# B-32 Exploration Ltd.

## Scalable & Multi-Decade Duvernay Company

June 2026

B-32 EXPLORATION

# Introduction

## Section I

B-32 EXPLORATION

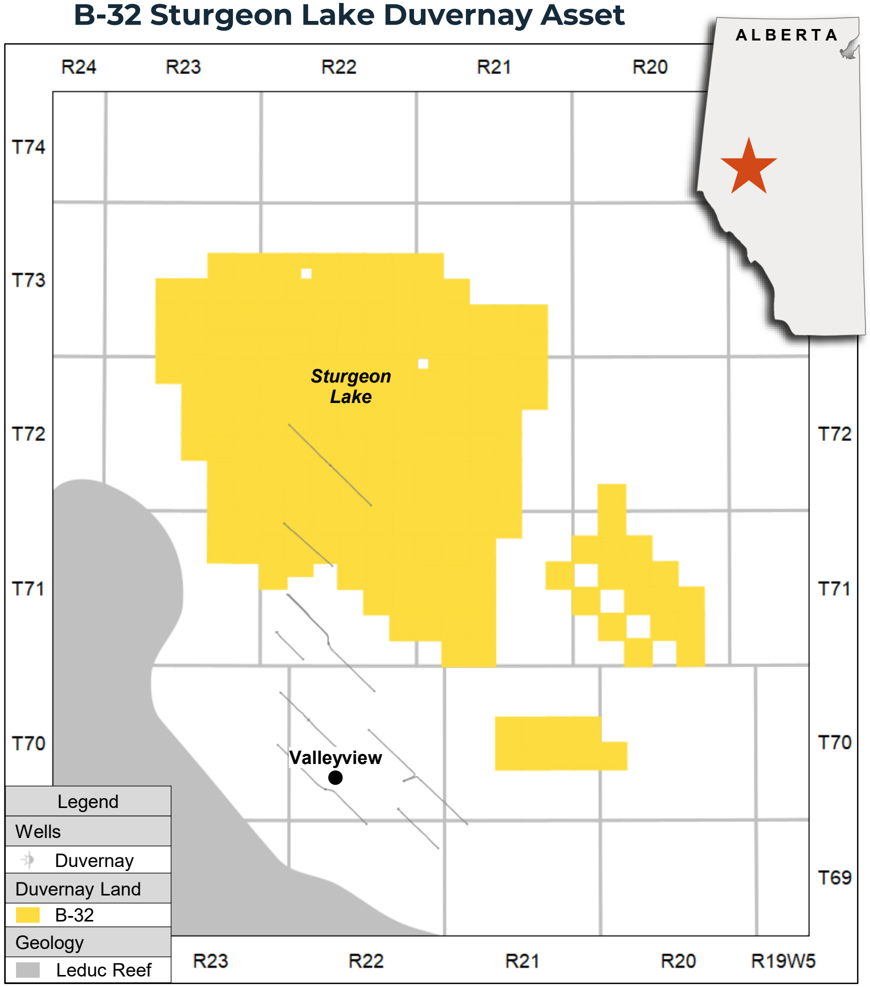
# B-32 Highlights

## Introduction

### B-32 Highlights

| | |
|---|---|
| **Large Contiguous Land Base** | • ~128,000 contiguous acres in the emerging Sturgeon Lake Duvernay play<br>• Meaningfully de-risked with more than $125 million invested in the area over the past 4 years by B-32 and other operators |
| **Evolving Development Stage** | • Sturgeon Lake Duvernay shifting from appraisal to development<br>• High-quality reservoir proven by historical drilling<br>• Past learnings driving optimization of design and execution, supported by offsetting results |
| **Scalable Growth and Development Potential** | • 250 locations independently identified by McDaniel provide growth potential to 20+ mboe/d. 87 locations benefit from ERP C* (effective 5% royalty for majority of life)<br>• Light oil weighting drives peer-leading netbacks and attractive single well economics |
| **Proven Management Team** | • Proven track record of identifying and developing high quality resource plays, including the Duvernay<br>• Strong shareholder alignment, with management and board owning ~53% (pre-financing) |

### B-32 Sturgeon Lake Duvernay Asset




**B-32 has meaningfully advanced the development and de-risking of the Sturgeon Lake Duvernay and is positioned to move the asset into the commercial development stage with the potential to grow production to over 20 mboe/d**

# Leadership Team

## Introduction

### Executive Team

**Larry Evans**
**P.Eng.**
*President, CEO & Director*

- 40+ years of experience in the energy and financial industries, co-founded, grew, and successfully exited four oil and gas companies, averaging >5x return on invested capital and was Managing Partner and Co-founder of a series of private equity funds investing in emerging oil and gas companies
- Currently Co-founder and Managing Partner of 32 Degrees Capital and on the board of Artis Exploration (Duvernay pure-play)

**Melissa Fabreau**
**P.Eng., ICD.D**
*Chief Operating Officer*

- 20+ years of energy industry experience, initially honed at Enerplus as an exploitation engineer, focused on resource development, reservoir engineering, project economics, and reserve evaluation in Western Canada
- Past 8 years specializing in the Sturgeon Lake Duvernay, leading all engineering disciplines across B-32's three-well drilling, completions, and production program, and collaborating with unconventional experts to drive progress in the play

**Kim Benders**
**CPA, CMA**
*Chief Financial Officer*

- 20+ years of progressive finance and accounting experience in the oil and gas sector, with senior finance roles including CFO, Interim CFO and Corporate Controller
- Previously held senior finance roles at Ikkuma Resources, Briko Energy and Covee Energy, and most recently provided interim and fractional CFO and Controller services to a range of junior oil and gas and resource companies

**Kristal Gibson**
**P.Geo.**
*VP of Geosciences*

- 20+ years of diverse subsurface evaluation experience, specializing in new play growth with 7+ years focused on the appraisal and development of the Duvernay formation
- Prior to joining B-32, served in various senior geologist roles at Sinopec Canada and worked at Talisman Energy (Repsol)

### Board of Directors

**Mitch Putnam**
**P.Geol.**
*Director*

- 40+ years of experience in the energy and financial industries, co-founded and successfully exited multiple oil and gas companies averaging >5x return on invested capital. Brings technical geoscience oversight as a P.Geol. with deep experience evaluating and de-risking unconventional resource plays across Western Canada

**Jason Smith**
**B.S./M.S. Petroleum Engineering, Texas A&M | MBA**
*Director*

- 30+ years of international oil and gas experience including direct leadership of Murphy Oil's highly successful Kaybob Duvernay and Tupper Montney developments. Brings hands-on unconventional development execution experience, significant M&A and commercial negotiation expertise, and board-level operational oversight as former COO of QuarterNorth Energy, a deepwater Gulf of Mexico producer, prior to its sale to Talos Energy

# Sturgeon Lake Duvernay

## Section II

B-32 EXPLORATION

# Duvernay Regional Landscape

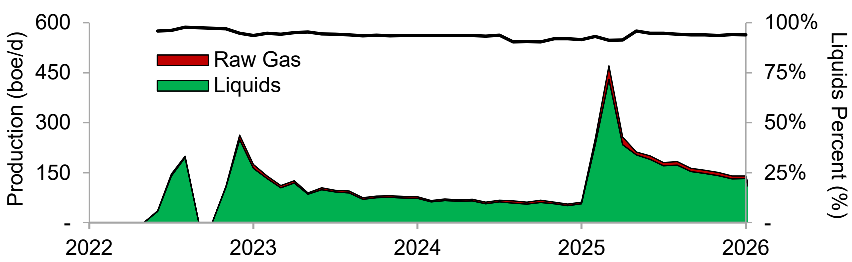
## Sturgeon Lake Duvernay

### Highlights

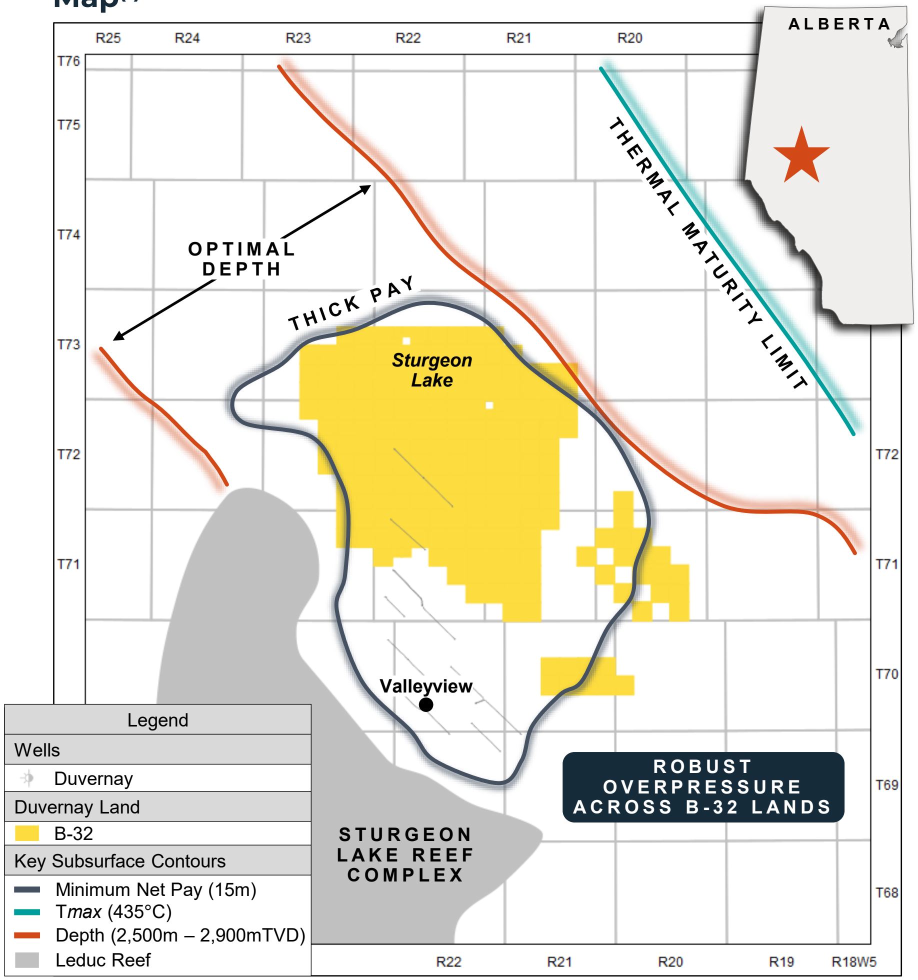
- B-32 holds a strategic Duvernay position at Sturgeon Lake, situated within a prolific light oil fairway in Northwest Alberta
- The company maintains a significant position of ~200 sections (~51,000 hectares / 128,000 acres) of contiguous Duvernay rights
- Current production from initial wells is 140 boe/d (94% liquids)
- Learnings from initial appraisal wells and offset operators have defined an optimized, high-performance design for the next phase of drilling
- Sturgeon Lake possesses the critical reservoir characteristics required for a premier shale oil play: depth, pressure, thermal maturity, and substantial net pay


