Canadian Natural

CORPORATE PRESENTATION

February 2024

The Canadian Natural Advantage

Large, Low Risk, High Value Reserves

Diversified, Balanced Asset Base

Flexible Capital Allocation

Effective & Efficient Operations

Leading ESG Performance

PREMIUM VALUE CREATION

Corporate Overview

Strategy: Premium Value Creation

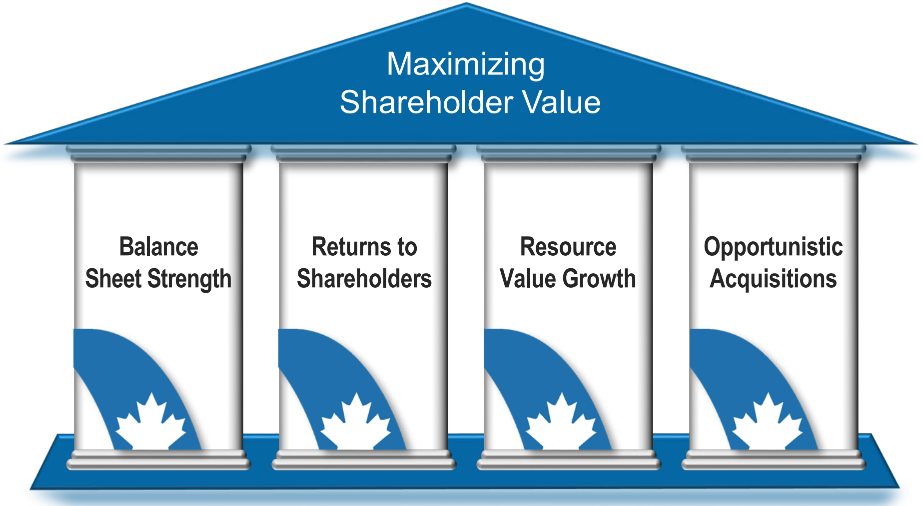
Driving material free cash flow & maximizing returns to shareholders

- Strong Balance Sheet supporting investment grade credit ratings
- Defined growth/value enhancement plans by product/basin and opportunistic acquisitions
- Diverse, balanced asset base – strong differentiation versus peers
  - Product mix – Project timelines – Long reserve life, low decline rate
- Effective and efficient operations
  - Area knowledge – Extensive infrastructure ownership – Operatorship of core areas
- Industry leadership in Environmental, Social and Governance (ESG) stewardship
- Low maintenance capital
- Maximize free cash flow and cash distributions to shareholders

Canadian Natural

Balancing the Four Pillars

Disciplined capital allocation, focused on value creation



Balance Sheet Strength

Balance Sheet strengthens with free cash flow generation

Returns to Shareholders

Growing, sustainable dividends & opportunistic share repurchases

Resource Value Growth

Disciplined capital allocation, focused on asset development & margin growth

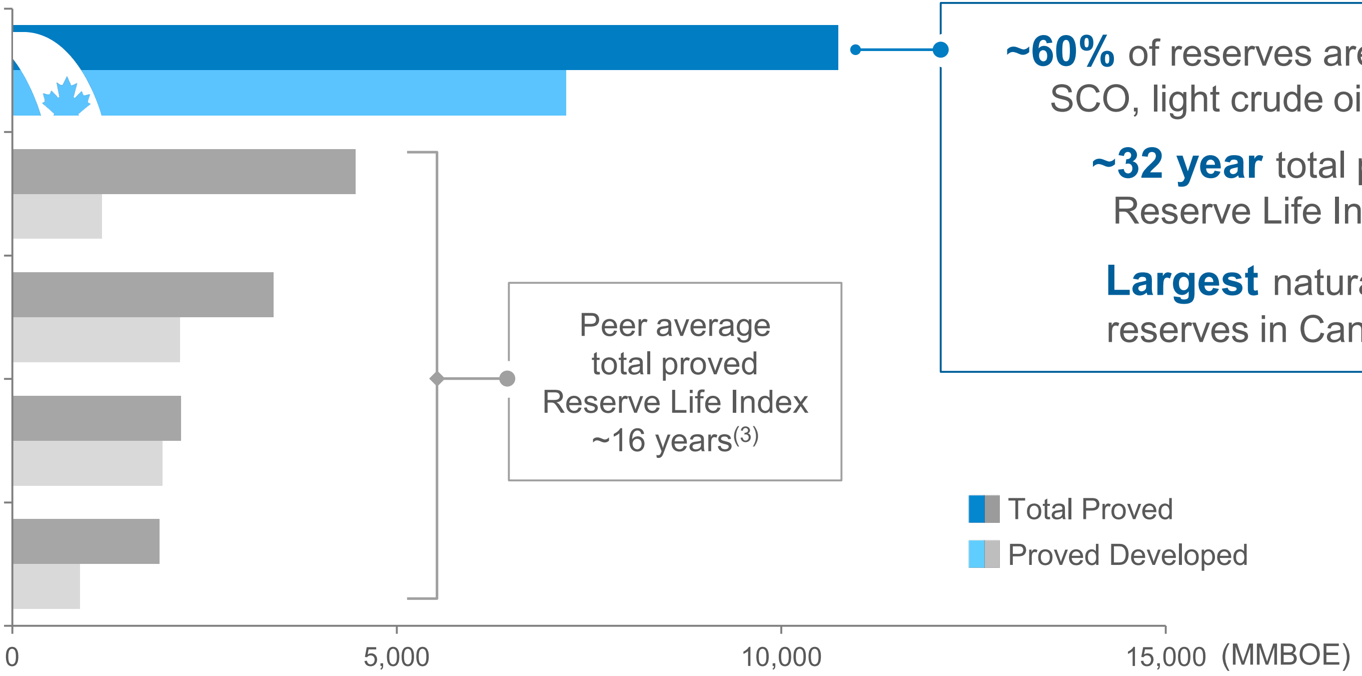
Opportunistic Acquisitions

No gaps / must add value

FLEXIBLE CAPITAL ALLOCATION MAXIMIZES SHAREHOLDER VALUE

Leading Total Proved & Proved Developed Reserves

Canadian peers



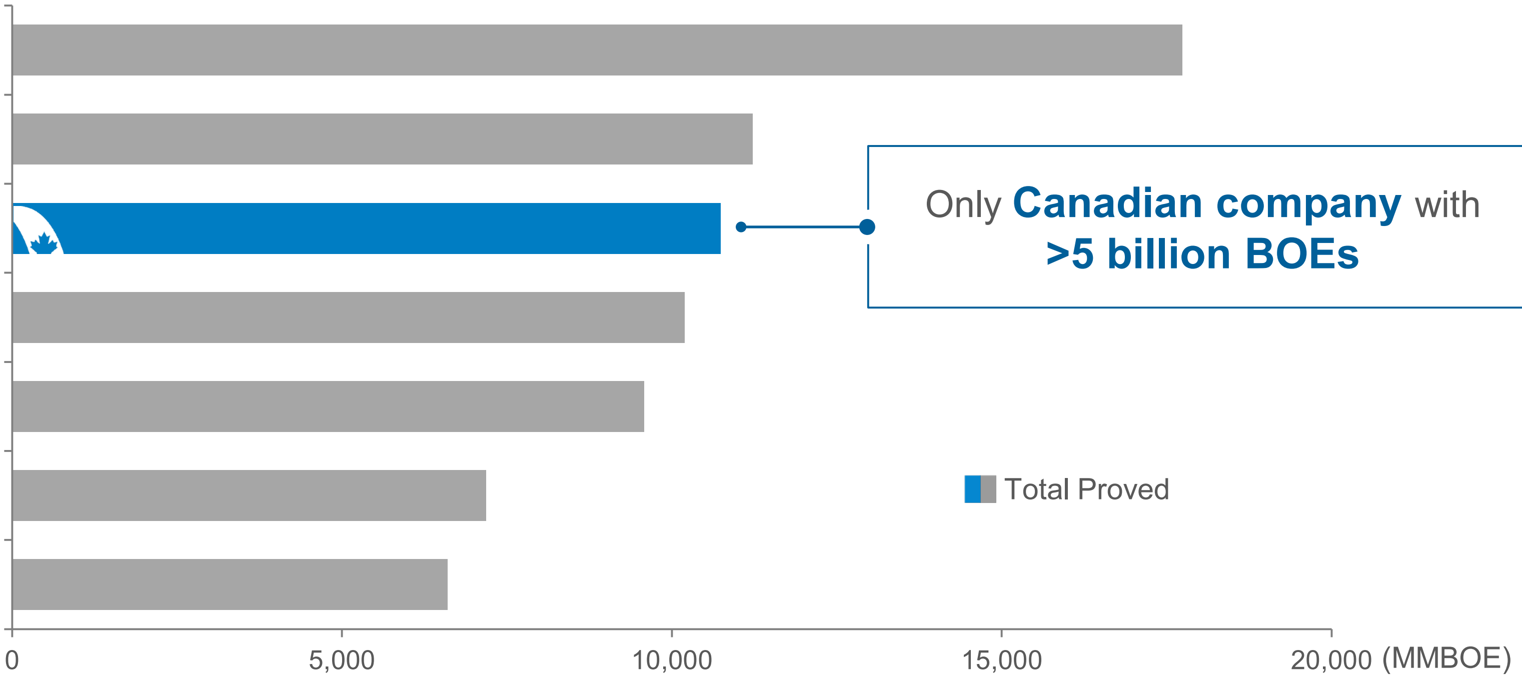
~60% of reserves are high value SCO, light crude oil & NGLs

~32 year total proved Reserve Life Index(1)

Largest natural gas reserves in Canada(2)

Peers include: CVE, IMO, SU and TOU.
(1) RLI is calculated using 2022 total proved net reserves, based on SEC constant prices and costs, divided by the estimated 2023 proved developed producing net production.
(2) Based on total proved reserves, as of December 31, 2022.
(3) Based on SEC 40-F total proved net reserves where available; otherwise NI 51-101 total proved gross reserves and gross production were used to calculate RLI.
Source: 2022 net proved reserves, based on SEC constant prices and costs, per company reports, with the exception of TOU which is based on NI 51-101 total proved net reserves.

Total Proved Reserves
Global peers



Peers include: BP, COP, CVX, SHEL, TTE and XOM.
Source: 2022 net proved reserves, based on SEC constant prices and costs, per company reports.

