

ATHABASCA OIL CORPORATION

FOCUSED | EXECUTING | DELIVERING

MARCH 2023

ATHABASCA
OIL CORPORATION

CORPORATE SNAPSHOT

~35,000 BOE/D / 93% LIQUIDS / 5% ANNUAL BASE DECLINE

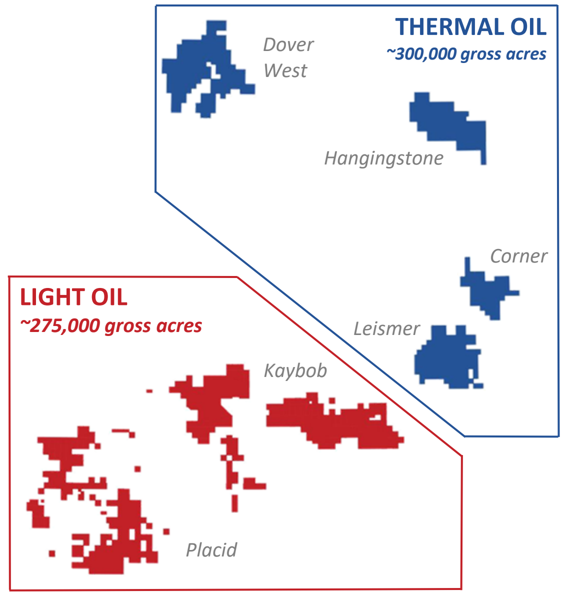
THERMAL OIL

- Predictable, low decline projects
- Efficient brownfield SAGD development
- Long reserve life resource

LIGHT OIL

- Montney and Duvernay focused
- Stable production & flexible development
- De-risked resource and high margins

ATHABASCA ASSETS



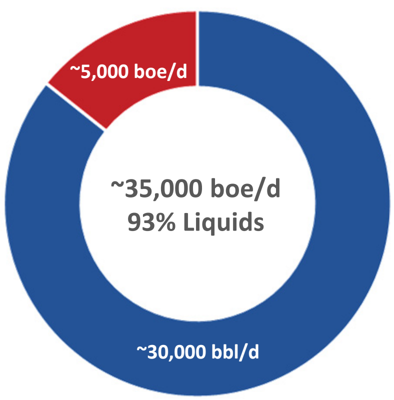
CAPITALIZATION (ATH-TSX)

Basic Shares	586MM
Market Cap. ($3/sh)	~$1,800MM
Net Debt	~$35MM
Liquidity	~$285MM

2023 GUIDANCE (US$85 WTI)

Production	34,500 – 36,000 boe/d
Adj. Funds Flow	~$415MM
Capital Exp.	~$145MM
Free Cash Flow	~$270MM

PRODUCTION BY ASSET



Basic shares and Net Debt as at December 31, 2022. Liquidity includes Cash & available credit capacity as at December 31, 2022. 2023e forecasts based on flat pricing assumptions (US$85 WTI, US$17.50 WCS diff, C$5 AECO, 0.75 US$/C$ FX).
2023 production forecast: 84% Bitumen, 7% natural gas (comprised of 99%+ of shale gas), 3% Condensate NGLs, 2% Other NGLs, 4% Oil (comprised of 99%+ of tight oil).
Free Cash Flow = Adjusted Funds Flow less Capital Expenditures. Additional information included in the back as reader advisories.

WHY OWN ATHABASCA

TOP TIER, LONG LIFE ASSET BASE

- ~1.3 MMboe 2P reserves; 5% corporate decline
- Low sustaining capital (~$125MM annually)
- 850 gross de-risked Montney & Duvernay locations with flexible development plans

MANAGING FOR SHAREHOLDER RETURNS

- Return >75% of Excess Cash Flow to shareholders
- Competive cost structure with tax-free horizon and pre-payout Crown royalties in Thermal Oil
- $1.1 Billion Free Cash Flow (2023-25)

STRONG FINANCIAL CAPACITY

- Ultra low leverage
- Strong Liquidity of ~$285MM (including $198MM cash)

INTEGRATED SUSTAINABILITY

- Strong governance; Board oversight of ESG
- Committed to reducing emissions; CCUS project with Entropy
- Proudly and responsibly produce Energy to improve people's lives

2023 forecasts based on US$85 WTI, US$17.50 WCS diff, C$5 AECO, 0.75 US$/C$ FX; 2024+ forecasts based on US$85 WTI, US$12.50 WCS diff, C$5 AECO, 0.75 US$/C$ FX Liquidity includes Cash & available credit capacity as at December 31, 2022. Excess Cash Flow = Adjusted Funds Flow less Sustaining Capital. Free Cash Flow = Adjusted Funds Flow less Capital Expenditures. See Reader Advisory "Non-GAAP Financial Information" for more information.

2022 YEAR-END RESULTS

35,262 boe/d (92% Liquids)

Exceeded Increased Guidance of 34,000 – 35,000 boe/d

$308MM FFO & $161MM FCF

Record Cash Flow Metrics

1.3 Billion boe 2P Reserves

Significant Reserve Value $4.6B ($7.89/sh)

$42/boe Corporate Netback

Thermal Oil $40/bbl & Light Oil $48/boe

$285MM Liquidity

$198MM Cash + $88MM Credit Availability

$35MM Net Debt

Lowest Absolute Leverage in Corporate History

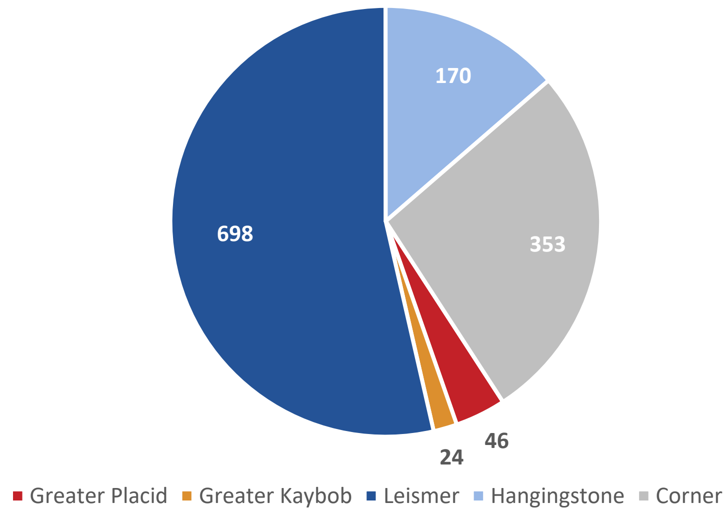
2022 production volumes by product: 28,989 bbl/d Bitumen, 16,169 mcf/d natural gas (>99% shale gas), 962 bbl/d condensate NGLs, 730 bbl/d other NGLs, 1,886 bbl/d Oil (>99% tight oil). Consolidated reserves as at December 31, 2022. Liquidity & Cash as at December 31, 2022. See reader advisory "Additional Oil and Gas Information", "Reserve Information" and "Non-GAAP Financial Information" for more information.

2022 RESERVE HIGHLIGHTS

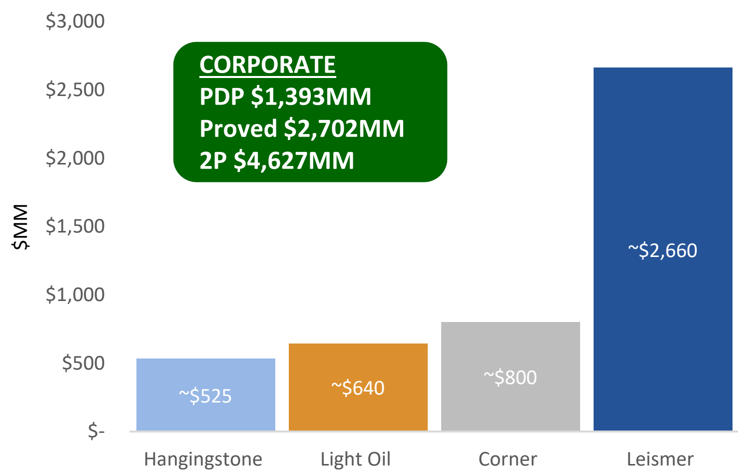
RESERVE OVERVIEW

- ~1.3 billion boe 2P reserves & ~950mmbbl contingent resource
- Corporate Reserve Life Index of ~100 years
- Compelling value
  - Proved Developed Producing (PDP): $2.38/share
  - Total Proved (TP): $4.61/share
  - Proved plus Probable (2P): $7.89/share
- Significant unbooked Light Oil Inventory
  - 180 of ~850 gross Montney/Duvernay locations booked
- Compelling Thermal Oil project reserve metrics
  - Pad L8 (5 wells) ~15mmbbl reserves to be reclassified as PDP from TP in 2023
  - ~$48MM project cost → ~$3/bbl finding cost

2P RESERVES BY ASSET (MMBOE)



2P RESERVE VALUE ($MM)



Consolidated reserves as of December 31, 2022. Calculation for RLI is 2022 year-end reserves divided by 2023e production.
See reader advisory “Additional Oil and Gas Information”, “Reserve Information” and “Non-GAAP Financial Information” for more information.

