in the future) located at the southern tip of the Alberta oil sands which benefit from a low viscosity, high quality crude that fetches a premium to the benchmark price further north in Athabasca. Production growth this year was primarily driven by the success of new lower-drainage wells (LDWs) at our Tucker project which outperformed expectations. LDWs were first pioneered by Strathcona at our Orion property in 2021 and involve drilling a second producer below an existing SAGD well pair. Because the wells are accessing pre-heated oil, they require little incremental steam and serve to lower our steam-oil-ratio (helping improve Cold Lake’s combined SOR by 7% vs. 2024), enhancing profitability.

Our Lloydminster Thermal business, led by Ryan Tracy, also had a strong year which saw 12% annual production growth to approximately 30 Mbbls / d. While our four Lloydminster projects (three on-stream today, one to be developed in the future) are smaller than a typical Alberta thermal project, they are subject to a favorable regulatory regime in Saskatchewan which allows for faster cycle times and lower capital costs using modular, prefabricated steam facilities. Production growth in 2025 was driven by the completion of one-such modular, pre-fab expansion to our Meota property to target the General Petroleum formation for the first time. The expansion exceeded expectations, adding approximately 6 Mbbls / d at a cost of approximately \$90 million, with the four initial well pairs ranking amongst the most productive in Saskatchewan thermal history. Next up for Ryan and team is our Meota Central brownfield project which we sanctioned in 2024 and is expected to deliver a peak rate of 13 Mbbls / d at a total installed cost of \$360 million. The project has progressed well to date and is currently 85% complete, on time and on budget.

Finally, our Lloydminster Conventional business had a more challenging year in 2025 producing 23 Mbbls / d, down 6% versus 2024. Contributing to the decrease were our polymer floods at Cactus Lake and Bodo-Cosine, both of which experienced flood conformance challenges, leading to steeper base production declines. President Seamus Murphy and team are laser-focused on remedying these issues, including by taking over previously outsourced conformance services and diversifying our polymer providers. Despite recent challenges, the economics of our Lloydminster Conventional properties remain fundamentally attractive, generating strong operating netbacks with a low base decline rate across a diversified portfolio of massive oil-in-place fields which stand to benefit from future technological improvements. While not a growth business, Lloydminster Conventional remains a consistent free cash flow generator for Strathcona, helping fund our thermal growth ambitions in Cold Lake and Lloydminster Thermal. 2025 was not a year to write home about, but for most of these assets’ 50+ year history they have been the gift that keeps on giving (including a very strong 2024), and we are confident the team can bounce back.

## 2. Profitability

Operating earnings from continuing operations were \$744 million or \$3.47 / share in 2025, down approximately 10% versus 2024. On a per barrel basis operating earnings from continuing operations fell from \$20.50 / bbl in 2024 to \$17.82 / bbl in 2025. These figures exclude \$186 million in operating earnings from our divested Montney business.

In evaluating profitability, we focus on operating earnings, which reflect the profits attributable to our shareholders after deducting *all* current and recurring costs including “non-cash” expenses such as depletion, depreciation and amortization (DD&A), finance expense, current income taxes, and (in the case of peers) stock-based compensation. While expenses like DD&A may be “non-cash” they are not “non-real”, particularly in a capital-intensive sector like ours. For peers who insist these costs aren’t relevant (and should be removed from preferred measures like EBITDA or debt-adjusted-cash-flow), we would be happy to enter into a deal where we paid their stock-based comp in cash in return for them covering our “non-cash” DD&A – any executive interested in this offer knows where to find us.

	<b>Production</b>	<b>Field Operating Income<sup>1</sup></b>	<b>G&amp;A</b>	<b>DD&amp;A</b>	<b>Interest and Finance</b>	<b>Current Income Tax</b>	<b>Operating Earnings</b>
	<i>(Mboe / d)</i>	<i>(\$mm)</i>	<i>(\$mm)</i>	<i>(\$mm)</i>	<i>(\$mm)</i>	<i>(\$mm)</i>	<i>(\$mm)</i>
2017	23	\$160	(\$21)	(\$136)	(\$42)	\$0	<b>(\$39)</b>
2018	32	\$208	(\$20)	(\$147)	(\$45)	\$0	<b>(\$3)</b>
2019	34	\$259	(\$15)	(\$167)	(\$46)	\$0	<b>\$31</b>
2020	52	\$227	(\$30)	(\$145)	(\$53)	\$0	<b>(\$1)</b>
2021	68	\$735	(\$44)	(\$184)	(\$64)	\$0	<b>\$443</b>
2022	114	\$1,746	(\$69)	(\$396)	(\$139)	\$0	<b>\$1,142</b>
2023	155	\$1,855	(\$92)	(\$733)	(\$282)	\$47	<b>\$795</b>
2024	183	\$2,203	(\$101)	(\$874)	(\$258)	\$0	<b>\$970</b>
<b>2025</b>	<b>152</b>	<b>\$1,925</b>	<b>(\$98)</b>	<b>(\$697)</b>	<b>(\$200)</b>	<b>\$0</b>	<b>\$930</b>
<i>24-Cont. Ops.</i>	<i>111</i>	<i>1,720</i>	<i>(\$76)</i>	<i>(\$595)</i>	<i>(\$220)</i>	<i>\$0</i>	<b>\$829</b>
<i>25-Cont. Ops.</i>	<i>115</i>	<b><i>\$1,626</i></b>	<b><i>(\$88)</i></b>	<b><i>(\$607)</i></b>	<b><i>(\$187)</i></b>	<b><i>\$0</i></b>	<b><i>\$744</i></b>

The decrease in operating margins year-over-year was primarily driven by lower Western Canada Select (WCS) prices. WCS declined \$8.47 / bbl year-over-year while operating earnings from continuing operations declined only \$2.68 / bbl, meaning lower royalties, operating costs, transportation costs, DD&A and interest costs per barrel helped blunt almost 70% of the impact of lower prices.

While there are large parts of our cost structure we do not control (such as royalties and per unit energy costs) we remain maniacally focused on those line items we can, the most important being non-energy operating costs. After seeing inflation in non-energy costs in the first half of 2025, each team took an “all-hands-on-deck” approach to re-thinking every aspect of our cost structure from the ground up. Early results from this effort are encouraging, with non-energy operating costs for the second half of 2025 down approximately 16% versus the first half of 2025.

	<b>WCS Hardisty</b>	<b>Field Operating Netback<sup>1</sup></b>	<b>G&amp;A</b>	<b>DD&amp;A</b>	<b>Interest and Finance</b>	<b>Current Income Tax</b>	<b>Operating Earnings<sup>1</sup></b>
	<i>(\$/bbl)</i>	<i>(\$/boe)</i>	<i>(\$/boe)</i>	<i>(\$/boe)</i>	<i>(\$/boe)</i>	<i>(\$/boe)</i>	<i>(\$/boe)</i>
2017	\$50.55	\$19.47	(\$2.61)	(\$16.48)	(\$5.06)	\$0.00	<b>(\$4.69)</b>
2018	\$49.84	\$17.70	(\$1.68)	(\$12.46)	(\$3.81)	\$0.00	<b>(\$0.25)</b>
2019	\$58.81	\$20.63	(\$1.22)	(\$13.30)	(\$3.66)	\$0.00	<b>\$2.45</b>
2020	\$35.61	\$11.92	(\$1.58)	(\$7.62)	(\$2.78)	\$0.00	<b>(\$0.06)</b>
2021	\$68.76	\$29.51	(\$1.76)	(\$7.41)	(\$2.57)	\$0.00	<b>\$17.77</b>
2022	\$98.50	\$41.87	(\$1.65)	(\$9.49)	(\$3.34)	\$0.00	<b>\$27.39</b>
2023	\$79.51	\$32.71	(\$1.62)	(\$12.93)	(\$4.96)	\$0.83	<b>\$14.03</b>
2024	\$83.53	\$32.89	(\$1.51)	(\$13.04)	(\$3.86)	\$0.00	<b>\$14.48</b>
<b>2025</b>	<b>\$75.06</b>	<b>\$34.66</b>	<b>(\$1.76)</b>	<b>(\$12.55)</b>	<b>(\$3.60)</b>	<b>\$0.00</b>	<b>\$16.74</b>
<i>24-Cont. Ops.</i>	<i>\$83.53</i>	<i>\$42.51</i>	<i>(\$1.88)</i>	<i>(\$14.70)</i>	<i>(\$5.43)</i>	<i>\$0.00</i>	<i>\$20.50</i>
<i>25-Cont. Ops.</i>	<b><i>\$75.06</i></b>	<b><i>\$38.86</i></b>	<b><i>(\$2.10)</i></b>	<b><i>(\$14.49)</i></b>	<b><i>(\$4.45)</i></b>	<b><i>\$0.00</i></b>	<b><i>\$17.82</i></b>

### 3. Capital Efficiency

Strathcona believes the best measure of its capital efficiency is its finding and development cost for proved developed producing reserves (“PDP F&D”). By comparing organic capital spending against organic PDP reserve additions, PDP F&D provides the best proxy for how much it costs to bring a barrel of undeveloped resource on-stream (at a 90% confidence level as determined by our third-party reserves evaluator). We operate in a highly capital-intensive industry, which means the efficiency of our capital programs will determine our future success. Metrics such as PDP F&D are therefore closely tracked at our offices and are the single biggest determinant of management’s incentive compensation. With that in mind, let’s see how we did this year.

