



# ATHABASCA OIL CORPORATION

FOCUSED | EXECUTING | DELIVERING

**AUGUST 2024**

**ATHABASCA**  
OIL CORPORATION

# CORPORATE SNAPSHOT

**~37,000 BOE/D / 98% LIQUIDS / ~5% ANNUAL BASE DECLINE**

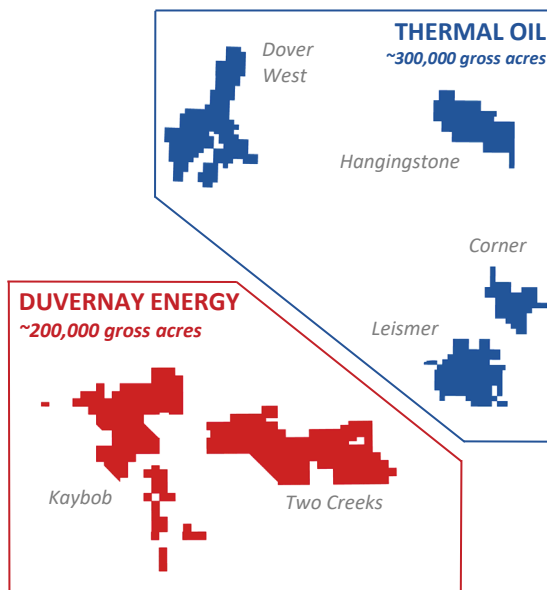
## THERMAL OIL

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

## DUVERNAY ENERGY CORP. (“DEC”)

- Pure play Duvernay subsidiary
- Self-funded & flexible development
- De-risked resource and high margins

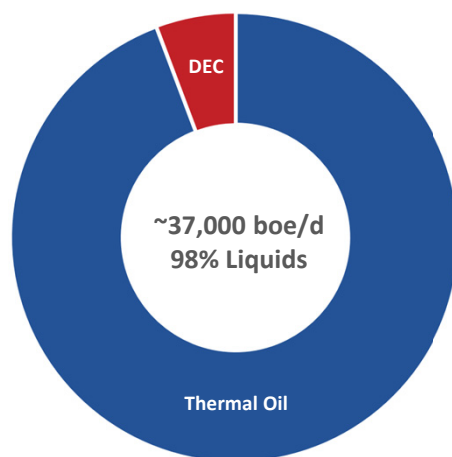
## ATHABASCA ASSETS



## CAPITALIZATION

Basic Shares (ATH-TSX)	548MM
Market Cap. (\$5.25/sh)	~\$2,900MM
Net Cash	~\$110MM
Liquidity	~\$400MM
Cash	~\$270MM

## PRODUCTION BY ASSET



## 2024 GUIDANCE (US\$80 WTI)

	Thermal Oil	DEC (100%)
Production (boe/d)	33,000 – 34,000	~3,000
Adj. Funds Flow	~\$540MM	~\$50MM
Capital	\$193MM	\$82MM*
Free Cash Flow	~\$350MM	--

\*DEC capital funded by Adjusted Funds Flow & initial seed capital

# WHY OWN ATHABASCA



## TOP TIER, LONG LIFE ASSET BASE

- ~1.2 billion boe 2P reserves; ~1 billion bbl cont. resource
- Top-tier Thermal Assets with regulatory approval in place for expansions
- Low decline and sustaining capital (~\$125MM annually)
- Self-funded pure-play Duvernay Energy Corp. with ~500 estimated gross locations



## STRONG FINANCIAL CAPACITY

- Net Cash position of ~\$110MM
- Strong Liquidity of ~\$400MM (including ~\$270MM Cash)
- Competitive cost structure; \$2.5 billion of tax pools shelter cash taxes for ~7 years



## MANAGING FOR SHAREHOLDER RETURNS

- \$1.4 Billion Free Cash Flow (2024-27)
- Top Tier CFPS Growth; Return 100% of Free Cash Flow to shareholders in 2024 through buybacks
- >20% three-year CAGR Funds Flow Flow per Share
- Pre-payout Crown royalties in Thermal Oil (~7%)



## INTEGRATED SUSTAINABILITY

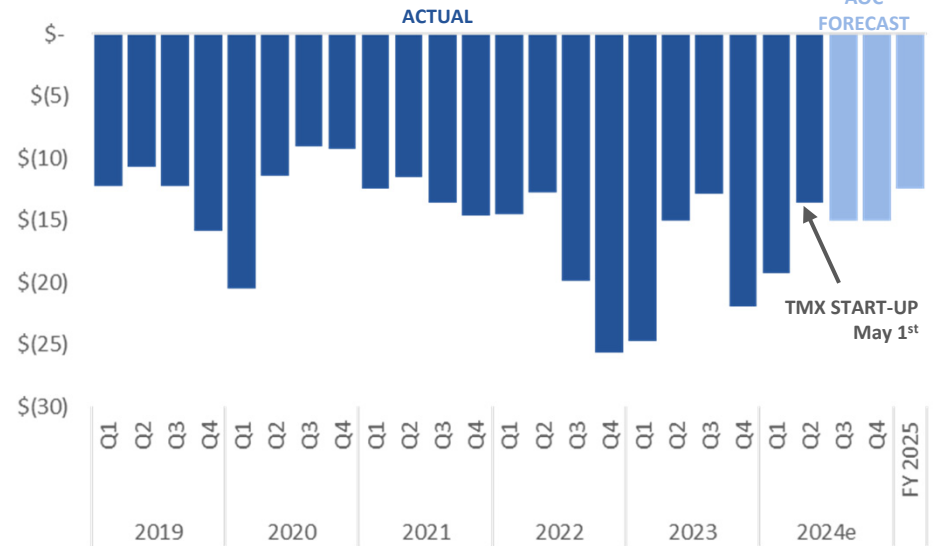
- Strong governance; Board oversight of ESG
- Proudly and responsibly produce Energy to improve people's lives

# EXPOSURE TO A BULLISH HEAVY OIL THESIS

## CANADIAN HEAVY DIFFERENTIALS

- Positive structural changes for Canadian heavy oil
  - Trans Mountain Expansion (+590 mbb/d); May 1<sup>st</sup> start-up
- Stronger and less volatile WCS heavy pricing expected
- Excess pipeline egress to 2028+

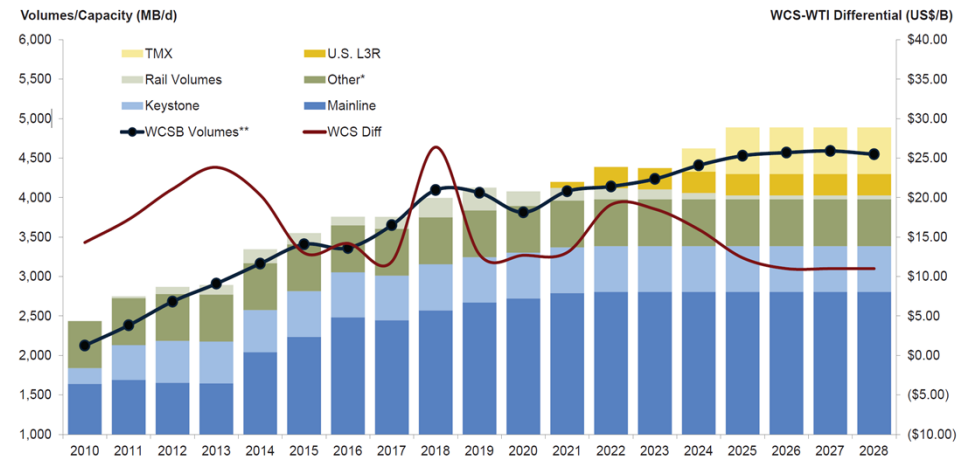
## WCS HEAVY DIFFERENTIALS (US\$)



## ATHABASCA'S UNIQUE POSITIONING

- Heavy oil weighted producer
  - Repositioned egress contracts to local benchmarks
- Cash flow torque
  - US\$5/bbl WCS diffs → \$85MM annually

## CANADIAN EGRESS OUTLOOK



Source: Peters & Co Winter Playbook (Jan. 2024) – WCSB Crude Volumes vs. Operational Export Capacity & Oil Differentials.  
\*Other includes Express, Rangeland, Trans Mountain Base. \*\* Volumes net of domestic WCSB refinery demand.

# ROBUST FREE CASH FLOW PROFILE

## BUSINESS OUTLOOK

- Thermal Oil assets with low base decline
  - Leismer brownfield growth to 40,000 bbl/d
- Duvernay Energy enhances growth
  - Self-funded & independent capital allocation framework
- Competitive growth outlook
  - 23% 3-year production per share CAGR

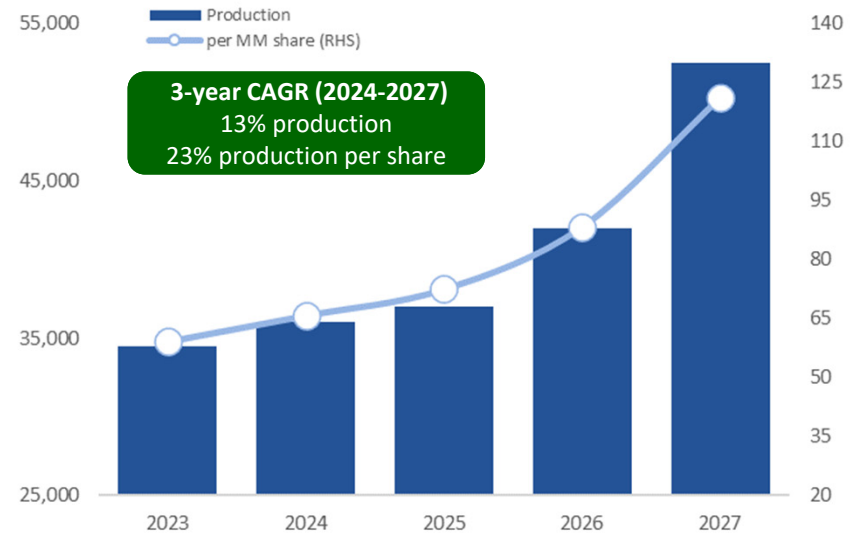
## COMPETITIVE COST STRUCTURE

- Tax free horizon (\$2.5 billion of pools)
- Pre-payout Crown Thermal royalties (7% at US\$80 WTI)
- Low leverage (~\$110MM Net Cash)