B-32 Sturgeon Lake lands exhibit all the key attributes of a successful shale play

### B-32 Production History[2]




### Map[1]




**The technical foundation of Sturgeon Lake is fully established through premium depth, pressure, maturity, and net pay; initial well data has successfully isolated the design variables needed to drive outsized returns moving forward**

*Source: geoSCOUT*
*1) Western Canadian Sedimentary Basin Atlas, 1994*
*2) Liquids include wellhead oil and wellhead condensate*

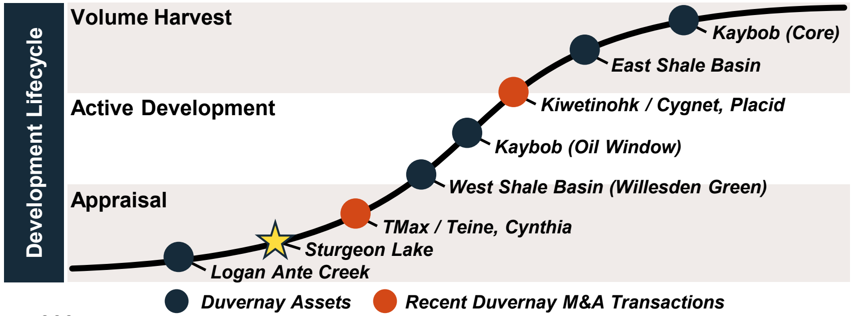
# Duvernay Regional Landscape

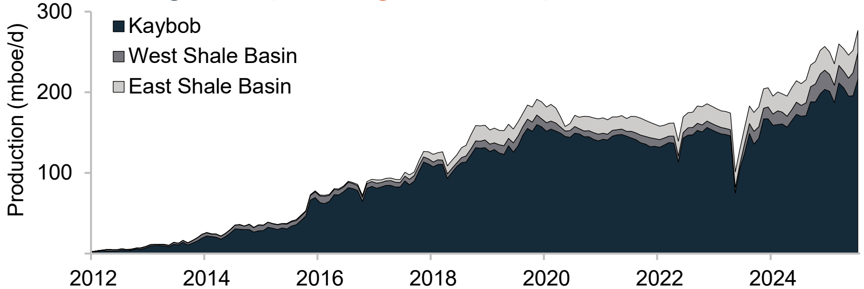
## Sturgeon Lake Duvernay

### Highlights[1]

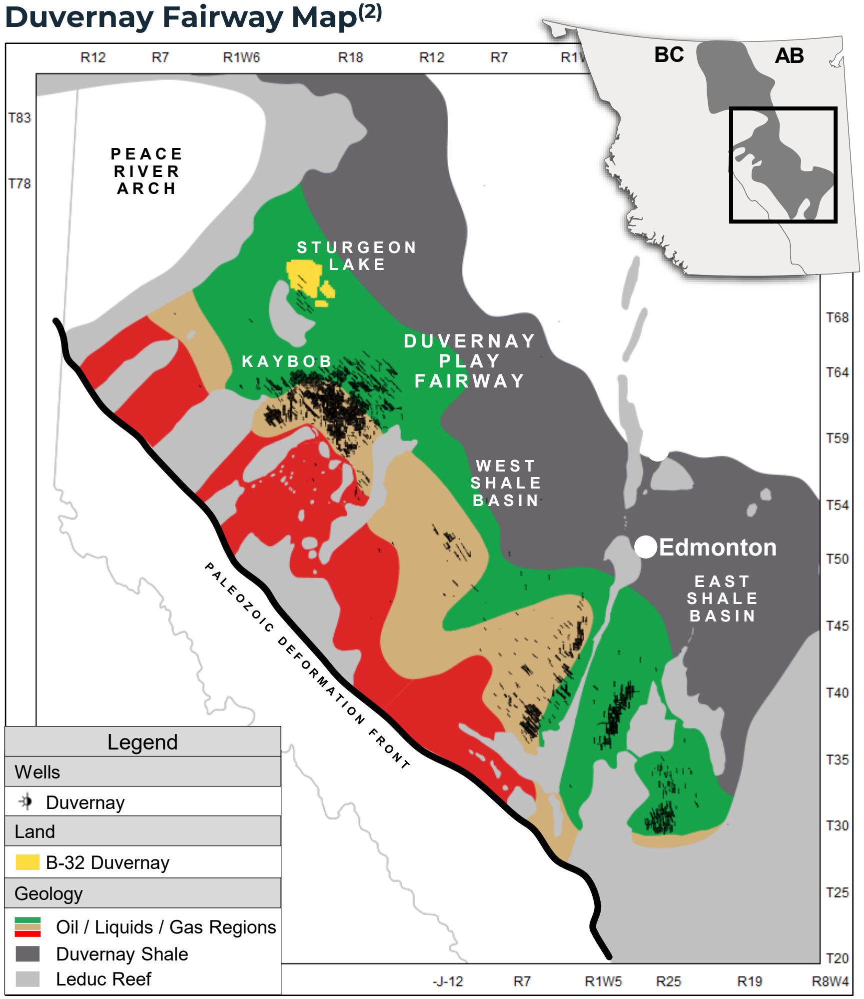
- The Duvernay formation covers a significant portion of central Alberta, underlying approximately 130,000 km$^2$, making it one of the largest shale plays in North America
- The Duvernay formation holds a significant amount of recoverable hydrocarbons, estimated to be 77 TCF natural gas, 6.3 billion barrels of NGL's and 3.4 billion barrels of crude oil
- The Duvernay play is divided into major basins separated by major reef complexes: Kaybob, West Shale Basin & East Shale Basin

### Duvernay Development Phase and Production History[3]




### Duvernay Fairway Map[2]




**The Duvernay Formation in central Alberta is a massive shale play, rich in natural gas, NGLs, and crude oil; this vast resource is divided into three main areas—Kaybob, West Shale Basin and East Shale Basin each contributing to its significant hydrocarbon potential**

*Source: geoSCOUT*
*1) Alberta Geological Society Energy Briefing, 2017*
*2) Western Canadian Sedimentary Basin Atlas, 1994*
*3) Enverus gross operated production*

# Duvernay Regional Geology

## Sturgeon Lake Duvernay

### Highlights(1,2,4)

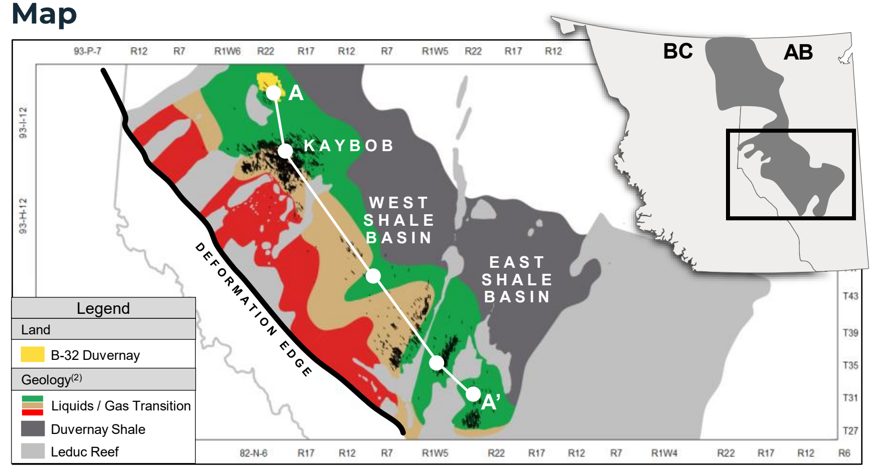
- B-32 has compared Duvernay characteristics across B-32's Sturgeon Lake with other major Duvernay regions, and observed the following:
- Sturgeon Lake features a concentrated, thick Upper Shale bench that completely lacks the restrictive carbonate barriers found in other Duvernay regions, creating a single clean, continuous reservoir
- Sturgeon Lake's ideal thermal maturity places it firmly in the premium light oil window, delivering a stable, low-GOR system that significantly reduces surface infrastructure capital
- Shielded by the Sturgeon Lake Leduc reef system, the asset avoids the high effective stress found in deeper trends, resulting in lower drilling complications, reduced completion risks, and predictable fracture propagation

### Geological Comparison(2,3,4,5)

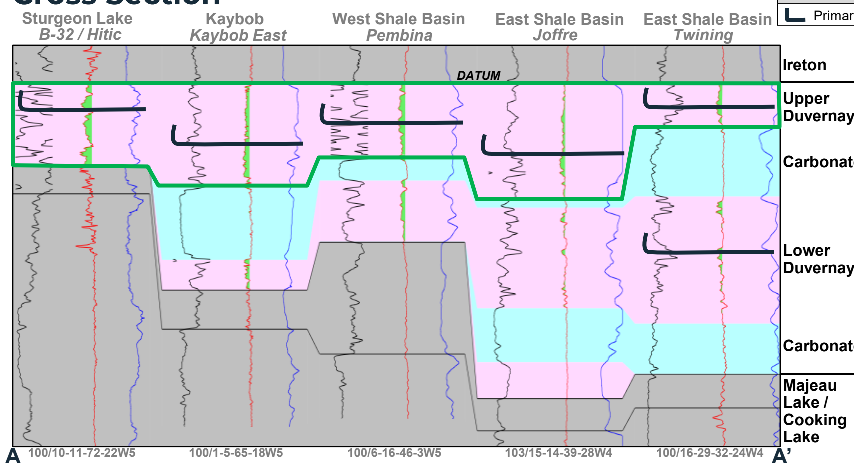
| Area | - | Sturgeon Lake | Kaybob | West Shale Basin | East Shale Basin | East Shale Basin |
|---|---|---|---|---|---|---|
| Pool | - | Sturgeon Lake South | Kaybob (East) | Pembina | Joffre | Twining |
| Average Depth | (mTVD) | 2,700 | 3,500 | 3,200 | 2,500 | 2,300 |
| Lithology | - | Basinal bituminous shale | Basinal bituminous shale | Basinal bituminous shale | Shale, carbs & siliciclastics | Shale, high carb content |
| Deposition | - | Restricted shale basin | Restricted shale basin | Restricted shale basin | Restricted shale basin | Restricted shale basin |
| Primary Targets | - | Upper Shale | Upper Shale | Upper Shale | Upper Shale | Upper & Lower Shales |
| Upper Shale Net Pay | (m) | 15 - 20 | 12 - 50 | 12 - 17 | 8 - 25 | 10 - 20 |
| Porosity | (%) | 6 - 12 | 3 - 5 | 3 - 6 | 3 - 4 | 3 - 4 |
| Sw | (%) | <30 | <15 | 10 - 15 | 10 | 25 |
| Pressure Gradient | (kPa/m) | 13 - 17 | 14 - 20 | 14 - 19 | 12 - 17 | 12 - 18 |
| Tmax | (°C) | 439 - 448 | 440 - 470 | 445 - 465 | 440 | 440 |
| Isotherm | (°C) | 85 - 95 | 90 - 110 | 90 - 110 | 65 - 90 | 65 - 80 |
| Hydrogen Index | (mg/g) | 200 - 350 | 50 - 160 | 40 - 150 | 150 - 300 | 150 - 300 |
| Maturity | - | Oil | Dry Gas to Oil | Dry Gas to Oil | Oil | Oil |
| Oil Gravity | (°API) | >40 | >45 | >45 | 40 | 40 |