In 2025, Strathcona’s PDP F&D, including changes in future developments costs, was \$21.24/bbl which, when combined with its 2025 operating netback of \$38.49/bbl, equated to a PDP recycle ratio of 1.8x. While our PDP F&D costs were up significantly (and our recycle ratio down) versus past years, this was almost entirely driven by major portions of our capital program which did not contribute to PDP bookings in 2025, but will in coming years.

Specifically, 2025 included approximately \$260 million in capital for Meota Central (which will not contribute to PDP until 2026) as well as a steam expansion at Meota West 2 (adding capacity but not current production). In addition, we invested approximately \$120 million in Cold Lake on various facility debottlenecking projects at Lindbergh and Tucker which will serve to increase total Cold Lake facility capacity to over 70 Mbbls/d by the end of 2026 but won’t add production until then. 2025 also saw us complete our Organic Rankin Cycle power project at Orion at a cost of approximately \$20 million, which lowers energy operating costs but doesn’t add barrels.

Normalizing for this approximately \$400 million in Meota Central and other facility expansion capital (but including capitalized G&A and other corporate capital), PDP F&D costs would have been approximately \$12.25/bbl in 2025, which we view as the best proxy for Strathcona’s sustaining capital per barrel. In turn, comparing this metric to our field operating netback results in a healthy “run rate” recycle ratio of 3.1x. 2025 was an unusually heavy year in “non-PDP adding” capital spending, and we expect our unadjusted PDP F&D in 2026 to improve, driven by Meota Central coming on stream.

	<b>Organic Capex<sup>1</sup></b>	<b>Change in PDP FDC<sup>2</sup></b>	<b>Organic PDP Additions<sup>3</sup></b>	<b>PDP F&amp;D<sup>4</sup></b>	<b>Organic Operating Netback<sup>1</sup></b>	<b>PDP Recycle Ratio<sup>5</sup></b>	<b>DD&amp;A</b>
	<i>(C\$mm)</i>	<i>(C\$mm)</i>	<i>(MMbbls)</i>	<i>(C\$/boe)</i>	<i>(C\$/boe)</i>	<i>(x)</i>	<i>(C\$/boe)</i>
2017	\$144	(\$10)	14	\$9.50	\$19.47	2.1x	\$16.47
2018	\$202	\$31	13	\$18.12	\$17.70	1.0x	\$12.50
2019	\$180	\$14	12	\$16.65	\$20.63	1.2x	\$13.26
2020	\$140	(\$5)	25	\$5.51	\$11.63	2.1x	\$8.01
2021	\$231	\$44	36	\$7.72	\$29.07	3.8x	\$7.98
2022	\$476	\$10	44	\$10.97	\$46.62	4.3x	\$9.55
2023	\$919	\$119	75	\$13.90	\$33.18	2.4x	\$12.88
2024	\$1,235	\$56	96	\$13.49	\$32.94	2.4x	\$13.06
<b>2025</b>	<b>\$901</b>	<b>(\$72)</b>	<b>39</b>	<b>\$21.24</b>	<b>\$38.49</b>	<b>1.8x</b>	<b>\$14.49</b>

Returning to our most important “non-cash” (but very real) expense of DD&A, our PDP F&D is informative here as well. Our DD&A of \$14.49 / boe in 2025 can be thought of as the estimated annual capital required to maintain our current earning power, which in turn can be decomposed into (1) how much capital is required to *convert* undeveloped reserves to production and (2) how much capital is required to *replace* those undeveloped reserves once produced. Our PDP F&D (normalized as above), therefore provides an estimate of the former (\$12.25 / bbl to convert undeveloped reserves to developed), with the remaining approximately \$2.25 / bbl roughly tracking what our historical acquisition cost of undeveloped reserves has been. While there is no guarantee we will be able to make future acquisitions at the same cost, the good news is we have more than 60-years of undeveloped resource remaining (discussed in more detail below) meaning we won’t have to worry about this for a while...

#### 4. Capital Allocation

We are big believers in the adage that it is better to look at what people do, not what they say, and nowhere is this more true than in regard to capital allocation. In 2025 we made some big calls regarding where we think the best returns on capital are, both now and in the future. While some of these moves may have appeared a little unorthodox, we promise there was a method to the madness.

On an organic basis, 2025 saw us invest approximately \$1.2 billion in our assets with approximately \$950 million attributable to our continuing operations excluding the Montney. Of this, approximately \$515 million was the capital required to sustain our existing production (approximately \$12.25 / bbl, as discussed above) and approximately \$435 million was allocated to growth. Our Lloydminster Thermal business accounted for the majority of this growth capital, with approximately \$260 million invested in Meota Central and the Meota West 2 expansion. The remaining approximately \$175 million of growth capital was invested in Cold Lake in a combination of facility projects at Lindbergh, Orion and Tucker as well as a major new SAGD well pair pad at Lindbergh. While this growth capital only contributed to approximately 5 Mbbls / d of production growth year-over-year, it is expected to contribute to exit production in 2026 of approximately 135 Mbbls / d, up 25 Mbbls / d (or 23%) versus 2024.

Since Strathcona was founded in 2017 investing in organic growth has gone in and out of fashion in the sector, with some maintaining that the goal of oil and gas companies should simply be to hold production flat, maximize current free cash flow (FCF), and pay it all out to shareholders. While we believe this may make sense for short reserve life businesses with poor drilling prospects, this is not the situation for Strathcona. To frame the opportunity as simply as possible, Strathcona has over 60 years' worth of undeveloped resource which we believe we can bring on stream at an average capital efficiency<sup>1</sup> of less than \$30,000/bbl/d, versus current peer trading multiples of more than \$100,000/bbl/d. When you can add production (and a lot of it) at less than 1/3 the cost of what that production is worth today, a large margin of safety exists.

Going forward, we will continue to allocate significant portions of our annual capital programs to organic growth, with a plan to grow to 200 Mbbls / d by 2031 and then to 300 Mbbls / d by 2035 (in each case a 10% CAGR). While it is true that this approach will inevitably reduce *near-term* FCF, we are willing to do so because we are confident it will be compensated for (and then some) by increased *long-term* FCF.

	<b>Funds from Operations<sup>1</sup></b>	<b>Capex</b>	<b>Decommissioning</b>	<b>FCF<sup>1</sup></b>	<b>A&amp;D<sup>6</sup></b>	<b>Distributions<sup>7</sup></b>
	<i>(\$mm)</i>	<i>(\$mm)</i>	<i>(\$mm)</i>	<i>(\$mm)</i>	<i>(\$mm)</i>	<i>(\$mm)</i>
2017	\$81	\$147	\$1	(\$67)	\$279	\$0
2018	\$104	\$206	\$2	(\$104)	\$332	\$0
2019	\$192	\$184	\$5	\$3	\$0	\$0
2020	\$183	\$141	\$7	\$35	\$731	\$0
2021	\$367	\$283	\$18	\$66	\$881	\$0
2022	\$1,234	\$621	\$23	\$590	\$3,838	\$0
2023	\$1,562	\$1,027	\$38	\$498	\$740	\$0
2024	\$1,937	\$1,296	\$36	\$605	\$41	\$107
<b>2025</b>	<b>\$1,594</b>	<b>\$1,186</b>	<b>\$44</b>	<b>\$364</b>	<b>(\$2,278)</b>	<b>\$2,391</b>

Turning to M&A, the first transaction we completed in 2025 was the acquisition of the Hardisty Rail Terminal (“HRT”) in April out of receivership for approximately \$45 million. HRT is the largest crude-by-rail terminal in Canada, with capacity of 262 Mbbls / d. While only 20% of this capacity is being utilized today, throughput should increase if heavy oil differentials widen in the future, meaning the fees HRT earns should serve as a natural hedge to Strathcona’s upstream earnings. We continue to like the crude-by-rail business in general, with Strathcona-owned terminals (HRT and Hamlin) accounting for approximately 85% of total Western Canadian crude-by-rail in 2025. Importantly, given the current optimism around egress out of the basin, we were able to acquire HRT at a deep discount to replacement cost and at an attractive FCF yield<sup>1</sup> of greater than 25% per annum, backstopped by a take-or-pay contract with an investment grade counterparty – a reminder that it is always better to buy straw hats in winter...

In May we made our biggest decision of the year, choosing to sell our Montney business unit for total value of approximately \$2.85 billion in three separate transactions. This was not a decision we made lightly, as we had experienced success growing the Montney to approximately 75 Mboe / d (from just 5 Mboe / d in 2017), and it was being run by a strong team led by President Al Grabas who we trusted. Ultimately, we determined that despite our scale we were still too small a fish in too big and competitive a pond, and that our next-door neighbors at each of our three assets (who happened to be the three largest gas producers in Canada), would be better able to maximize value from the properties going forward. While in this case we ultimately determined we could earn better returns by reinvesting the capital elsewhere, we still primarily think of ourselves as “builders” and not “traders”, and expect future divestitures to be few and far between.