Typical Shale Well vs Oil Sands Mining & Upgrading

Unique, Sustainable & Robust

Typical Shale Well

High decline ~70% in year one

More reservoir risk

More reserve replacement risk

Shorter reserve life of ~10 years

Oil Sands Mining & Upgrading

✓**No** decline

✓**No** reservoir risk

✓**No** reserve replacement risk

✓**Long** reserve life of **>40 years**

Oil Sands Mining & Upgrading has **significantly lower** risk & capital to maintain production

Source: Permian (Delaware & Midland average) per Company reports, presentations and Peters & Co. research.

Shale Well Example vs Oil Sands Mining & Upgrading

Annual capital required to maintain ~460,000 bbl/d

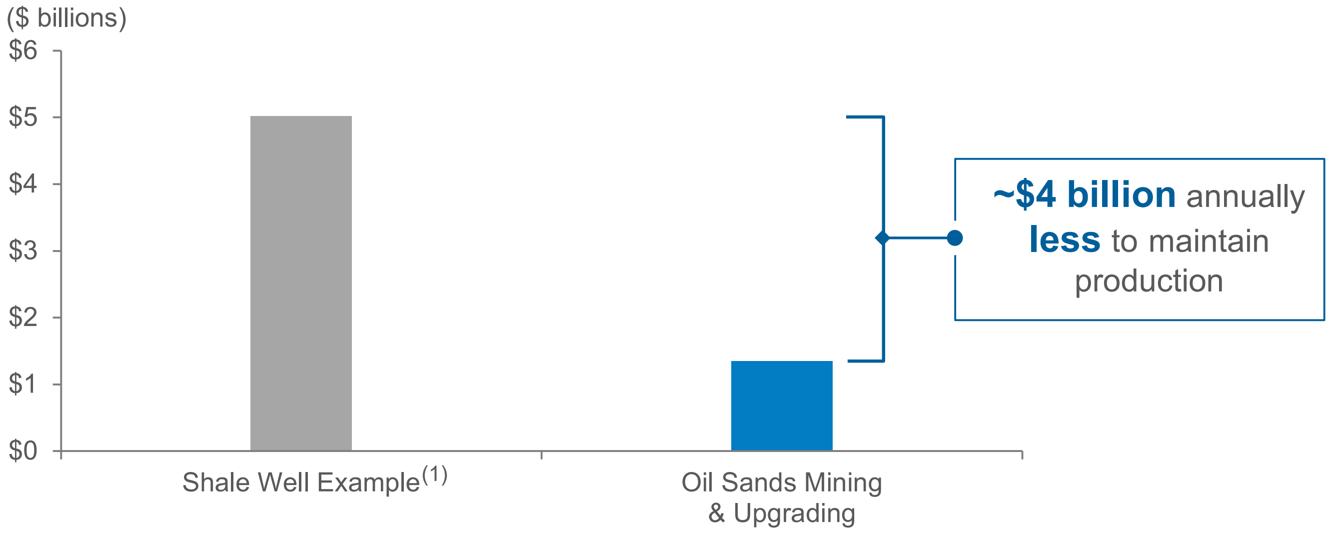
Shale Well Example

- **~1,000 wells** required initially
- **~400 wells** of annual production required to maintain
- **~$5.0 billion** to maintain production annually or ~$30/bbl

Oil Sands Mining & Upgrading

✓ **No** reservoir risk

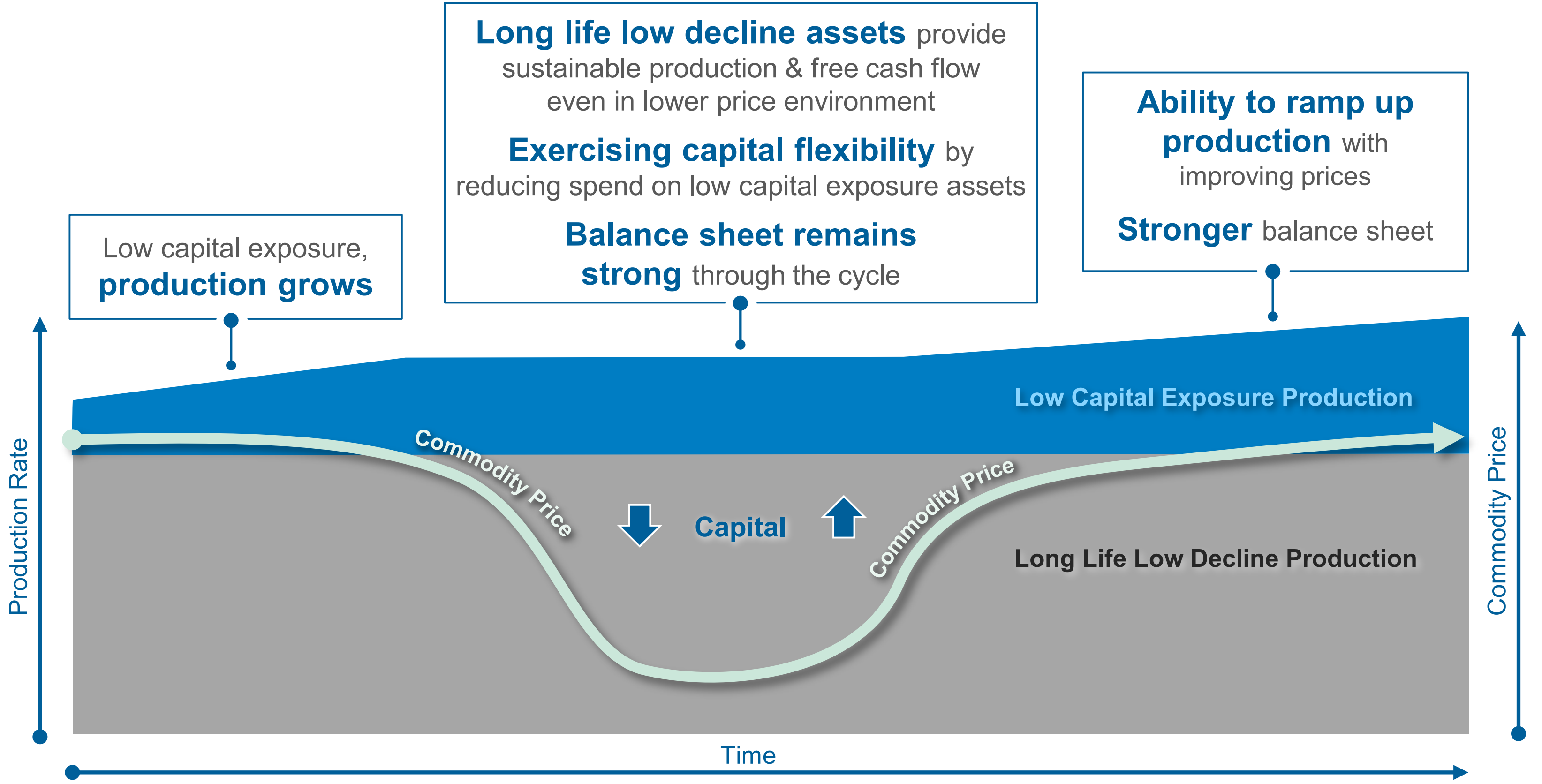
✓ **Low** maintenance capital requirements of ~$8/bbl



(1) Permian (Delaware & Midland average) per Company reports, presentations and Peters & Co. research.

Canadian Natural's Assets are Unique

Robust through all cycles

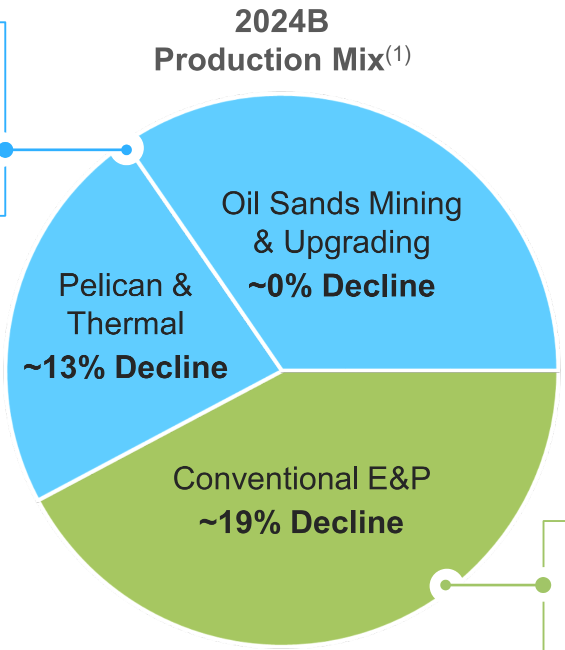


MAXIMIZES CORPORATE ASSET VALUE & FREE CASH FLOW

Canadian Natural's Advantage

Low corporate decline rate

~58%
Long Life
Low Decline
production



~42%
Conventional
E&P
production

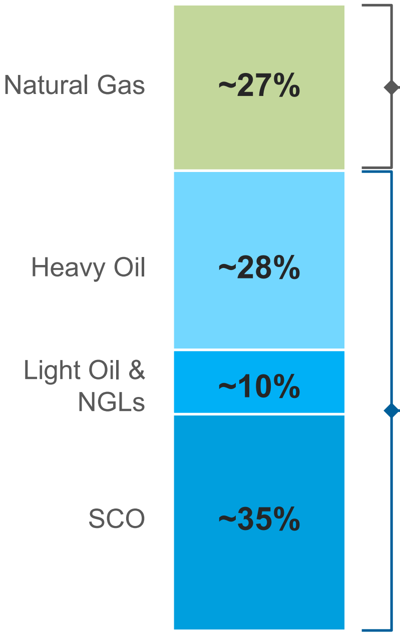
~11%
Corporate
Decline Rate

(1) Based upon targeted 2024B BOE production.
Note: Conventional E&P assets include North America natural gas, NGLs and crude oil and International crude oil and natural gas.