B-32 EXPLORATION

### Map




### Cross Section




**Sturgeon Lake offers a premier light-oil Duvernay opportunity featuring an overpressured, continuous, thick Upper Shale target**

*Source: geoSCOUT*
*1) Western Canadian Sedimentary Basin Atlas, 1994*
*2) Potma et al., 2001, Canadian Discovery*
*3) While localized areas within the Joffre field exhibit pressure gradients reaching ~18 kPa/m, these high values are not regionally representative of the East Shale Basin*
*4) The West Shale Basin is particularly prone to high effective stress and drilling complications due to the Snowbird Shear Zone; Sturgeon Lake and Kaybob, benefit from the "shielding" effect of offset carbonate complexes*
*5) AER Pool Card Index*

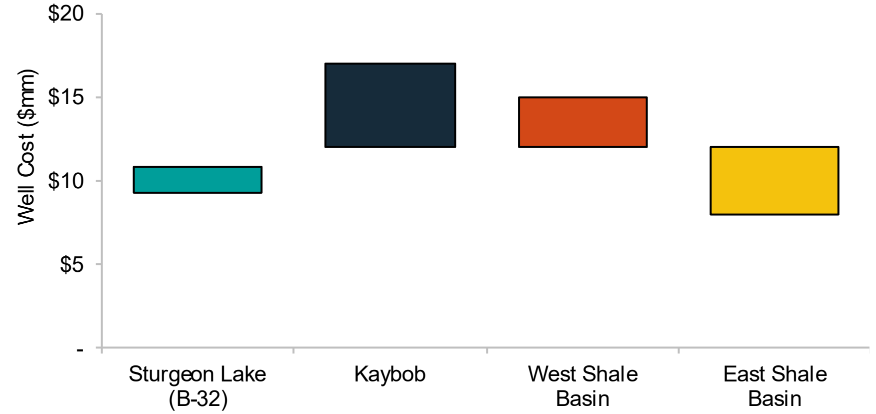
# Regional Benchmarking

## Sturgeon Lake Duvernay

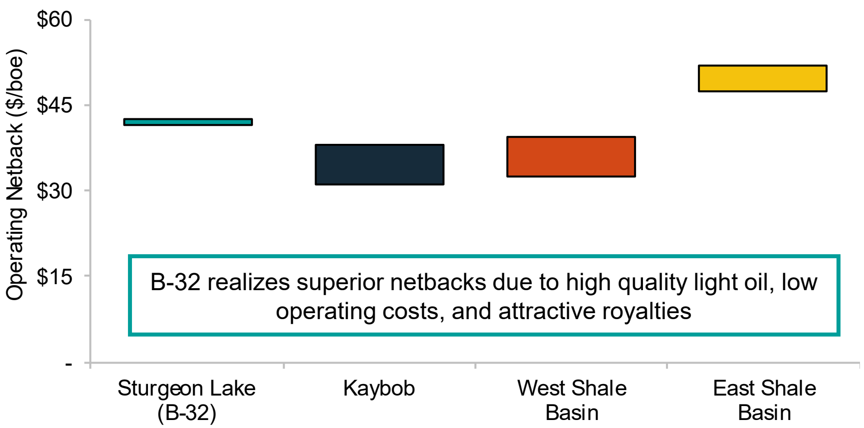
### Highlights

- The Sturgeon Lake Duvernay offers compelling half-cycle economics due to lower capital well costs and higher operating netback relative to other Duvernay regions
- The ERP offers favourable C* benefits and Crown tenure, further reducing the early-life royalty burden and improving single well half-cycle economics
- Low infrastructure costs, farmland surface access, established road infrastructure, and no environmental restrictions position Sturgeon Lake as a low full cycle cost development

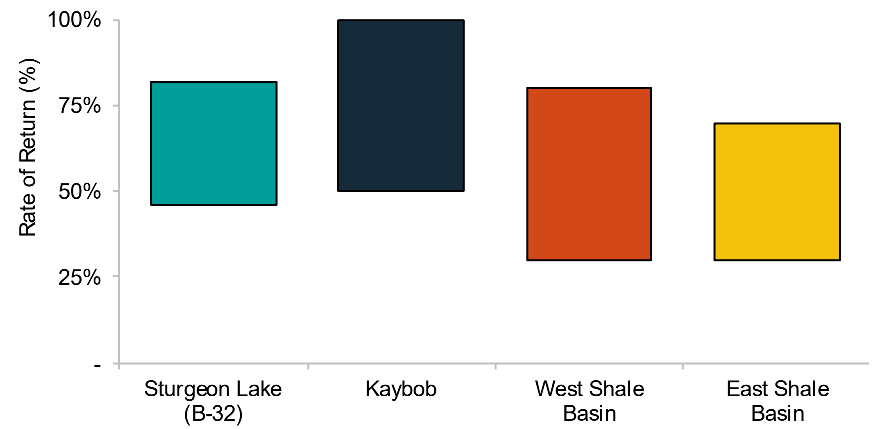
### Per Well Capital Costs




### Operating Netback(1)




### Rate of Return(2,3)




**Low costs and high netbacks position Sturgeon Lake as one of the Duvernay's lowest-cost entry point**

*Source: Corporate Disclosures*
*1) Based on full year 2025 operating netbacks*
*2) Based on disclosed figures at price decks between US$65/bbl and US$75/bbl WTI, $2.50/mcf and $3.50/mcf AECO, and 0.71 USD/CAD to 0.75 USD/CAD Exchange Rate*
*3) Rate of return for a single development well*

# Duvernay Regional Landscape

## Sturgeon Lake Duvernay

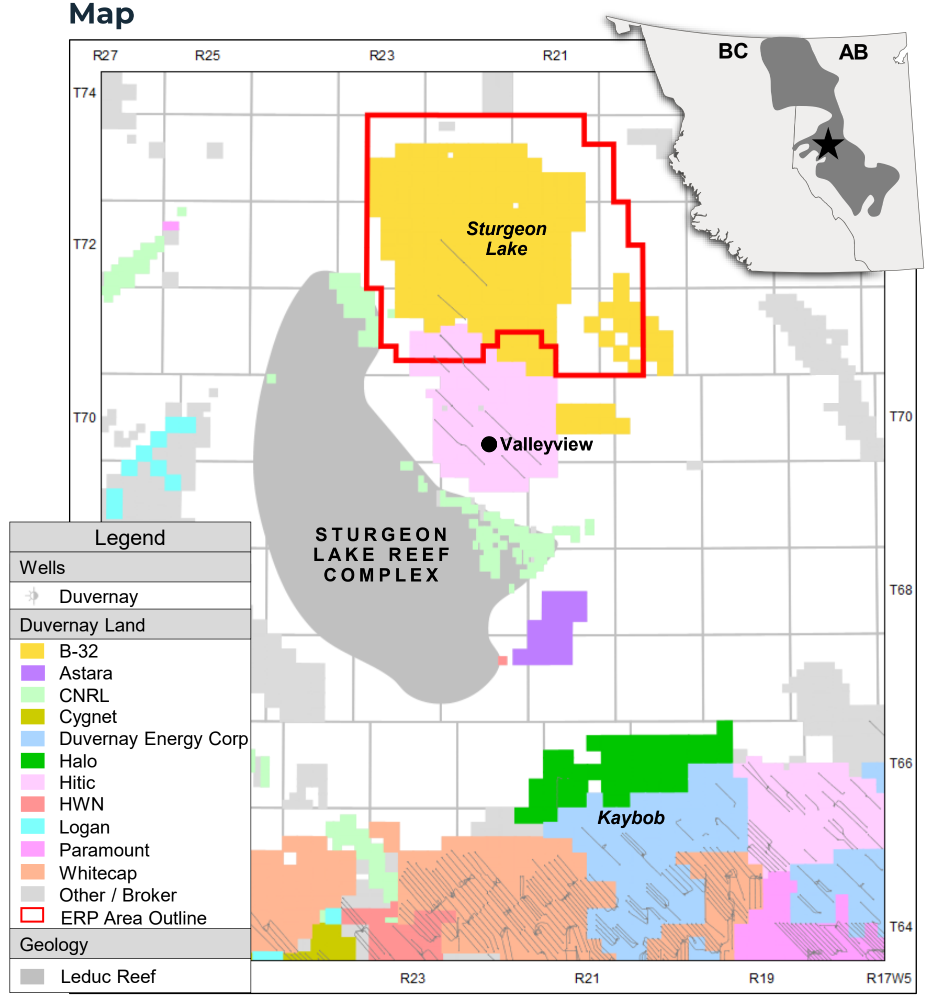
### Highlights[1]

- The Sturgeon Lake field is ideally situated within the premium black oil window, capturing the high-margin liquids and low gas-oil ratios that maximize netbacks and streamline surface facilities
- Local asset development is led by two primary operators, B-32 and Hitic, positioning the region as a highly concentrated growth area
- Located directly north of the world-renowned Kaybob fairway, placing the asset in an equally compelling geological setting alongside regional peers like CNRL, Paramount, Duvernay Energy Corporation, Hitic and Cygnet
- Early-stage regional development offers immense valuation upside through systematic play de-risking and multi-well inventory expansion