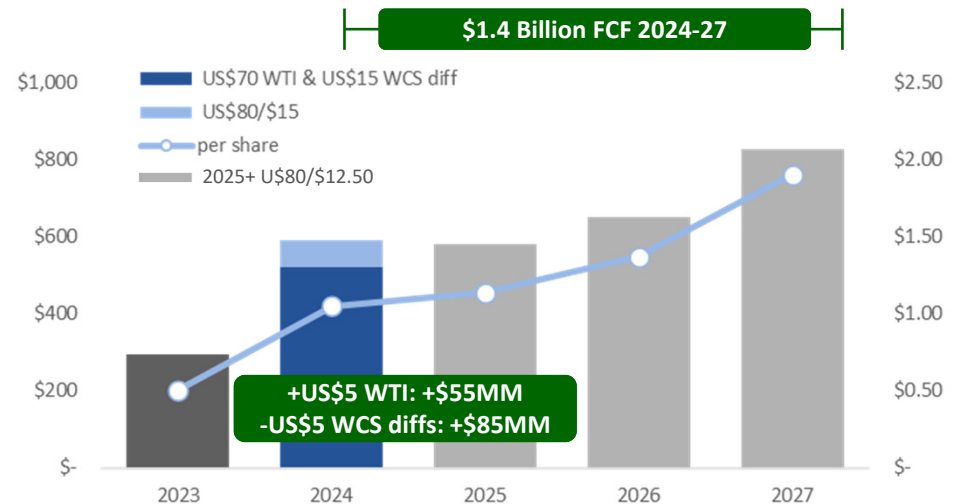
## ROBUST FREE CASH FLOW

- **\$1.4 billion Free Cash Flow (2024-27)**
- **>20% 3-year CAGR Funds Flow per Share**

## NET PRODUCTION (BOE/D)<sup>1</sup>



## NET ADJUSTED FUNDS FLOW (\$MM)<sup>1</sup>



Note: per share metrics assume a 10% annual share buyback program. \$5.25/sh in H2 2024 and an implied share price of 4.5x EV/DACF in 2025-27.

<sup>1</sup>Assumes AOC 100% Thermal Oil and DEC 70%. H1 2024 prices actualized and flat pricing of US\$80 WTI, US\$15 WCS heavy differential, C\$67/MWh, C\$1.48 AECO, and 0.73 C\$/US\$ FX for the balance of the year. 2025+ pricing US\$80 WTI, US\$12.50 WCS diff, C\$3 AECO, 0.75 US\$/C\$ FX. Compound Annual Growth Rate "CAGR". Net Cash as at June 30, 2024 pro forma refinancing transaction. Net Cash = face value of debt less working capital surplus (excl. risk management & warrant liability). See reader advisory "Non-GAAP Financial Information" for more information.

# RETURN OF CAPITAL STRATEGY

## 2023 SHAREHOLDER RETURNS

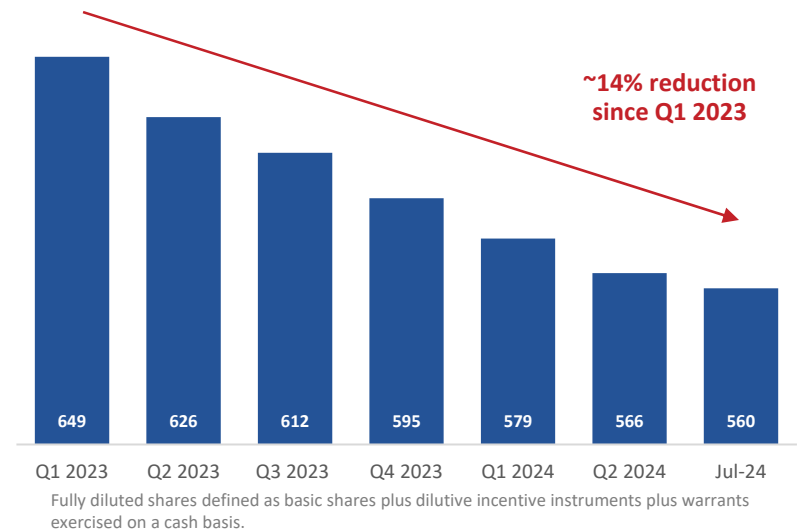
- Fully completed first Normal Course Issuer Bid (“NCIB”)
  - \$225MM share repurchases (April 2023 – March 2024)
  - 58MM common shares at \$3.88/sh avg. price
- Exceeded commitment to return >75% of Excess Cash Flow
  - 94% of ECF returned to shareholders in 2023

## 2024 RETURN OF CAPITAL FRAMEWORK

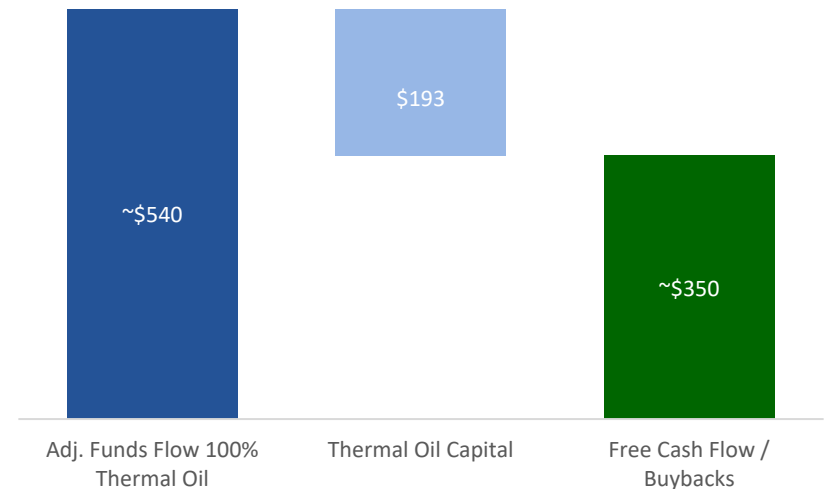
- Annual NCIB renewed mid-March (55MM shares)
  - Funded by Thermal Oil business
  - ~\$180MM share repurchases YTD to July 31 (36MM shares)

## DUVERNAY ENERGY STANDALONE, SELF-FUNDED ENTITY

## FULLY DILUTED SHARE COUNT



## 2024 RETURN OF CAPITAL OUTLOOK (\$MM)





## **THERMAL OIL – ASSET OVERVIEW**

# THERMAL OIL DIVISION

## PREDICTABLE, LOW DECLINE

### HIGHLIGHTS

100% Working Interest

33,765 bbl/d Q2 2024 Production

\$193MM 2024e Capital Expenditures

404MMbbl | ~30 yr Proved Reserves & RLI  
1,216MMbbl | ~70 yr 2P Reserves & RLI

\$41 WTI Operating Resilient Break-Evens  
\$49 WTI Sustaining

#### LEISMER

2010 First Production

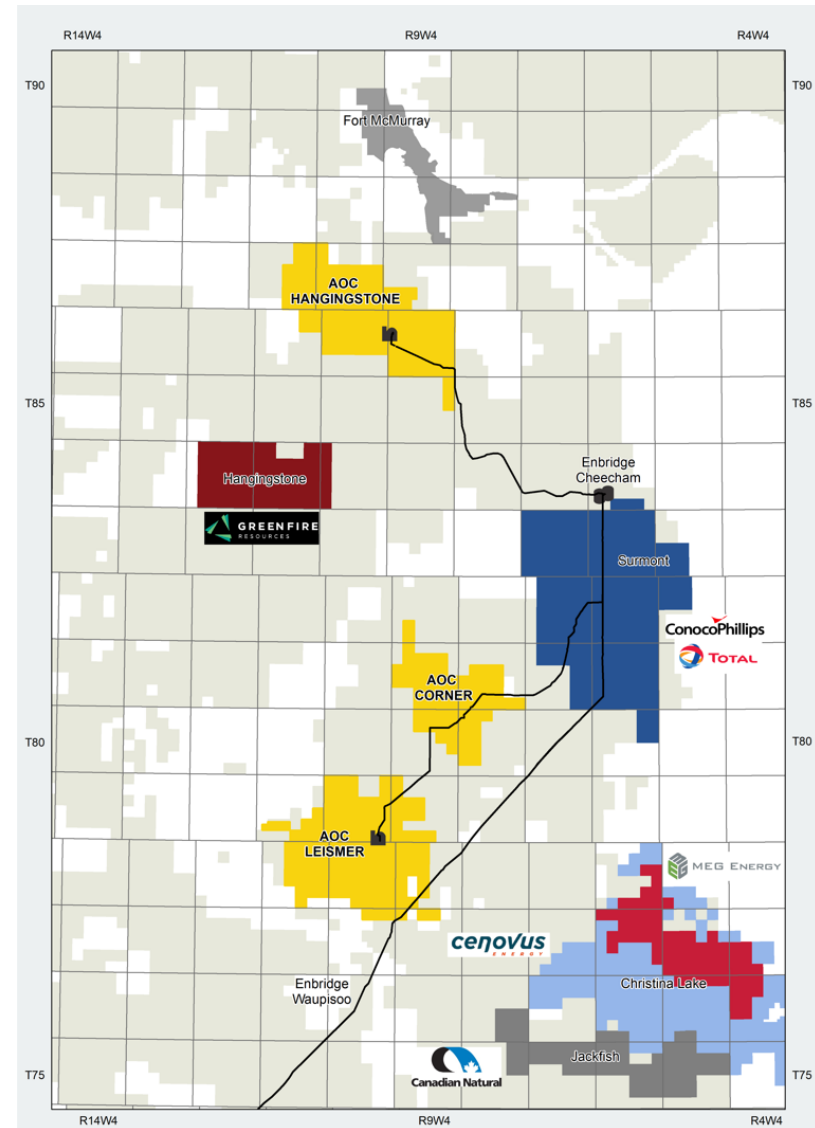
#### HANGINGSTONE

2015 First Production

#### CORNER (future development)

351 MMbbl 2P + 520 MMbbl Contingent resource  
>300 vertical wells, top quality resource  
40,000 bbl/d regulatory approval in place