Canadian Natural

Balanced, diverse asset portfolio

2024B Production Mix[1]



2.12 - 2.23 Bcf/d
of natural gas

2nd largest natural gas producer in Canada

977 - 1,008 MBOE/d
of total liquids

Largest crude oil producer in Canada

>60% of liquids production is **high value** SCO, light crude oil & NGLs

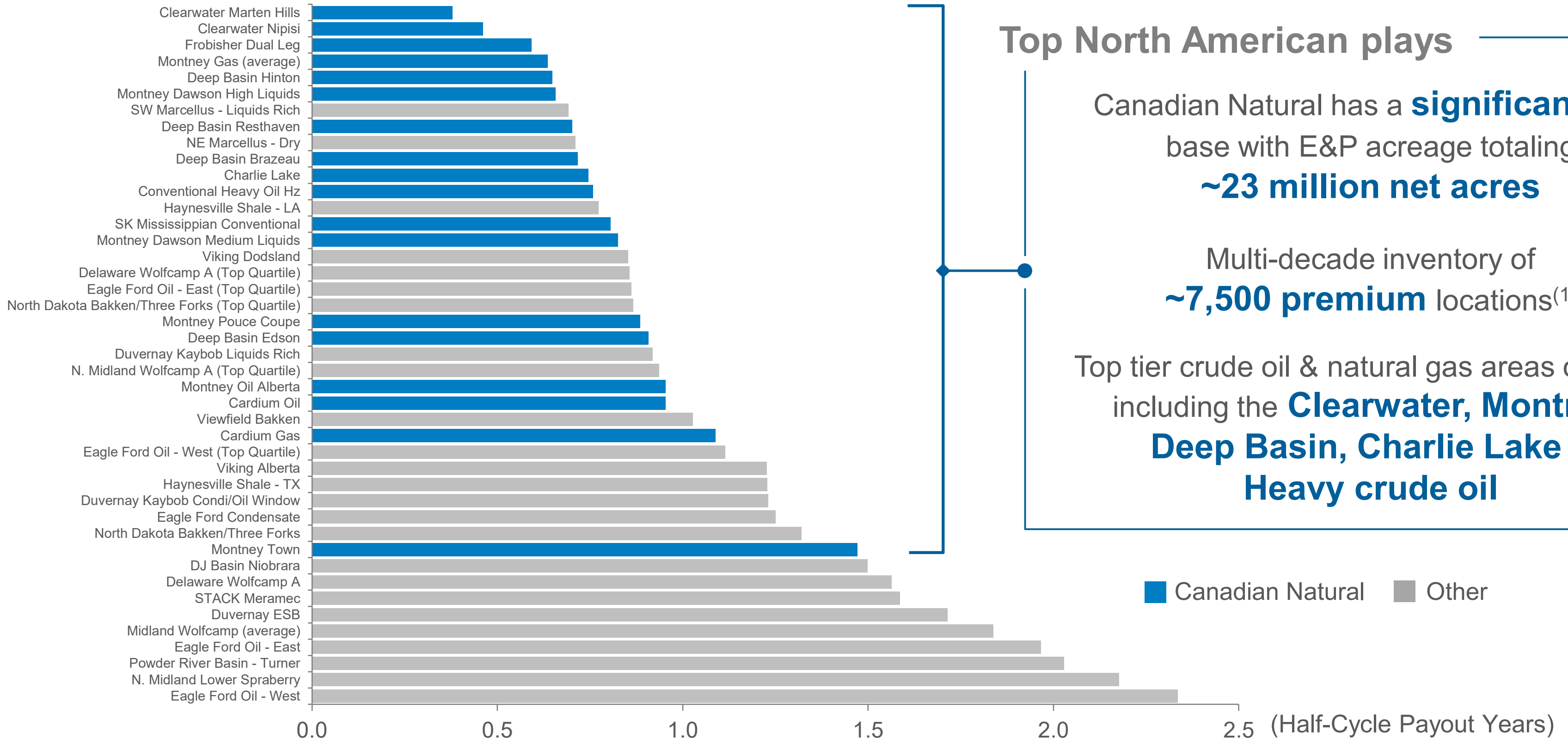
- Vast, balanced resource base to develop
- Unique, balanced, diverse product mix
  - Large, low risk, high value reserves
  - High value light crude oil and SCO production
  - Long life low decline asset base
    - ~79% of total liquids production

(1) *Based upon targeted 2024B BOE production.*

Top Tier Conventional E&P, Thermal In Situ & Oil Sands Mining & Upgrading Assets

Conventional E&P

Top tier plays throughout the asset base



Top North American plays

Canadian Natural has a **significant** land base with E&P acreage totaling **~23 million net acres**

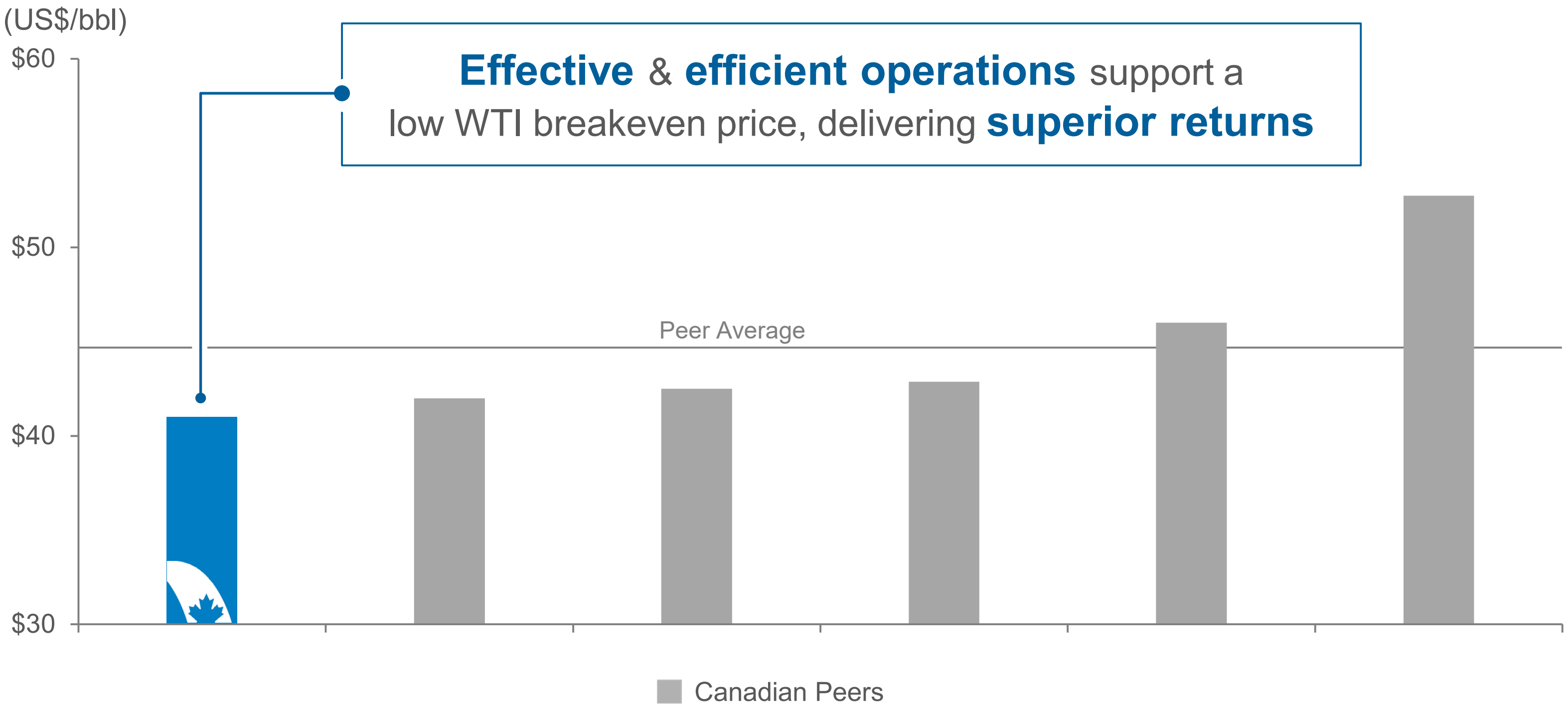
Multi-decade inventory of **~7,500 premium** locations(1)

Top tier crude oil & natural gas areas of focus including the **Clearwater, Montney, Deep Basin, Charlie Lake** & **Heavy crude oil**

(1) Assumes US$70/bbl WTI, 22% WCS differential, C$3.25/GJ AECO and US$1.00 to C$1.30 foreign exchange. See Advisory for cautionary statements.
Source: Peters & Co. – Crude Oil and Natural Gas Plays – September 2022.