### Emerging Resources Program (ERP)

- Created by the Alberta government to incentivize new play development, the Emerging Resources Program (ERP) grants B-32 an elite fiscal status typically reserved for major basin pioneers
- The program provides an immediate safety net for initial capital deployment by slashing the Crown royalty rate to a flat 5 percent for the project's first 87 wells (with only 3 drilled to date)
- By combining this low flat rate with enhanced cost multipliers (1.50x to 1.75x standard C* benefits), the ERP effectively defers higher royalty tiers for years, allowing operators to rapidly recover well costs and reinvest free cash flow
- This strategic royalty cushion fundamentally alters the economics, transforming Sturgeon Lake into one of the most insulated, high-netback entry points in the entire Duvernay play

### Map




**As a northern extension of established fairways, the Sturgeon Lake region represents an emerging, high-upside development opportunity insulated by premium ERP fiscal incentives**

*Source: geoSCOUT*

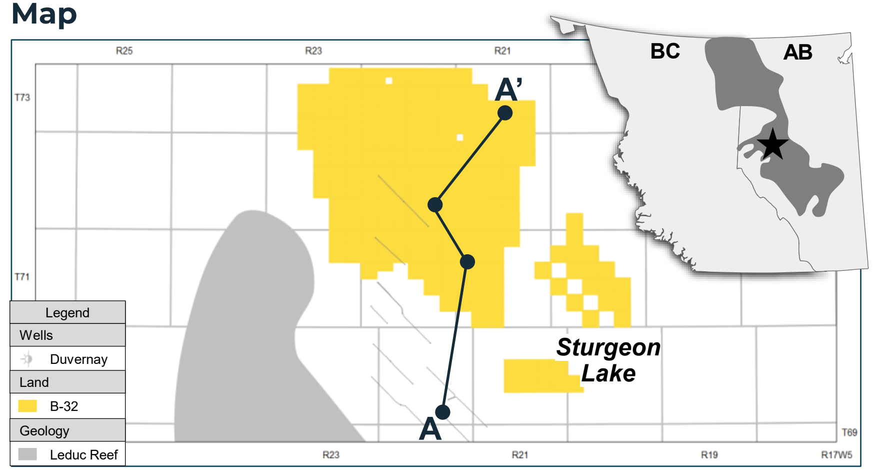
# Duvernay Local Geology

## Sturgeon Lake Duvernay

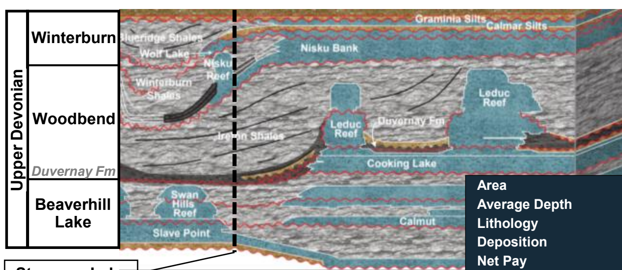
### Highlights[1]

- Located along the northern margin of the Sturgeon Lake Leduc reef complex, the asset sits within a distinct depositional fairway that directly enhanced reservoir thickness and organic richness
- Unique to this depositional environment, clay is uniformly dispersed throughout the section rather than trapped in the un-fracable layers found in other Duvernay regions, eliminating completion risks
- Additionally, high carbonate and quartz content (>60%) provides excellent rock brittleness and favourable geomechanical behavior for hydraulic fracturing
- Thermal maturity mapping places the Sturgeon Lake area within the black oil window, where a significant overpressured reservoir provides robust internal energy for hydrocarbon recovery

### Map




### Depositional Model[2]



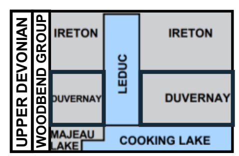

Euxinic Black Shale

Argillaceous Limestones / Calcareous Shales

Shallow Water Carbonates

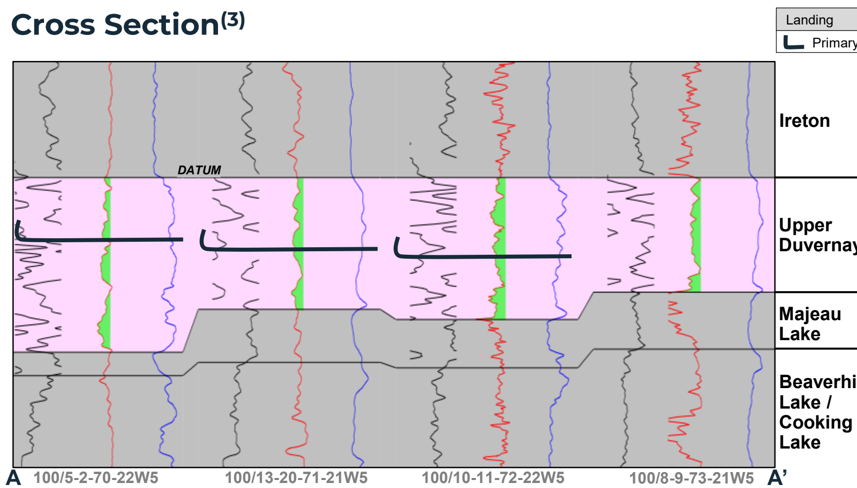
Siliciclastic Siltstones

### Stratigraphy




| | | |
|---|---|---|
| Area | - | Sturgeon Lake |
| Average Depth | (mTVD) | 2700 |
| Lithology | - | Basinal bituminous shale |
| Deposition | - | Restricted shale basin |
| Net Pay | (m) | 15 - 20 |
| Porosity | (%) | 6 - 12 |
| Sw | (%) | <30 |
| Pressure Gradient | (kPa/m) | 13 - 17 |
| Tmax | (°C) | 439 - 448 |
| Isotherm | (°C) | 85 - 95 |
| Hydrogen Index | (mg/g) | 200 - 350 |
| Maturity | - | Oil |
| Oil Gravity | (°API) | >40 |
| OOIP *per section* | (mmbbl) | 13 - 15 |

### Cross Section[3]




**Located within a unique depositional fairway along the Leduc reef complex, the Sturgeon Lake Duvernay features an overpressured black oil reservoir characterized by a thick, continuous shale bench and a dispersed-clay profile optimized for low-risk completion execution**

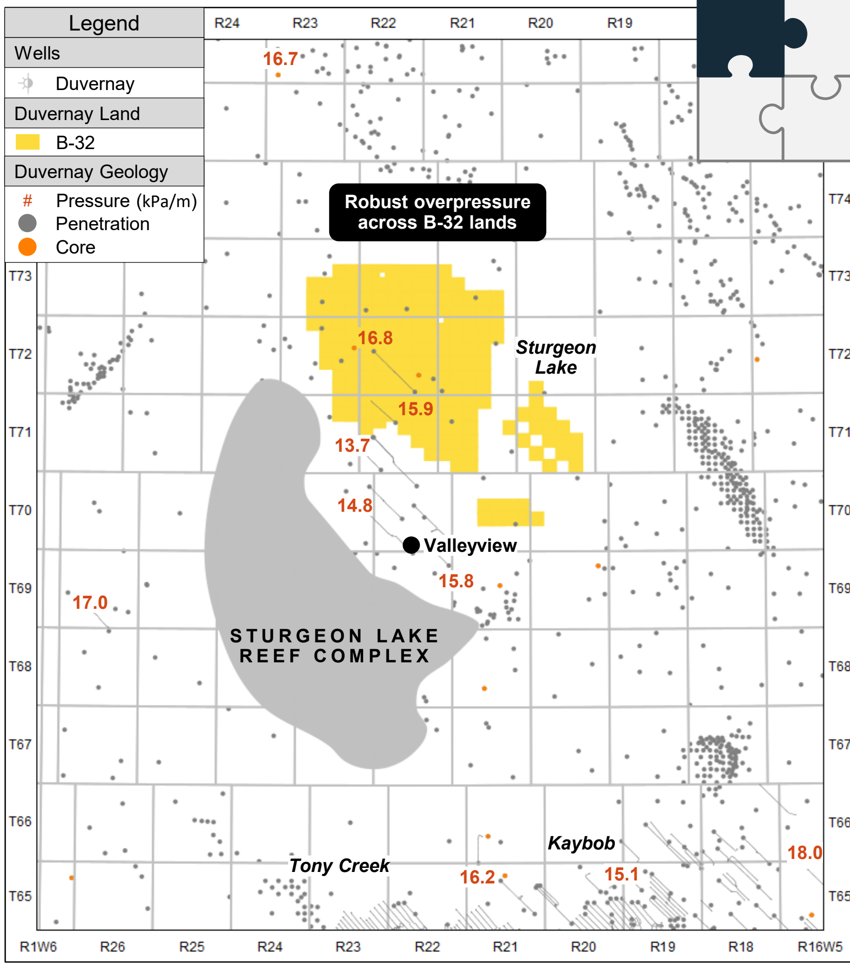
*Source: geoSCOUT*
*1) Western Canadian Sedimentary Basin Atlas, 1994*
*2) Potma et al., 2001, Canadian Discovery*
*3) Illustrative log colors and cutoffs used for interpretation are as follows: Gamma Ray (Black); Density Porosity (Red, shaded for >0%); Deep Resistivity (Blue)*