### THERMAL PROPERTIES





# LEISMER – OVERVIEW

## TOP TIER OIL SANDS PROJECT

- Long reserve life; ~70 year current reserve life index
  - 697MMbbl 2P reserves; 384MMbbl Best Est. Contingent resource
  - ~50 year 2P RLI at 40,000 bbl/d
- Excellent reservoir underpins low corporate decline
  - New wells have flat production profile for 5 – 7 years
  - ~3x long-term steam oil ratio
- Q2 2024 operating netback of \$53/bbl
  - Low pre-payout Crown royalties of 5-9% until 2027
- 2024 capital expenditures ~\$160MM

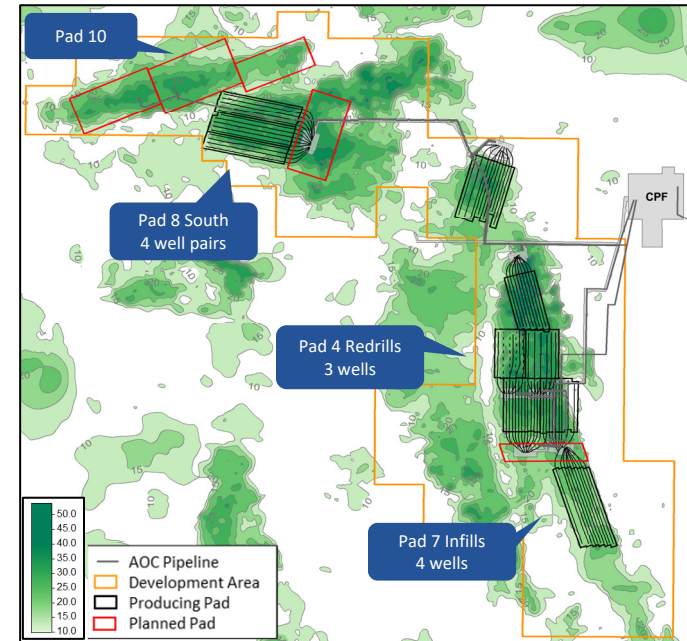
## 2024 BASE ACTIVITY

- Successfully completed expansion project
  - Achieved production of ~28,000 bbl/d (June)
  - Competitive ~\$14,000/bbl/d project capital efficiency
- Spud four sustaining well pairs and two redrills in H2

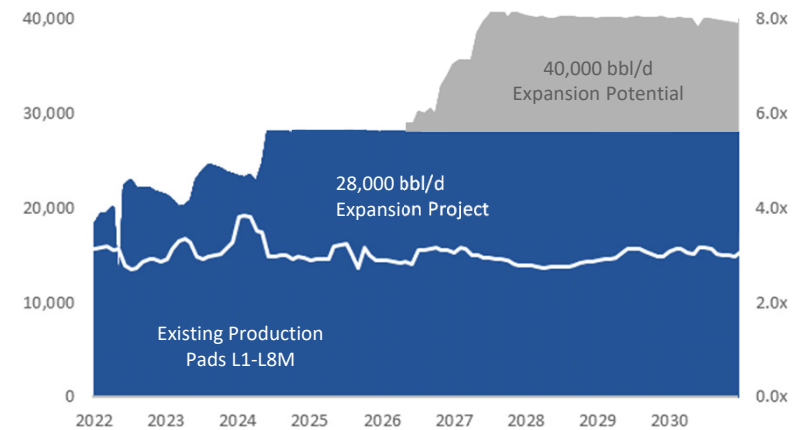
## SANCTIONED 40,000 BBL/D EXPANSION

- Phased growth stages are flexible and highly economic
- Project capital of \$300M (~\$25,000/bbl/d capital efficiency)
- +12,000 bbl/d growth by 2028 (~40% increase)

### DEVELOPMENT MAP

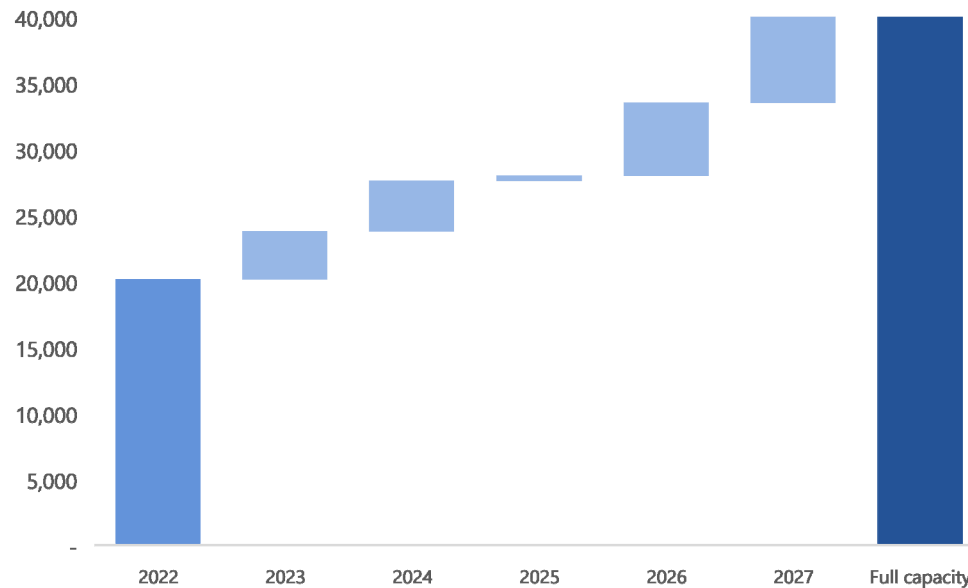


### LEISMER DEVELOPMENT (BBL/D) <sup>SOR</sup>



# LEISMER – 40,000 BBL/D EXPANSION

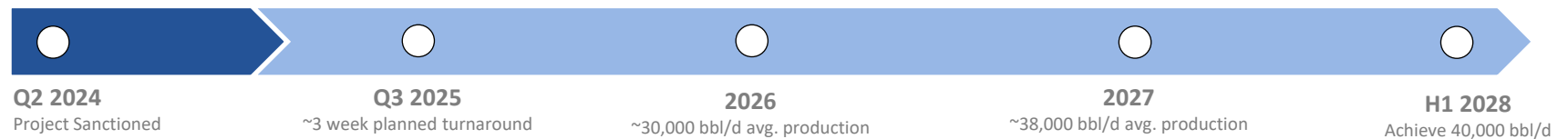
## GROWTH TRAJECTORY (YEAR-END EXIT; BBL/D)



## PROJECT OVERVIEW

Project Cost	~\$300MM
Incremental Rate	12,000 bbl/d
Capital Efficiency	~\$25,000/bbl
IRR	>35%

**Leismer NPV10 @ 40,000 bbl/d  
\$3.3 Billion**



## COMPLETED

- ✓ Regulatory approval for 40,000 bbl/d
- ✓ No egress expansions required
- ✓ Established transportation to Edmonton
- ✓ Long-lead steam generators acquired counter-cyclically

## SCOPE

- Central processing facility capacity expansion (~130,000 bbl/d steam & ~200,000 ~bbl/d emulsion)
- ~20 SAGD well pairs (sustaining & growth)

# HANGINGSTONE – OVERVIEW

## PROJECT HIGHLIGHTS

- Long reserve life; ~65 year reserve life index
  - 167 MMbbl 2P reserves
- Improved SOR due to the field wide NCG co-injection
  - 3.4x H1 2024 average

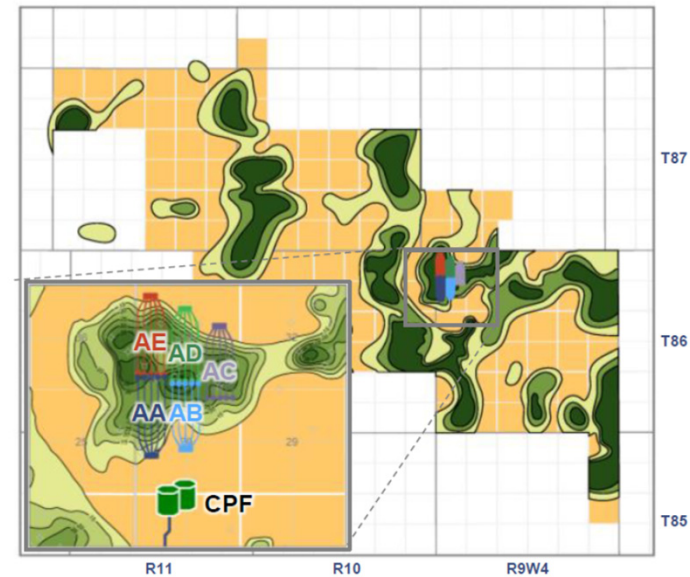
## 2024 ACTIVITY (~\$30MM)

- Two well pairs rig released in August
  - Utilizing ~1,400 meter laterals
  - Competitive capital efficiencies of ~\$15,000 bbl/d
- Well pairs expected to support base production in 2025 and beyond