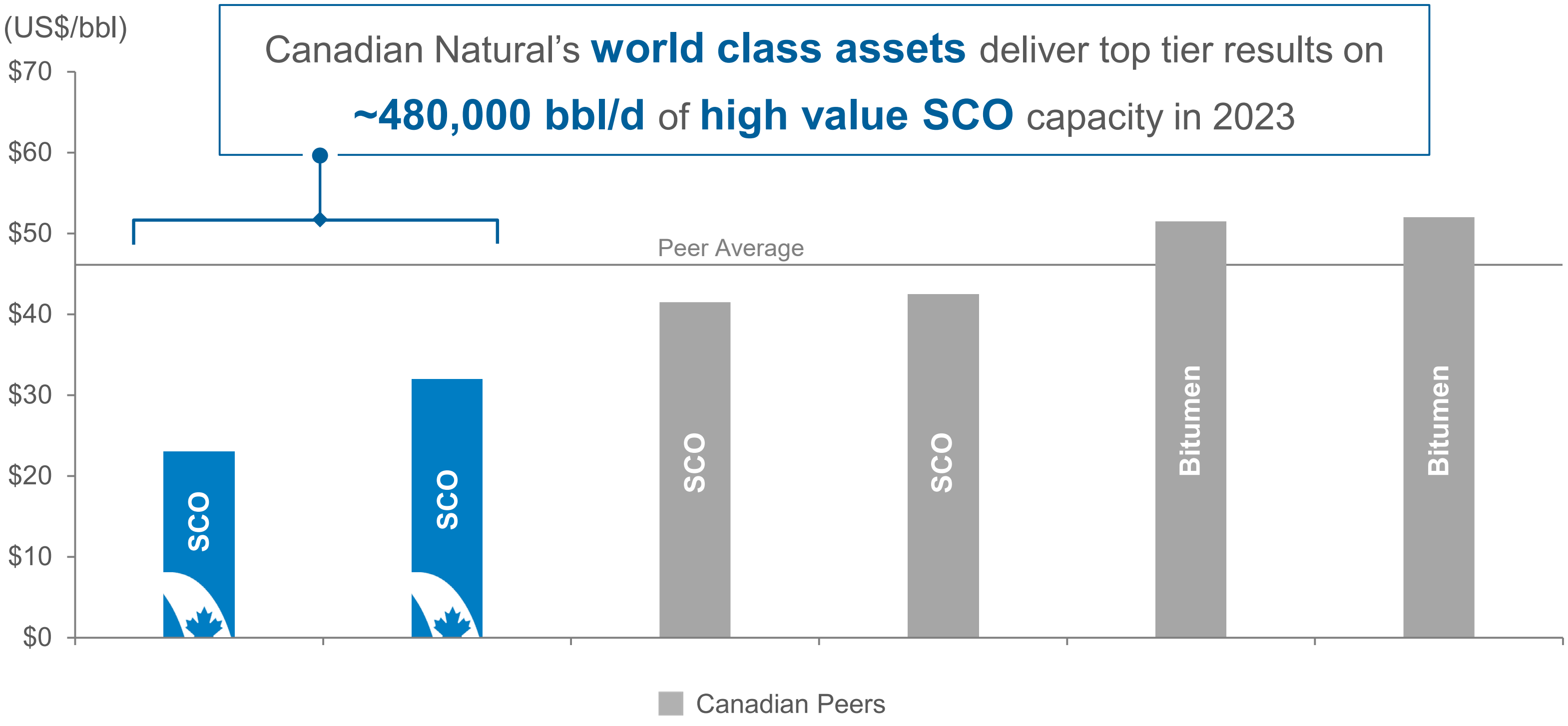
Thermal In Situ Oil Sands

Top tier WTI breakeven price



Peers include: ATH, CVE, IMO, MEG and SU.
Source: Peters & Co. North American Crude Oil Update; September 2022 – Breakeven defined as WTI crude oil price required for a project to be free cash flow neutral.

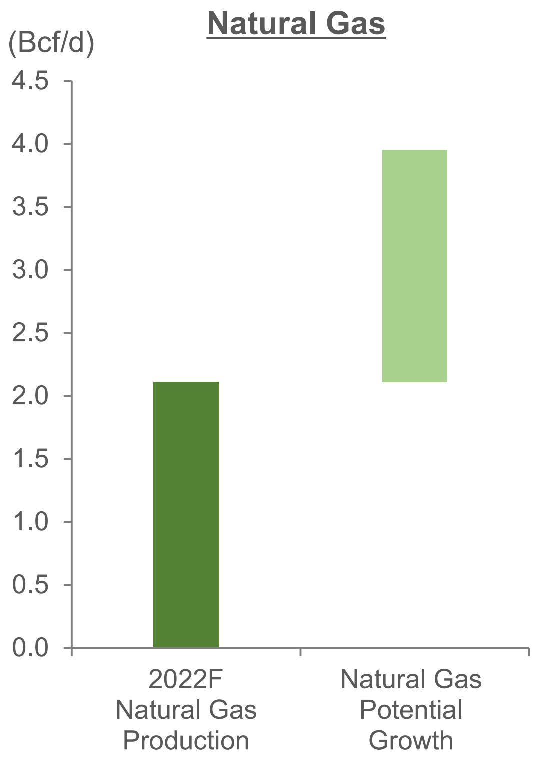
World Class Oil Sands Mining Assets
Top tier WTI breakeven price

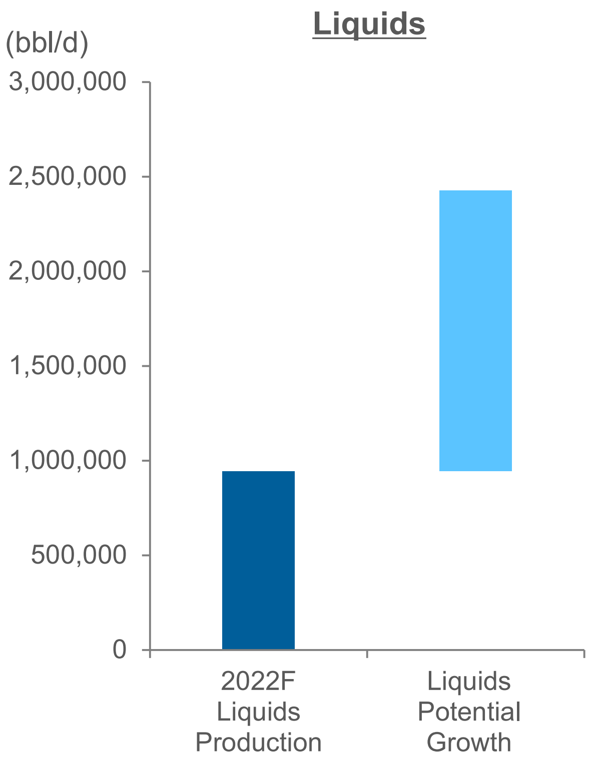


Peers include: IMO, SU and Syncrude.
Source: Peters & Co. North American Crude Oil Update; September 2022 – Breakeven defined as WTI crude oil price required for a project to be free cash flow neutral.

Canadian Natural

Total development potential





Total corporate future growth potential of **~1,790,000 BOE/d**(1)

~72% from long life low decline assets

(1) Assumes US$70/bbl WTI, 22% WCS differential, C$3.25/GJ AECO and US$1.00 to C$1.30 foreign exchange.
Note: See Advisory for cautionary statements and definitions.

Returns on Capital, Leading Free Cash Flow & Returns to Shareholders

Canadian Natural

Asset base drives long-term value: 2023F

Low maintenance capital & **disciplined** capital program

~4% production growth

Leading free cash flow generation of **~$6 billion** after dividends

Strong balance sheet with year end net debt at **<$11 billion**

Increased dividend twice, totaling **~18%** with total distributions of **~$4 billion**

Share repurchases of **>$3 billion**

2023F

- Asset base drove **resilience, value growth & upside**
- **Increased annual dividend** to $4.00 per common share[1]

Canadian Natural's **Advantage**

(1) Current quarterly dividend of $1.00 per share, annualized.
Note: See Advisory for cautionary statements, definitions, pricing assumptions and non-GAAP and other financial measures disclosure.

Canadian Natural
Free Cash Flow Allocation Policy

When net debt is between

$10 - $15 billion

Adjusted Funds Flow

Less: Base Capital

Less: Dividends

Free Cash Flow

50%
Balance Sheet
less
Strategic Growth Capital /
Opportunistic Acquisitions

50%
Share Repurchases

When net debt is

< $10 billion

Adjusted Funds Flow

Less: Total Capital [1]

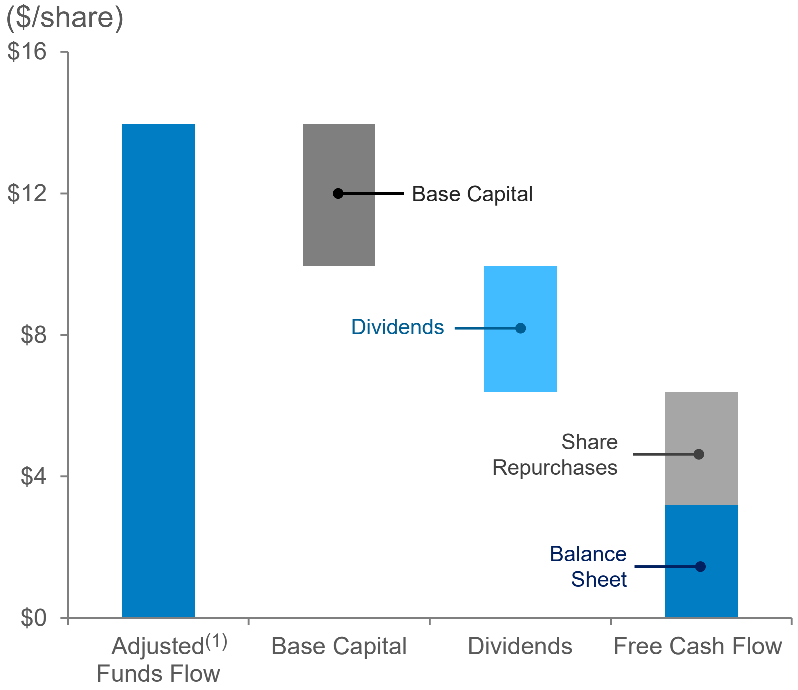
Less: Dividends

Free Cash Flow

100%
Returns to
Shareholders

(1) Total capital is comprised of base capital plus strategic growth capital. Acquisitions do not impact returns to shareholders as acquisitions are not included in total capital.
Note: See Advisory for cautionary statements, definitions, pricing assumptions and non-GAAP and other financial measure disclosure.