EXPOSURE TO A BULLISH HEAVY OIL THESIS

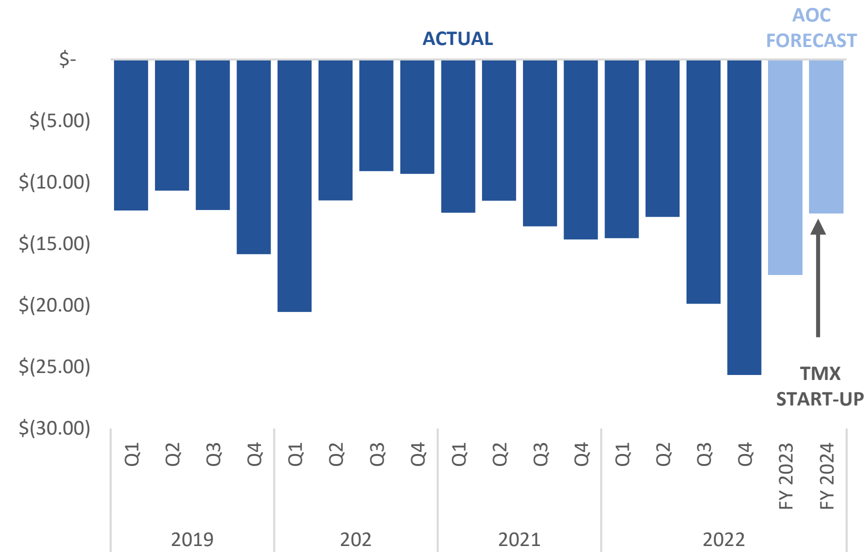
CANADIAN HEAVY DIFFERENTIALS

- Transient headwinds in the rearview mirror
  - US heavy weighted strategic petroleum reserve releases
  - TC Energy Keystone pipeline leak
  - Russian sanctions impacting global oil trade flows
  - Elevated US refinery downtime
- Tailwinds expected
  - Improving demand as China emerges from COVID restrictions
  - New global heavy refining capacity (+340kbbl/d Mexico)
  - Trans Mountain Expansion (+590kbbl/d late 2023)
  - Lower industry supply growth with focus on return of capital

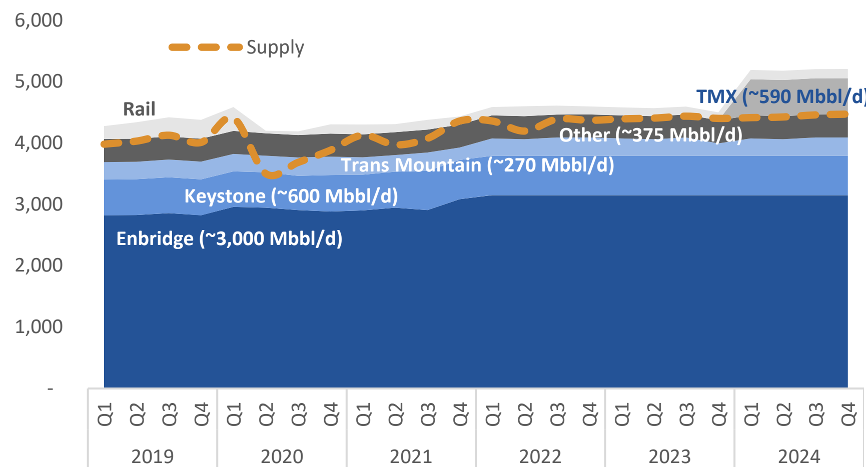
ATHABASCA'S UNIQUE POSITIONING

- Heavy oil weighted producer
  - Repositioned egress contracts to local price benchmarks
- Cash flow torque
  - US$5 WCS diffs → $80MM annually
- Differentiated long-life reserves
  - 1.2 Billion barrel 2P heavy oil reserves

WCS HEAVY DIFFERENTIALS (US$)



CANADIAN EGRESS OUTLOOK (MMBBL/D)



Source: BMO Capital Markets

2023 forecasts based on US$85 WTI, US$17.50 WCS diff, C$5 AECO, 0.75 US$/C$ FX; 2024+ forecasts based on US$85 WTI, US$12.50 WCS diff, C$5 AECO, 0.75 US$/C$ FX. Consolidated reserves as at December 31, 2022.
See Reader Advisory "Non-GAAP Financial Information" for more information.

ROBUST FREE CASH FLOW PROFILE

BUSINESS OUTLOOK

- Low-risk, sustainable capital projects
  - Thermal Oil underpins growth and low decline
  - Light Oil provides natural internal cost hedge

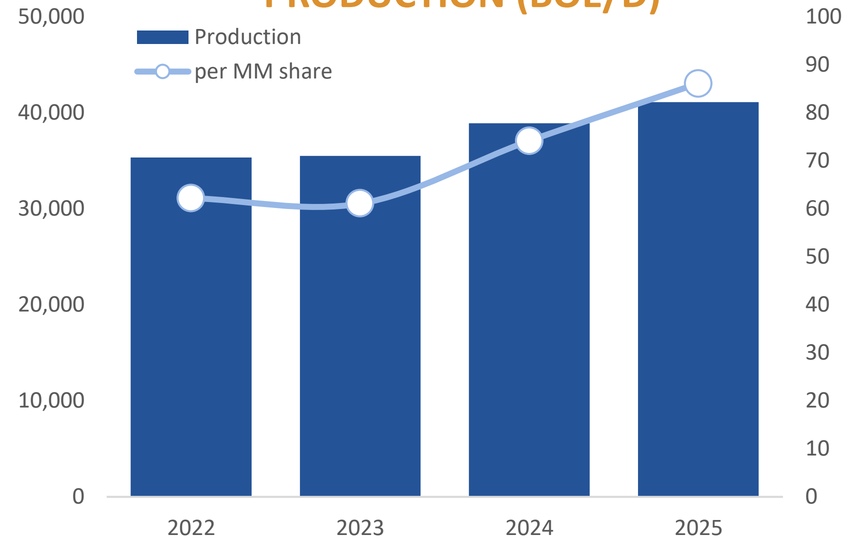
COMPETITIVE COST STRUCTURE

- Tax free horizon ($3B of pools)
- Pre-payout Crown royalties in Thermal Oil
- Low leverage

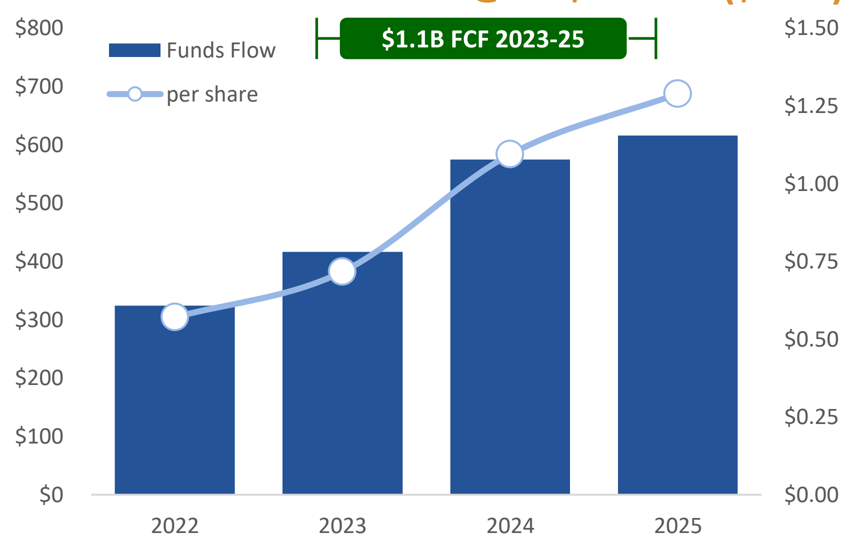
ROBUST FREE CASH FLOW PROFILE

- Low annual sustaining capital of ~$125MM
- Modest growth capital of ~$20MM in 2023
- Strong cash flow profile
  - $1.1B Free Cash Flow (2023-25)

PRODUCTION (BOE/D)



ADJUSTED FUNDS FLOW @ US$85 WTI ($MM)



Note: per share metrics assume a 10% annual share buyback program at $3/sh in 2023 and an implied share price of 3x EV/DACF in 2024-25. AOC's return of capital strategy targets >75% of Excess Cash Flow to shareholders and that implies incremental flexibility above this illustrative case.

2023 forecasts based on US$85 WTI, US$17.50 WCS diff, C$5 AECO, 0.75 US$/C$ FX; 2024+ forecasts based on US$85 WTI, US$12.50 WCS diff, C$5 AECO, 0.75 US$/C$ FX. Excess Cash Flow = Adjusted Funds Flow less Sustaining Capital. Free Cash Flow = Adjusted Funds Flow less Capital Expenditures. See reader advisory "Non-GAAP Financial Information" for more information.

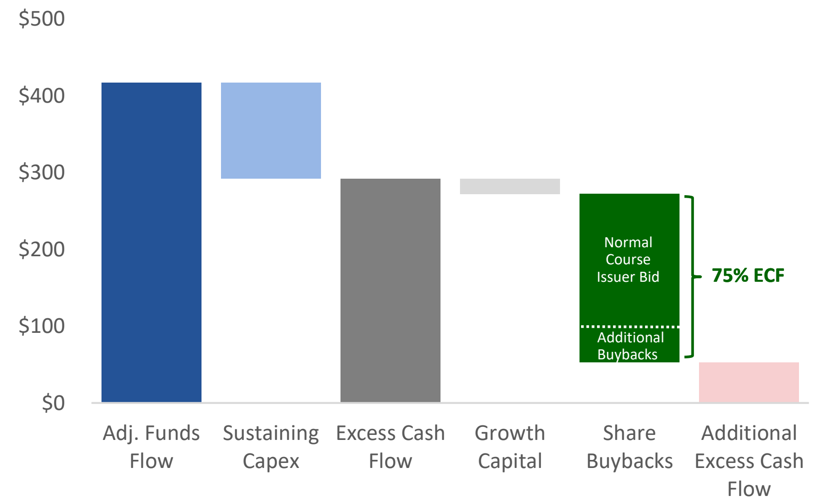
BUYBACK FOCUSED RETURN OF CAPITAL STRATEGY

ATHABASCA OIL CORPORATION

2023 CAPITAL ALLOCATION GUIDANCE

- >75% Excess Cash Flow ("ECF") returned to shareholders
  - Normal Course Issuer Bid ("NCIB") program approved by Board
  - NCIB application to be submitted to the TSX early March
  - Buy back program to commence April 2023
- Flexibility for additional ECF to be allocated to:
  - Additional buybacks
  - Debt reduction
  - High return growth projects