Concerned the proceeds from our Montney sale may burn a hole in our pocket, the day after the sale was announced we made an offer to acquire MEG Energy for cash and shares (later varying to all shares). Our investment thesis was predicated on acquiring a high-quality asset we knew and understood well, and that combining the two largest remaining heavy oil pure plays would deliver meaningful synergies and accretion to both sets of shareholders. Direct-to-shareholder offers are inherently messy – more akin to political races where easy to digest fiction can matter just as much as actual fact – which can discourage bidders and support entrenchment. This was certainly the case with MEG, and while our offer was not universally popular in certain quarters in Calgary, to echo Teddy Roosevelt, “it is not the critic who counts... it is the man actually in the arena... face marred by dust and sweat and blood...”. While we came away from the MEG bid with more than a little dust and sweat on our brow (but no blood), we will not shy away from stepping back into the arena in the future if we believe taking a big swing can earn big returns for our shareholders. In the meantime, we are pleased our bid ultimately delivered a positive outcome for MEG shareholders (including for our 14.2% ownership position) and we have no doubt Cenovus will do an excellent job in improving operations. In the immortal words of Barry Diller after losing the battle for Paramount Pictures to Sumner Redstone in 1994, “They won. We lost. Next.”

“Next” for us was the acquisition of the Vawn project and undeveloped lands at Plover Lake and Glenbogie, which we closed in December for an upfront purchase price of \$75 million plus up to \$75 million in contingent consideration. The acquired assets are a hand-in-glove fit with Strathcona’s existing operations, with Vawn bringing approximately 5 Mbbls / d of production directly adjacent to our Edam project, sharing the same reservoir. With both halves of the same asset finally under one roof, we expect to achieve both higher production and lower costs (which we have already seen in our first few months of operations). In addition, we are even more excited by the acquired land at Plover and Glenbogie, which unlocks substantial resource across our asset base that was previously stranded due to being checkerboarded. On a combined basis the acquired assets are expected to increase our long-term production plateau by 40 Mbbls / d, making the acquisition far more than a MEG consolation prize.

Our final major capital allocation decision of the year was to use the proceeds from the Montney divestiture to fund a special distribution of \$10 / share, payable in either a return of capital or dividend, reflecting approximately 75% of the value of our divested Montney business. This left Strathcona with approximately \$2.1 billion of debt at year-end under our bank deal (giving us \$1.4 billion of liquidity). While opinions on the right amount of debt have waxed and waned over the past 9 years, we have always managed the balance sheet to approximately 20%-25% debt / 1P After Tax PV-10 and expect to continue to capitalize the business at this level going forward.

	<u>Shares Outstanding</u>	<u>Debt<sup>8</sup></u>	<u>1P PV-10, After-Tax</u>	<u>Debt / 1P PV-10 After-Tax</u>
	<i>(\$mm)</i>	<i>(\$mm)</i>	<i>(\$mm)</i>	<i>(\$mm)</i>
2017	62.9	\$286	\$1,286	22%
2018	78.1	\$390	\$1,838	21%
2019	78.1	\$422	\$1,794	24%
2020	130.7	\$505	\$2,550	20%
2021	173.6	\$912	\$5,653	16%
2022	195.2	\$3,010	\$12,455	24%
2023	214.2	\$2,665	\$13,616	20%
2024	214.2	\$2,462	\$11,888	21%
<b>2025</b>	<b>214.2</b>	<b>\$2,095</b>	<b>\$8,960</b>	<b>23%</b>

## 5. Long-Term Resource Capture

Much of our discussion thus far has focused on the operating and financial results looking *backward* to 2025; our year-end reserves, on the other hand, help us look *forward*. Normalizing for the disposition of our Montney business, PDP, 1P and 2P reserves grew 2%, 5% and 7% respectively in 2025, bringing our 2P reserve life index to 51 years based on Q4 2025 production – the highest it has been since 2021 and the longest of any oil company of scale in North America. In addition, we also hold 16 years of 2C best estimate contingent resources (unrisked) that is waiting on the shelf to be converted to 2P over time.

While Strathcona often gets incorrectly labeled as a business which has grown only through acquisition, it is important to note that organic growth has been part of our strategy since day 1, with 2025 being no exception. While PDP reserves were approximately flat year-over-year (for the reasons mentioned in our discussion of PDP F&D), 1P reserves grew 1% and 2P reserves 4% on an organic basis, replacing 297% production (our best organic reserve replacement since 2021).

Organic additions<sup>9</sup> were also supported by positive technical revisions across all categories, meaning that last year's reserves forecast proved conservative – a trend we hope continues. Going all the way back to our founding in 2017, PDP, 1P and 2P reserves have now grown at a CAGR of 5%, 7% and 6% on a pure organic basis.

	PDP Growth / Share			1P Growth / Share			2P Growth / Share		
	Organic <sup>10</sup>	A&D <sup>11</sup>	Total <sup>12</sup>	Organic <sup>10</sup>	A&D <sup>11</sup>	Total <sup>12</sup>	Organic <sup>10</sup>	A&D <sup>11</sup>	Total <sup>12</sup>
	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)
2017	12%	(38%)	(26%)	20%	1%	20%	9%	17%	26%
2018	2%	(15%)	(14%)	14%	3%	17%	-	7%	6%
2019	(1%)	-	(1%)	4%	-	4%	7%	-	7%
2020	8%	(21%)	(13%)	22%	39%	61%	17%	24%	41%
2021	10%	(2%)	8%	4%	(6%)	(2%)	9%	26%	35%
2022	2%	55%	57%	1%	41%	42%	1%	23%	24%
2023	7%	12%	19%	1%	0%	1%	2%	(2%)	1%
2024	8%	-	8%	3%	-	3%	2%	-	2%
2025	(1%)	(33%)	(34%)	1%	(21%)	(20%)	4%	(22%)	(18%)
<b>25-Cont. Ops.</b>	<b>(1%)</b>	<b>3%</b>	<b>2%</b>	<b>1%</b>	<b>3%</b>	<b>5%</b>	<b>4%</b>	<b>3%</b>	<b>7%</b>
<b>CAGR</b>	<b>5%</b>			<b>7%</b>			<b>6%</b>		

The large gains to our 2P reserves book this year were primarily attributable to an extension of our Plover Lake project in Lloydminster Thermal following new delineation and geotechnical work, adding 40 MMbbls to 2P (and 120 MMbbls to 2C). We also converted approximately 35 MMbbls of 2C resource to 2P reserves at Orion, through a recent delineation program which expanded the approved project area. While we will always be on the look-out for acquisitions to add reserves (such as our recent acquisition of a 50% operated interest in the Selina project near Lindbergh), the delineation and exploration programs our geologists undertake every year will typically be cheaper, and therefore our first choice.

	RLI <sup>13</sup>			Organic 2P Replacement <sup>14</sup>	PDP % of 2P
	1P	2P	2C		
	(Years)	(Years)	(Years)	(%)	(%)
2017	19	33		238%	24%
2018	18	29		98%	19%
2019	19	32		309%	18%
2020	30	44		467%	11%
2021	31	62	28	437%	9%
2022	26	45	18	136%	11%
2023	22	38	14	199%	13%
2024	22	39	15	165%	14%
<b>2025</b>	<b>29</b>	<b>51</b>	<b>16</b>	<b>297%</b>	<b>11%</b>

## 6. Intrinsic and Market Value

Strathcona’s net asset value, as measured by its 1P and 2P PV-10 *after-tax* and net of debt, decreased 2% and 11% respectively in 2025, inclusive of distributions. Relative to Strathcona’s 214 million shares outstanding, this equates to an after-tax NAV of approximately \$32 / share on a 1P basis and \$50 / share on a 2P basis.

The decrease in NAV this year was primarily due to a reduction in the third-party reserves evaluator price deck by approximately US\$10 / bbl (now starting at approximately US\$60 / bbl WTI and increasing to US\$68 / bbl on a real basis long-term). Remarkably, after nine years of ups and downs, the reserve evaluator price deck is now roughly back to where it was when we made our initial investments in 2017 (when it started at an initial WTI price of US\$58/bbl, increasing to US\$67/bbl long-term).

The consistency in price deck between year-end 2017 and year-end 2025 highlights that our long-term compound annual growth rates in 1P and 2P NAV of 13% and 14% haven’t come from oil price increases, but rather *almost entirely* by growing production, adding reserves and improving margins. For those who think we are brilliant “market timers” who went all-in when oil was cheap, this simply isn’t the case (although we certainly wish it was, as would have made a lot more money...).