2023F Free Cash Flow Allocation
Significant direct returns to shareholders



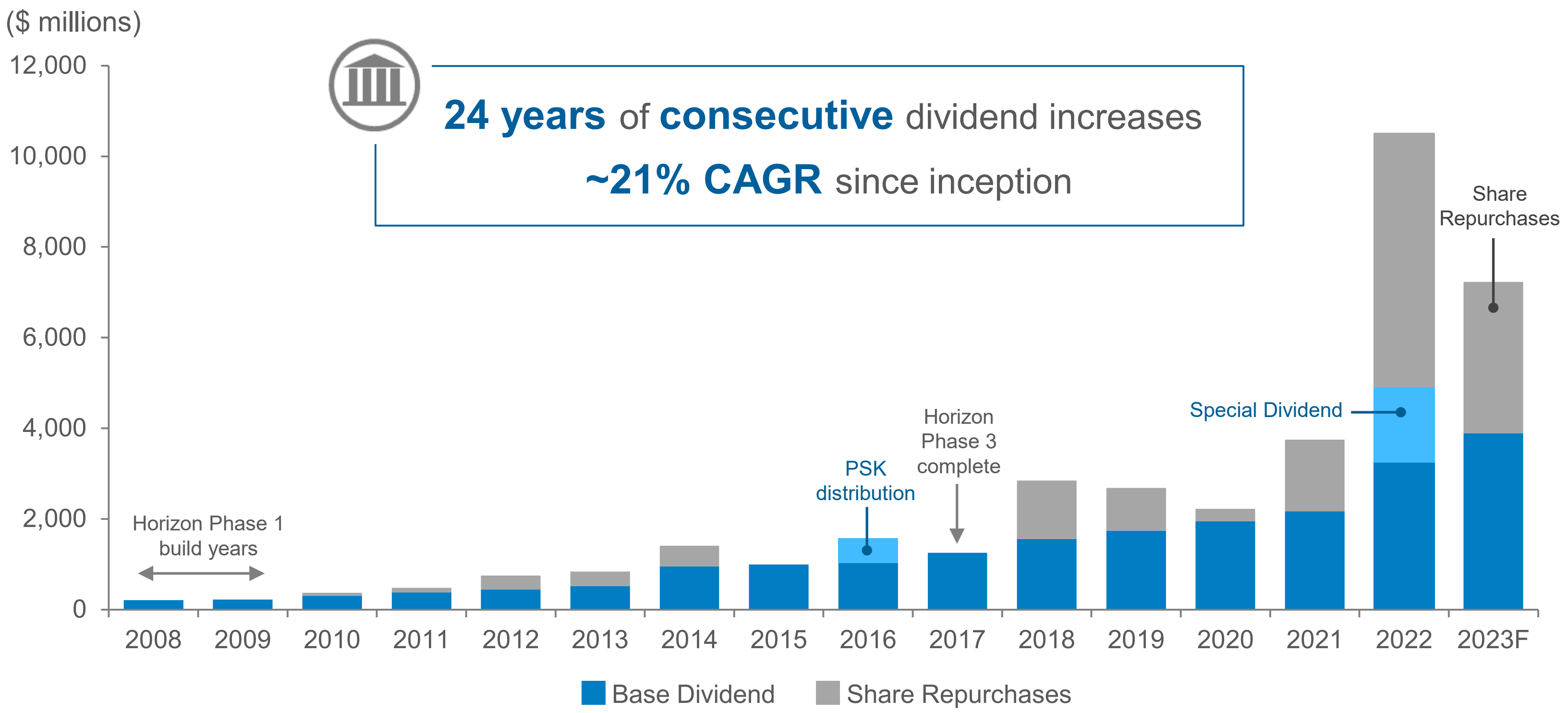
Direct returns to shareholders of
~$6.75 per share
in 2023 via
~$3.55 per share of dividends &
~$3.20 per share of share repurchases

Free cash flow distribution to shareholders **increases** to **100%** when net debt reaches $10 billion, targeted for **Q1/24**

(1) Based upon November 28, 2023 strip pricing with an annual average WTI price of US$77.98/bbl during 2023.

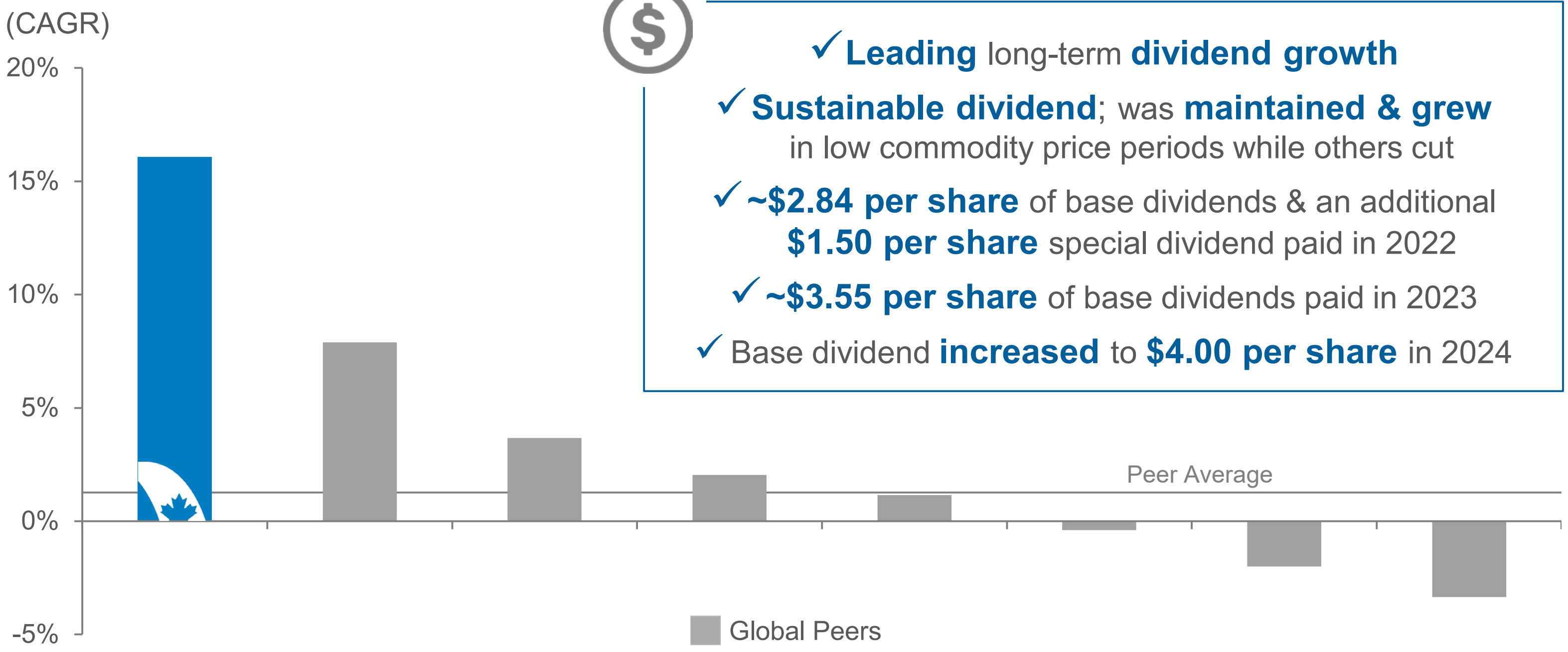
Canadian Natural

Leading history of returns to shareholders growth



Note: Based upon annualized dividends declared. See Advisory for cautionary statements, definitions, pricing assumptions and non-GAAP and other financial measures disclosure.

Long-Term Dividend Growth vs. Global Peers
10 year CAGR: 2024



✓ **Leading** long-term **dividend growth**

✓ **Sustainable dividend**; was **maintained & grew** in low commodity price periods while others cut

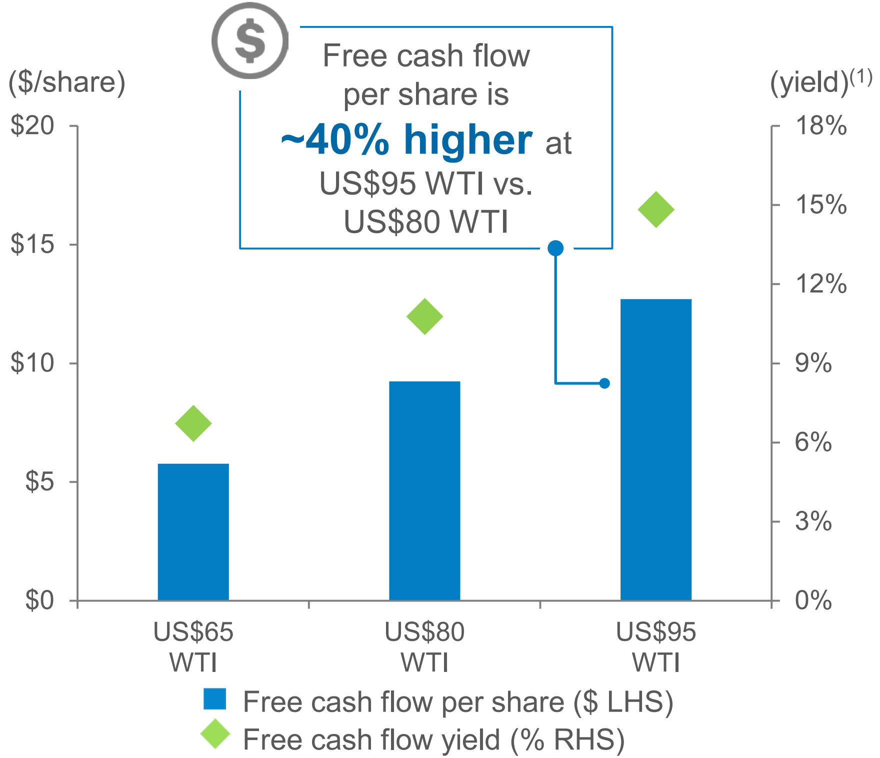
✓ **~$2.84 per share** of base dividends & an additional **$1.50 per share** special dividend paid in 2022

✓ **~$3.55 per share** of base dividends paid in 2023

✓ Base dividend **increased** to **$4.00 per share** in 2024

Peers include: BP, COP, CVX, SHEL, SU, TTE and XOM.
Note: Annual 2014 to 2024. 2024 based upon latest announced quarterly dividend, annualized, as per company reports. See Advisory for cautionary statements, definitions, pricing assumptions and non-GAAP and other financial measures disclosure.

Free Cash Flow Sensitivity
Adjusted funds flow less capital



Diverse, balanced asset base underpinned by **long life low decline** production

Effective & efficient operations combined with **execution excellence**

Top tier cost structure & a **culture of continuous improvement**

Low maintenance capital requirements drives **significant free cash flow**

(1) Free cash flow calculated as adjusted funds flow less total capital expenditures, excluding abandonment and reclamation costs. Free cash flow yield based on closing price on December 13, 2023, annual 2024B estimated free cash flow based on strip pricing as at November 28, 2023.