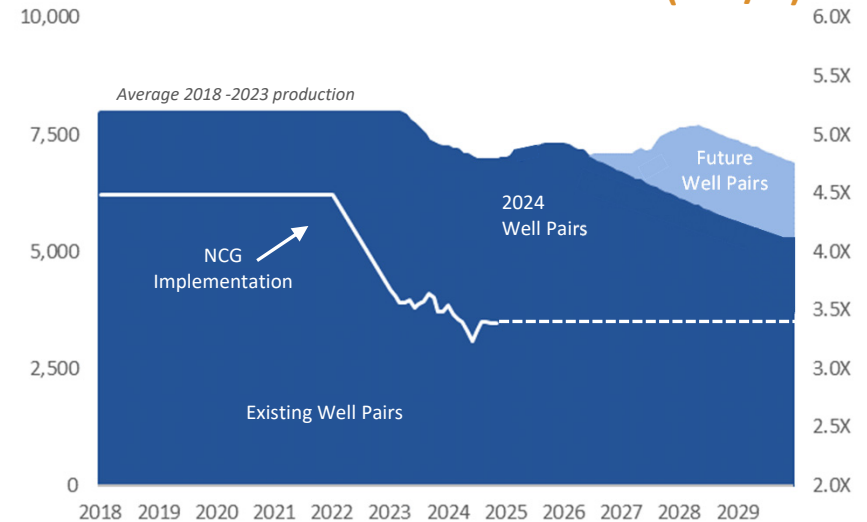
## CASH GENERATION

- ~\$200MM Operating Income generated between 2022-23 with minimal capital
- Q2 2024 operating netback of \$52/bbl
  - Low pre-payout Crown royalties of 5-9% into the 2030s

## DEVELOPMENT MAP



## HANGINGSTONE DEVELOPMENT (BBL/D) SOR



# CORNER – OVERVIEW

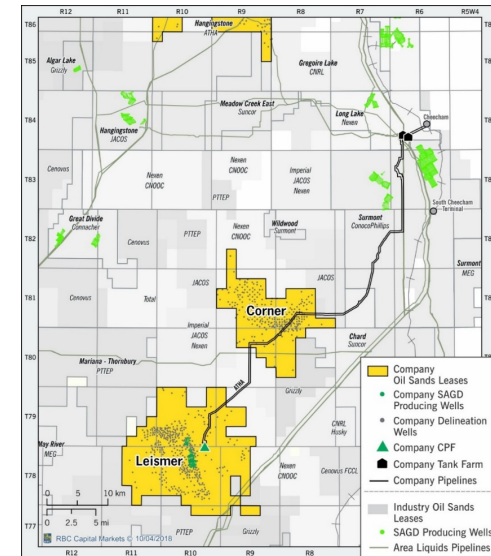
## TOP TIER OIL SANDS PROJECT

- Large De-risked Asset
  - 351 MMbbl 2P reserves and 520 MMbbl Contingent Resource (Best Est.)
  - 304 delineation wells with ~80% 3D seismic coverage
- High Quality Reservoir
  - Up to ~45 m of pay in initial development with high quality sands
  - Expect to fill a 20,000 bbl/d facility with one pad (16 well pairs)
  - Reservoir analogous to Christina Lake & Jackfish\*
- Regulatory & Infrastructure
  - Approved for 40,000 bbl/d
  - Existing diluent and dilbit pipeline pass through Corner lease

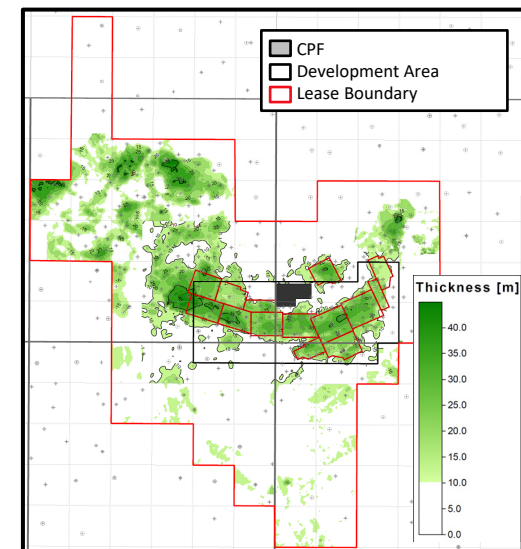
## 2024 ACTIVITY

- Updated development plans for latest well designs
- Completed testing in the Clearwater to confirm viability of disposal near the central processing facility
- Facility engineering study to prepare cost estimates
- Explore external funding options

### REGIONAL MAP



### NET PAY MAP





**DUVERNAY ENERGY CORPORATION**

**ATHABASCA**  
OIL CORPORATION

# DUVERNAY ENERGY – CORPORATE SNAPSHOT

## CREATION OF NEW PRIVATE COMPANY

- Athabasca and Cenovus combine Duvernay assets
  - Athabasca to operate Duvernay Energy (“DEC”)
- Unparalleled exposure to Kaybob Duvernay oil window
- Debt-free entity seeded with \$90MM Liquidity

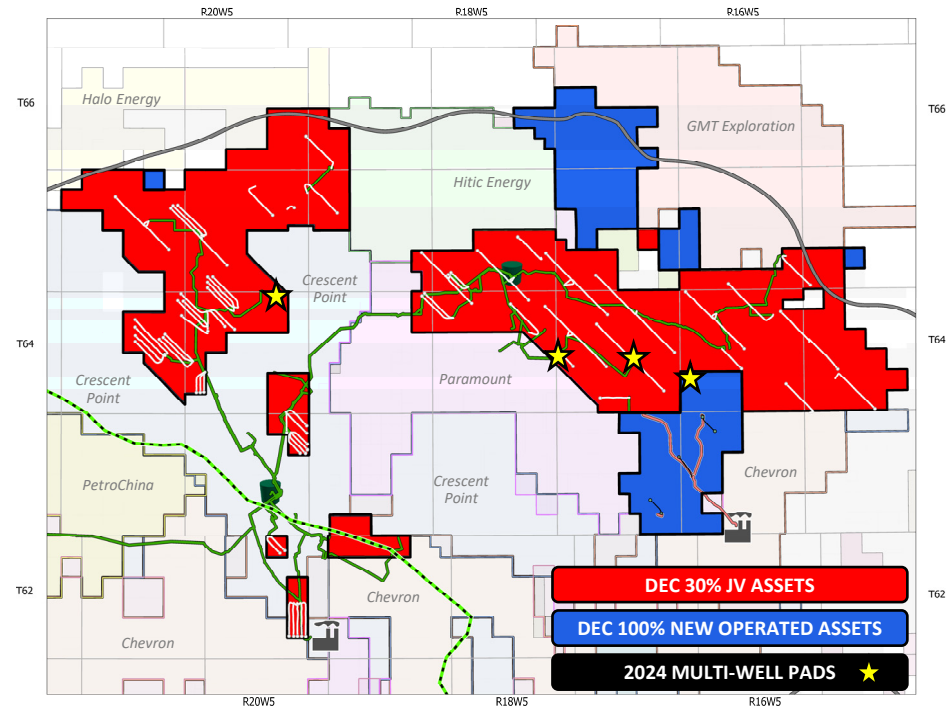
## ASSET HIGHLIGHTS

- ~200,000 gross acres
  - ~46,000 acres 100% WI newly operated position
  - ~155,000 acres 30% WI existing joint venture assets
- ~500 gross estimated well locations
- Operatorship of strategic infrastructure

## CATALYST TO ACCELERATE VALUE CREATION

- Self-funded development within Duvernay Energy with growth to ~20,000 boe/d (75% Liquids) in late 2020s
- Athabasca’s strategy remains intact
  - No change in ability to fund Thermal Oil development
  - Maintaining 2024 return of capital commitment

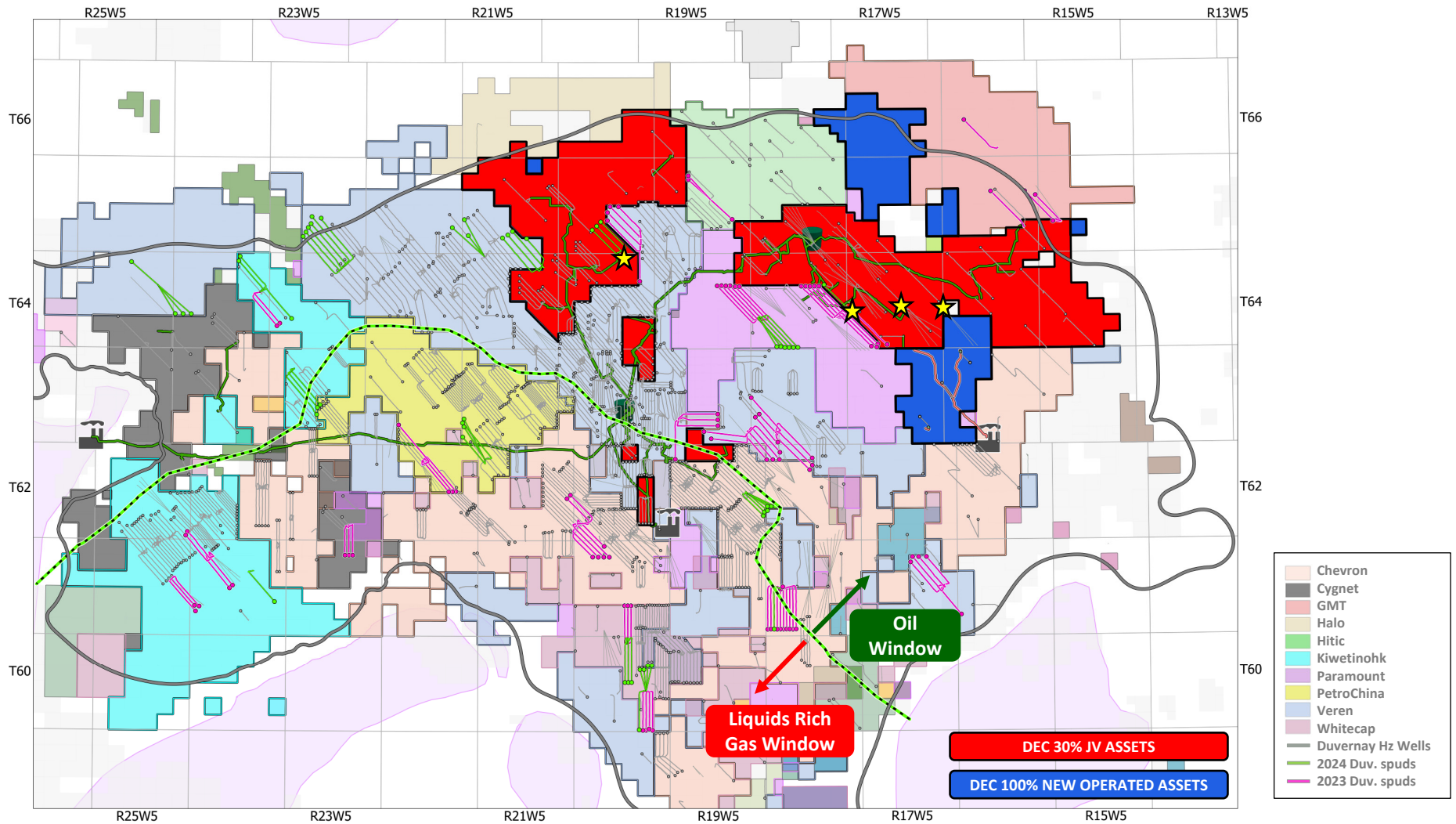
## DUVERNAY ENERGY ASSETS



## HIGHLIGHTS

Equity Ownership	70% AOC / 30% CVE
2024e Production (gross)	~3,000 boe/d
2024e Capital Budget (gross)	\$82MM
Liquidity (seed capital + RBL)	\$90MM