# Duvernay Regional Landscape

## Sturgeon Lake Duvernay

### Map[1]

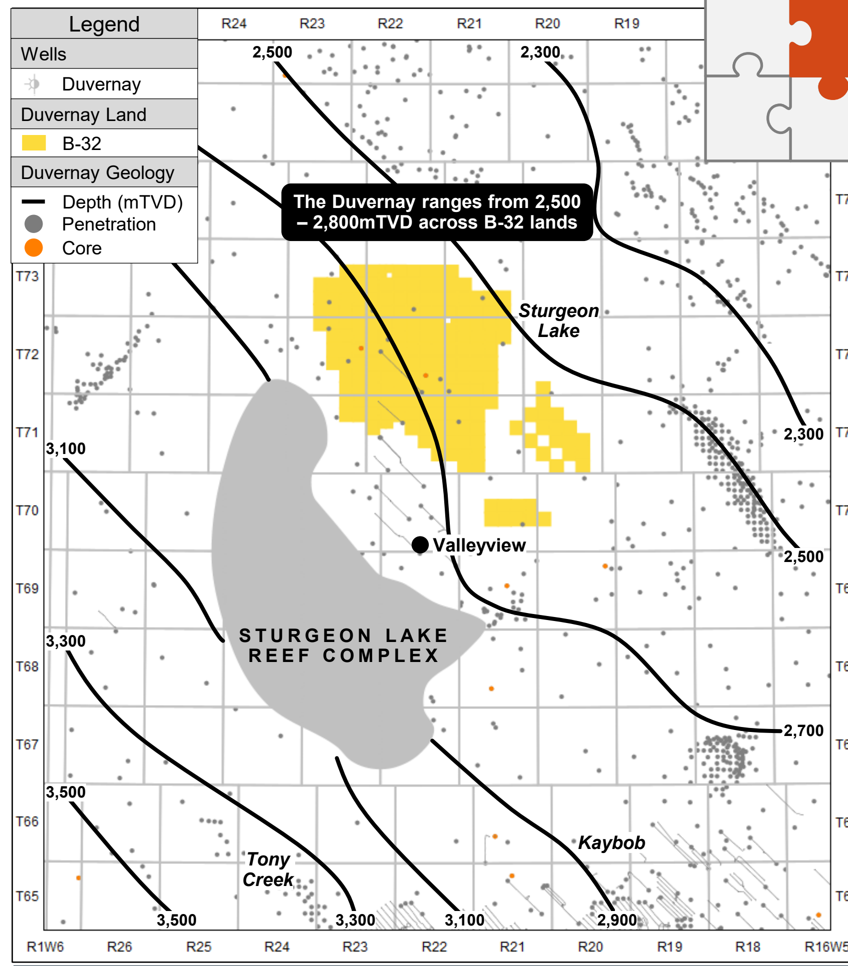
**Pressure**




**Pressure ranges between 13 – 17kPa/m through Sturgeon Lake**

### Map

**Depth**



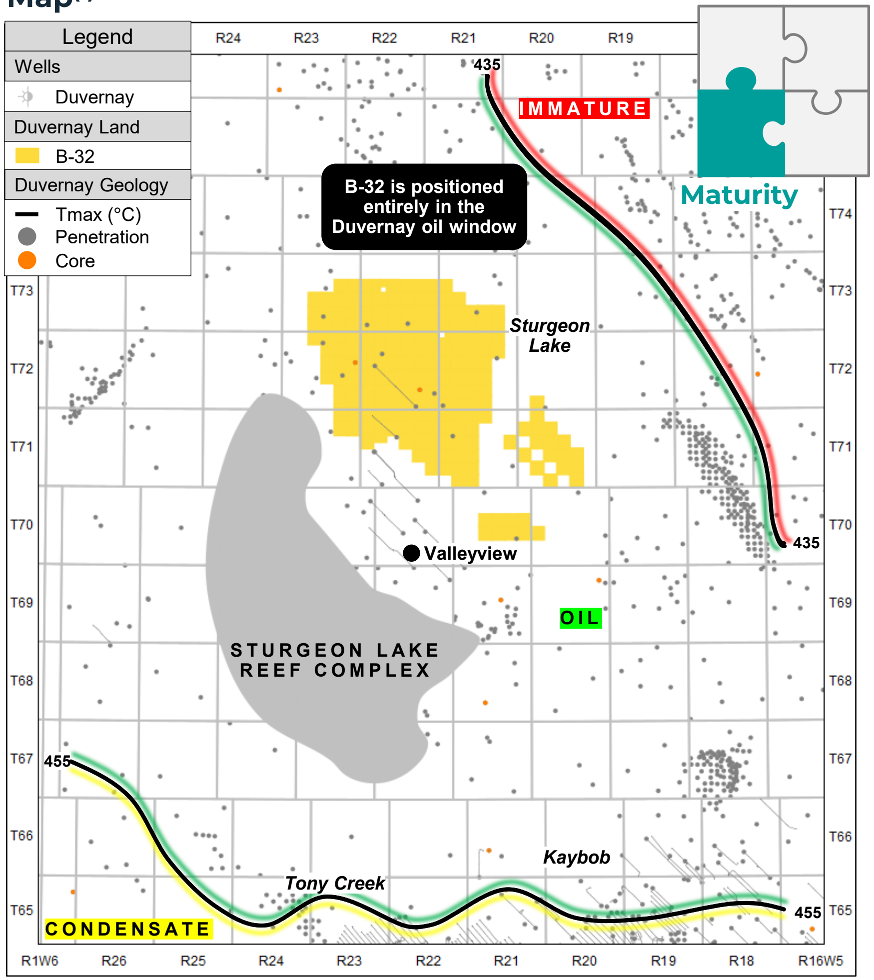

**Depth ranges between 2,500 – 2,800mTVD at Sturgeon Lake**

*Source: geoSCOUT*
*1) Pressure-depth profiles are modeled using a combination of public DST/static gradient data*

# Duvernay Regional Landscape

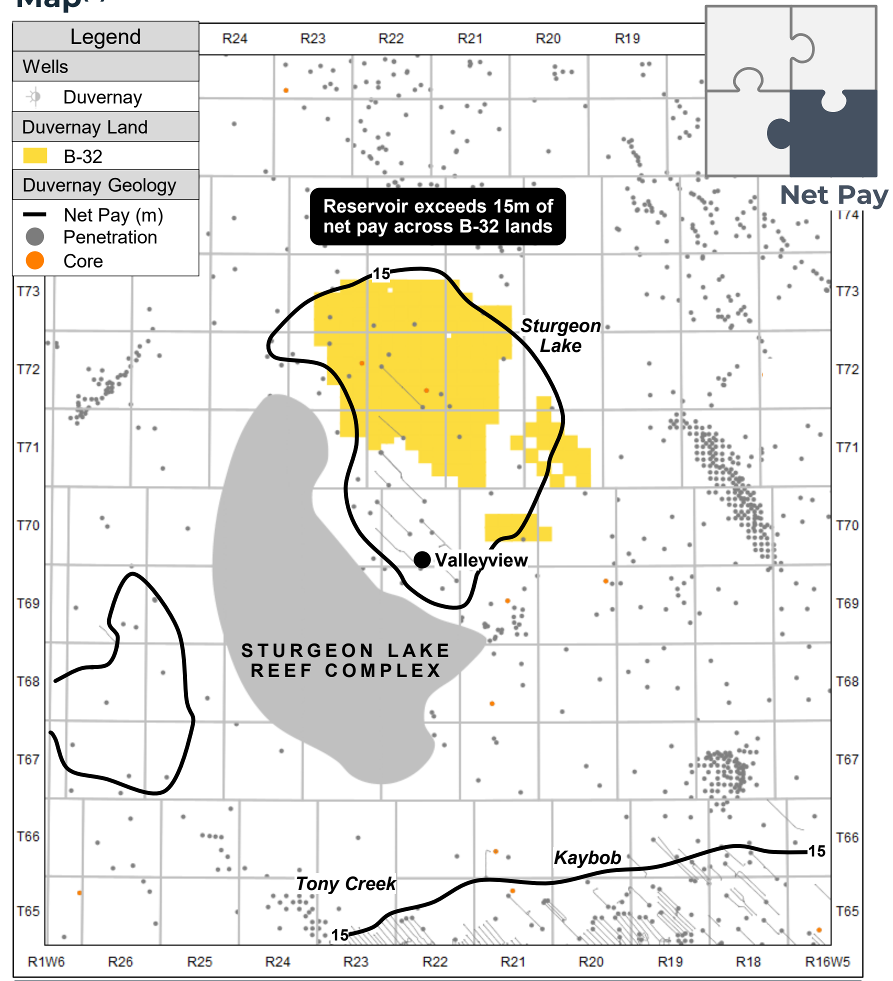
## Sturgeon Lake Duvernay

### Map[1]




**Tmax ranges between 439 - 448°C through Sturgeon Lake**

### Map[2]




**Upper Duvernay net pay is >15m through Sturgeon Lake**

*Source: geoSCOUT*
1) Fluid windows defined by Tmax & Hydrogen Index values as follows: *Oil = 435 - 455°C*, Condensate Window = 455 - 470°C
2) *Upper Duvernay net pay determined using a 0% porosity cutoff (limestone-scale)*

# Well Design, Performance, and Forecast Type Curve

## Section III

B-32 EXPLORATION

# Reservoir Quality and Performance Variability

## Well Design, Performance, and Forecast Type Curve

### Reservoir Quality – Confirmed and Consistent

All 13 Sturgeon Lake wells penetrate the same high-quality Duvernay reservoir.
Pressure, pay thickness, and fluid quality are consistent across the dataset.

**Landing Zone**

**Completion Design & Execution**

**Soak Duration**

**Flowback & Artificial Lift**

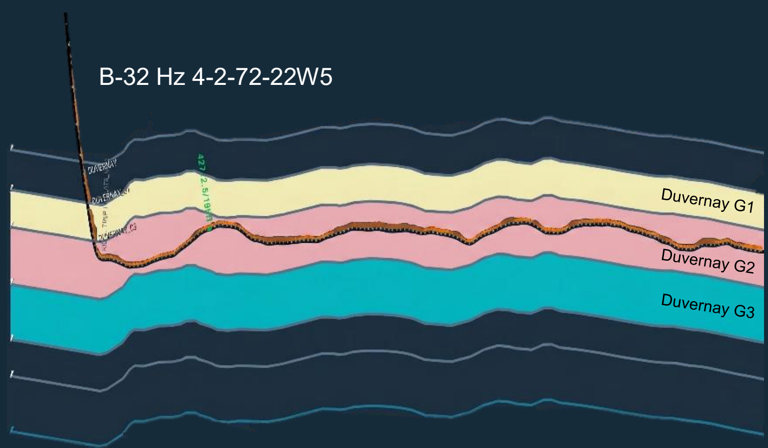
**Analysis of Sturgeon Lake wells confirms that performance variability is execution-driven. Reservoir quality is not the variable.**
**The key variables that drive performance are landing zone, completion design & execution, soak duration, and flowback & artificial lift**

# Well Design & Execution Variables (1/2)

## Well Design, Performance, and Forecast Type Curve

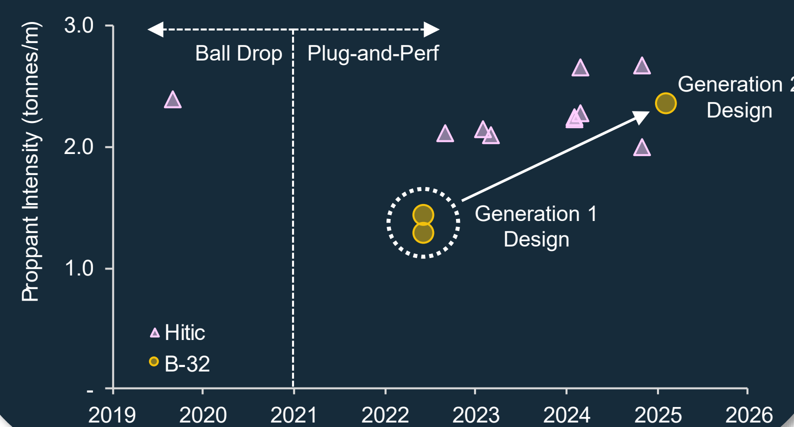
### Landing Zone

- Precise placement within the Duvernay, targeting the highest quality reservoir in the G2 interval
- Geosteering in real time ensures maximum contact with the highest-quality reservoir