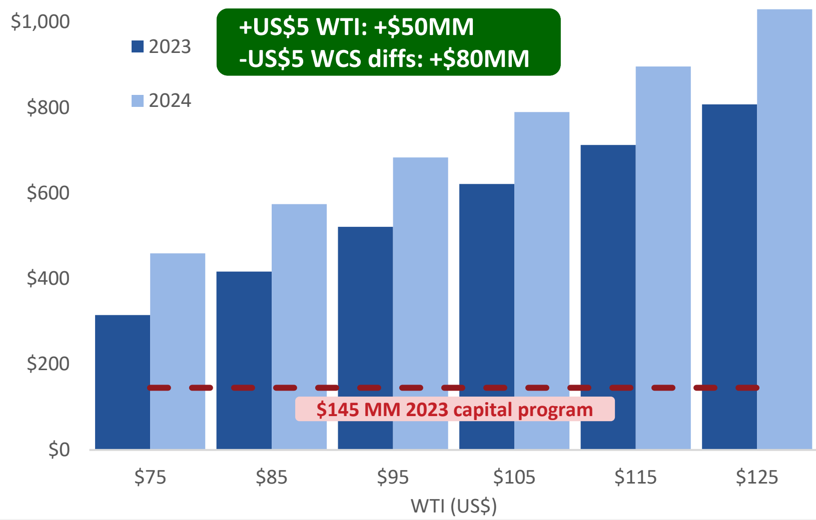
2023 CAPITAL ALLOCATION ($MM)



EXCELLENT EXPOSURE TO COMMODITY UPSIDE

- Strong Liquidity and low sustaining capital advantage provides protection against price volatility
- Risk management program
  - 25% hedged in accordance with debt agreements
  - Target wide collars to provide downside protection with maximum pricing upside
  - 2023 collars provide upside to ~US$110 WTI

ADJ. FUNDS FLOW ($MM)



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ASSET OVERVIEW

THERMAL OIL DIVISION

PREDICTABLE, LOW DECLINE

HIGHLIGHTS

100%	Working Interest
~30,000 bbl/d	2023E Production
~$380MM	2023E Operating Income
~$120MM	2023E Capital Expenditures
403 MMbbl & 1,220 MMbbl	Gross Reserves (Proved & 2P)
~40 years & >100 years	RLI (Proved & 2P)

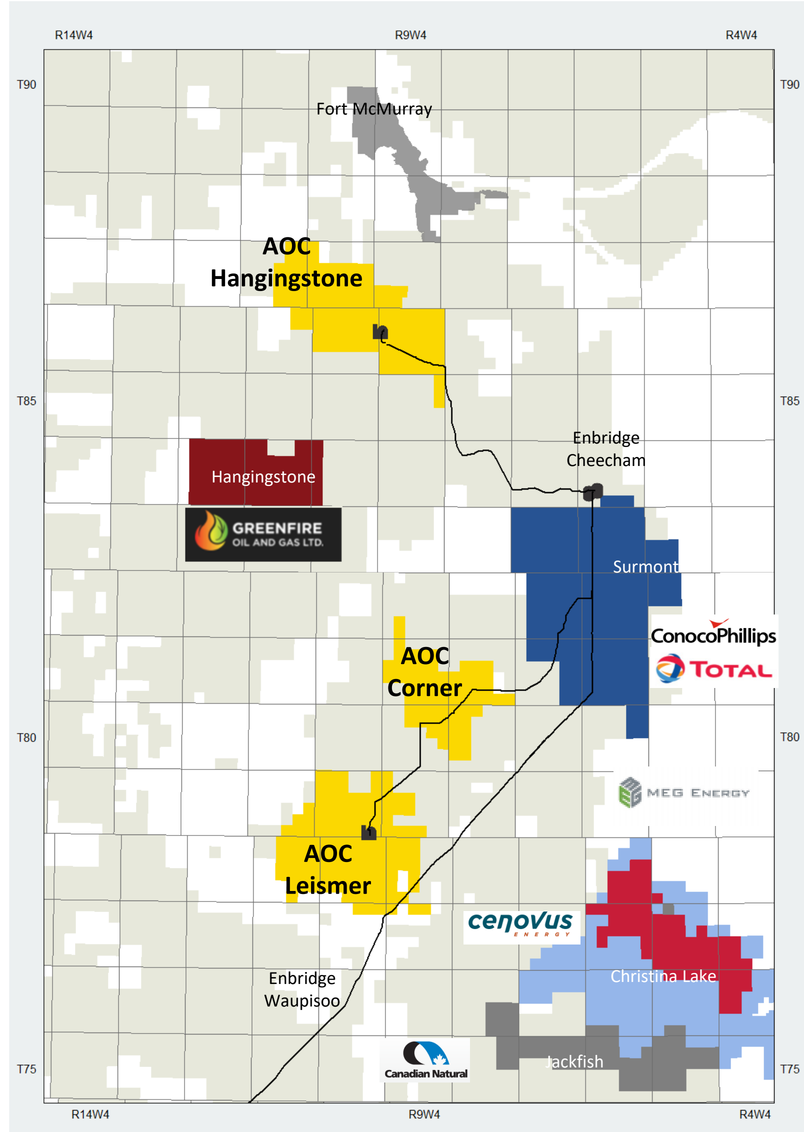
LEISMER

2010 First Production

HANGINGSTONE

2015 First Production

THERMAL PROPERTIES



2023 forecasts based on US$85 WTI, US$17.50 WCS diff, C$5 AECO, 0.75 US$/C$ FX.
Consolidated reserves as of December 31, 2022. Calculation for RLI is 2022 year end reserves divided by 2023e production.
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LEISMER – OVERVIEW

TOP TIER OIL SANDS PROJECT

- ~22,000 bbl/d & 2.9x SOR (Q4 2022)
- Long reserve life; 85 year RLI
  - 698MMbbl 2P reserves; 395MMbbl Best Est. Contingent resource

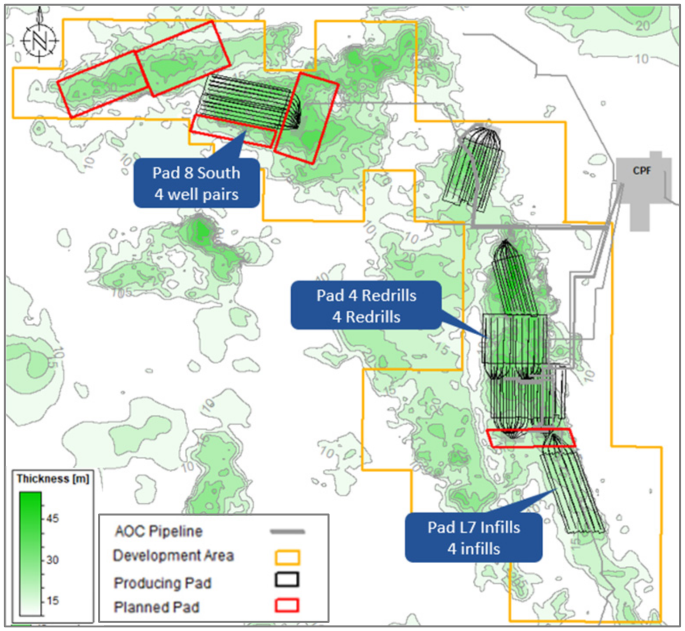
2023 ACTIVITY

- Pad L8 expansion
  - New 5 well pad commenced steaming in Q1
  - Ramp-up to ~6,000 bbl/d plateau by year-end
- Advance expansion project
  - Drill 12 additional sustaining & infill wells; oil facility upgrades
  - ~$14,000/bbl/d project capital efficiency
- Sustainable growth
  - ~24,000 bbl/d 2023 exit
  - ~28,000 bbl/d mid-2024

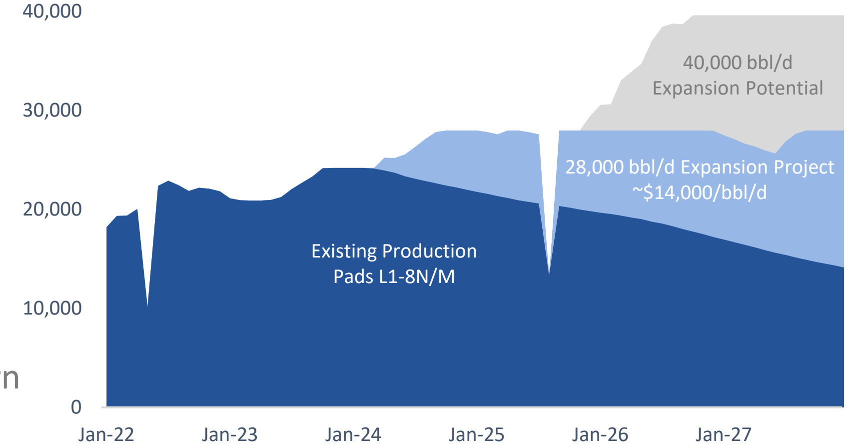
FUTURE OPTIONS

- Regulatory approval in place for expansion to 40,000 bbl/d
- Critical path long-lead items in inventory (2 steam generators & free water knockout)
- Future expansion dependent on oil prices, prioritizing return of capital initiatives and balance sheet strength

DEVELOPMENT MAP



LEISMER DEVELOPMENT (BBL/D)



Reserves as of December 31, 2022. Calculation for RLI is 2022 year end reserves divided by 2023e production.
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LEISMER – COMPELLING ECONOMICS

FINANCIAL & ECONOMIC HIGHLIGHTS

- Project underpins corporate cash flow and torque to oil
- Low Crown royalties
  - 9% max (pre-payout) vs. 40% (post-payout) at other projects
  - ~$1.5B royalty balance; pre-payout into 2027 (US$85 WTI)
- **Compelling investment metrics**