Also contributing to our changes in NAV was our busy year on M&A. The divestiture of our Montney business was completed at an approximately 10% discount to after-tax 2P PV-10 (based on YE 2024’s *higher* price deck) while our Vawn acquisition added approximately \$700 million in after-tax 2P PV-10 (based on YE 2025’s *lower* price deck). Importantly, only a very small portion of the acquired undeveloped thermal lands at Plover Lake and Glenbogie are booked to 2P at YE 2025, implying there is significant additional value to be added in coming years.

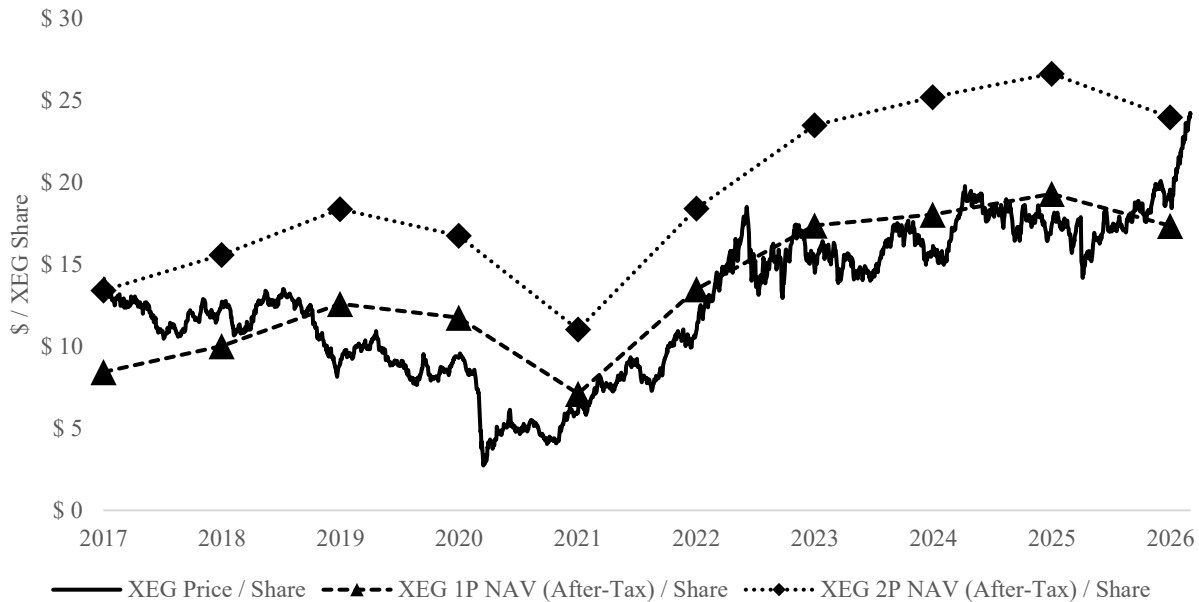
	Year-End / Annual			After-Tax PV-10		Change in NAV/Share, incl. Distributions		Reserves Price Deck (WTI) <sup>17</sup> (US\$/bbl)
	Shares <sup>15,16</sup>	Debt <sup>8</sup>	Distributions <sup>7</sup>	1P	2P	1P	2P	
	(mm)	(\$mm)	(\$mm)	(\$mm)	(\$mm)	(%)	(%)	
2017	62.9	\$286		\$1,286	\$1,963			\$58.13
2018	78.1	\$390		\$1,838	\$2,719	17%	12%	\$63.00
2019	78.1	\$422		\$1,794	\$2,653	(5%)	(4%)	\$61.00
2020	130.7	\$505		\$2,550	\$3,758	(11%)	(13%)	\$46.00
2021	173.6	\$912		\$5,653	\$8,438	74%	74%	\$73.00
2022	195.2	\$3,010		\$12,455	\$17,908	77%	76%	\$86.00
2023	214.2	\$2,665		\$13,616	\$19,329	6%	2%	\$76.00
2024	214.2	\$2,462	\$107	\$11,888	\$17,069	(13%)	(12%)	\$71.58
<b>2025</b>	<b>214.2</b>	<b>\$2,095</b>	<b>\$2,391</b>	<b>\$8,960</b>	<b>\$12,692</b>	<b>(2%)</b>	<b>(11%)</b>	<b>\$59.92</b>
<b>CAGR</b>						<b>13%</b>	<b>14%</b>	

Moving to a brief discussion of the market environment, 2025 saw the beginning of an increase in sector valuations, with the S&P/TSX energy index (XEG) up 12% in 2025 despite WTI prices closing 20% down. While this may appear counterintuitive, if you believe as we do that businesses are worth the sum of the cash they will produce between now and judgement day, discounted to the present at a reasonable rate, then the discounted cash flows contained in company year-end reserve reports provide part of the answer.

Looking at the chart below which plots the S&P/TSX energy index (daily) against its constituent companies 1P and 2P NAVs after-tax (annually) since Strathcona was founded in 2017, some interesting takeaways emerge. First, while there has been lots of volatility, stock prices have closely tracked NAV over time, trading roughly in-line with 1P NAV over the past 5 years. Second, valuations have recently become unmoored from this trend, with companies now on average trading at a slight premium to their 2P NAV for the first time since 2017.

While it is impossible to know for sure what has caused this “re-rating”, one of two things must be true: (1) investors are now willing to accept a smaller margin of safety when valuing future cash flows (moving from the 90% confidence level inherent in 1P reserves to the 50% confidence level of 2P reserves), or (2) investors expect future cash flows to exceed what is booked in current reserves reports, perhaps because oil prices will increase from 2025 levels.

**S&P/TSX Energy Index (XEG) Share Price vs. 1P and 2P NAV (After-Tax)<sup>18</sup>**



With the valuations of our peers implying an approximately \$50 Strathcona share price, we are reminded of legendary oilman T. Boone Pickens’ line that sometimes it is “cheaper to drill for oil on the floor of the New York Stock Exchange than in the ground.” Setting aside *relative* valuation and focusing on *absolute* value, buying more of a business we know and understand well (our own) at a large discount to a reserves value predicated on WTI prices in the mid US\$60s appears attractive to us.

While in the past we have been unable to take advantage of the relative discount we have traded at due to our small float and low average daily trading volumes – which both limited the size of the opportunity and made a buyback self-defeating – this has improved in recent months, with Strathcona’s daily trading volumes recently averaging more than \$30 million per day (up from a meager \$1 to \$2 million per day when we first went public). With volumes up, our shackles are now off and we have a new tool in our capital allocation tool kit.

We intend to initiate our first normal course issuer bid (NCIB) in coming weeks, for up to 5% of shares outstanding. In allocating capital to the NCIB, our intent is to do so sporadically and opportunistically, rather than following a formula as a percent of free cash flow like has become popular (the best time to buy our shares will be when we have *no* free cash flow...). In all cases, we will seek to make repurchases when we view our stock as discounted to our intrinsic value, conservatively determined and then applying a margin of safety.

**7. Conclusion**

2025 was a pivotal year for Strathcona, one in which we chose to move on from a Montney business which had been a big part of our history and double-down on heavy oil assets which will propel our future. 2026 will mark our 10<sup>th</sup> year of operations and it is already off to a turbulent start with war in the Middle East reminding markets of oil’s global importance. While we have no idea what this year holds for markets or geopolitics, we know that if we maintain our focus on profitability, capital efficiency and prudent capital allocation, good things should happen.

Following the retirement of our US\$ senior unsecured notes in December we no longer have a requirement to hold quarterly conference calls and instead will focus our shareholder communication efforts on best-in-class quarterly financial and operating disclosure, annual shareholder meetings, and this annual letter. We look forward to reporting back to you next year on Strathcona’s progress.