### Completion Design & Execution

- Stage spacing and proppant intensity are engineered to maximize stimulated reservoir volume
- The design has moved towards Generation 2, which includes 2.5 tonnes/m proppant intensity and tailored stage spacing
- 95% to 100% sand placement is considered to be a successful execution



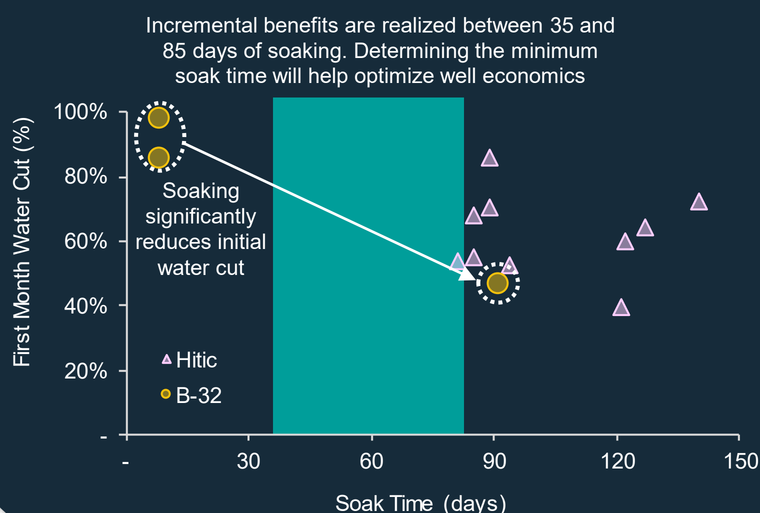

**Landing zone and completion design have advanced materially;**
**Continued optimization of both variables represents identified upside in the next drilling program**

# Well Design & Execution Variables (2/2)

## Well Design, Performance, and Forecast Type Curve

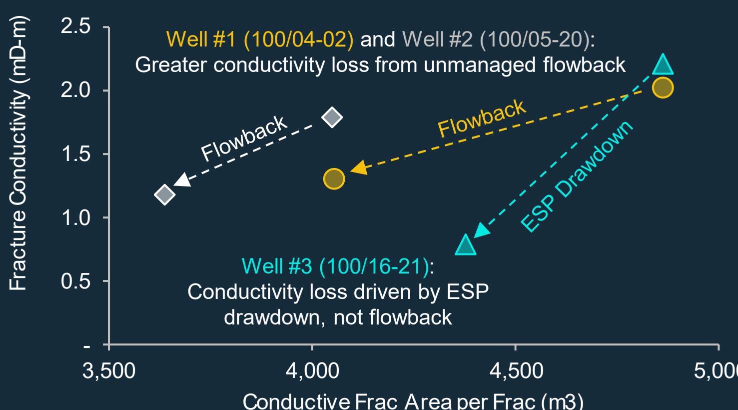
### Soak Duration

- Post-completion shut-in significantly reduces initial water cut from >90% to ~40%
- With reduced total fluid production, the reservoir fracture conductivity is protected from day one
- Determining the minimum soak time will accelerate production while maintaining the benefits of soaking




### Flowback & Artificial Lift

- Managed pressure drawdown during flowback and artificial lift is required to protect fracture conductivity
- Pump sizing and timing optimized to balance early production with reservoir protection




**Significant improvements in future, sustainable rates and recoveries will be driven by optimizations in soak duration and drawdown management**

# Summary of Historical Development

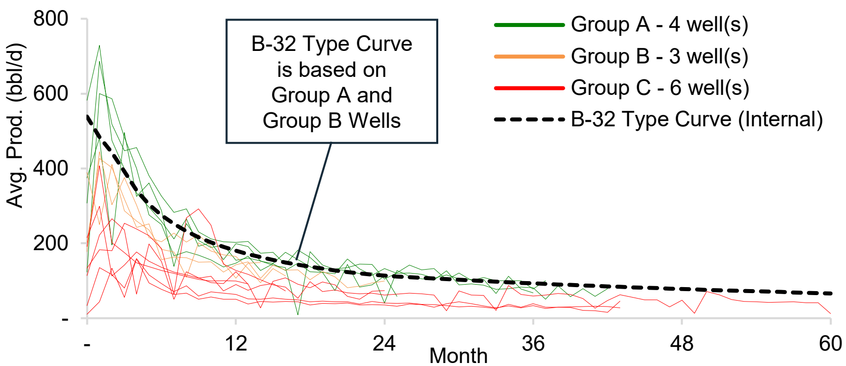
## Well Design, Performance, and Forecast Type Curve

### Execution Matrix

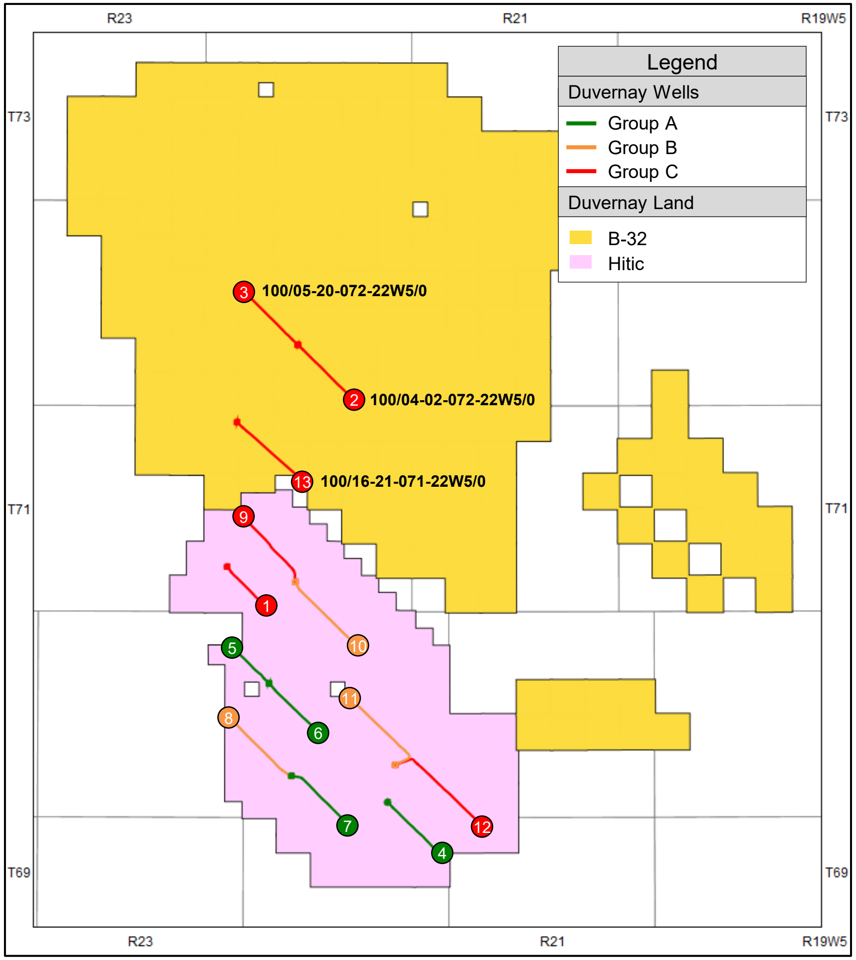
| Vintage | Execution Parameters | | | | Result | |
|---|---|---|---|---|---|---|
| | Landing Zone | Completion Design | Soak | Flowback & Artificial Lift | | |
| Sep. 2019 | ✓ | ✗ | ✓ | ✓ | ✗ | 1 |
| Jun. 2022 | ✓ | – | ✗ | ✗ | ✗ | 2 |
| Jun. 2022 | ✓ | – | ✗ | ✗ | ✗ | 3 |
| Sep. 2022 | – | ✓ | ✓ | ✓ | ✓ | 4 |
| Feb. 2023 | – | ✓ | ✓ | ✓ | ✓ | 5 |
| Mar. 2023 | – | ✓ | ✓ | ✓ | ✓ | 6 |
| Feb. 2024 | – | ✓ | ✓ | – | ✓ | 7 |
| Feb. 2024 | – | ✓ | ✓ | – | – | 8 |
| Mar. 2024 | ✗ | ✓ | ✓ | – | ✗ | 9 |
| Mar. 2024 | ✓ | ✓ | ✓ | – | – | 10 |
| Nov. 2024 | ✓ | ✓ | ✓ | – | – | 11 |
| Nov. 2024 | ✗ | ✓ | ✓ | – | ✗ | 12 |
| Feb. 2025 | ✓ | ✓ | ✓ | ✗ | ✗ | 13 |

✓ Optimal / Best Practice – Improvement Area ✗ Performance Limiting

### Oil Performance(1)




### Map




**Performance variability is execution driven and explainable;**
**No well drilled to date is optimized in all categories, suggesting that significant potential upside remains**

*Source: geoSCOUT*
*1) Oil performance is length normalized to 4,000m*

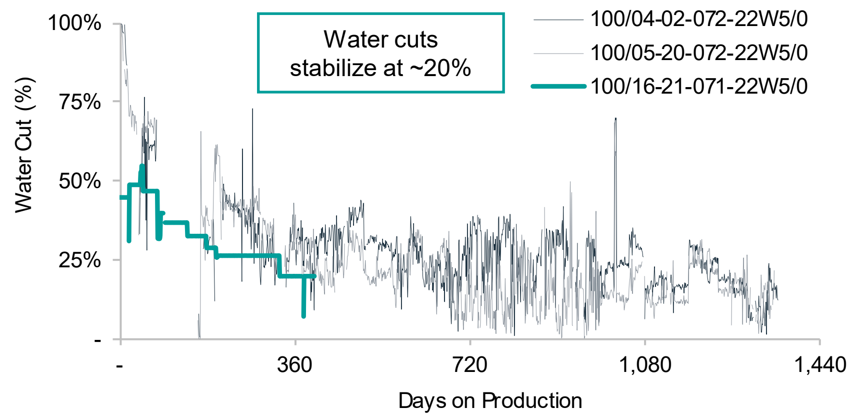
# B-32 Well Results

## Well Design, Performance, and Forecast Type Curve

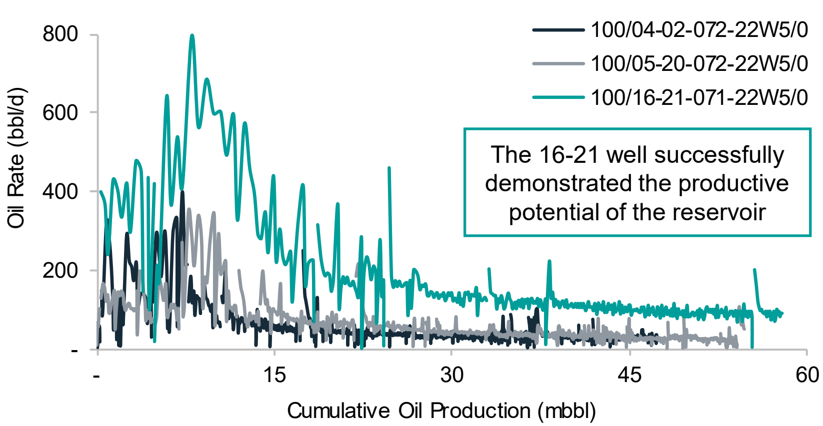
### Highlights

- The two June 2022 wells (04-02 and 05-20) were not 'soaked' and, as a result, initially produced at higher water cuts
  - The most recent February 2025 well (16-21), which was 'soaked', initially produced at much lower water cuts of ~50%
  - All the wells eventually reach a stable water cut of ~20%
- The 16-21 well produced at sustained oil rates in excess of 500 bbl/d, a significant increase relative to the prior two wells
  - Studies indicate that the production decline is due to conductivity losses in the fracture network from pumping at high fluid rates
  - Both flowback and artificial lift drawdown will be carefully controlled in order to optimize production in future programs