2024 Budget

2024 Budget: Strategy

Driving material free cash flow & maximizing returns to shareholders

- Disciplined capital budget
- Low maintenance capital
- Top tier execution through flexible capital allocation
- Defined growth/value enhancement plan
  - Focused on returns on capital
- Progress projects that add value and production in 2024 and beyond
- Maintain balance sheet strength
- Focused on increasing returns to shareholders

2024 Budget
Capital

Capital Expenditures ($ millions)[1]	**2024B**
Conventional E&P (excluding Thermal)	$2,540
Thermal and Oil Sands Mining & Upgrading	$2,880
Total	$5,420

The Company's **diversified asset portfolio** of short, mid and long cycle projects provides a **key competitive advantage providing greater flexibility** to manage the pace and timing of development

In the first half of 2024 focus will be on longer cycle projects and in the second half of the year focus will shift to shorter cycle development opportunities to better align with incremental market egress **maximizing value for our shareholders**

(1) 2024 capital budget reflects budgeted net capital expenditures, before abandonment expenditures of approximately $635 million related to the execution of the Company's abandonment and reclamation programs in North America and the North Sea. The Company currently carries an Asset Retirement Obligation ("ARO") liability on its balance sheet for these budgeted future expenditures. Abandonment expenditures are reported before the impact of current income tax recoveries. Current tax recoveries are refundable at a rate of approximately 23% in Canada and at a combined current income tax and Petroleum Revenue Tax ("PRT") rates approximating 70% to 75% in the UK portion of the North Sea. The Company is eligible to recover interest on refunded PRT previously paid. With our ongoing commitment to environmental stewardship, 2024 will be the third year of our well abandonment program, with a pace to abandon the Company's North American inactive well inventory, existing as of December 31, 2021, in approximately 10 years.

Note: Rounded to the nearest $ million. See Advisory for cautionary statements, definitions, pricing assumptions and non-GAAP and other financial measures disclosure.

2024 Budget
Production

Targeted Production(1)	2024B
Natural Gas (MMcf/d)	2,120 - 2,230
Conventional E&P Crude Oil & NGLs (Mbbl/d)	253 - 265
Thermal and Oil Sands Mining & Upgrading (Mbbl/d)	724 - 743
Total Liquids (Mbbl/d)	977 - 1,008
Total (MBOE/d)	1,330 - 1,380

Our focus on returns to shareholders and generating strong returns on capital drives **production per share growth** between **3%** & **7%** from 2023F to 2024B(2)

(1) Reflects planned downtime for turnaround activities in all areas, including at Horizon and Scotford Upgrader through Canadian Natural's 70% ownership in the AOSP.
(2) Based upon the Company's free cash flow allocation policy and resulting forecasted ending period shares outstanding as a result of 100% of free cash flow returned to shareholders in 2024B, once net debt level of $10 billion is reached. Estimates based on November 28, 2023 strip pricing.

Note: Rounded to the nearest 1,000 bbl/d. See Advisory for cautionary statements, definitions, pricing assumptions and non-GAAP and other financial measures disclosure.

2024 Budget
Strategic Drilling Program

- Drilling program timed for incremental market egress
- Heavy crude oil program primarily targeting Mannville/Clearwater multilaterals
- Light crude oil and natural gas primarily targeting liquids-rich Montney
- Flexibility to adjust second half activity depending on commodity prices/egress

Number of Rigs per area	1st half 2024		2nd half 2024
Thermal	5	→	2
Light Crude Oil & Natural Gas	5	→	7
Heavy Crude Oil	2	→	7
Total	12	→	16

Future production not impacted by current egress constraints

Increased market egress available

2024 Budget
Conventional E&P Drilling Program

(net producer wells)	2024B
Natural Gas wells	91
Crude Oil wells	
Primary Heavy	154
Pelican Lake	10
Light	43
International	–
Total Crude Oil wells	207
Total Conventional E&P wells	298

~65% of total net budgeted Conventional E&P wells are targeted to be drilled in the **second half of 2024**

2024 Budget

Thermal In Situ Development Program

- Primrose
  - Drilling two CSS pads targeted to come on production in Q2/25
- Wolf Lake (Primrose)
  - Drilling one SAGD pad targeted to come on production in Q1/25
- Jackfish
  - Drilling one SAGD pad targeted to come on production in Q3/25
- Kirby North
  - Commercial scale solvent SAGD pad development, targeting to begin solvent injection in mid-2024
  - Reduce Steam to Oil Ratio by up to 50%
  - Reduce GHG intensity by 40% to 50%

Continuing with
strong capital efficient drill to fill
development program &
utilizing existing facility capacity

2024 Budget
Oil Sands Mining & Upgrading

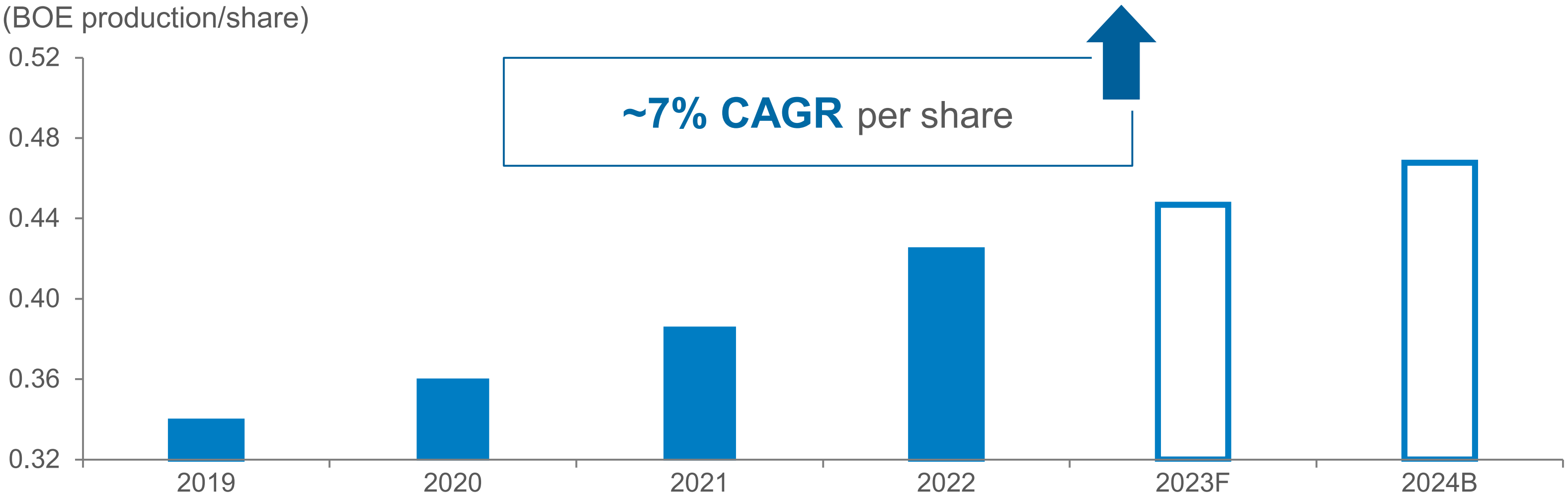
- Horizon
  - Complete remaining components for the reliability enhancement project during turnaround in Q2/24
    - Increase capacity of SCO production by shifting planned turnarounds to once every two years from the current annual cycle
    - Targets to increase annual production in 2025 by ~28,000 bbl/d, with the two year average annual SCO capacity increasing by ~14,000 bbl/d
- AOSP
  - Debottlenecking at Scotford Upgrader is targeted to increase production by ~5,600 bbl/d (net) upon completion of the turnaround in Q4/24
- Total Oil Sands Mining and Upgrading production capacity is targeted to increase by ~33,600 bbl/d in 2025 and subsequent non-turnaround years

Increasing **long life zero decline**
Oil Sands Mining & Upgrading production & capacity
through **debottlenecking** & **increased reliability**

Horizon Oil Sands
Increasing long-term SCO production

- Naphtha Recovery Unit Tailings Treatment (NRUTT) Project
  - Increases SCO production by ~6,300 bbl/d
  - GHG reduction of ~308,000 tCO2e/year
    - ~6% reduction in Horizon's total Scope 1 emissions
  - Capital cost: ~$350 million
    - ~$48 million in 2024 budget
  - Targeted to be operational in Q3/27
  - Future reclamation cost avoidance at Horizon of ~$700 million over the life of the project

Canadian Natural
Production per share growth: 2019 - 2024B



Targeting **production growth** of **~40 MBOE/d** from 2023F exit to 2024B exit levels of **~1,455 MBOE/d,** driving average targeted **annual production growth** of **4% to 5%** in 2025F

Note: Based upon actual and forecasted ending period shares outstanding and targeted 2024B BOE production guidance. See Advisory for cautionary statements, definitions, pricing assumptions and non-GAAP and other financial measures disclosure. Based upon strip pricing on November 28, 2023.

Canadian Natural

Environmental, Social & Governance

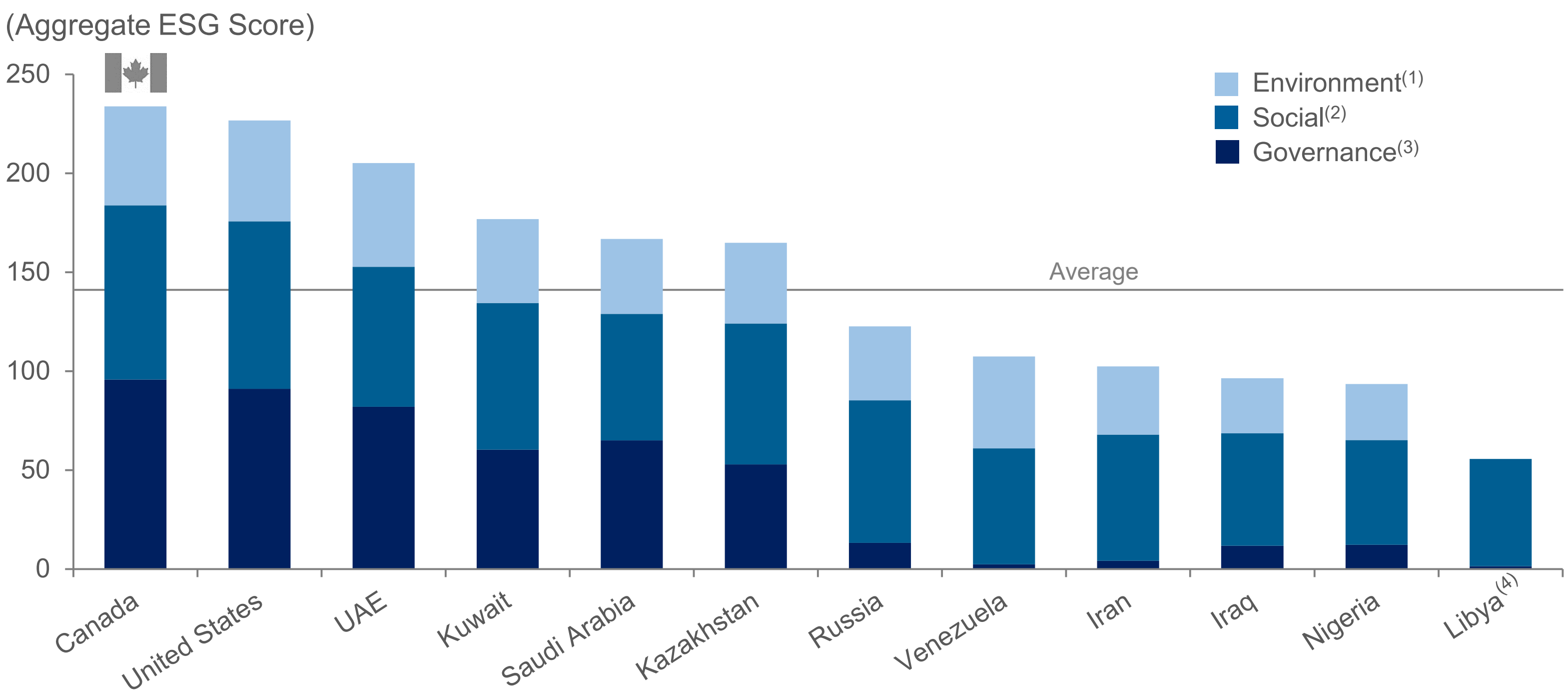
The World Needs More Canadian Energy
Overview