Signed  
Adam Waterous, Executive Chairman

Signed  
Connor Waterous, Chief Financial Officer

**Appendix A: Reconciliation of Changes in Reserves Since 2016**

	<b>PDP</b> <i>(MMboe)</i>	<b>1P</b> <i>(MMboe)</i>	<b>2P</b> <i>(MMboe)</i>
<b>YE 2016</b>	51.2	75.4	127.7
Organic Additions <sup>9</sup>	14.2	23.0	19.6
Acquisitions / Dispositions <sup>6</sup>	9.2	68.8	142.7
Production	(8.2)	(8.2)	(8.2)
<b>YE 2017</b>	<b>66.4</b>	<b>159.0</b>	<b>281.7</b>
Organic Additions <sup>9</sup>	12.9	34.6	11.6
Acquisitions / Dispositions <sup>6</sup>	3.7	49.6	90.9
Production	(11.8)	(11.8)	(11.8)
<b>YE 2018</b>	<b>71.2</b>	<b>231.3</b>	<b>372.4</b>
Organic Additions <sup>9</sup>	11.7	20.7	38.8
Acquisitions / Dispositions <sup>6</sup>	0.1	0.1	0.1
Production	(12.5)	(12.5)	(12.5)
<b>YE 2019</b>	<b>70.4</b>	<b>239.6</b>	<b>398.8</b>
Organic Additions <sup>9</sup>	24.6	70.9	88.8
Acquisitions / Dispositions <sup>6</sup>	26.0	353.1	474.7
Production	(19.0)	(19.0)	(19.0)
<b>YE 2020</b>	<b>102.0</b>	<b>644.6</b>	<b>943.2</b>
Organic Additions <sup>9</sup>	35.6	51.3	108.8
Acquisitions / Dispositions <sup>6</sup>	34.3	169.9	665.4
Production	(24.9)	(24.9)	(24.9)
<b>YE 2021</b>	<b>147.0</b>	<b>840.9</b>	<b>1,692.5</b>
Organic Additions <sup>9</sup>	44.3	47.0	56.9
Acquisitions / Dispositions <sup>6</sup>	110.0	493.4	652.2
Production	(41.7)	(41.7)	(41.7)
<b>YE 2022</b>	<b>259.6</b>	<b>1,339.6</b>	<b>2,359.9</b>
Organic Additions <sup>9</sup>	74.7	71.2	113.1
Acquisitions / Dispositions <sup>6</sup>	61.2	134.5	195.8
Production	(56.7)	(56.7)	(56.7)
<b>YE 2023</b>	<b>338.8</b>	<b>1,488.6</b>	<b>2,612.1</b>
Organic Additions <sup>9</sup>	95.7	112.8	110.2
Acquisitions / Dispositions <sup>6</sup>	-	(0.4)	(0.5)
Production	(67.0)	(67.0)	(67.0)
<b>YE 2024</b>	<b>367.4</b>	<b>1,534.0</b>	<b>2,654.8</b>
Organic Additions <sup>9</sup>	39.1	58.1	124.3
Acquisitions / Dispositions <sup>6</sup>	(123.4)	(324.6)	(571.1)
Production	(41.8)	(41.8)	(41.8)
<b>YE 2025</b>	<b>241.3</b>	<b>1,225.7</b>	<b>2,166.2</b>
<b>YE 2016</b>	51.2	75.4	127.7
Organic Additions <sup>9</sup>	352.7	489.6	672.1
Acquisitions / Dispositions <sup>6</sup>	121.1	944.4	1,650.1
Production	(283.7)	(283.7)	(283.7)
<b>YE 2025</b>	<b>241.3</b>	<b>1,225.7</b>	<b>2,166.2</b>

## Appendix B: Detailed Reconciliation of Changes in Reserves Since 2016

MMboe	Proved			Proved plus Probable		
	Cona	Strath	Combined/ Strathcona	Cona	Strath	Combined/ Strathcona
<b>December 31, 2016</b>	<b>75.4</b>	-	<b>75.4</b>	<b>127.7</b>	-	<b>127.7</b>
Extensions, improved recovery and infill drilling	8.0	9.4	17.4	7.7	11.5	19.2
Technical revisions	6.7	-	6.7	1.9	-	1.9
Discoveries	-	-	-	-	-	-
Economic factors	(1.1)	-	(1.1)	(1.4)	-	(1.4)
Acquisitions	-	68.9	68.9	-	142.8	142.8
Dispositions	(0.1)	-	(0.1)	(0.1)	-	(0.1)
Production	(6.3)	(2.0)	(8.3)	(6.3)	(2.0)	(8.3)
<b>December 31, 2017</b>	<b>82.7</b>	<b>76.3</b>	<b>159.0</b>	<b>129.4</b>	<b>152.4</b>	<b>281.8</b>
Extensions, improved recovery and infill drilling	17.9	9.3	27.2	24.3	35.3	59.6
Technical revisions and economic factors	19.5	(12.2)	7.3	5.1	(53.2)	(48.1)
Discoveries	-	-	-	-	-	-
Acquisitions	3.0	53.4	56.4	10.7	90.1	100.8
Dispositions	(6.9)	-	(6.9)	(10.0)	-	(10.0)
Production	(5.8)	(6.0)	(11.8)	(5.8)	(6.0)	(11.8)
<b>December 31, 2018</b>	<b>110.4</b>	<b>120.9</b>	<b>231.3</b>	<b>153.7</b>	<b>218.7</b>	<b>372.4</b>
Extensions, improved recovery and infill drilling	1.1	4.2	5.3	2.2	23.7	25.9
Technical revisions and economic factors	8.7	6.8	15.5	7.6	5.3	12.9
Discoveries	-	-	-	-	-	-
Acquisitions	0.1	-	0.1	0.1	-	0.1
Dispositions	-	-	-	-	-	-
Production	(5.0)	(7.5)	(12.5)	(5.0)	(7.5)	(12.5)
<b>December 31, 2019</b>	<b>115.3</b>	<b>124.3</b>	<b>239.6</b>	<b>158.6</b>	<b>240.1</b>	<b>398.7</b>
Extensions and improved recovery	7.5	-	7.5	17.5	-	17.5
Technical revisions	24.4	36.1	60.5	17.8	53.5	71.3
Discoveries	-	-	-	-	-	-
Economic factors	(4.5)	-	(4.5)	(9.7)	-	(9.7)
Infill drilling	7.4	-	7.4	9.7	-	9.7
Acquisitions	508.4	(155.3)	353.1	763.2	(288.5)	474.7
Dispositions	-	-	-	-	-	-
Production	(13.9)	(5.1)	(19.0)	(13.9)	(5.1)	(19.0)
<b>December 31, 2020<sup>19</sup></b>	<b>644.6</b>	-	<b>644.6</b>	<b>943.2</b>	-	<b>943.2</b>
Extensions and improved recovery	-	-	2.3	-	-	16.6
Technical revisions	-	-	26.6	-	-	46.0
Discoveries	-	-	-	-	-	-
Economic factors	-	-	14.7	-	-	27.4
Infill drilling	-	-	7.6	-	-	18.9
Acquisitions	-	-	178.2	-	-	692.9
Dispositions	-	-	(8.3)	-	-	(27.5)
Production	-	-	(24.9)	-	-	(24.9)
<b>December 31, 2021</b>	-	-	<b>840.9</b>	-	-	<b>1,692.5</b>
Extensions and improved recovery	-	-	26.1	-	-	36.2
Technical revisions	-	-	(21.1)	-	-	(31.4)
Discoveries	-	-	-	-	-	-
Economic factors	-	-	13.1	-	-	26.4
Infill drilling	-	-	28.9	-	-	25.6
Acquisitions	-	-	493.4	-	-	652.2
Dispositions	-	-	-	-	-	-
Production	-	-	(41.7)	-	-	(41.7)
<b>December 31, 2022</b>	-	-	<b>1,339.6</b>	-	-	<b>2,359.9</b>
Extensions and improved recovery	-	-	49.8	-	-	81.6
Technical revisions	-	-	8.2	-	-	29.6
Discoveries	-	-	-	-	-	-
Economic factors	-	-	0.8	-	-	(0.1)
Infill drilling	-	-	12.5	-	-	2.1
Acquisitions	-	-	134.5	-	-	195.8
Dispositions	-	-	-	-	-	-
Production	-	-	(56.7)	-	-	(56.7)
<b>December 31, 2023</b>	-	-	<b>1,488.6</b>	-	-	<b>2,612.1</b>
Extensions and improved recovery	-	-	53.2	-	-	52.5
Technical revisions	-	-	61.0	-	-	60.8
Discoveries	-	-	-	-	-	-
Economic factors	-	-	(1.4)	-	-	(3.1)
Infill drilling	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	(0.4)	-	-	(0.5)
Production	-	-	(67.0)	-	-	(67.0)
<b>December 31, 2024</b>	-	-	<b>1,534.0</b>	-	-	<b>2,654.8</b>
Extensions and improved recovery	-	-	16.4	-	-	86.5
Technical revisions	-	-	43.8	-	-	39.5
Discoveries	-	-	-	-	-	-
Economic factors	-	-	(2.3)	-	-	(2.9)
Infill drilling	-	-	-	-	-	-
Acquisitions	-	-	41.1	-	-	65.8
Dispositions	-	-	(351.7)	-	-	(622.1)
Production	-	-	(55.5)	-	-	(55.5)
<b>December 31, 2025</b>	-	-	<b>1,225.7</b>	-	-	<b>2,166.2</b>

## **Presentation of Reserves and Other Oil and Gas Information**

*In respect of 2025, Strathcona's reserves have been evaluated in accordance with Canadian reserve evaluation standards under National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“Canadian NI 51-101 Standards”). McDaniel & Associates Consultants Ltd., an independent petroleum consulting firm based in Calgary, Alberta, has evaluated the petroleum and natural gas reserves associated with all of Strathcona's properties as at December 31, 2025 dated March 3, 2026.*