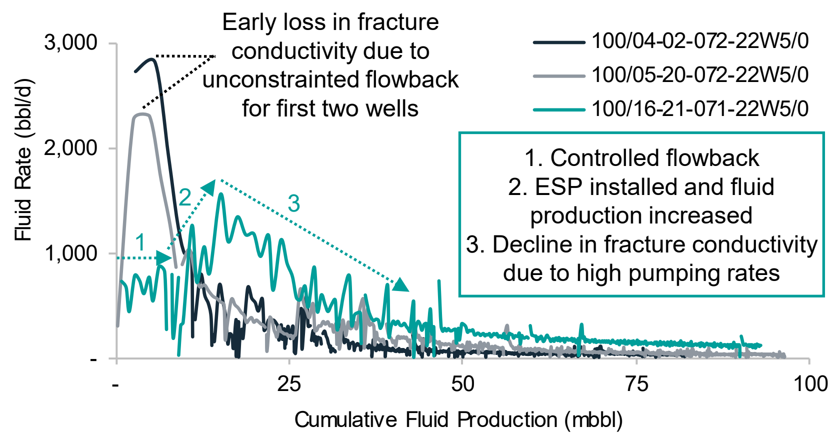
### Water Cut




### Oil Rate(1)




### Fluid Rate(1)




**The most recent B-32 well successfully demonstrated the productive potential of the optimized well design; A more moderated drawdown strategy will help maintain the integrity of the fracture network, facilitating higher long-term production rates**

*1) Results are presented on an absolute, non-length normalized, basis*

# B-32 Type Curve Economics

## Well Design, Performance, and Forecast Type Curve

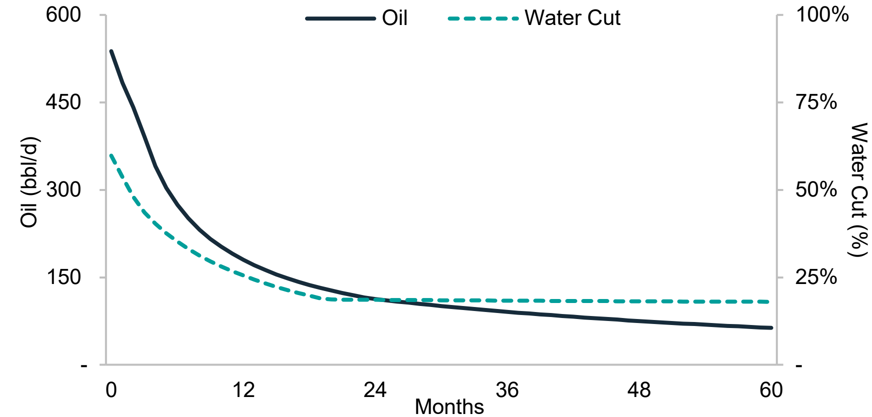
### Highlights

- B-32's identified inventory is based on a 4,000m lateral length design, and assumes a 4 month spud to production period to account for 60-90 days of soaking
  - ~20% stabilized water cut and consistent GOR (300-400 scf/bbl) expected
- Up to the next 84 wells can contribute to pooled C* ERP benefit:
  - Wells drilled before February 2030 receive 1.75 x C*
  - Wells drilled before February 2032 receive 1.50 x C*
- Initial DCET costs are expected to be ~$10.8 million; meaningful improvement expected through pad drilling
- Future infrastructure tie-in drives meaningful cost savings

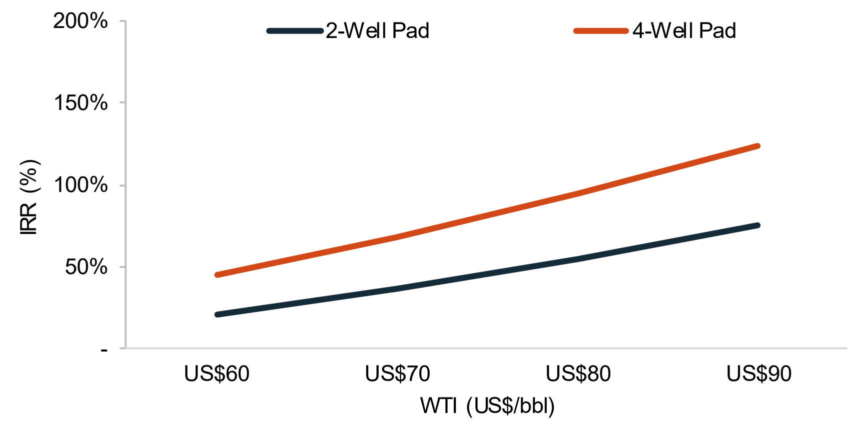
### Type Curve Parameters and Assumptions[1]

| | | 2-Well Pad | 4-Well Pad |
|---|---|---|---|
| **Cost Assumptions** | | | |
| DCET | *($mm)* | $10.8 | $9.3 |
| Fixed Opex | *($/well/mth)* | $28,000 | $25,000 |
| Var. Oil Opex + Trans. | *($/bbl)* | $7.41 | $3.78 |
| Var. Water Opex | *($/bbl)* | $8.45 | $1.86 |
| Var. Gas Opex | *($/mcf)* | $1.50 | $1.50 |
| **IP and Recovery** | | | |
| IP30 | *(bbl/d)* | 538 | 538 |
| IP90 | *(bbl/d)* | 488 | 488 |
| EUR | *(mbbl)* | 497 | 497 |
| **Half Cycle Economics - US$75 WTI** | | | |
| Btax NPV10 | *($mm)* | $8.0 | $12.0 |
| IRR | *(%)* | 45% | 80% |
| Payout | *(mths)* | 22 | 15 |
| F&D | *($/boe)* | $23.35 | $19.99 |
| Recycle Ratio | *(x)* | 2.9x | 3.9x |

### Type Curve Rate Vs. Time[2]




### Economic Sensitivities[3]




**250 future development locations identified with significant economic enhancement available through full field development efficiencies**

*1) B-32 internal type curve estimates. Half cycle economics assume US$75.00 WTI, US$3.50 MSW differential, $2.50 AECO and 0.73 FX. 4-well pad economics assumes wells are tied in for operating cost purposes. Assumes 4-month spud to production and DCET costs incurred in months one and two*
*2) B-32 internal type curve estimates*
*3) Flat price decks assume US$3.50 MSW differential, $2.50 AECO and 0.73 FX*

# Inventory and Development Potential

## Section IV

B-32 EXPLORATION

# Inventory

## Inventory and Development Potential

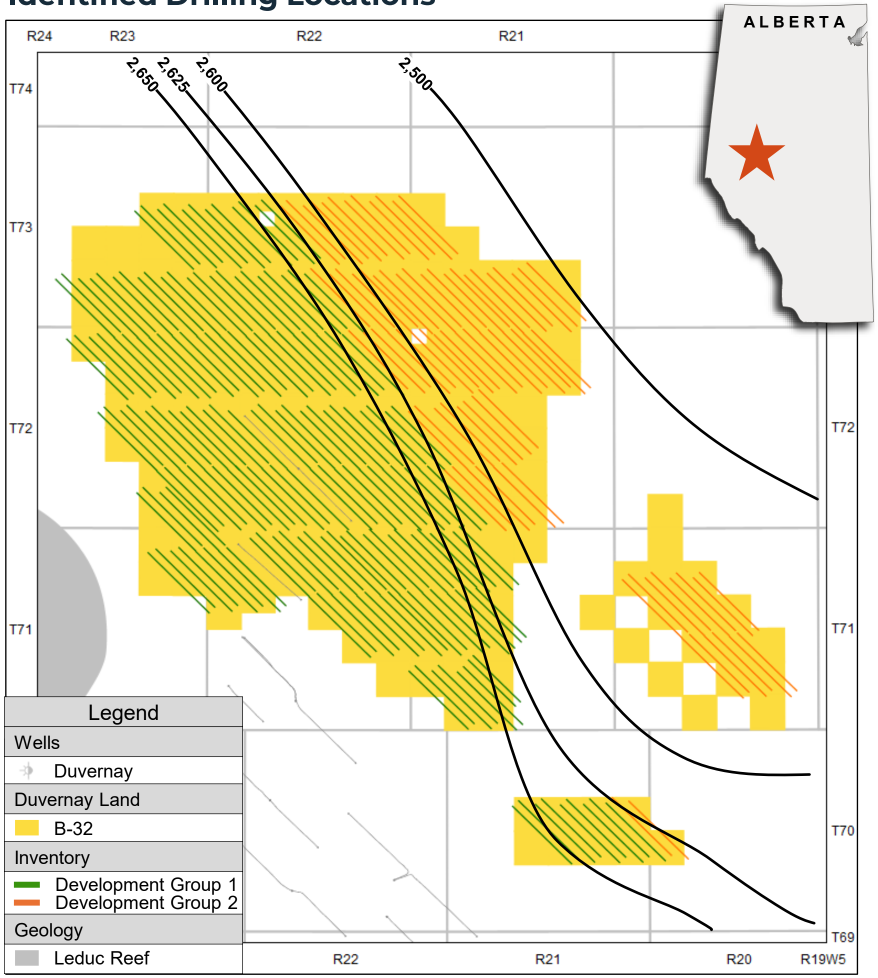
### Highlights[1,2]