# DUVERNAY ENERGY – KAYBOB ACTIVITY MAP



# DUVERNAY ENERGY – DEVELOPMENT PLANS

## 2024 ACTIVITY (\$82MM CAPITAL BUDGET)

- 100% working interest operated activity
  - Two-well pad (03-18-64-17W5) on-stream in late April
    - Average restricted IP90 rate of ~1,000 boe/d per well (86% liquids)
  - Three-well pad to spud in September; on-stream in 2025
- 30% working interest JV activity
  - Three-well pad (02-03-65-20W5) on-stream in late May
    - Approx. IP60 rate of ~1,000 boe/d per well (87% liquids)
  - Four pad to spud in December; on-stream in 2025

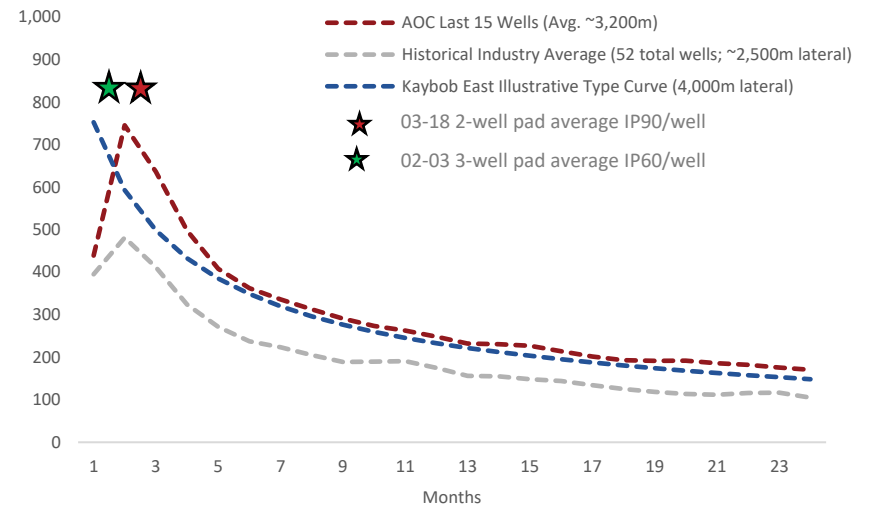
## LONG-TERM ACTIVITY

- Development plans to be funded within cash flow and flexible for a range of commodity prices
- Impactful activity on DEC’s 100% WI acreage
- Augmented by JV activity on DEC’s 30% WI acreage
- Deep drilling inventory with growth target to >20,000 boe/d (75% Liquids) in the late 2020s

## KAYBOB EAST ILLUSTRATIVE ECONOMICS 4,000M LATERAL & 1,000 LB/FT (US\$80 WTI)

		2-WELL PAD	4+ MULTI WELL PAD
Capital (DCET) per well	\$MM	\$14	\$10
IP365	boe/d	618	618
EUR	mboe	975	975
Liquids yield	%	78%	78%
IRR	%	92%	201%
Recycle Ratio	x	4.1x	5.7x
P/I	x	1.3x	2.1x
Payout	months	10	6

## KAYBOB EAST ILLUSTRATIVE TYPE CURVE (OIL/CONDENSATE ONLY; BBL/D)







## **APPENDIX**

# MANAGEMENT TEAM



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

- President and Chief Executive Officer since 2015; 12 Years at Athabasca
- Over 30 years of exploration and production experience including 18 years with Talisman Energy with roles as President, Talisman Energy USA Inc. and Senior Vice President, North American Shale.
- BSc. in Chemical Engineering from the University of Alberta and graduate of Ivey Executive Program



**Matt Taylor, CFA**  
*Chief Financial Officer*

- Chief Financial Officer since 2019; 10 years at Athabasca
- 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
- BCom. in Finance from UBC Sauder School of Business and Chartered Financial Analyst designation



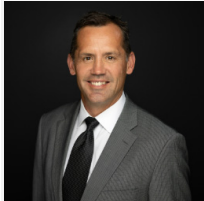
**Karla Ingoldsby, P.Eng.**  
*Vice President, Thermal Oil*

- Vice President, Thermal Oil since 2018; 14 years at Athabasca
- Over 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
- BSc. in Mechanical Engineering from the University of Alberta



**Bruce Beynon, P. Geol, MSc.**  
*Vice President, Light Oil*

- Joined Athabasca in December 2023 as Vice President Light Oil
- Over 30 years of oil and gas industry experience included roles of Executive Vice President, Exploration and Corporate Development at Baytex Energy Corporation and President of Raging River Exploration
- Professional geologist with a Bachelors and Master of Science degrees in Geology from the University of Alberta



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

- General Counsel & VP Business Development since joining Athabasca in 2022
- Over 20 years of legal, business development, and investment banking experience; previously VP, Legal, General Counsel and Corporate Secretary at Total Energy Services
- LLB and BCom. in Finance from the University of Alberta

# CAPITALIZATION & HEDGING

## LONG-TERM DEBT

- C\$200MM New Notes
  - Issued August 2024; 5-year term to 2029
  - 6.75% coupon; ~\$6MM reduction in annual debt servicing costs

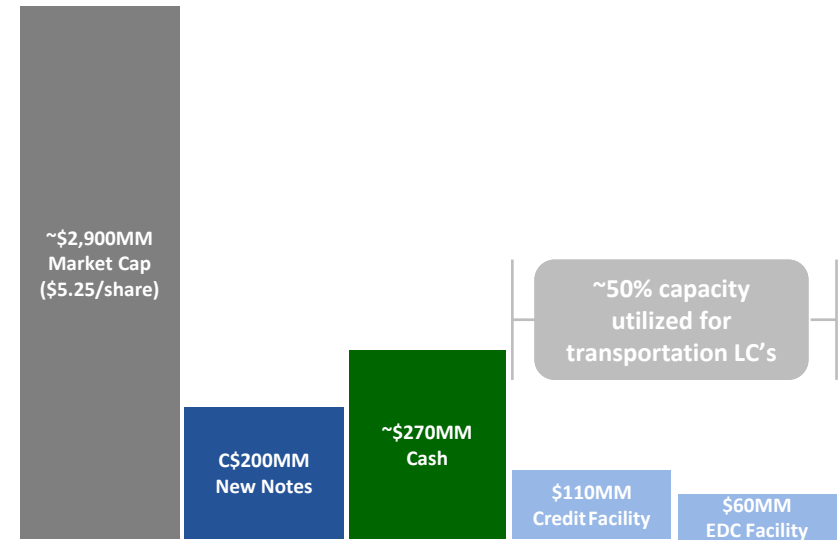
## STRONG LIQUIDITY

- ~\$400MM Liquidity, including ~\$270MM cash
- Facilities utilized for transportation LCs & hedging capacity

## EXCELLENT EXPOSURE TO COMMODITY UPSIDE

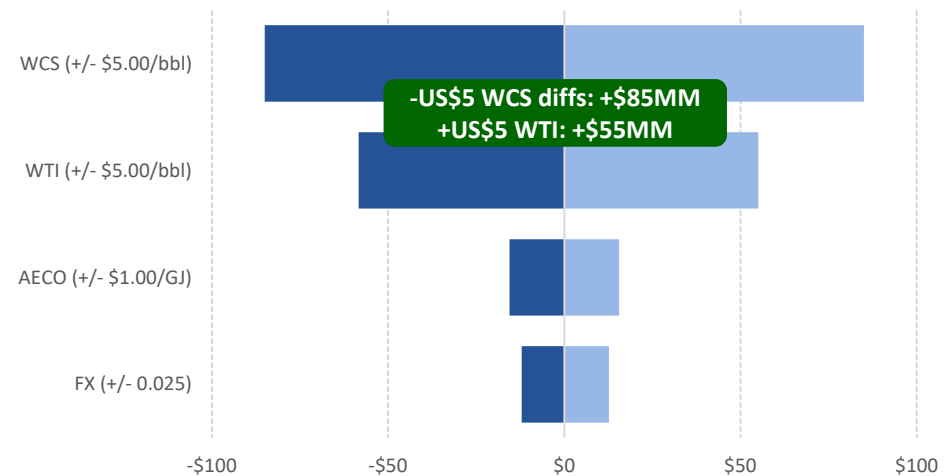
- Strong Liquidity and low sustaining capital provides protection against price volatility
- Hedging program
  - 25% rolling 12-month hedges in accordance with debt agreements
  - WTI: Q3 2024 ~20,600 bbl/d at US\$50-\$108/bbl  
Q4 2024 ~7,600 bbl/d at US\$50-\$109/bbl
  - Gas input cost: 2024 20,000 GJ/d at C\$2.35-2.84/GJ