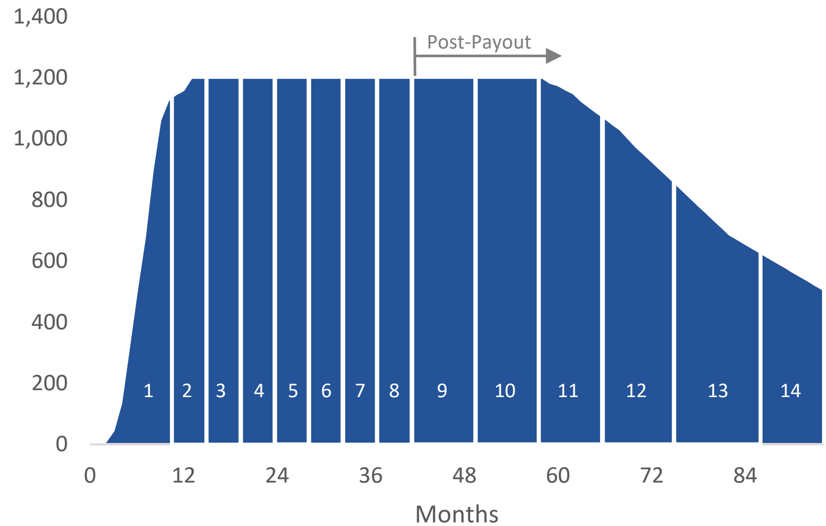
ILLUSTRATIVE SUSTAINING PAD ECONOMICS (US$85 WTI)*

		L8 Mid
Capital (lease edge)	*$MM*	$48
Plateau Rate per project	*bbl/d*	6,000
EUR per project	*mbbl*	15,000
IRR	*%*	170%
NPV10	*$MM*	$380
Recycle Ratio	*x*	14.0x
Capital Efficiency	*$/bbl/d*	$8,000
P/I	*x*	8.0x

THE POWER OF COMPOUNDING

- Leismer underpins low corporate decline
  - 14% mature well annual decline
  - New wells have flat production profile for 5 – 7 years
  - New pads currently account for ~50% of production
- Stable productions additions drive sustainable growth
- **Sustaining well pairs payout ~10x in the first 5 years**

WELL PAIR TYPE WELL (BBL/D) & PAYOUTS*



*Flat long-term commodity price assumptions: US$85 WTI, US$12.50 WCS diff, US$0 C5+ diff, C$5.00 AECO, 0.75 US$/C$ FX
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HANGINGSTONE – OVERVIEW

PROJECT HIGHLIGHTS

- ~8,500 bbl/d & 3.7x SOR (Q4 2022)
- Long reserve life
  - 170 MMbbl 2P reserves
  - ~60 year 2P RLI
- Improved SOR due to the field wide NCG co-injection

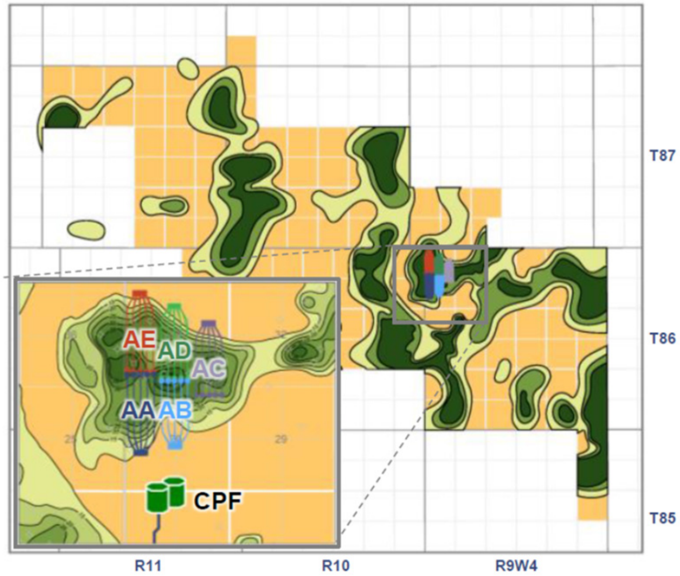
COST OPTIMIZATION

- Third-party truck-in terminal
- Amended transportation contract completed in 2021, lowering tolls & removing onerous LC requirements

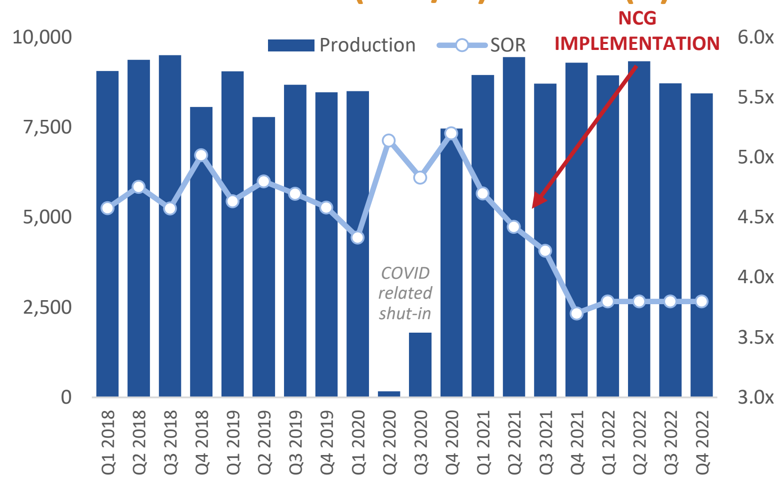
STRATEGIC POSITIONING

- Maximize margins and near-term free cash flow
  - $120MM 2022 Operating Income (~$38/bbl)
- Operational readiness for future sustaining well pairs in 2024 and beyond to maintain production levels

DEVELOPMENT MAP



PRODUCTION (BBL/D) & SOR (X)



Historical financial and operating results found on Company's website or on SEDAR www.sedar.com. SORs are quarterly averages.
2023 forecasts based on US$85 WTI, US$17.50 WCS diff, C$5 AECO, 0.75 US$/C$ FX.
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LIGHT OIL DIVISION
DE-RISKED, FLEXIBLE CAPITAL

ATHABASCA OIL CORPORATION

HIGHLIGHTS

~5,500 boe/d	2023E Production
~$80MM	2023E Operating Income
~$25MM	2023E Net Capital Expenditures
~850	Gross Locations
~275,000	Gross Acres
29 MMboe & 70 MMboe	Gross Reserves (Proved & 2P)
~13 years & ~31 years	RLI (Proved & 2P)

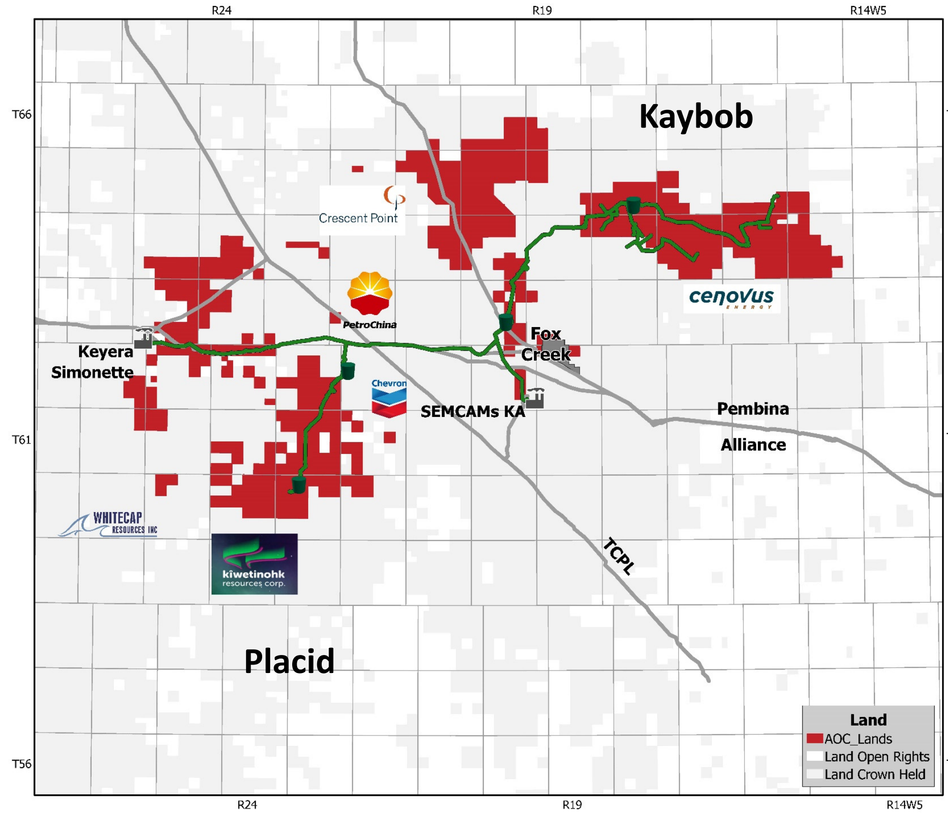
PLACID MONTNEY

70%	W. I. and Operated

KAYBOB DUVERNAY

30%	W. I. and non-Operated

LIGHT OIL PROPERTIES



- Joint Venture with Murphy
- Duvernay activity has de-risked the asset with $1B+ JV investment to date
- No near-term land maturities
- Capital expenditures governed through a joint development agreement

2023 product breakdown: 43% natural gas (comprised of 99%+ of shale gas), 15% Condensate NGLs, 12% Other NGLs, 30% Oil (comprised of 99%+ of tight oil). Reserves as of December 31, 2022. Calculation for RLI is 2022 year end reserves divided by 2023e production. 2023 forecasts based on US$85 WTI, US$17.50 WCS diff, C$5 AECO, 0.75 US$/C$ FX.
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LIGHT OIL – 2023 ACTIVITY

STRATEGIC OBJECTIVES

- Maintain optionality for future development program

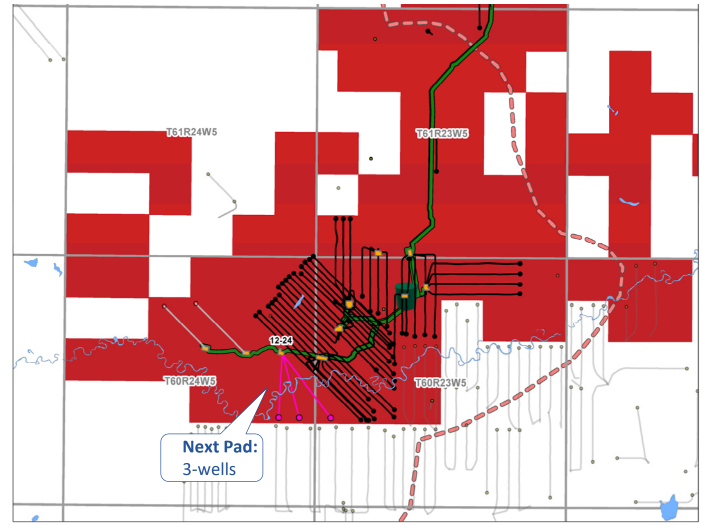
2023 ACTIVITY

- 3 Placid Montney development wells
  - Maximize netbacks and cash flow generation