Canadian Natural is part of the solution

- Canada is the top rated ESG country among the top crude oil exporting nations
- Canada has world class CCUS infrastructure
  - Canadian Natural is the largest owner of carbon capture capacity in Canada
- Industry and Federal and Provincial governments working together to achieve climate goals, in an economically responsible manner
- Supplier of affordable, reliable, safe and responsible energy
- Net zero in oil sands operations by 2050 is achievable through the Pathways Alliance
- Top tier disclosure of financial and operational data

ESG Performance Among Top Oil Exporting Nations

The world needs more Canadian energy



(1) 2022 Yale Environment Performance Index (EPI).
(2) 2022 Social Progress Index (SPI) prepared by Social Progress Imperative.
(3) 2022 World Governance Indicators (WGI), Regulatory Quality Score percentile rank.
(4) Libya Environmental score not shown due to insufficient data and Governance score is negligible.

Environmental Targets

Strong commitment to improving performance

40% Reduction in **corporate absolute scope 1 & 2** GHG emissions by 2035 from 2020 baseline

50% Reduction in North America E&P methane emissions by 2030 from 2016 baseline

40% Reduction in in situ fresh water intensity by 2026 from 2017 baseline

40% Reduction in mining fresh river water intensity by 2026 from 2017 baseline

Technology & Innovation

One of Canada's leading R&D investors

- Ongoing investment in technology and innovation will ensure the crude oil and natural gas remains sustainable, competitive and productive for years to come
- Advancing innovation drives performance

~$5.2 billion
invested in research & development since 2009[(1)]

~$587 million
invested in technology, development & deployment in 2022

~$151 million
invested in GHG research, technologies & reduction projects in 2022

(1) Total research and development investment includes eligible Scientific Research and Experimental Development (SRED) claims for Canadian income tax purposes from 2009 to 2022 as well as ~$843 million in research and development investment with academic institutions and other activities that create or deploy new technology, or improve existing technology from 2019 to 2022.

Environment
Land management

- Committed to supplying safe, reliable and responsible energy, along with reducing environmental footprint

The above photo is of a reclamation area on Onion Lake First Nation. The majority of the work was completed using community owned businesses, developing the community's capacity for future reclamation and decommissioning opportunities.

>3,000 abandoned wells/year
in each of last two years

At this pace, **100% abandonment** of current inactive well inventory in **~10 years**

~4.2 million trees planted in our oil sands mining operations since 2009

~4.4 million trees planted to date in our NA E&P operations

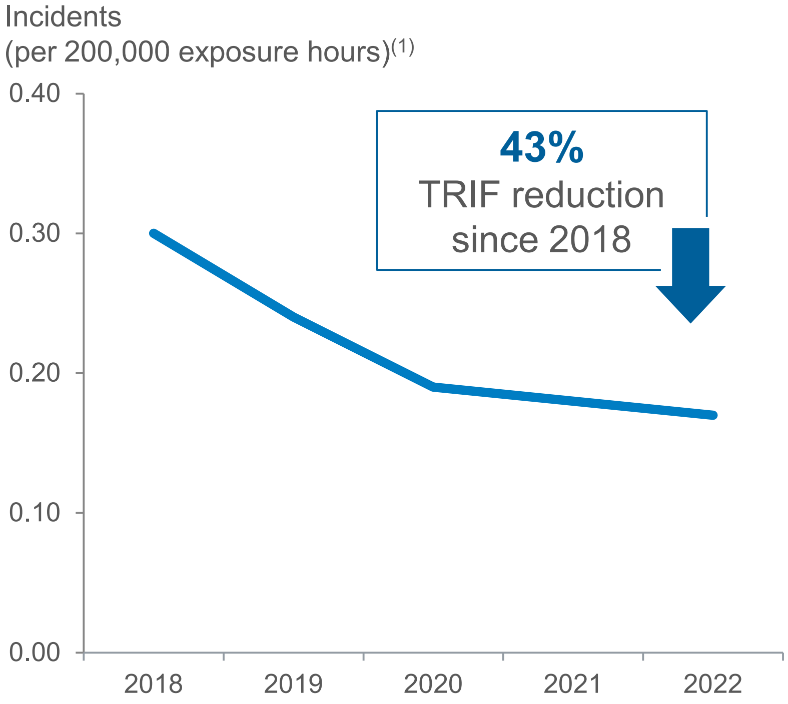
~12,641 hectares reclaimed in NA E&P since 2016

2023 goal of **>1,200 reclamation** certificates per year

Social

Frontline driven incident prevention

Total Recordable Injury Frequency (TRIF)



Comprehensive frontline driven safety management system

78,029 Worksite Safety Observations in 2022

80% reduction in Lost Time Incident (LTI) frequency since 2018

Action plans focus on top causes of injuries through:

- Worksite Safety Observations
- Proactive safety audits
- Coaching frontline supervisors
- Safety Excellence/Mission Statement Meetings

(1) Revised to align with Energy Safety Canada's methodology.

TARGET: NO HARM TO PEOPLE, NO SAFETY INCIDENTS

Social
Working together with communities

Canadian Natural and the Northeast Alberta Apprenticeship Initiative partnered with the Tribal Chiefs Employment & Training Services Association on the Tiny Homes project. The project brought together employment opportunities and affordable housing developments in areas that lack adequate housing or training required to complete such a feat.

In 2022

Canadian Natural worked with **~167** Indigenous businesses

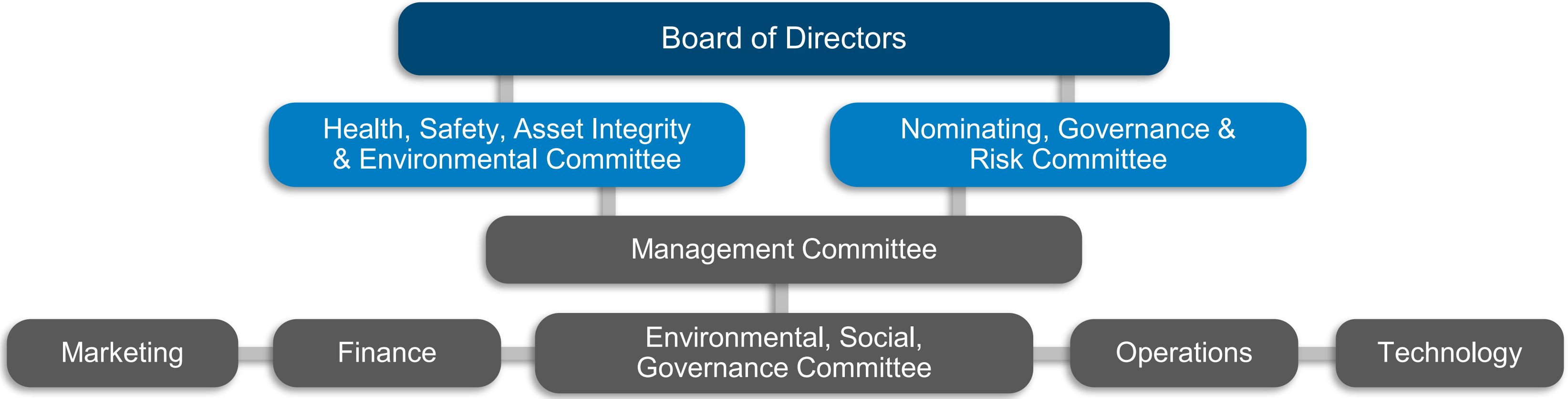
Awarded **~$684** million in contracts with local Indigenous businesses, a 20% increase from 2021

~$2.2 million donated to United Way through employee giving & corporate matching ($30+ million over 30+ years)

1,047 units of blood donations to Canadian Blood Services, receiving

Governance
Risk assessment & mitigation

- Strong track record of identifying, assessing, adapting, aligning and executing
- Board of Directors as well as Board Governance and Risk Committees
  - Review and hold management accountable to identify and mitigate risks
- Strong, effective strategies and plans to address risks
  - Financial, Operational, Market, Technology, Environmental, Social, Governance, Safety, Asset Integrity



Technology & Innovation
Journey to net zero

Current Actions

- Carbon capture and storage
  - Horizon's CCUS
  - Quest CCS
  - North West Refinery CCUS trunkline
  - Hays gas plant capture for EOR
- Molten carbonate fuel cell (MCFC)
- Solvent EOR pilots
- In-Pit Extraction Process (IPEP)
- Methane Reductions
  - Enhanced detection and measurement technologies for fugitive emissions
  - Pneumatic retrofits
  - Heavy oil venting reductions projects
- Ultra-low emissions heavy oil pad
- Cyclic CO_2 injection pilot
- Advanced data analytics/digital operationalization
- Water Technology Development Centre

Medium-Term Actions

- Leverage CCUS advancements and learnings into the next generation of CCUS facilities
- MCFC commercialization
- Solvent EOR commercialization
- IPEP commercialization
- Advanced data analytics/digital operationalization
- High temperature reverse osmosis water treatment
- Technology to enhance water treatment and reduce GHG emissions