*In respect of 2016, information disclosed herein is derived from the PNG reserves evaluation of NBRI prepared by Ryder Scott as at December 31, 2016 dated January 27, 2017. In respect of 2017, information disclosed herein is derived from the addition of the PNG reserves evaluation of Cona performed by Ryder Scott as at December 31, 2017 dated January 26, 2018 and the PNG reserves evaluation of Strath performed by McDaniel as at December 31, 2017 dated March 23, 2018. In respect of 2018, information disclosed herein is derived from the addition of PNG reserves evaluation of Cona performed by Ryder Scott as at December 31, 2018 dated February 19, 2019 and the PNG reserves evaluation of Strath performed by McDaniel as at December 31, 2018 dated March 15, 2019. In respect of 2019, information disclosed herein is derived from the addition of PNG reserves evaluation of Cona performed by Sproule as at December 31, 2019 dated February 12, 2020 and the PNG reserves evaluation of Strath performed by McDaniel as at December 31, 2019 dated March 16, 2020. In respect of 2020, information disclosed herein is derived from the PNG reserves evaluation of Strathcona performed by Sproule as at December 31, 2020 dated February 25, 2021, as adjusted by Strathcona (Refer to the Appendix B for further details). In respect of 2021, information disclosed herein is derived from the PNG reserves evaluation of Strathcona performed by Sproule as at December 31, 2021 dated February 23, 2022. In respect of 2022, information disclosed herein is derived from the addition of PNG reserves evaluation of Strathcona performed by Sproule as at December 31, 2022 dated February 23, 2023 and PNG reserves evaluation of Strathcona by McDaniel as at December 31, 2022 dated February 1, 2023 and February 14, 2023. In respect of 2023, information disclosed herein is derived from the addition of PNG reserves evaluation of Strathcona performed by Sproule as at December 31, 2023 dated March 11, 2024 and PNG reserves evaluation of Strathcona by McDaniel as of December 31, 2023 dated March 11, 2024. In respect of 2024, Strathcona's reserves have been evaluated in accordance with Canadian reserve evaluation standards under National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“Canadian NI 51-101 Standards”). McDaniel & Associates Consultants Ltd., an independent petroleum consulting firm based in Calgary, Alberta, has evaluated the petroleum and natural gas reserves associated with all of Strathcona's properties as at December 31, 2024 dated March 4, 2025. Refer to the Appendix B for further details.*

*Reserves volumes and net present values of future net revenue for periods prior to 2024 have been calculated using the forecast prices and costs of the applicable qualified reserves evaluator as at the year-end dates of their respective report. These price decks may not be consistent among the different evaluators.*

*The foregoing metrics do not have any standardized meanings or definitions and may not be comparable with the calculations of similar metrics of other entities.*

*Complete disclosure of our oil and gas reserves and other oil and gas information presented in accordance with Canadian NI 51-101 Standards can be found in our Annual Information Form for the year ended December 31, 2025 (the "AIF"), which will be available on our website at [www.strathconaresources.com](http://www.strathconaresources.com) and under our SEDAR+ profile at [www.sedarplus.ca](http://www.sedarplus.ca). Readers are also urged to review the audited financial statements for the year ended December 31, 2025 and related management's discussion & analysis for more complete disclosure on our operations.*

## **Specified Financial Measures**

### **Non-GAAP and Other Financial Measures and Ratios**

Non-GAAP financial measures and ratios are used internally by management to assess the performance of the Company. They also provide investors with meaningful metrics to assess the Company's performance compared to other companies in the same industry. However, the Company's use of these terms may not be comparable to similarly defined measures presented by other companies. Investors are cautioned that these measures should not be construed as an alternative to financial measures determined in accordance with GAAP and these measures should not be considered to be more meaningful than GAAP measures in evaluating the Company's performance.

*Presentation of Continuing and Discontinued Operations*

During the year ended December 31, 2025 the Company entered into three separate asset purchase and sale agreements to dispose of its Montney assets which has been presented in the Company's consolidated financial statements and management's discussion and analysis for the three months and year ended December 31, 2025 and 2024 as discontinued operations. The historical financial and operating results for the year ended December 31, 2025 and 2024 have been presented throughout this shareholder letter based on the aggregation of continuing and discontinued operations. The aggregation of continuing and discontinued financial results are non-GAAP measures and do not have a standardized meaning under IFRS® Accounting Standards (the "Accounting Standards");

The financial results for the year ended December 31, 2025 and December 31, 2024, are presented below to reconcile continuing and discontinued operations to total results. Total results in a non-GAAP measure used by Management to assess the historical financial performance of the total business and is not intended to be indicative of future results.

(\$ millions, unless otherwise indicated)	Year Ended December 31, 2025			Year Ended December 31, 2024		
	Continuing	Discontinued	Total	Continuing	Discontinued	Total
<b>Revenues and other income</b>						
Oil and natural gas sales	4,096	521	<b>4,617</b>	4,373	963	<b>5,336</b>
Sale of purchased product	67	—	<b>67</b>	75	—	<b>75</b>
Royalties	(435)	(35)	<b>(470)</b>	(567)	(96)	<b>(663)</b>
Oil and natural gas revenues	3,728	486	<b>4,214</b>	3,881	867	<b>4,748</b>
Loss on risk management contracts	(86)	—	<b>(86)</b>	(44)	—	<b>(44)</b>
Midstream revenue	24	—	<b>24</b>	—	—	<b>—</b>
Other income	16	—	<b>16</b>	—	—	<b>—</b>
	3,682	486	<b>4,168</b>	3,837	867	<b>4,704</b>
<b>Expenses</b>						
Purchased product	68	—	<b>68</b>	75	—	<b>75</b>
Blending costs	1,034	—	<b>1,034</b>	1,081	—	<b>1,081</b>
Production and operating	672	76	<b>748</b>	641	171	<b>812</b>
Transportation and processing	368	111	<b>479</b>	364	213	<b>577</b>
General and administrative	88	10	<b>98</b>	76	25	<b>101</b>
Interest	131	—	<b>131</b>	170	—	<b>170</b>
Transaction related costs	44	27	<b>71</b>	1	—	<b>1</b>
Finance costs	56	13	<b>69</b>	50	38	<b>88</b>
Depletion, depreciation and impairment	607	90	<b>697</b>	595	279	<b>874</b>
Foreign exchange (gain) loss	(34)	—	<b>(34)</b>	68	—	<b>68</b>
Change in decommissioning	(13)	—	<b>(13)</b>	—	—	<b>—</b>
	3,397	327	<b>3,724</b>	3,121	726	<b>3,847</b>
Gain on marketable securities	171	—	<b>171</b>	—	—	<b>—</b>
Gain on sale of assets, net	—	609	<b>609</b>	—	—	<b>—</b>
Loss on settlement of other	—	(1)	<b>(1)</b>	—	(4)	<b>(4)</b>
<b>Income before income taxes</b>	456	767	<b>1,223</b>	716	137	<b>853</b>
Income tax expense	90	222	<b>312</b>	209	40	<b>249</b>
<b>Income and comprehensive income</b>	366	545	<b>911</b>	507	97	<b>604</b>

"**Field Operating Income**" and "**Field Operating Netback**" are common metrics used in the oil and natural gas industry to assess the profitability and efficiency of the Company's field operations. Field operating netback is calculated as field operating income divided by sales volumes.

(\$ millions, unless otherwise indicated)	Year Ended	
	December 31, 2025	December 31, 2024
<b>Revenues</b>		
Oil and natural gas sales	4,617	5,336
Sale of purchased product	67	75
Blending costs	(1,034)	(1,081)
Purchased product	(68)	(75)
Midstream revenue	24	—
<b>Oil and natural gas sales, net of blending</b>	<b>3,606</b>	<b>4,255</b>
<b>Expenses</b>		
Royalties	470	663
Production and operating	748	812
Transportation and processing	479	577
<b>Field operating income<sup>(1)</sup></b>	<b>1,909</b>	<b>2,203</b>
<b>Field operating netback</b>	<b>34.66</b>	<b>32.89</b>

(1) Field operating income presented in this shareholder letter includes other income of \$16 million for the year ended December 31, 2025.

"**Operating Earnings - Discontinued**" is considered a key financial metric for evaluating the profitability of Strathcona's discontinued business. "**Operating Earnings - Continuing**" is a GAAP financial measure as it is used by the Company's CODMs to evaluate profit or loss and is presented in the annual financial statements.

A quantitative reconciliation of Operating Earnings - Discontinued to the most directly comparable GAAP financial measure, Oil and natural gas sales, is set forth below.

(\$ millions, unless otherwise indicated)	Year Ended	
	December 31, 2025	December 31, 2024
<b>Revenues</b>		
Oil and natural gas sales	521	963
<b>Expenses</b>		
Royalties	35	96
Production and operating - Energy	—	7
Production and operating - Non-energy	76	164
Transportation and processing	111	213
Depletion, depreciation and amortization	90	279
General and administrative	10	25
Finance costs	13	38
<b>Operating Earnings - Discontinued</b>	<b>186</b>	<b>141</b>

"**Funds from Operations**" is used by management to analyze operating performance and provides an indication of the funds generated by Strathcona's principal business to either fund operating activities, re-invest to either maintain or grow the business or make debt repayments. Funds from Operations is derived from Operating Earnings and adjusted for DD&A, finance costs, gains and losses on risk management contracts – realized and gains and losses on foreign exchange - realized, operating.