FUTURE ACTIVITY

- Land held and de-risked
- Deep inventory: ~150 Montney & ~700 Duvernay locations (gross)
- Spending governed by a strong Joint Development Agreement

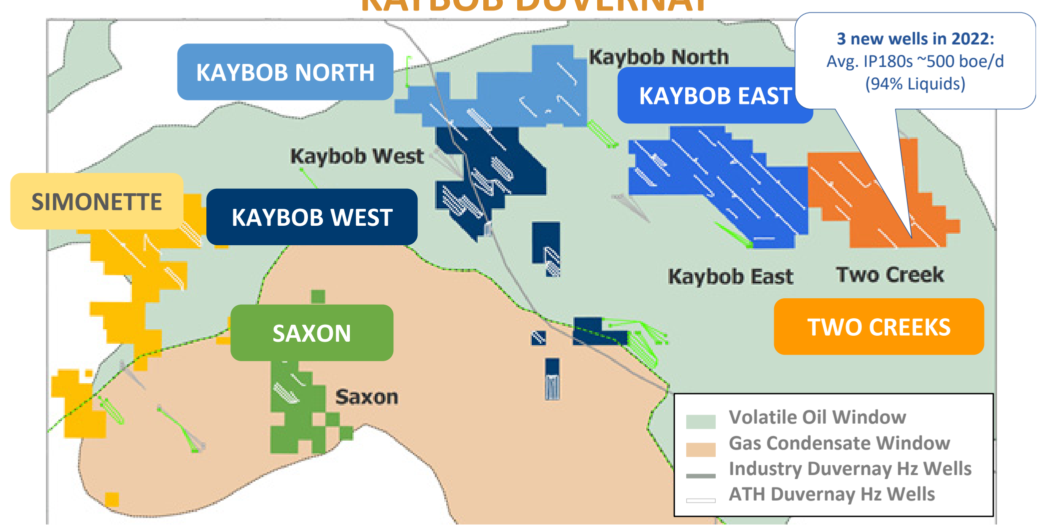
PLACID MONTNEY



ILLUSTRATIVE MULTI WELL PAD ECONOMICS (US$85 WTI)*

		MONTNEY SINGLE WELL	DUVERNAY SINGLE WELL
Capital	*$MM*	$8.1	$9.6
IP365	*boe/d*	483	460
EUR	*mboe*	520	725
Liquids yield	*%*	52%	78%
IRR	*%*	95%	135%
Recycle Ratio	*x*	3.5x	4.5x
P/I	*x*	1.2x	1.5x

KAYBOB DUVERNAY



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Placid Montney IP365 rates are ~40% shale gas, ~50% condensate NGLs and ~10% other NGLs; EURs are ~50% shale gas, ~40% condensate NGLs and ~10% other NGLs. Kaybob East IP365 rates are ~25% shale gas, ~70% tight oil and ~5% NGLs; EURs are ~30% shale gas, ~65% tight oil and ~5% NGLs. *Flat long-term commodity price assumptions: US$85 WTI, US$0 C5+ diff, C$5.00 AECO, 0.75 US$/C$ FX.

ESG OVERVIEW

ESG – ANNUAL REPORT

We believe that the responsible energy we produce here in Alberta makes people's lives better.

Our ESG report is an opportunity for us to showcase the positive impacts we have made and explain how sustainability and responsibility are being embedded into every decision we make.

"Our commitment to ESG responsibility and sustainability is part of our long-term strategy and an ongoing process."

2021 ESG Report available on our website & SEDAR

Introduction | GHG Management | Environment & Safety | Social | Governance | Data & Advisories

MESSAGE FROM OUR PRESIDENT & CEO

2021 was an exciting year at Athabasca. We saw signs of recovery from the COVID-19 global pandemic and the increasing demand for energy worldwide. I am incredibly thankful for the commitment, resiliency, and flexibility that our staff have shown over the past two years, maintaining safe operations and driving our business priorities forward.

At Athabasca, we believe that the responsible energy we produce here in Alberta makes people's lives better. We are at a turning point in our history where the world is working to transition to a lower-carbon future and Athabasca is seizing the opportunity to be a part of that future. This second annual ESG report is an opportunity for us to showcase the positive impacts we have made, highlight growth from last year, and explain how sustainability and responsibility are embedded into every decision we make.

We have a longstanding commitment to Environmental, Social, and Governance (ESG) initiatives and we are proud of the work we do to take care of the environment and the communities where we operate. I want to highlight some examples of how we are putting our commitment to ESG into actions.

Environmental Leadership

Athabasca continues to make progress in reducing our carbon footprint through investment in lower GHG intensity resources where new technology can also be deployed. In 2022, the Federal Government of Canada announced the **2030 Emissions Reduction plan**, which includes a pledge to reduce emissions by 40-45% from 2019 baseline with a path to net-zero emissions by 2050. We have reduced our GHG emissions intensity by greater than 20% since 2015 and are targeting a total 30% reduction by 2025. Athabasca is doing our part to help Canada achieve its **Paris Agreement** commitments and believes the world would greatly benefit from more Canadian energy.

In 2021 Athabasca established a partnership with Entropy Inc. to develop and implement a carbon capture and storage ("CCS") project at Leismer using Entropy's proprietary technology. The partnership is currently progressing detailed engineering plans and has developed a commercial model for investment that aligns with reducing carbon emissions and supporting our future aspiration of producing a net-zero barrel.

We continue to invest in technologies that increase energy efficiency and reduce land disturbance. An example is the continued expansion of non-condensable gas ("NCG") co-injection at our thermal assets where we have seen up to 50% reduction in GHG emissions on mature well pads.

Technology is the cornerstone to improving our environmental footprint and we look forward to engaging with industry and government to push boundaries and find innovative solutions that improve emissions intensity and lower overall emissions.

Safety, Our People and Our Communities

The safety of our people and communities is foundational to our business. It underpins all of our decisions and continues to be a top priority for Athabasca. Our safety culture is deeply embedded and our total recordable injury frequency has averaged 0.2 cases per 200,000 work hours over the last three years, well below Industry average. We also recorded a third consecutive year with zero reportable hydrocarbon spills.

We have made strides integrating new employee offerings that foster Diversity & Inclusion within the organization including an International Women's Day celebration. We have also set a 2022 goal of hosting Indigenous Cultural Awareness Training for our organization.

With the ongoing pandemic through 2021, we did not lose sight of the importance of taking care of those who need it the most. We have continued to give back to our local communities through initiatives including charitable donations, and post-secondary scholarships and endowments across Calgary, Fort McMurray, Fox Creek and Edmonton.

Governance

Our ESG strategy and performance is reviewed, considered, and fully integrated at the Board level. Our management team and Board are committed to incorporating ESG considerations and the application of technology in all our capital allocation decisions. HSE targets currently make up 20% of our annual corporate performance scorecard and will continue to reflect the importance of our broader ESG performance in years to come.

Looking Ahead

Our focus on these ESG priorities aligns with our long-term business strategy. We will continue to execute our capital program in a safe and efficient manner with free cash flow generation directed to debt reduction in the near-term.

As we progress, I can promise you a focus on transparency and continuous advancement as we deliver on our commitments to our stakeholders, communities, and employees. I am proud of our progress to date and look forward to providing updates on our ESG journey.

Sincerely,

Robert Broen,
President & Chief Executive Officer

ATHABASCA
OIL CORPORATION

ESG – INTEGRATED SUSTAINABILITY

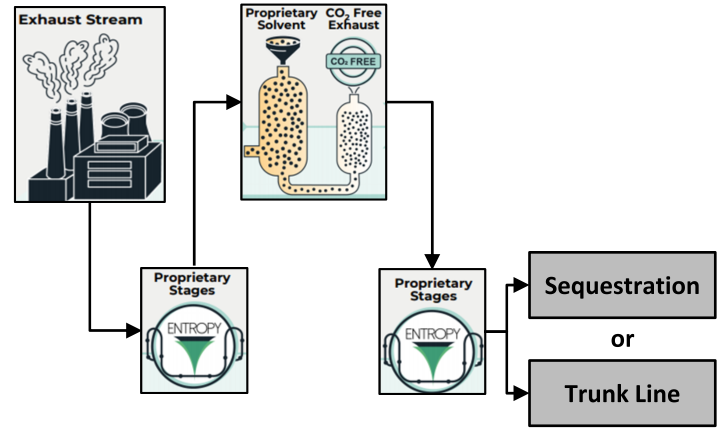
CARBON CAPTURE – AOC'S LOW-CARBON BARREL

- Entropy Inc. (Entropy) modular carbon capture technology (CCS)
  - Project to be sanctioned once government fiscal and regulatory policy for CCS projects are fully in place
- Sequestration into regional disposal zones or carbon trunk line

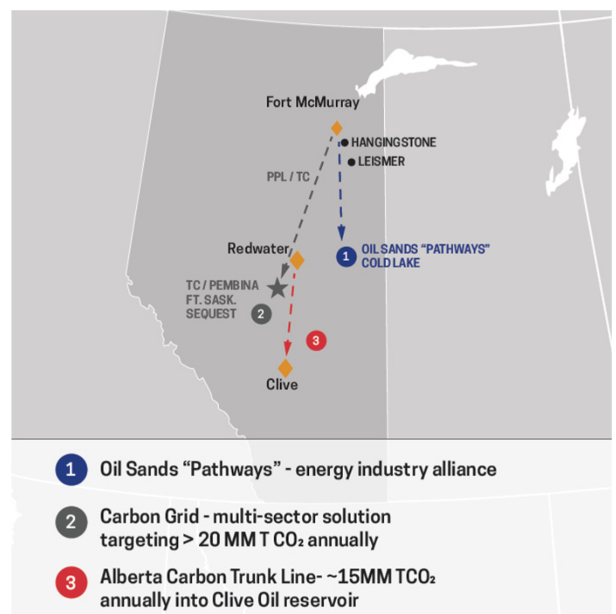
ALBERTA BASED INDUSTRY & GOVERNMENT INITIATIVES

- Multiple proposed open access carbon pipeline systems
- 50% Federal Government incentive tax credits for CCS projects