## AOC CAPITAL STRUCTURE



Note: market capitalization bar not to scale

## 2024 FUNDS FLOW SENSITIVITY (\$MM)



Note: 2024 annualized numbers

# Q2 2024 RESULTS (JULY 24<sup>TH</sup>)

**37,621 boe/d (98% Liquids)**

*2024e upwardly revised guidance  
+1,000 boe/d to 36,000 – 37,000 boe/d*

**\$166MM Adj. Funds Flow**

*Strong Cash Flow Metrics; 2024e ~\$590MM*

**\$53/bbl Thermal Op. Netback  
\$51/boe Duvernay Op. Netback**



**\$34MM AOC Capex  
\$14MM DEC Capex**

*2024e \$275MM (incl. sanctioned Leismer 40k)*

**\$173MM Return of Capital YTD**

*34.7 million Shares Repurchased to July 24*

**\$125MM Net Cash  
\$430MM Liquidity**

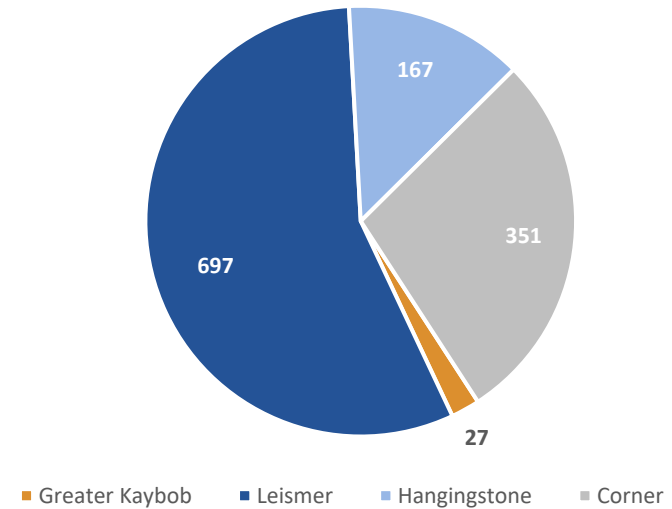
*Strategic Flexibility*

# DIFFERENTIATED LONG-LIFE RESERVES

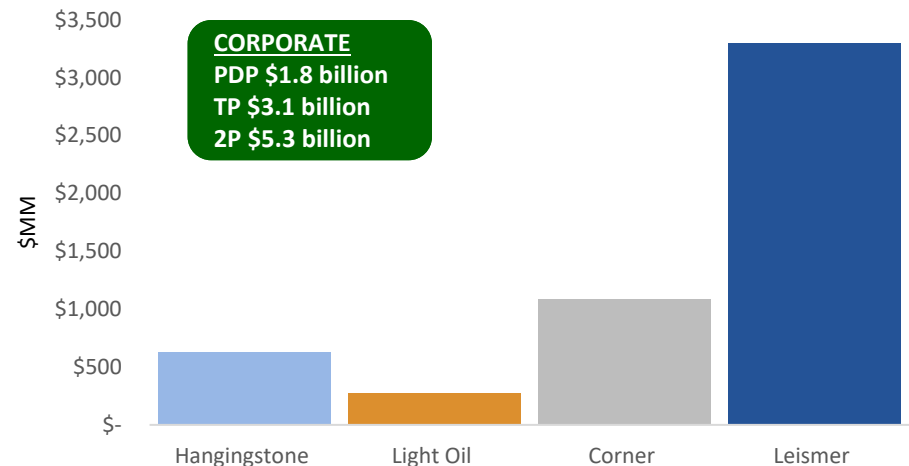
## 2023 RESERVE OVERVIEW

- Deep resource inventory
  - ~1.2 billion boe 2P reserves; ~100 year reserve life
  - ~1 billion bbl contingent resource
  - 113 of ~500 gross estimated Duvernay locations booked
- Significant intrinsic value; \$5.3 billion 2P NPV10
  - Proved Developed Producing: \$3.09/share
  - Total Proved: \$5.44/share
  - Proved plus Probable: \$9.23/share
- Compelling Thermal Oil project reserve metrics
  - Pad L8 (5 well pairs) placed on production with ~15mmbbl reclassified to PDP from TP
  - <\$5/bbl lease-edge finding costs on sustaining pads

## 2P RESERVES BY ASSET (MMBOE)

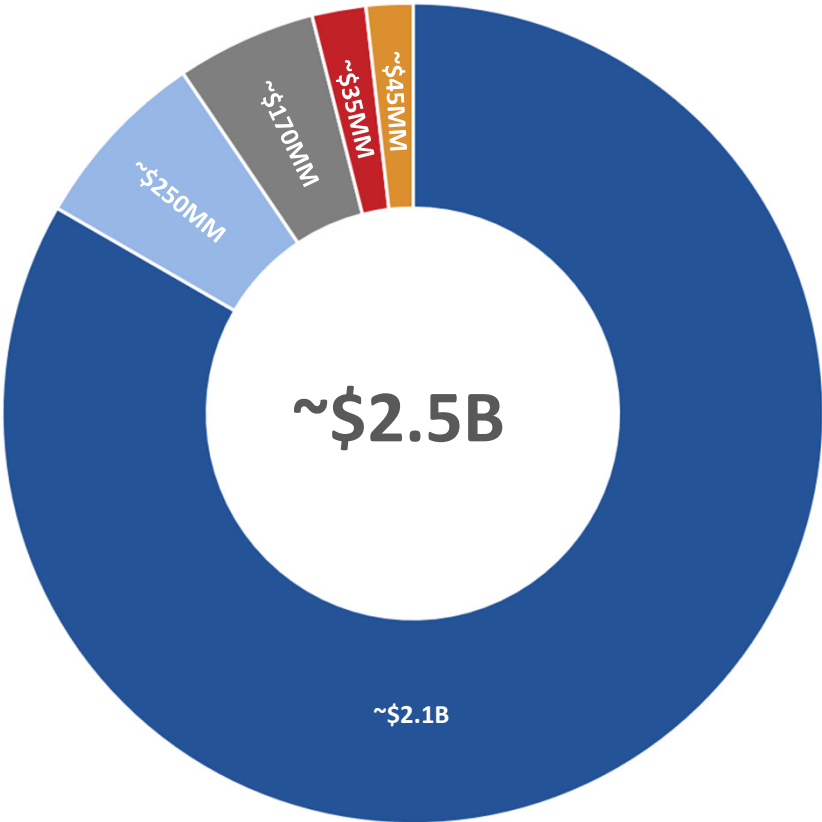


## 2P RESERVE VALUE (NPV10, \$MM)



# VALUABLE TAX POOLS

## TAX POOL SUMMARY (Q2 2024)



- Non-Capital Loss & Canadian Exploration Expense (100% Deductible)
- Canadian Cost Allowance - Class 41 & Other (25%)
- Canadian Development Expense (30%)
- Canadian Oil & Natural Gas Property Expense (10%)
- CCA - Class 17 & 49 (8%)

## ILLUSTRATIVE TAX POOL VALUATION (NPV10)

\$250MM annual deduction	~\$320MM	~\$0.57/sh
\$500MM annual deduction	~\$450MM	~\$0.80/sh
\$750MM annual deduction	~\$500MM	~\$0.90/sh
Fully Maximized	~\$560MM	~\$1.00/sh

# THERMAL OIL – CROWN ROYALTY ADVANTAGE

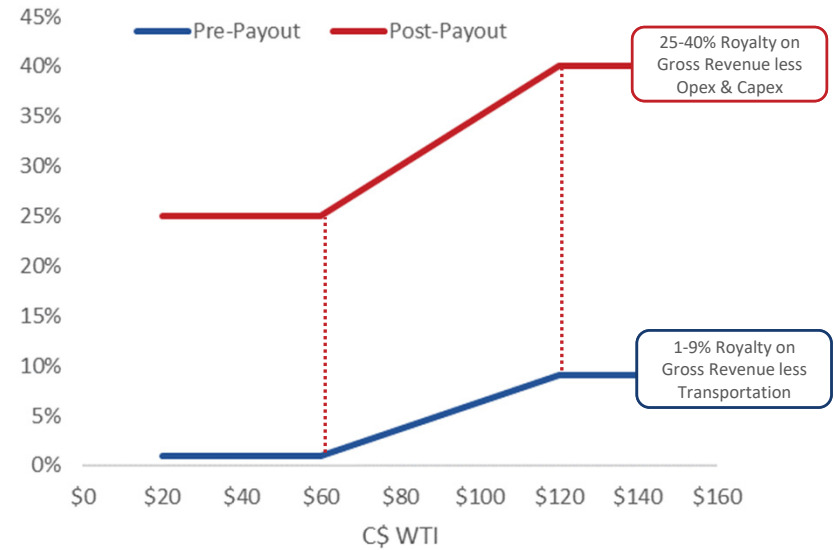
## CROWN ROYALTY OVERVIEW

- Royalty structure depends on whether a project is in pre-payout or post-payout phase
- Pre-payout advantage designed to support the recovery of the initial investment