"Free Cash Flow" indicates funds available for deleveraging, funding future growth, or shareholder returns. Free Cash Flow is derived from Operating Earnings and adjusted for DD&A, finance costs, gains and losses on risk management contracts – realized and gains and losses on foreign exchange - realized, operating, capital expenditures and decommissioning costs.

Quantitative reconciliations of Funds from Operations and Free Cash Flow for both continuing and discontinued operations to the most directly comparable GAAP financial measure, Operating Earnings, are set forth below.

(\$ millions, unless otherwise indicated)	Year Ended	
	December 31, 2025	December 31, 2024
<b>Operating Earnings - Continuing</b>	744	829
Depletion, depreciation and amortization	607	595
Finance costs	56	50
Loss on risk management contracts - realized	(100)	(107)
Foreign exchange gain (loss) - realized, operating	(2)	—
<b>Funds from Operations - Continuing</b>	<b>1,305</b>	1,367
Capital expenditures	(957)	(826)
Decommissioning costs	(42)	(15)
<b>Free Cash Flow - Continuing</b>	<b>306</b>	526

(\$ millions, unless otherwise indicated)	Year Ended	
	December 31, 2025	December 31, 2024
<b>Operating Earnings - Discontinued</b>	186	141
Depletion, depreciation and amortization	90	279
Finance costs	13	38
Realized loss on deferred premium settlement	—	112
<b>Funds from Operations - Discontinued</b>	<b>289</b>	570
Capital expenditures	(229)	(470)
Decommissioning costs	(2)	(21)
<b>Free Cash Flow - Discontinued</b>	<b>58</b>	79

The following table reconciles operating earnings, funds from operations and free cash flow from continuing and discontinued operations:

(\$ millions, unless otherwise indicated)	Year Ended	
	December 31, 2025	December 31, 2024
<b>Operating Earnings</b>	930	970
Depletion, depreciation and amortization	697	874
Finance costs	69	88
Loss on risk management contracts - realized	(100)	(107)
Foreign exchange gain (loss) - realized, operating	(2)	—
Realized loss on deferred premium settlement	—	112
<b>Funds from Operations</b>	<b>1,594</b>	1,937
Capital expenditures	(1,186)	(1,296)
Decommissioning costs	(44)	(36)
<b>Free Cash Flow</b>	<b>364</b>	605

"Capital Efficiency" is calculated as capital expenditures related to a specific field or project, divided by the incremental production resulting from those expenditures. Management uses capital efficiency to evaluate which capital projects yield the most productive use of funds.

“Free Cash Flow Yield” is a non-GAAP financial ratio calculated as the estimated annual Free Cash Flow generated an asset divided by the purchase price paid at acquisition. This measure is used to illustrate the expected return on capital deployed for a transaction.

“Organic Operating Netback” is used to assess the profitability and efficiency of Strathcona's field operations before the impact of acquisitions.

The following table reconciles “Organic Operating Netback” to the nearest GAAP measure which is "Oil and natural gas sales”:

(\$ millions, unless otherwise indicated)	Year Ended December 31, 2025
Oil and natural gas sales	4,096
Sales of purchased products	67
Purchased product	(68)
Blending costs	(1,034)
Midstream revenue	(24)
<b>Oil and natural gas sales, net of blending - Continuing</b>	<b>3,085</b>
Royalties	435
Production and operating	672
Transportation and processing	368
<b>Field Operating Income – Continuing</b>	<b>1,610</b>
Less: Operating income from properties acquired in the year	(14)
<b>Organic Field Operating Income</b>	<b>1,596</b>
Sales volumes (boe/d)	114,763
Less: sales volumes from properties acquired in the year (boe/d)	(479)
<b>Organic Sales volumes (boe/d)</b>	<b>114,284</b>
<b>Organic Operating Netback (\$/boe)</b>	<b>38.49</b>

“Organic Capex” is defined as total property, plant and equipment expenditures, excluding capitalized overhead, expenditures on corporate assets, and capital expenditures on assets acquired during the period. Management uses Organic Capex to evaluate the underlying capital investment in Strathcona’s existing asset base, excluding the effects of acquisitions and non-operational capital. This measure provides insight into the Company’s capital efficiency. Per Strath, Cona and Strathcona annual financial statements, adjusted for spending on properties acquired in the respective year by Strathcona.

The following table reconciles “Organic Capex” to the nearest GAAP measure which is “Property, plant and equipment expenditures”:

(\$ millions)	Year Ended December 31, 2025
Property, plant and equipment expenditures	1,186
Less: capitalized overhead	(49)
Less: expenditures on corporate assets	(7)
Less: property, plant and equipment expenditures on assets acquired in the year	-
Less: property, plant and equipment expenditures on assets disposed of in the year	(229)
<b>Organic Capex</b>	<b>901</b>

### Product Type Production and Reserve Information

The Company's annual average daily production volumes, and the references to "total liquids" reported in this shareholder letter consist of the following product types, as defined in NI 51-101 and using a conversion ratio of 6 mcf : 1 bbl where applicable:

	Year Ended	
	December 31, 2025	December 31, 2024
Heavy crude oil (bbl/d)	52,658	51,107
Light and medium crude oil (bbl/d)	263	651
Total crude oil (bbl/d)	52,921	51,758
Bitumen (bbl/d)	61,327	59,516
NGLs (bbl/d)	16,128	31,229
Total liquids (bbl/d)	130,376	142,503
Conventional natural gas (mcf/d)	130,729	243,456
Total (boe/d)	152,163	183,080

The Company's reserve volumes, and the references to "total oil" reported in this shareholder letter consist of the following product types as defined by NI 51-101:

#### 2025

Reserves Category	NI 51-101 Light & Medium (MMbbl)	NI 51-101 Heavy Oil (MMbbl)	NI 51-101 Bitumen (MMbbl)	Total Oil (MMbbl)
Proved				
Developed Producing <sup>(1)</sup>	—	101	139	241
Developed Non-Producing <sup>(1)</sup>	—	1	—	1
Undeveloped <sup>(1)</sup>	—	415	568	983
Total Proved <sup>(1)</sup>	—	517	707	1,225
Probable <sup>(1)</sup>	—	220	720	940
Total Proved plus Probable <sup>(1)</sup>	—	737	1,428	2,165

(1) Figures may not add due to rounding

Reserves Category	NI 51-101 Natural Gas (MMbbl)	NI 51-101 Natural Gas (Bcf)	Total (MMboe)
Proved			
Developed Producing <sup>(1)</sup>	—	2	241
Developed Non-Producing <sup>(1)</sup>	—	—	1
Undeveloped <sup>(1)</sup>	—	2	984
Total Proved <sup>(1)</sup>	—	5	1,226
Probable <sup>(1)</sup>	—	2	940
Total Proved plus Probable <sup>(1)</sup>	—	7	2,166

(1) Figures may not add due to rounding

## Barrels of Oil Equivalent

This letter also contains references to “BOE” (barrels of oil equivalent), “MBOE” (one thousand barrels of oil equivalent), and “MMBOE” (one million barrels of oil equivalent). Strathcona has adopted the standard of six thousand cubic feet of gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs. BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading.

## Definitions

1P	proved reserves
2P	proved plus probable reserves
CAGR	compound annual growth rate
Cona	Cona Resources Ltd.
F&D	finding & development
FDC	future development capital
McDaniel	McDaniel and Associates Consultants Ltd.
NAV	net asset value
NBRI	Northern Blizzard Resources Inc.
PUD	proved undeveloped reserves
PDP	proved developed producing reserves
2C	proved plus probable contingent resources
Pengrowth	Pengrowth Energy Corporation
Pipestone	Pipestone Energy Corp
PNG	Petroleum and Natural Gas
RLI	reserves life index
Ryder Scott	Ryder Scott Company-Canada
Sproule	Sproule Associates Limited
Strath	Strath Resources Ltd.
Strathcona	Strathcona Resources Ltd.
WEF	Waterous Energy Fund
YE	Year end
YE Shares	The number of Strathcona shares outstanding at the end of the applicable year

## Forward-Looking Information

*Certain statements contained in this document constitute forward-looking information within the meaning of applicable securities laws. The forward-looking information in this document is based on Strathcona’s current internal expectations, estimates, projections, assumptions and beliefs. Strathcona believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable as of the time of such information, but no assurance can be given that these factors, expectations and assumptions will prove to be correct, and such forward-looking information included in this document should not be unduly relied upon.*