TECHNOLOGY OVERVIEW



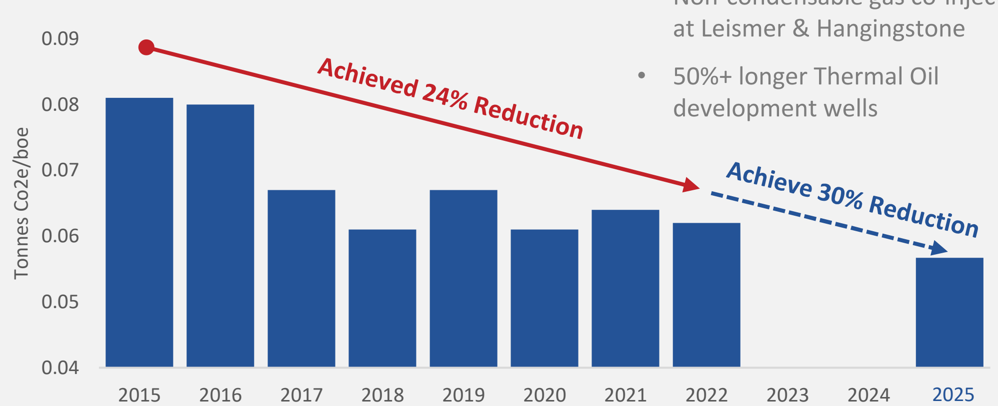
PROJECT MAP



NET GHG EMISSIONS INTENSITY

Implementing proven technologies to reduce emissions:

- Non-condensable gas co-injection at Leismer & Hangingstone
- 50%+ longer Thermal Oil development wells



Additional information included in the back as reader advisories.
Sources: Corporate disclosure and press releases.

ESG – GOVERNANCE & SOCIAL

GOVERNANCE

- Technically-focused, experienced management team
  - Four most senior executives have managed current portfolio for an aggregate of ~40 years
- Compensation aligned with financial, operational and environmental goals
- Independent and energy-rich experienced Board provides oversight for long-term strategy

2021 KEY BOARD STATISTICS

Number of Directors	7
Independent Directors	6 or 86%
Female Directors	1 or 14%
Governance Experience	7 or 100%
Health, Safety & Environment Experience	4 or 57%
Risk Management Experience	6 or 86%
Tenure	range 1-10 years, average of 5.6 years

SOCIAL

- Contributed 61% of the Provincial Park Expansion Lands to Create the World's Largest Boreal Forest
  - Expanded the ecologically and culturally significant Kitaskino Nuwenene Wildland Provincial Park by relinquishing 235,000 acres of mineral rights
- Collaborated and supported Indigenous businesses through expenditures of $12 million in 2021
- Best in class safety performance and environmental stewardship
  - 2022 TRIF of 0.08, well below industry average
  - Fourth consecutive year with no reportable spills

Strong governance, social responsibility and safety are core to AOC's business

Reported spill disclosure as per Sustainability Accountability Standards Board (SASB): Code EM-EP-160a.2

ESG – COMMITMENT TO RESPONSIBILITY

Environmental

GHG Intensity: By 2025, reduce Scope 1 emissions intensity by 30% from our 2015 baseline.

Carbon Capture and Storage: In support of our GHG Intensity goals and our future net zero aspirations, Athabasca and Entropy are targeting to FID the Leismer CCS project following the completion of front end engineering design and a local injection test.

Social

Safety: TRIF target of 0.5 in 2022, with an aspiration of no harm to people and no reportable hydrocarbon spills. ✓ **2022 TRIF of 0.08 and ongoing target <0.50**

Indigenous Relations: Complete Indigenous cultural awareness training for Executives, leadership, and key team members in 2022. ✓ **Completed in the Fall of 2022**

Governance

Board Governance with ESG: Incorporate ESG goals into capital allocation decisions.

Disclosures: Continually improve external disclosure with alignment to leading ESG standards and frameworks including GRI, SASB and TCFD.

APPENDIX

MANAGEMENT TEAM

ATHABASCA OIL CORPORATION

Rob Broen, P.Eng.
President & Chief Executive Officer

- Joined Athabasca in 2012 as Senior Vice President Light Oil. Promoted to Chief Operating Officer in 2013 and President and Chief Executive Officer in 2015
- 30 years of exploration and production experience including 18 years with Talisman Energy in various technical and management capacities (President, Talisman Energy USA Inc. and Senior Vice President, North American Shale). At Talisman, managed capital budgets over $1 billion and a 120,000 boe/d North American shale portfolio (Montney, Duvernay, Marcellus and Eagle Ford)
- Bachelor of Science in chemical engineering from the University of Alberta and a graduate of the Ivey Executive Program at the Richard Ivey School of Business

Matt Taylor, CFA
Chief Financial Officer

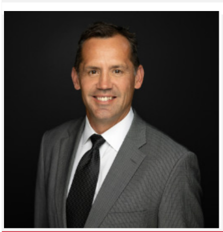
- Joined Athabasca in 2014 as Vice President Capital Markets & Communications. Promoted to Chief Financial Officer in 2019
- Over 15 years of financial, corporate and capital markets experience including equity research and investment banking at National Bank Financial, GMP Securities and CIBC World Markets
- Bachelor of Commerce with a specialization in finance from UBC Sauder School of Business and holds a Chartered Financial Analyst designation

Karla Ingoldsby, P.Eng.
Vice President, Thermal Oil

- Joined Athabasca in 2010 as a Senior Reservoir Engineer and has been progressively appointed into more senior roles including Development Manager in the Joint Venture with PetroChina Canada and Director positions for Geoscience Reservoir and Development, Ventures & Land, and Thermal Oil Production
- 20 years of Oil and Gas experience, including reservoir engineering roles at Royal Dutch Shell overseeing thermal oil assets and conventional oil and gas assets
- Bachelor of Science in Mechanical Engineering from the University of Alberta

Mike Wojcichowsky, P.Eng.
Vice President, Light Oil

- Joined Athabasca in 2013 as the Thermal Drilling Manager. Progressively appointed to more senior roles including Director of Drilling & Completions Services and Director of Light Oil
- 20 years of Oil and Gas experience in both Canada and the North Sea. Former Drilling & Engineering Manager at Talisman Energy for their Montney and Duvernay assets
- Bachelor of Science and Master of Science degrees in Mechanical Engineering from the University of Alberta



Cam Danyluk, LLB, B.Comm.
General Counsel & VP Business Development

- Joined Athabasca in August 2022 as General Counsel & VP Business Development
- Over 20 years of legal, business development, and investment banking experience including roles of Vice President, Legal, General Counsel and Corporate Secretary at Total Energy Services Inc and Vice President, Investment Banking at Mackie Research Capital Corporation and previously worked for Bennett Jones LLP in Calgary
- Bachelor of Laws and Bachelor of Commerce in Finance from the University of Alberta

ATHABASCA OIL CORPORATION

THERMAL OIL – CROWN ROYALTY ADVANTAGE

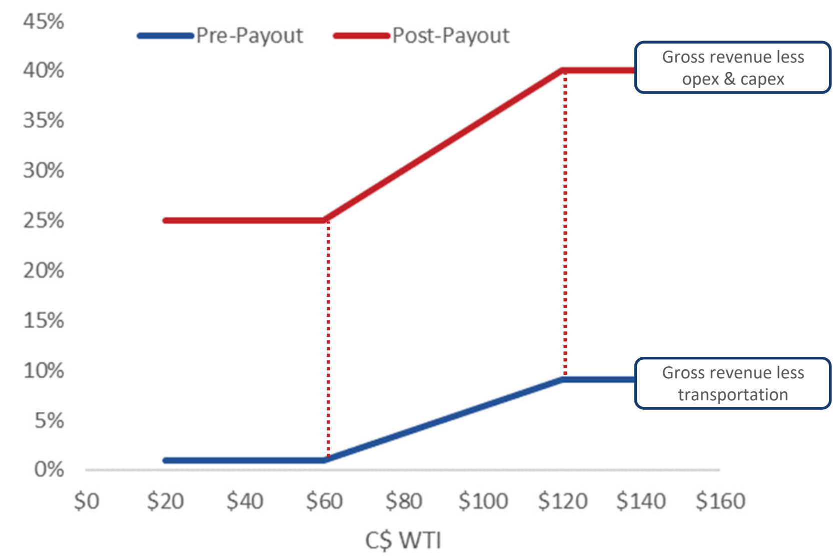
CROWN ROYALTY OVERVIEW

- Royalties vary depending on whether a project is in pre-payout or post-payout phase
  - Pre-payout royalty rates are lower to account for the initial cost of investment
  - Post-payout royalties occur when the project's cumulative revenues exceed cumulative costs

THE AOC ADVANTAGE

- Leismer has a ~$1.6B Unrecovered Balance
  - At ~US$85 WTI, post-payout is reached in 2027/28
- Hangingstone has a ~$1.0B Unrecovered Balance
  - At ~US$85 WTI, post-payout is reached in 2030+

OIL SANDS ROYALTY RATES



PEER ROYALTY PAYOUT STATUS

Operator Name	Project Name	Project Type	Payout Status	When Will it Convert to Post-Payout?		
				$65 WTI	$75 WTI	$85 WTI
SU	Syncrude Mine	Mine + Upgrader	POST	n/a	n/a	n/a
SU	Suncor Oil Sands	Mine + Upgrader	POST	n/a	n/a	n/a
IMO	Cold Lake	CSS	POST	n/a	n/a	n/a
CVE	Foster Creek	Insitu	POST	n/a	n/a	n/a
CNQ	Muskeg River Mine	Mine + Upgrader	POST	n/a	n/a	n/a
CNQ	Primrose	CSS	POST	n/a	n/a	n/a
SU	MacKay River	Insitu	POST	n/a	n/a	n/a
CNQ	Jackfish 1	Insitu	POST	n/a	n/a	n/a
BTE	Harmon Valley Bluesky	Heavy Oil	POST	n/a	n/a	n/a
BTE	Peace River	Insitu	POST	n/a	n/a	n/a
CVE	Christina Lake	Insitu	POST	n/a	n/a	n/a
CNQ	Jackfish 2	Insitu	POST	n/a	n/a	n/a
CVE	Tucker	Insitu	POST	n/a	n/a	n/a
SU	Firebag	Insitu	POST	n/a	n/a	n/a
CNQ	Jackpine Mine	Mine + Upgrader	POST	n/a	n/a	n/a
CNQ	Jackfish 3	Insitu	PRE	2022	2022	2021
CNQ	Horizon Mine	Mine + Upgrader	PRE	2023	2022	2022
MEG	Christina Lake	Insitu	PRE	2025	2024	2023
CNQ	Kirby South	Insitu	PRE	2025+	2025	2024
CNQ	Kirby North	Insitu	PRE	2025+	2025	2024
IMO	Kearl	Mine	PRE	2025+	2025+	2025+
CVE	Sunrise	Insitu	PRE	2025+	2025+	2025+
SU	Fort Hills	Mine	PRE	2025+	2025+	2025+

Source: Government of Alberta; Scotiabank GBM estimates.