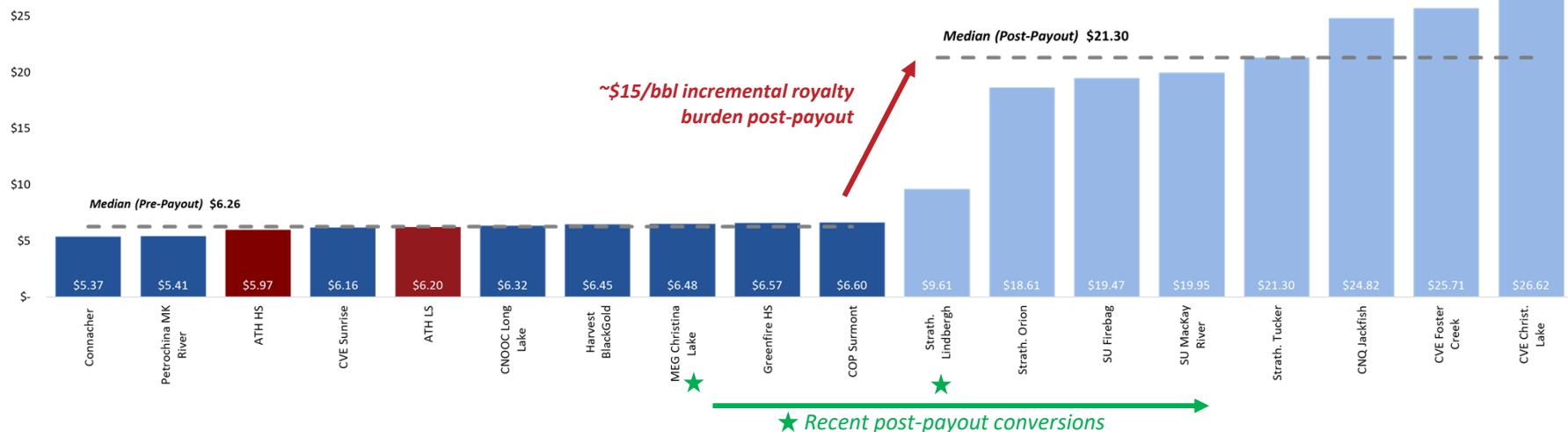
### ATHABASCA ADVANTAGE (US\$85 WTI)

- Leismer to remain in pre-payout into 2027
  - \$1.4B royalty balance
- Hangingstone to remain in pre-payout until 2030+

## OIL SANDS ROYALTY RATES



## 2022 CROWN ROYALTIES (\$/BBL) – ALBERTA GOVERNMENT OIL SANDS ROYALTY DATA

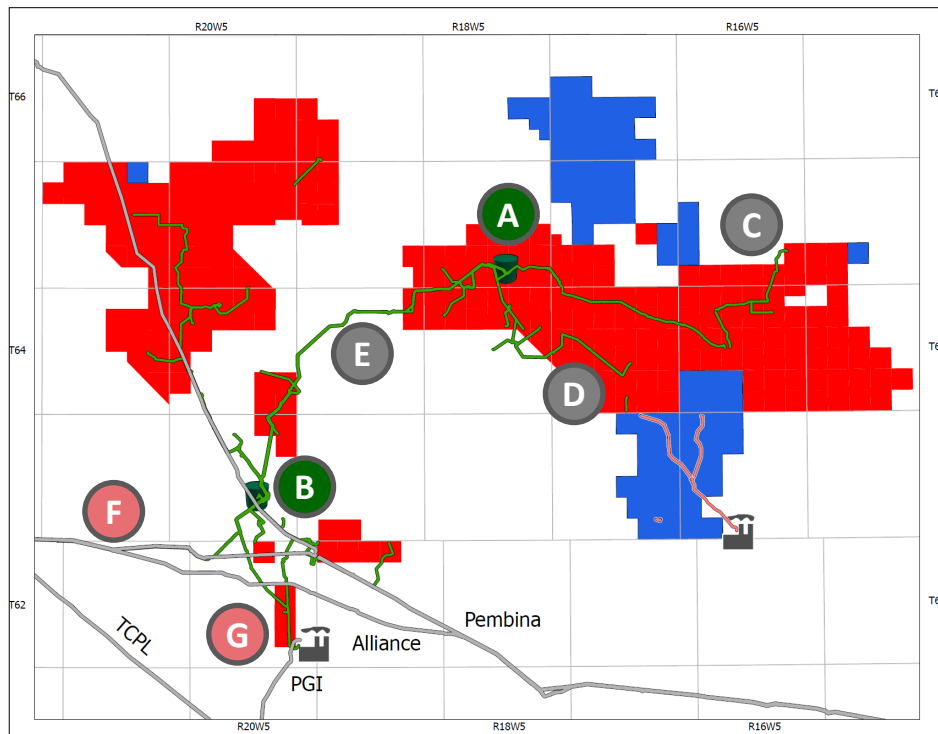


# DUVERNAY ENERGY – INFRASTRUCTURE

## INFRASTRUCTURE ADVANTAGE

- Operated strategic infrastructure
- Underutilized capacity with flexibility for future expansions
- Oil infrastructure directly connected to the Pembina Peace liquids system
- Gas infrastructure dually connected to Pembina Gas Infrastructure KA Facility and Keyera Simonette Facility

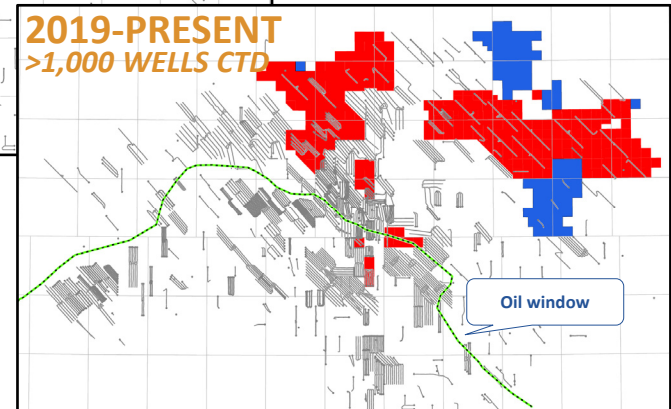
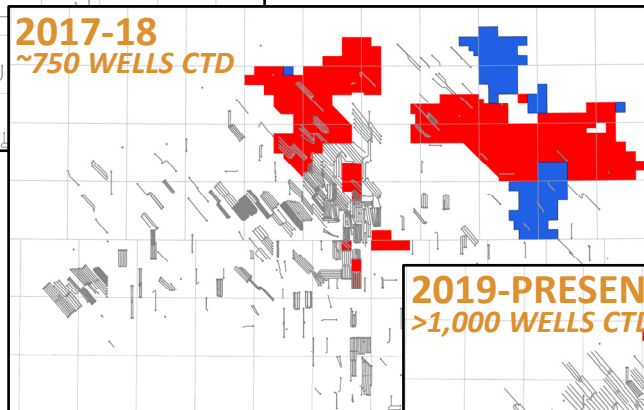
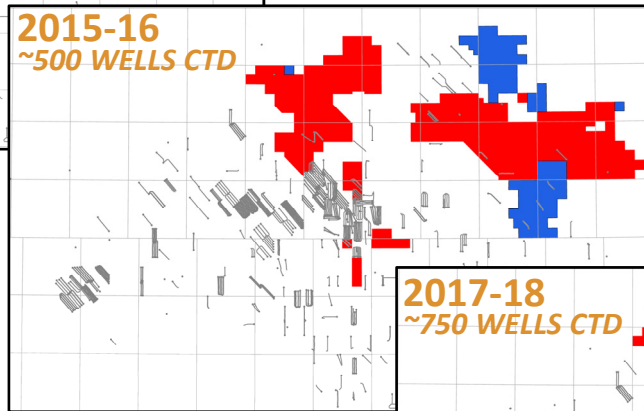
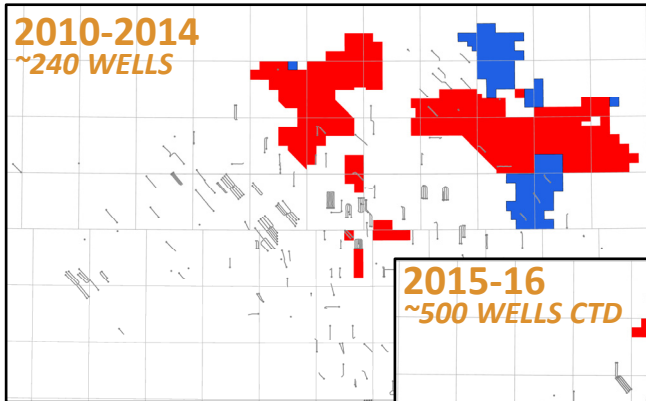
## DUVERNAY ENERGY INFRASTRUCTURE OVERVIEW



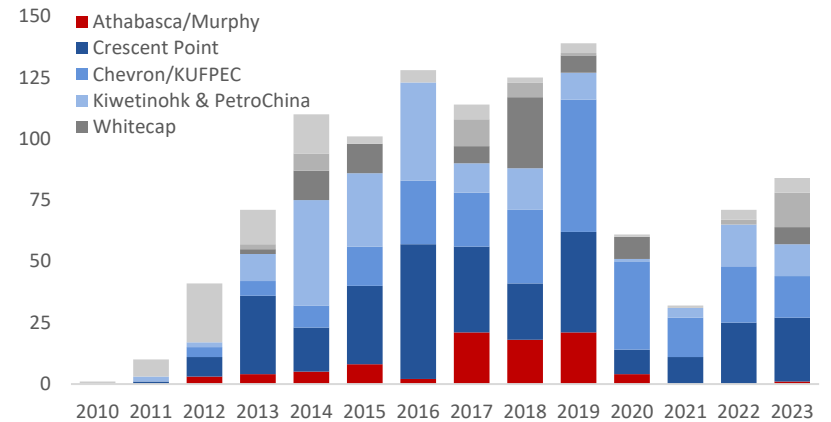
- A** Kaybob East Oil Battery  
24 mmcf/d & 10,000 bbl/d
- B** Kaybob West Oil Battery  
60 mmcf/d & 15,000 bbl/d
- C** Two Creeks Gathering Line
- D** Kaybob East Gathering Line
- E** Kaybob East / West Interconnect
- F** Keyera Simonette Gas Interconnect
- G** Pembina Gas Infrastructure Gas Interconnect