*The use of any of the words “expect”, “anticipate”, “estimate”, “objective”, “ongoing”, “may”, “will”, “project”, “believe”, “depends”, “could” and similar expressions are intended to identify forward-looking information. In particular, but without limiting the generality of the foregoing, this document contains forward-looking information pertaining to the following: Strathcona’s business strategy and future plans; expectations in respect of our Meota Central project, including an expected peak rate of 13 Mbbls / d and an anticipated total installed cost of \$360 million; expected improved results for our Lloydminster Conventional business in 2026; our expectation that PDP F&D costs will contribute to PDP bookings in coming years and that our 2026 unadjusted PDP F&D will improve as a result of Meota Central coming on stream; the expectation that we have more than 60-years of undeveloped resource remaining; our expectation that growth capital will contribute to exit production in 2026 of approximately 135 Mbbls / d; our belief that we can bring undeveloped resource on stream at an average capital efficiency of less than \$30,000/bbl/d; our expectation that fees HRT earns should serve as a natural hedge to Strathcona’s upstream earnings; our expectation that we may make acquisitions in the future; our expectation that the Vawn assets will increase our long-term production plateau by 40 Mbbls / d; our expectation that we will continue to manage our balance sheet to approximately 20%-25% debt / 1P After Tax PV-10; our reserves life index of 51 years and holdings of 16 years of 2C best estimate contingent resources (unrisked); future additional value at Plover Lake and Glenbogie; our expectations regarding our normal course issuer bid, including the number of shares to be repurchased and capital allocation strategy.*

*In addition, statements relating to “reserves” and “resources” are deemed to be forward-looking information as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated and can be profitably produced in the future. Forward-looking information in this document relating to oil and gas exploration, development and production, and management’s general expectations relating to the oil and gas industry are based on estimates prepared by management using data from publicly available industry sources as well as from market research and industry analysis and on assumptions based on data and knowledge of the industry which management believes to be reasonable. Although generally indicative of relative market positions, market shares and performance characteristics, this data is inherently imprecise. Management is not aware of any misstatements regarding any industry data presented in this document. Oil and gas exploration, development and production involves risks and uncertainties and industry data is subject to change based on various factors. See the “Risk Factors” section in the AIF, and from time to time in Strathcona’s public disclosure documents, which are or will be available at [www.sedarplus.ca](http://www.sedarplus.ca).*

*All forward-looking information reflects Strathcona’s beliefs and assumptions based on information available at the time the applicable forward-looking information disclosed herein is disclosed and in light of Strathcona’s current expectations with respect to such things as: Strathcona’s ability to generate sufficient cash flow to fund debt repayment; the success of Strathcona’s operations and growth and expansion projects; expectations regarding production growth, future well production rates and reserve volumes; expectations regarding Strathcona’s capital program, including the outlook for general economic trends, industry trends, prevailing and future commodity prices, foreign exchange rates and interest rates; expectations regarding the impact of tariffs on Strathcona’s operations and its ability to effectively mitigate the impact thereof; the availability of third party services; prevailing and future royalty regimes and tax laws; future well production rates and reserve volumes; fluctuations in energy prices based on worldwide demand and geopolitical events; the impact of inflation; the integrity and reliability of Strathcona’s assets; decommissioning obligations; and the governmental, regulatory and legal environment. Management believes that its assumptions and expectations reflected in the forward-looking information contained herein are reasonable based on the information available on the date such information disclosed herein is provided and the process used to prepare the information. However, it cannot assure readers that these expectations will prove to be correct.*

*The forward-looking information included in this document is not a guarantee of future performance and involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information, including, without limitation: changes in commodity prices; changes in the demand for or supply of Strathcona’s products; the continued impact, or further deterioration, in global economic and market conditions, including from inflation, tariffs and/or certain geopolitical conflicts, such as the ongoing Russia/Ukraine conflict and the conflict in the Middle East, and other heightened geopolitical risks and the ability of Strathcona to carry on operations as contemplated in light of the foregoing; determinations by the Organization of the Petroleum Exporting Countries and other countries as to production levels; unanticipated operating results or production declines; changes in tax or environmental laws, climate change, royalty rates or other regulatory matters; changes in Strathcona’s development plans or by third party operators of Strathcona’s properties; competition from other producers; inability to retain drilling rigs and other services; failure to realize the anticipated benefits of Strathcona’s acquisitions; incorrect assessment of the value of acquisitions; delays resulting from or inability to obtain required regulatory approvals; increased debt levels or debt service requirements; changes in foreign exchange rates; inaccurate estimation of Strathcona’s oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets or other sources of capital; increased costs; a lack of adequate insurance coverage; the impact of competitors; and the other factors to be discussed under the “Risk Factors” section in the AIF, and from time to time in Strathcona’s public disclosure documents, which are or will be available at [www.sedarplus.ca](http://www.sedarplus.ca). The foregoing risks should not be construed as exhaustive.*

*Any forward-looking information contained herein is expressly qualified by this cautionary statement. The forward-looking information contained in this document speaks only as of the date of this document and Strathcona does not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.*

## Notes

<sup>1</sup> A non-GAAP financial measure which does not have a standardized meaning under the Accounting Standards; see the "Specified Financial Measures" section of this shareholder letter.

<sup>2</sup> "Change in PDP FDC" is calculated as the change in total PDP future development costs in the year excluding the impact of acquisitions and dispositions. Changes in forecast FDC occur annually as a result of development activities, acquisition and divestment activities and capital cost estimates that reflect the evaluators' best estimate of the capital required to bring the proved developed producing reserves on production. The aggregate of the exploration and development costs incurred in the most recent year and the change during the year in estimated FDC generally reflect the total finding and development costs related to reserves additions for that year.

<sup>3</sup> "Organic PDP Additions" refers to the volume of PDP reserves added during the year through the Company's own capital development activities, excluding the impact of acquisitions and dispositions.

<sup>4</sup> "PDP F&D" is calculated as  $(\text{Organic Capex} + \text{Change in PDP FDC}) / \text{PDP organic reserve additions}$  for the respective year.

<sup>5</sup> "PDP Recycle Ratio" as presented in this letter is used to measure the profit per barrel of oil to the cost of finding and developing that barrel of oil. The recycle ratio is calculated by dividing the organic operating netback by the F&D costs, including changes in FDC, in the period (excluding the impact of acquisitions and dispositions).

<sup>6</sup> Acquisitions / Dispositions is calculated as a sum of acquisitions and dispositions

<sup>7</sup> "Distributions" include quarterly dividends and the \$2.14 billion Special Distribution paid on December 22, 2025. Dividends paid by Cona in 2017 before the dividend program was suspended have been excluded.

<sup>8</sup> "Debt" is calculated as Debt, net of cash (where applicable).

<sup>9</sup> Organic Additions is calculated as a sum of extensions and improved recovery, infill drilling, technical revisions, discoveries and economic factors.

<sup>10</sup> "Organic Growth per Share" is calculated as the year-over-year percentage change in reserves per share, excluding the impact of acquisitions and dispositions. It is determined by comparing the reserves per share at year-end to the prior year, adjusted solely for reserves added through the Company's capital development activities. The formula is:  $(\text{Opening Reserves} + \text{Organic Additions} - \text{Production}) / \text{Opening Reserves} - 1$ . This metric is presented separately for Proved Developed Producing (PDP), Total Proved (1P), and Total Proved plus Probable (2P) reserves categories.

<sup>11</sup> Calculated as Total Growth less Organic Growth

<sup>12</sup> Calculated as  $(\text{Closing Reserves} / \text{Closing Shares}) / (\text{Opening Reserves} / \text{Opening Shares}) - 1$

<sup>13</sup> "RLI" stands for Reserve Life Index, which is calculated by dividing gross 1P reserves, 2P reserves or gross unrisks 2C resources by annualized Q4 production for the respective year.

<sup>14</sup> "Organic 2P Replacement" is calculated as 2P reserves additions, excluding acquisitions and dispositions, divided by production for the respective year.

<sup>15</sup> YE Shares have been adjusted to give effect to the amalgamation of Cona and Strath on August 14, 2020, where Cona shareholders received 3.254211965 Strathcona shares for each Cona share held.

<sup>16</sup> YE Shares have been adjusted to give effect to the amalgamation of Strathcona and Pipestone on October 3, 2023, where existing Strathcona shareholders received 0.089278 post-amalgamation Strathcona shares for each existing Strathcona share held.

<sup>17</sup> First Year WTI is the WTI price for the first forecast year from the reserve evaluator price deck used in the respective year-end reserves evaluation.

<sup>18</sup> Source: Public company filings (AIF, MD&A, financial statements) and BlackRock XEG trading data. XEG 1P and 2P NAV (after-tax) per share estimated by calculating NAV to price ratio for each constituent at year-end (excluding companies with

---

meaningful downstream operations and U.S. domiciled constituents), calculating index-weighted average NAV to price ratio, and multiplying by year end XEG price.

<sup>19</sup> Strathcona information is from the PNG reserves evaluation of Strathcona Resources Ltd. performed by Sproule as at December 31, 2020, dated February 25, 2021. The reconciliation table in the 2020 reserves report presented Pengrowth as if it had been acquired on December 31, 2019 (instead of January 6, 2020); since the acquisition of Pengrowth occurred in 2020, the acquisition amount was adjusted using the PNG reserves evaluation of Pengrowth performed by Sproule as of Dec 31, 2019, dated February 20, 2020. As Strath reserves are included in the 2020 opening balances, the impact of the amalgamation of Strath and Cona on August 14, 2020 was adjusted for in the "Strath" column based on a combination of information from the 2020 reserves report, 2020 financial information and internally generated estimates.