Peer royalty payout status from Scotiabank Equity Research 'Escalating Royalties – There are Worse Problems to Have' from November 2021.

CORPORATE CAPITALIZATION

ATHABASCA OIL CORPORATION

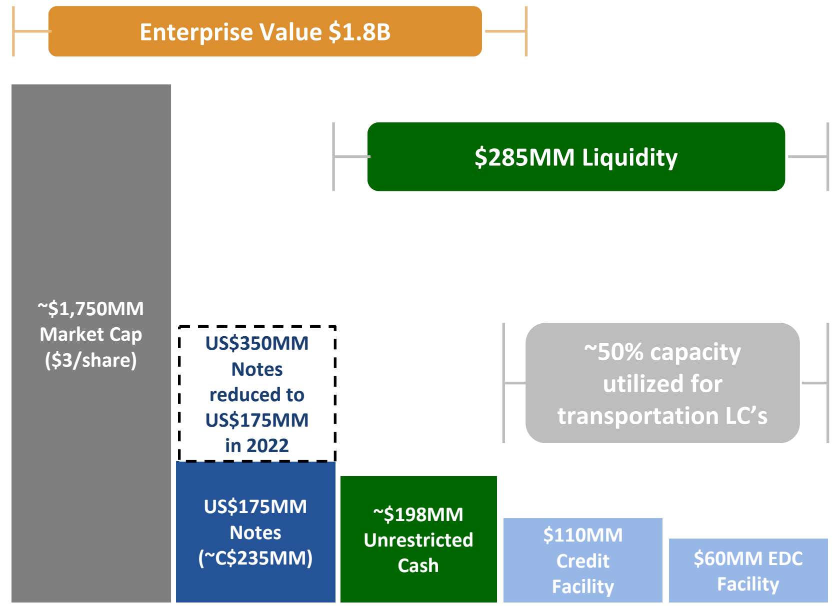
SENIOR SECOND LIEN NOTES

- US$175.2MM Notes
  - US$350MM issued October 2021 @ 9.75%; due Q4 2026
  - Retired ~US$175MM in 2022 using FCF redemption feature at 105 and proactive open market purchases
  - S&P issue-level rating BB-

STRONG LIQUIDITY

- $285MM Liquidity, including $198MM cash
- Facilities utilized for transportation LCs & hedging capacity
  - $110MM Reserve Based Facility @ 3.25%
  - $60MM Unsecured EDC LC Facility @ 3.0%

CAPITAL STRUCTURE (2022 YEAR-END)

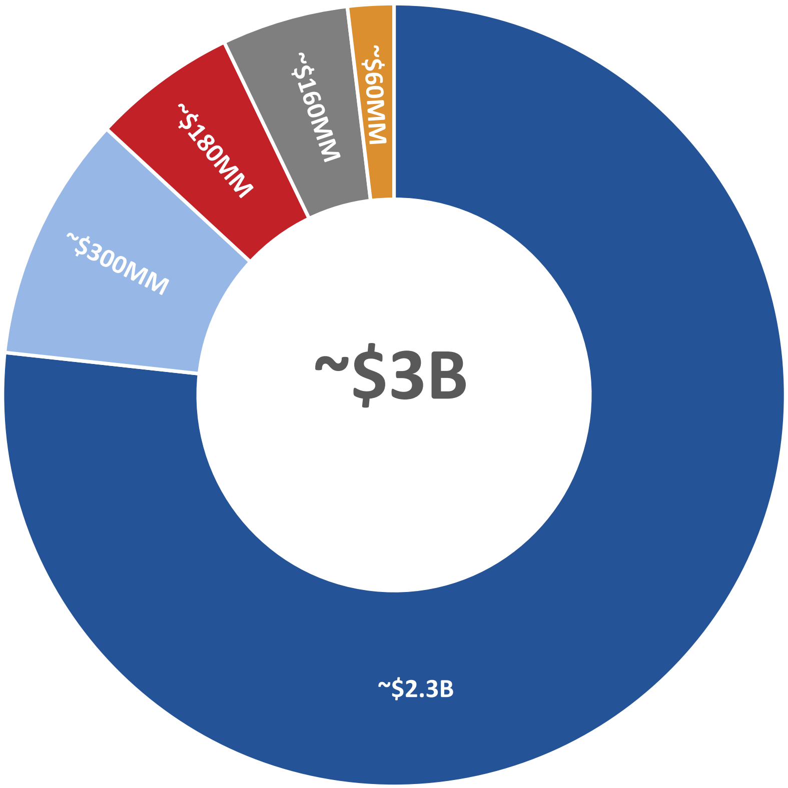


Basic Shares	586	MM
Market Capitalization ($3.00/sh)	**~$1,750**	**MM**
Net Debt	~$35	MM
Total Enterprise Value	**~$1,800**	**MM**
Warrants* ($0.94 exercise price)	~32	MM

See reader advisory "Non-GAAP Financial Information" for more information.
* Implied warrant dilution assuming a $0.94/sh cash exercise. Warrant dilution under the cashless exercise feature at $3/sh would equate to 22MM common shares.

TAX POOLS – MATERIAL VALUE

TAX POOL SUMMARY (2022)



- Non-Capital Loss & Canadian Exploration Expense (100% Deductible)
- Capital Cost Allowance - Class 41 & Other (25%)
- Canadian Oil & Natural Gas Property Expense (10%)
- Canadian Development Expense (10%)
- CAA - Class 17 & 41 (8%)

ILLUSTRATIVE TAX POOL VALUATION (NPV10)

$250MM annual deduction	~$390MM	~$0.65/sh
$500MM annual deduction	~$500MM	~$0.85/sh
$750MM annual deduction	~$530MM	~$0.90/sh
Fully Maximized	~$590MM	~$1.00/sh

Tax pool valuations are based on December 31, 2022 pool balances and assume a corporate tax rate of 23%. No future investments are included in the illustrative tax pool valuation analysis. Fully Maximized tax pool value assumes all Non-Capital Loss & Canadian Exploration Expense pools are utilized immediately. All per share values as based on share count of 586MM shares as of December 31, 2022.

READER ADVISORY

Forward Looking Statements

This Presentation contains forward-looking information that involves various risks, uncertainties and other factors. All information other than statements of historical fact is forward-looking information. The use of any of the words “anticipate”, “plan”, “continue”, “estimate”, “expect”, “may”, “will”, “target”, “forecast”, “goal”, “aspiration”, “commit”, “believe”, “should”, “could”, “intend”, “may”, “potential”, “outlook” and similar expressions suggesting future outcome are intended to identify forward-looking information. The forward-looking information is not historical fact, but rather is based on the Company’s current plans, objectives, goals, strategies, estimates, assumptions and projections about the Company’s industry, business and future operating and financial results. This information 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. No assurance can be given that these expectations will prove to be correct and such forward-looking information included in this Presentation should not be unduly relied upon. This information speaks only as of the date of this Presentation. In particular, this Presentation contains forward-looking information pertaining to, but not limited to, the following: our strategic plans; future debt levels and repayment plans; the allocation of future capital; return of capital strategy including timing and quantum of share buybacks; our drilling plans in Leismer; Leismer ramp-up to expected production rates; timing of Leismer’s pre-payout royalty status; applicability of tax pools; expected operating results at Hangingstone; Net Debt/Cash positions; Adjusted Funds Flow and Free Cash Flow in 2023 to 2025; the impact of future hedge levels; type well and project economic metrics; forecasted daily production and the composition of production; and other matters.

In addition, information and statements in this Presentation 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 that the reserves and resources described can be profitably produced in the future. With respect to forward-looking information contained in this Presentation, assumptions have been made regarding, among other things: commodity prices; the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts and will conduct business and the effects that such regulatory framework will have on the Company, including on the Company’s financial condition and results of operations; the Company’s financial and operational flexibility; the Company’s financial sustainability; Athabasca's cash flow break-even commodity price; the Company’s ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the applicability of technologies for the recovery and production of the Company’s reserves and resources; future capital expenditures to be made by the Company; future sources of funding for the Company’s capital programs; the Company’s future debt levels; future production levels; the Company’s ability to obtain financing and/or enter into joint venture arrangements, on acceptable terms; operating costs; compliance of counterparties with the terms of contractual arrangements; impact of increasing competition globally; collection risk of outstanding accounts receivable from third parties; geological and engineering estimates in respect of the Company’s reserves and resources; recoverability of reserves and resources; the geography of the areas in which the Company is conducting exploration and development activities and the quality of its assets. Certain other assumptions related to the Company’s Reserves and Resources are contained in the report of McDaniel & Associates Consultants Ltd. (“McDaniel”) evaluating Athabasca’s Proved Reserves, Probable Reserves and Contingent Resources as at December 31, 2022 (which is respectively referred to herein as the "McDaniel Report”).