- B-32 believes that reservoir pressure is the key attribute driving production potential across the asset, leading to a systematic inventory ranking based on the direct relationship between depth, pressure data, structural mapping, and fluid analysis
- Net pay continuity across the asset footprint provides the technical confidence required for predictable well performance
- The depth and pressure framework utilizes a northern constraint of 16.7 kPa/m at 2,500m TVD, which is supported by active production and fluid data from bounding wells across the acreage
- Supplemental evaluation of regional wells was integrated into the study to confirm fluid type, establishing high confidence in uniform oil saturation supported by a definitive oil test at 2,625m TVD
- A total of 171 locations (development group 1) are situated within this premium structural fairway at depths greater than or equal to 2,625m TVD, providing more than enough inventory to support the 20,000 boe/d development case
- An additional 79 locations (development group 2) exist at depths shallower than 2,625m TVD and may offer further upside as prospective inventory in the future
- 250 locations currently identified across existing B-32 lands at Sturgeon Lake, with the potential to expand the overall footprint to >300 locations

### Inventory Summary[1]

| Gross Development Inventory | | Total |
|---|---|---|
| Group 1 | Group 2 | |
| (#) | (#) | (#) |
| 171 | 79 | 250 |

### Identified Drilling Locations[1,2]



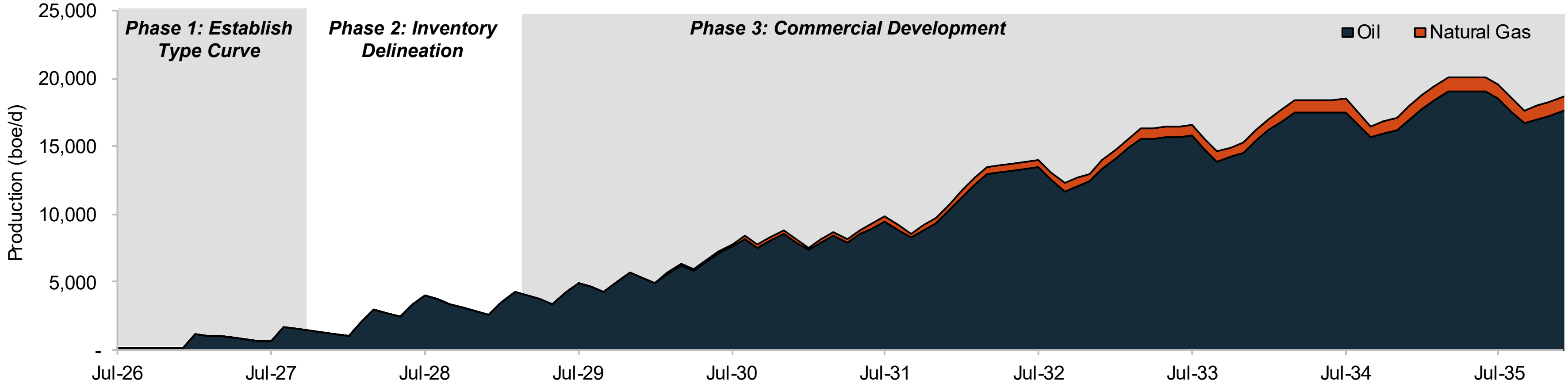

**By integrating regional structural mapping, pressure data, and fluid analysis, B-32's detailed subsurface mapping confirms regional pressure continuity and uniform oil saturation across a premium structural fairway, resulting in 250 total Duvernay locations**

*Source: geoSCOUT*
*1) Inventory locations are modeled assuming a standardized horizontal well design utilizing 4,000-meter lateral lengths and 400-meter inter-well spacing*
*2) Subsurface calibration incorporates data from key regional control wells including 9-6-73-23W5, which demonstrated a reservoir pressure gradient of 16.7 kPa/m at ~2,500m TVD alongside verified oil inflow, and 13-25-69-20W5, which confirmed liquid hydrocarbon presence via canister fluid analysis*

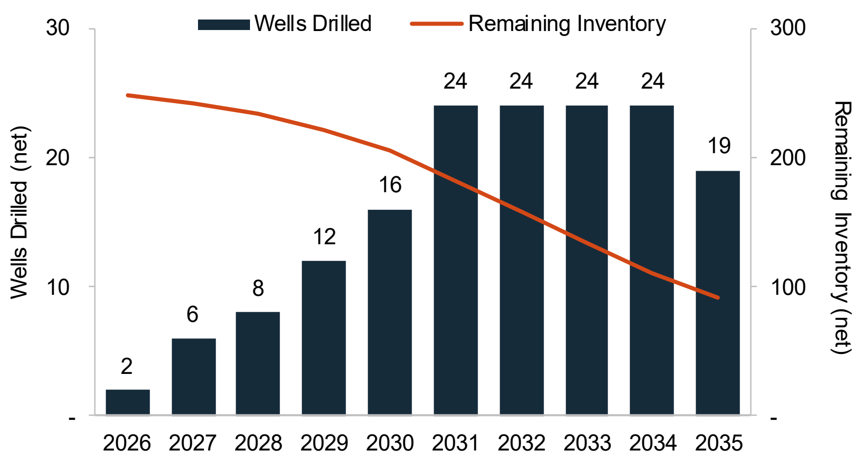
# Commercial Development Forecasts

## Inventory and Development Potential

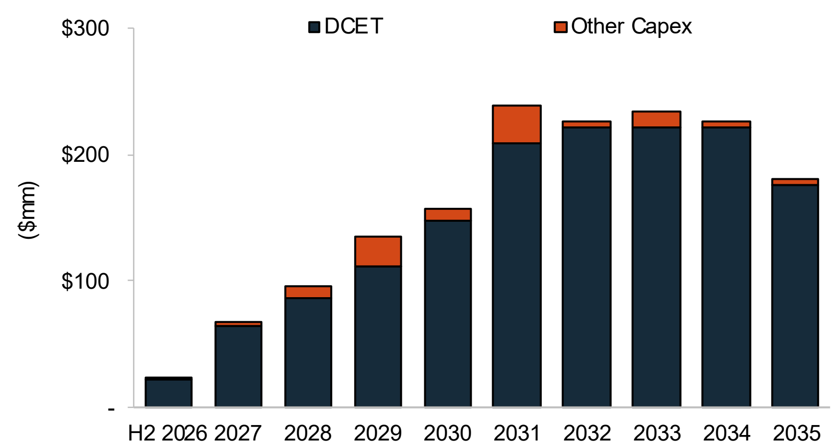
### Production




### Wells Drilled and Remaining Inventory[1]




### Capital Expenditures by Category




**B-32's development strategy is staged to establish its Sturgeon Lake Duvernay type curve and prove the 250 location inventory, followed by commercial development to reach ~20 mboe/d**

*Source: B-32 Management estimates*
*1) Assumes 250 identified drilling locations*

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Presentation of Oil and Gas Information

Certain type curves disclosure presented herein represents estimates of the production decline and ultimate volumes expected to be recovered from wells over the life of the well. The type curves represent what management thinks an average well will achieve, based on methodology that is analogous to wells with similar geological features. Individual wells may be higher or lower but over a larger number of wells, management expects the average to come out to the type curve. Over time type curves can and will change based on achieving more production history on older wells or more recent completion information on newer wells. The recovery and reserve estimates of reserves provided in this document are estimates only, and there is no guarantee that the estimated reserves will be recovered. Actual reserves may eventually prove to be greater than, or less than, the estimates provided herein.

This presentation contains references to type well production, capital costs and economics, which are derived from available information of analogous wells and, as such, there is no guarantee that B-32 will achieve the stated or similar results, capital costs and return costs per well.

Barrels of oil equivalent ("BOE") have been converted on the basis of six thousand cubic feet ("Mcf") natural gas to 1 barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 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. In addition, given that the value ratio based on the current price of oil as compared with natural gas is significantly different from the energy equivalent of six to one, utilizing a BOE conversion ratio of 6 Mcf: 1 bbl would be misleading as an indication of value.

This presentation contains metrics commonly used in the oil and natural gas industry, such as netback, free cash flow, NPV-10, IRR, IP 30, IP 90, IP 365, EUR, recycle ratio and F&D costs. "Netback" equals oil, gas and natural gas liquids revenues less royalties and operating costs (including transport) calculated on a per boe basis. "Free cash flow" is calculated by subtracting cash flow in a period by the capital expenditures spent during that same period. "NPV-10" or similar expressions represents the net present value (net of capex) of net income discounted at 10%, with net income reflecting the indicated oil, liquids and natural gas prices and IP rate, less internal estimates of operating costs and royalties. "EUR" means the estimated ultimate recovery, an approximation of the quantity of oil or gas that is potentially recoverable or has already been recovered from a reserve or well. "IP 30" means the estimated average daily sales volumes of production over the initial 30 days of production. "IP 90" means the estimated average daily sales volumes of production over the initial 90 days of production. "IP 365" means the estimated average daily sales volumes of production over the initial 365 days of production. "Recycle ratio" is defined as netback per BOE divided by F&D costs on a per BOE basis. "F&D costs" are calculated by dividing the sum of the total capital expenditures for the year (in dollars) by the change in reserves within the applicable reserves category (in BOE). F&D costs, including future development capital, includes all capital expenditures in the year as well as the change in future development capital required to bring the reserves within the specified reserves category on production. It should not be assumed that any estimates referred to herein from third parties represent the fair market value of the lands. These terms have been calculated by third parties and do not have a standardized meaning and may not be comparable to similar measures presented by other companies. Management uses these oil and gas metrics for its own performance measurements and to provide readers with measures to compare B-32's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this presentation, should not be relied upon for investment or other purposes.

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Free cash flow is calculated as after-tax operating cash flow minus capital expenditures. F&D costs are calculated by dividing the sum of total capital expenditures during the period by the change in reserves within the applicable reserves category (in boe).

Capital Efficiency is calculated by dividing total anticipated drill, complete, equip and tie-in costs (DCET) by the anticipated IP365 production rate expressed in boe/d. The measure is considered to be useful for management because it describes the magnitude of capital investment required to add production over the course of a year from each of the company's core operating regions.

Netback (including operating netback) is determined by adding oil, gas and natural gas liquids revenues minus royalties and operating costs (including transport) calculated on a per boe basis. Netbacks per boe are calculated by dividing the netbacks by total production volumes sold in the period. Management believes that netback is a key industry benchmark and a measure of performance for B-32 that provides investors with information that is commonly used by other oil and gas producers. The measurement on a per boe basis assists management with evaluating operational performance on a comparable basis.

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