# KAYBOB DUVERNAY >1,000 INDUSTRY WELLS



## HISTORICAL SPUDS BY OPERATOR



**DEC development plans will leverage off significant de-risking on its acreage and adjacent industry activity**

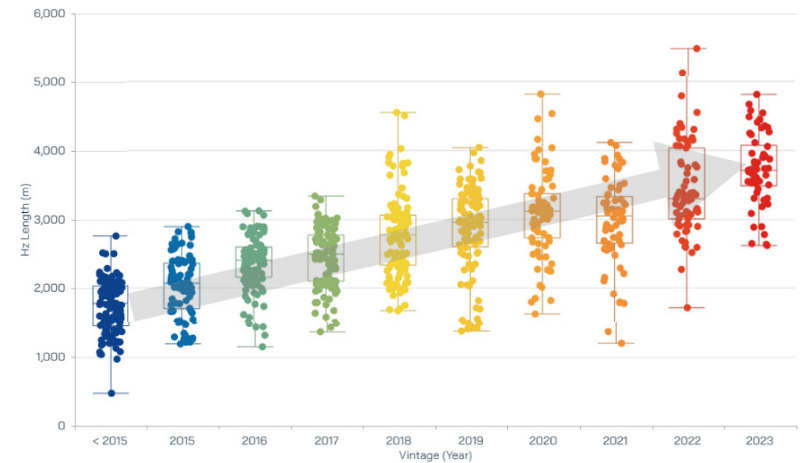
Source: GeoScout. Cumulative to date wells (CTD)

# KAYBOB DUVERNAY – EVOLVING WELL DESIGN

## LATERAL LENGTH

- Industry trend of increasing lateral length in resource plays
- Recent Kaybob Duvernay laterals between 3,500 – 4,500m
- DEC targeting ~4,000m to optimize land usage and improve capital efficiencies

## LATERAL LENGTH BY YEAR

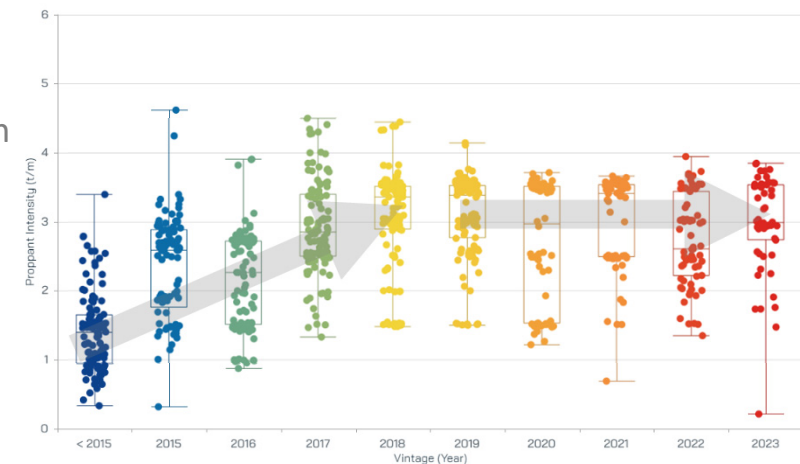


Source: McDaniel & Associates Research

## PROPPANT INTENSITY

- Proppant intensity is a significant performance factor
- Duvernay proppant loading has increased with play progression
- DEC targeting up to 1.5 – 3.0 t/m (1,000 – 2,000 lbs/ft)

## PROPPANT INTENSITY BY YEAR



Source: McDaniel & Associates Research

# READER ADVISORY

## Forward Looking Statements

This Presentation contains forward-looking information that involves various risks, uncertainties and other factors. Within this Reader Advisory and Forward Looking Statements, references to the “Company” means Athabasca and Duvernay Energy, as and where applicable. 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 and capital efficiencies; Leismer and Hangingstone ramp-up to expected production rates and improved margins with scale; timing of Leismer and Hangingstone’s pre-payout royalty status; applicability of tax pools; Net Debt/Cash positions; Adjusted Funds Flow, Operating Income and Free Cash Flow in 2024-27; the impact of future hedge levels; type well and project economic metrics; number of drilling locations; 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; the Company’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, 2023 (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 February 29, 2024 available on SEDAR at [www.sedarplus.ca](http://www.sedarplus.ca), 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 including deceptive marketing practices; 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; 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; 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 and 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; water use restrictions and/or limited access to water; relationship with Duvernay Energy Corporation; management estimates and assumptions; third-party claims; conflicts of interest; inflation and cost management; credit ratings; growth management; impact of pandemics; ability of investors resident in the United States to enforce civil remedies in Canada; and risks related to our debt and securities. 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 the Company’s 2024-27 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 Presentation 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 and Duvernay Energy 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 and Duvernay Energy % 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, 2023. 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, 2023 and based on average pricing of McDaniel, Sproule and GLJ as of January 1, 2024.

## Well Inventory

The 500 gross Kaybob drilling locations referenced include: 37 proved undeveloped or non-producing locations and 76 probable undeveloped locations for a total of 113 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, 2023 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 the Company'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 "Corporate Consolidated Adjusted Funds Flow", "Corporate Consolidated Adjusted Funds Flow per Share", "Athabasca (Thermal Oil) Adjusted Funds Flow", "Duvernay Energy Adjusted Funds Flow", "Corporate Consolidated Free Cash Flow", "Athabasca (Thermal Oil) Free Cash Flow", "Duvernay Energy Free Cash Flow", "Sustaining Capital", "Corporate Consolidated Operating Income", "Duvernay Energy Operating Income", "Duvernay Energy Operating Netback", "Athabasca (Thermal Oil) Operating Income", "Athabasca (Thermal Oil) Operating Netback", "Cash Financing and Interest Expense", "Cash Stock-Based Compensation Expense" and "Realized Foreign Exchange" 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 Cash and Liquidity are supplementary financial measures. The Leismer and Hangingstone operating results are a supplementary financial measure that when aggregated, combine to the Athabasca (Thermal 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 per share is a non-GAAP financial ratio calculated as Adjusted Funds Flow divided by the applicable number of weighted average shares outstanding.

Adjusted Funds Flow and Free Cash Flow are calculated as follows:

(\$ Thousands)	Three months ended June 30, 2024			Three months ended June 30, 2023	
	Athabasca (Thermal Oil)	Duvernay Energy <sup>(1)</sup>	Corporate Consolidated <sup>(1)</sup>	Corporate Consolidated	
Operating Income	\$ 161,694	\$ 18,057	\$ 179,751	\$ 95,118	
Realized gain (loss) on commodity risk mgmt contracts	(1,575)	—	(1,575)	(4,596)	
General and administrative	(4,577)	(1,245)	(5,822)	(4,670)	
Interest income	3,562	188	3,750	1,605	
Cash Financing and Interest	(6,406)	(137)	(6,543)	(6,389)	
Cash Stock-Based Compensation	(3,983)	—	(3,983)	1,241	
Realized Foreign Exchange	654	—	654	(564)	
Exploration expenses	44	—	44	(81)	
<b>ADJUSTED FUNDS FLOW</b>	<b>—</b>	<b>(530)</b>	<b>(530)</b>	<b>—</b>	
Capital expenditures	149,413	16,333	165,746	81,664	
<b>FREE CASH FLOW</b>	<b>(34,084)</b>	<b>(14,369)</b>	<b>(48,453)</b>	<b>(41,432)</b>	

(1) Duvernay Energy and Corporate Consolidated reflect gross financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.

# READER ADVISORY CONT'D

The Cash Financing and Interest Expense financial measures contained in the Presentation are calculated by subtracting the net non-cash financing and interest expense as reported in the Consolidated Statement of Cash Flows from the financing and interest expense as reported in the Consolidated Statement of Income (Loss) and are considered to be non-GAAP financial measures.

The Cash Stock-Based Compensation Expense financial measures contained in the Presentation are calculated by subtracting the net non-cash stock-based compensation expense as reported in the Consolidated Statement of Cash Flows from the stock-based compensation expense as reported in the Consolidated Statement of Income (Loss) and are considered to be non-GAAP financial measures.

The Realized Foreign Exchange financial measures contained in the Presentation are calculated by subtracting the realized foreign exchange (gain) loss on redemption of US dollar debt as reported in the Consolidated Statement of Cash Flows from the realized foreign exchange gain (loss) as reported in Note 19 of the Consolidated Financial Statements and are considered to be non-GAAP financial measures.

Sustaining Capital is managements assumption of the required capital to maintain the Company's production base.

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

The non-GAAP measure Athabasca (Thermal Oil) Operating Income is calculated by subtracting the Athabasca (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 Athabasca (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 Athabasca (Thermal Oil) Operating Income and the Athabasca (Thermal Oil) Operating Netback measures allow management and others to evaluate the production results from the Company's Athabasca (Thermal Oil) assets.

Net Cash 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 and warrant liability.

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 2023 year-end reserves with Q4 2023 production.

## Production

This Presentation also makes reference to Athabasca's forecasted total daily average Thermal Oil production of 33,000 - 34,000 bbl/d for 2024. Athabasca expects that 100% of that production will be comprised of bitumen. Duvernay Energy's forecasted total daily average production of approximately 3,000 boe/d for 2024 is expected to be comprised of approximately 67% tight oil, 23% shale gas and 10% NGLs.

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

Historical annual and 2023 year-end Corporate volumes by product are provided below:

Product		2016	2017	2018	2019	2020	2021	2022	2023
Bitumen	<i>bbl/d</i>	7,384	27,900	27,900	26,058	22,745	26,805	28,989	30,246
Natural Gas	<i>mcf/d</i>	13,858	20,890	33,104	28,281	23,229	20,506	16,169	10,769
Condensate NGLs	<i>bbl/d</i>	788	2,687	2,793	2,009	1,964	1,374	962	528
Other NGLs	<i>bbl/d</i>	383	505	1,049	918	785	856	730	525
Light & Medium Crude Oil	<i>bbl/d</i>	331	104	98	27	2	20	30	31
Tight Oil	<i>bbl/d</i>	784	758	1,823	2,471	3,116	2,145	1,856	1,364
<b>Total</b>	<i>boe/d</i>	<b>11,980</b>	<b>35,435</b>	<b>39,180</b>	<b>36,196</b>	<b>32,483</b>	<b>34,618</b>	<b>35,262</b>	<b>34,490</b>

## 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