Actual results could differ materially from those anticipated in this forward-looking information as a result of the risk factors set forth in the Company’s Annual Information Form (“AIF”) dated March 1, 2023 available on SEDAR at www.sedar.com, including, but not limited to: weakness in the oil and gas industry; exploration, development and production risks; prices, markets and marketing; market conditions; climate change and carbon pricing risk; statutes and regulations regarding the environment; regulatory environment and changes in applicable law; gathering and processing facilities, pipeline systems and rail; reputation and public perception of the oil and gas sector; environment, social and governance goals; political uncertainty; state of capital markets; ability to finance capital requirements; access to capital and insurance; abandonment and reclamation costs; continued impact of the COVID-19 pandemic; changing demand for oil and natural gas products; anticipated benefits of acquisitions and dispositions; royalty regimes; foreign exchange rates and interest rates; reserves; hedging; operational dependence; operating costs; project risks; supply chain disruption; labour supply, financial assurances; diluent supply; third party credit risk; indigenous claims; reliance on key personnel and operators; income tax; cybersecurity; advanced technologies; hydraulic fracturing; liability management; seasonality and weather conditions; unexpected events; internal controls; limitations of insurance; litigation; natural gas overlying bitumen resources; competition; chain of title and expiration of licenses and leases; breaches of confidentiality; new industry related activities or new geographical areas; and risks related to our debt and securities including level of indebtedness, restrictions in our debt instruments, additional indebtedness and issuance of additional securities. Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this Presentation could also have adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking information are reasonable based on information available to it on the date such forward-looking information are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking information, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements.

Also included in this Presentation are estimates of Athabasca’s 2023 and 2024 outlook which are based on the various assumptions as to production levels, commodity prices, currency exchange rates and other assumptions disclosed in this Presentation. To the extent any such estimate constitutes a financial outlook, it was approved by management and the Board of Directors of Athabasca and is included to provide readers with an understanding of the Company’s outlook. Management does not have firm commitments for all of the costs, expenditures, prices or other financial assumptions used to prepare the financial outlook or assurance that such operating results will be achieved and, accordingly, the complete financial effects of all of those costs, expenditures, prices and operating results are not objectively determinable. The actual results of operations of the Company and the resulting financial results may vary from the amounts set forth herein, and such variations may be material. The outlook and forward-looking information contained in this New Release was made as of the date of this Presentation and the Company disclaims any intention or obligations to update or revise such outlook and/or forward-looking information, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law.

Oil and Gas Information

“BOEs" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Other Oil and Gas terms: This presentation contains certain other oil and gas metrics, including D&C (drilling and completion costs), F&D, steam oil ratio (or SOR), reserves life index, recycle ratio, capital efficiency and P/I, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon.

D&C includes all capital spent to drill, complete, equip and tie-in a well. The calculation of F&D costs includes all exploration and development capital for the year plus the change in future development capital for the year. Steam oil ratio, or SOR, measures the average volume of steam required to produce a barrel of oil. Capital efficiency is a measure of how effective projects are at adding production. Lower capital efficiencies indicate a more productive investment for adding production. For Light Oil capital efficiency is calculated by dividing Capital and IP365 rates and for Thermal Oil is calculated by dividing Capital and plateau rates. All Thermal Oil production and volumes are bitumen. Light Oil % liquids include oil, condensate and NGLs as liquids. Consolidated % liquids include bitumen, oil, condensate and NGLs as liquids. Natural Gas volumes include both Conventional and Shale Gas, however most gas volumes are Shale Gas. Sustaining capital is a management estimate of annual capital projects required to maintain production levels.

READER ADVISORY CONT'D

Reserves Information

The McDaniel Report was prepared using the assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities, effective December 31, 2022. There are numerous uncertainties inherent in estimating quantities of bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For those reasons, estimates of the economically recoverable reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Reserves figures described herein have been rounded to the nearest MMbbl or MMboe. For additional information regarding the consolidated reserves and information concerning the resources of the Company as evaluated by McDaniel in the McDaniel Report, please refer to the Company's AIF.

Reserve Values (i.e. Net Asset Value) is calculated using the estimated net present value of all future net revenue from our reserves, before income taxes discounted at 10%, as estimated by McDaniel effective December 31, 2022 and based on average pricing of McDaniel, Sproule and GLJ as of January 1, 2023.

Well Inventory

The 700 gross Duvernay drilling locations referenced include: 5 proved undeveloped locations and 77 probable undeveloped locations for a total of 82 booked locations with the balance being unbooked locations. The 150 gross Montney drilling locations referenced include: 48 proved undeveloped locations and 50 probable undeveloped locations for a total of 98 booked locations with the balance being unbooked locations. Proved undeveloped locations and probable undeveloped locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by McDaniel as of December 31, 2022 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal management estimates. Unbooked locations do not have attributed reserves or resources (including contingent or prospective). Unbooked locations have been identified by management as an estimation of Athabasca's multi-year drilling activities expected to occur over the next two decades based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, commodity prices, provincial fiscal and royalty policies, costs, actual drilling results, additional reservoir information that is obtained and other factors.

Non-GAAP and Financial Measures and Production Disclosure

The "Adjusted Funds Flow", "Adjusted Funds Flow per Share", "Free Cash Flow", "Excess Cash Flow", " Sustaining Capital", "Light Oil Operating Income", "Light Oil Operating Netback", "Thermal Oil Operating Income", "Thermal Oil Operating Netback" financial measures contained in this Presentation do not have standardized meanings which are prescribed by IFRS and they are considered to be non-GAAP financial measures or ratios. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation with measures that are prepared in accordance with IFRS. Net Debt and Liquidity are supplementary financial measures. The Leismer and Hangingstone operating results are a supplementary financial measure that when aggregated, combine to the Thermal Oil segment results and the Greater Placid and Greater Kaybob operating results are a supplementary financial measure that when aggregated, combine to the Light Oil segment results.

Adjusted Funds Flow and Free Cash Flow are non-GAAP financial measures and are not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. The Adjusted Funds Flow and Free Cash Flow measures allow management and others to evaluate the Company's ability to fund its capital programs and meet its ongoing financial obligations using cash flow internally generated from ongoing operating related activities. Adjusted Funds Flow is calculated by adjusting for changes in non-cash working capital and settlement of provisions from cash flow from operating activities. Adjusted Funds Flow per share is a non-GAAP financial ratio calculated as Adjusted Funds Flow divided by the applicable number of weighted average shares outstanding. The Free Cash Flow measure is calculated by subtracting Capital Expenditures from Adjusted Funds Flow.

The Excess Cash Flow and Sustaining Capital measures allow management and others to evaluate the Company's ability to return capital to Shareholders. Sustaining Capital is managements assumption of the required capital to maintain the Company's production base. The Excess Cash Flow measure is calculated by Adjusted Funds Flow less Sustaining Capital.

The non-GAAP measure Light Oil Operating Income is calculated by subtracting the Light Oil Segments royalties, operating expenses and transportation & marketing expenses from petroleum and natural gas sales which is the most directly comparable GAAP measure. The Light Oil Operating Netback per boe is a non-GAAP financial ratio calculated by dividing the Light Oil Operating Income by the Light Oil production. The Light Oil Operating Income and the Light Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Light Oil assets.

The non-GAAP measure Thermal Oil Operating Income is calculated by subtracting the Thermal Oil segments cost of diluent blending, royalties, operating expenses and cash transportation & marketing expenses from heavy oil (blended bitumen) and midstream sales which is the most directly comparable GAAP measure. The Thermal Oil Operating Netback per boe is a non-GAAP financial ratio calculated by dividing the respective projects Operating Income by its respective bitumen sales volumes. The Thermal Oil Operating Income and the Thermal Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Thermal Oil assets.

Net Debt is defined as the face value of term debt, plus accounts payable and accrued liabilities, plus current portion of provisions and other liabilities less current assets and excluding risk management contracts.

Liquidity is defined as cash and cash equivalents plus available credit capacity.

Recycle ratio is calculated by dividing estimated project operating netbacks by finding and development costs per boe.

Profit-to-Investment Ratio is a measure of a projects net value relative to its capital investment and is calculated by dividing a project's NPV10 value by its Capital.

Reserve life is calculated by dividing year-end reserves with management's 2023 forecasted production guidance.

READER ADVISORY CONT'D

Production

Athabasca's 2023 forecasted total average daily production is between 34,500 – 36,000 boe/d. Athabasca expects that approximately 84% of that production will be comprised of bitumen, 7% shale gas, 4% tight oil, 3% condensate natural gas liquids and 2% other natural gas liquids.

Liquids is defined as bitumen, tight oil, light crude oil, medium crude oil and natural gas liquids.

Historical annual and 2022 year-end Corporate volumes by product are provided below:

Product		2016	2017	2018	2019	2020	2021	2022
Bitumen	*bbl/d*	7,384	27,900	27,900	26,058	22,745	26,805	28,989
Natural Gas	*mcf/d*	13,858	20,890	33,104	28,281	23,229	20,506	16,169
Condensate NGLs	*bbl/d*	788	2,687	2,793	2,009	1,964	1,374	962
Other NGLs	*bbl/d*	383	505	1,049	918	785	856	730
Light & Medium Crude Oil	*bbl/d*	331	104	98	27	2	20	30
Tight Oil	*bbl/d*	784	758	1,823	2,471	3,116	2,145	1,856
Total	***boe/d***	**11,980**	**35,435**	**39,180**	**36,196**	**32,483**	**34,618**	**35,262**

Initial Production Rates

Test Results and Initial Production Rates: The well test results and initial production rates provided in this presentation should be considered to be preliminary, except as otherwise indicated. Test results and initial production rates disclosed herein may not necessarily be indicative of long-term performance or of ultimate recovery

This Presentation makes reference to Athabasca's three well results in Two Creeks that have seen average productivity of ~500 boe/d IP180s (94% Liquids), which is comprised of ~92% tight oil, ~6% shale gas and ~2% NGLs.