Long-Term Actions

- Expand/develop future CCUS projects
- Carbon capture and conversion opportunities (carbon fibers, asphalts, plastics)
- Alternative fuels
- Advanced data analytics/ digital operationalization
- Natural gas decarbonization
- Direct air capture
- Small modular reactors

Targeting **net zero** GHG emissions in the Oil Sands by 2050

MULTIPLE PATHWAYS TO ACHIEVE NET ZERO

Carbon Capture & Sequestration/Storage Technology

Key to net zero

Quest

Horizon

	Capture Capacity (tonnes/year)
Horizon	~0.4 million
Quest[2]	~1.1 million
NWR[3]	~1.2 million
Total	~2.7 million

A **global leader** in CO_2 capture & sequestration[1]

- ✓ Reduced CO_2 footprint
- ✓ Reduced CO_2 charges

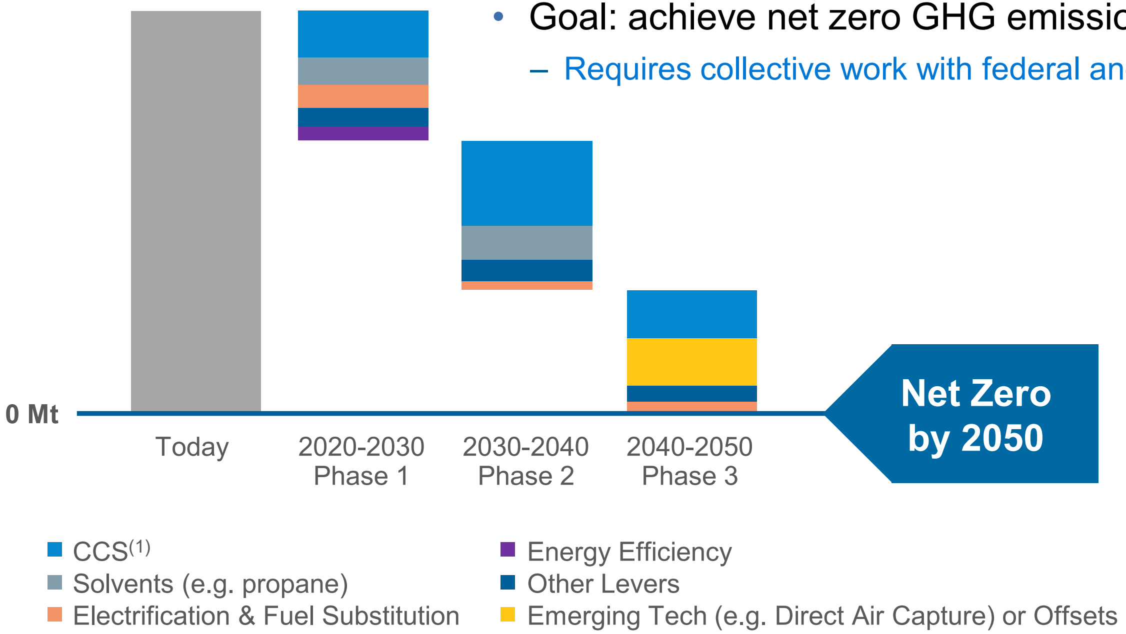
Equivalent to removing **~576,000** cars off the road annually

A portion of the CO_2 for these projects is captured from hydrogen manufacturing plants, producing "blue hydrogen" – hydrogen with reduced GHG emissions

(1) Per the Global CCS Institute.
(2) Canadian Natural is a 70% working interest owner in Quest.
(3) Canadian Natural is a 50% owner in North West Redwater (NWR).

Pathways Alliance
Net zero plan

- Canada's six largest oil sands operators
  – Accounts for ~95% of total oil sands production
- Goal: achieve net zero GHG emissions from oil sands operations by 2050
  – Requires collective work with federal and provincial governments

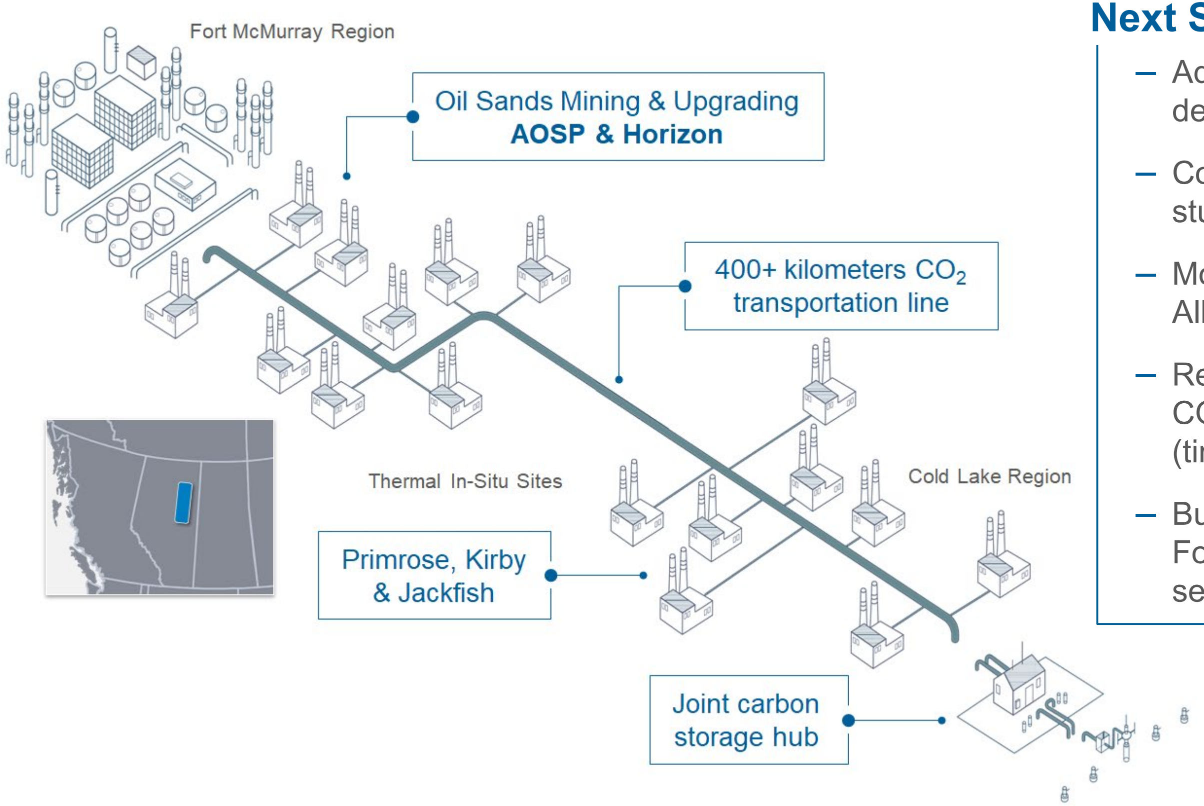


Phase 1 plan includes:

- **22 Mt/year reduction** in oil sands GHG emissions by 2030
  – Foundational CCS project targets to capture & store 10 Mt/year from 14+ facilities
  – Further reductions from projects, such as use of solvents, energy efficiency, cogeneration & electrification

(1) Carbon capture in Phase 1. Phase 2 or 3 could include carbon capture technology, small modular reactors and/or hydrogen.
Note: Magnitude of reductions in each decade can be adjusted based on chosen investment level.

Pathways Alliance Update
Industry collaboration to net zero



Next Steps:

- Advance detailed pore space development plan
- Continue with Engineering & Design studies for CO_2 pipeline & capture facilities
- More clarity on the Government of Alberta's policy for CCS
- Regulatory submissions for proposed CO_2 pipeline & storage network (timeline Q4/23)
- Build a CO_2 transportation line, connecting Fort McMurray & Cold Lake to a carbon sequestration hub

INDUSTRY-WIDE APPROACH TO REACH NET ZERO CO_2 EMISSIONS

Canadian Natural
Sustainability & ESG reporting

Stewardship Report to Stakeholders

ESG Highlights

Canadian Natural's 2022 ESG Highlights

GHG EMISSIONS MANAGEMENT

Corporate Scope 1 (Direct) GHG Emissions Intensity

8% reduction from 2018

North America E&P Methane Emissions

50% reduction from 2016 baseline year

10.4 million tonnes of CO_2e conserved in primary heavy crude oil and in situ operations since 2018

GHG EMISSIONS MANAGEMENT STRATEGY

- **Integrating emissions reduction** in project planning and operations
- **Leveraging technology** to create value, enhance performance and reduce emissions
- **Investing in research and development (R&D)** and supporting collaboration
- **Focusing on continuous improvement** to drive long-term emissions reductions through energy and process efficiencies
- **Leading in carbon capture, utilization, sequestration and storage (CCUS)**
- **Engaging proactively in policy and regulation** to effectively manage climate risks and opportunities, including trading capacity and offsetting emissions
- **Reviewing and developing new business opportunities and trends** that present further opportunities to reduce our environmental footprint

CDP Climate Change
CDP Water

Climate Change 'B' Score

Technology & Innovation Case Studies

Aligned with **Task Force on Climate-Related Financial Disclosures (TCFD), Sustainability Accounting Standards Board (SASB),** & **Global Reporting Initiative (GRI)**

Canadian Natural

Balance Sheet Strength

Canadian Natural
Robust financial position

	Long-Term Ratings	Outlook	Short-Term Ratings
DBRS	A (low)	Stable	R-1
Standard & Poor's	BBB-	Stable	A-3
Moody's	Baa1	Stable	P-2

- Balance Sheet strength as at September 30, 2023
  - Net debt → ~$11.5 billion, reduced by ~$9.8 billion since December 31, 2020
  - Debt to book capitalization → ~22.5%
  - Debt to adjusted funds flow → ~0.8x
  - Significant liquidity → ~$6.1 billion(1)

(1) Including committed and undrawn credit facilities, cash balances, cash equivalents and short term investments.
Note: See Advisory for cautionary statements, definitions, pricing assumptions and non-GAAP and other financial measures disclosure.

Balanced credit facility profile

Revolving Credit Facilities	(C$ millions)
June 2025[1]	$2,425
June 2027[1]	$2,425
February 2025[1]	$500
Operating demand loan	$100
Total	$5,450

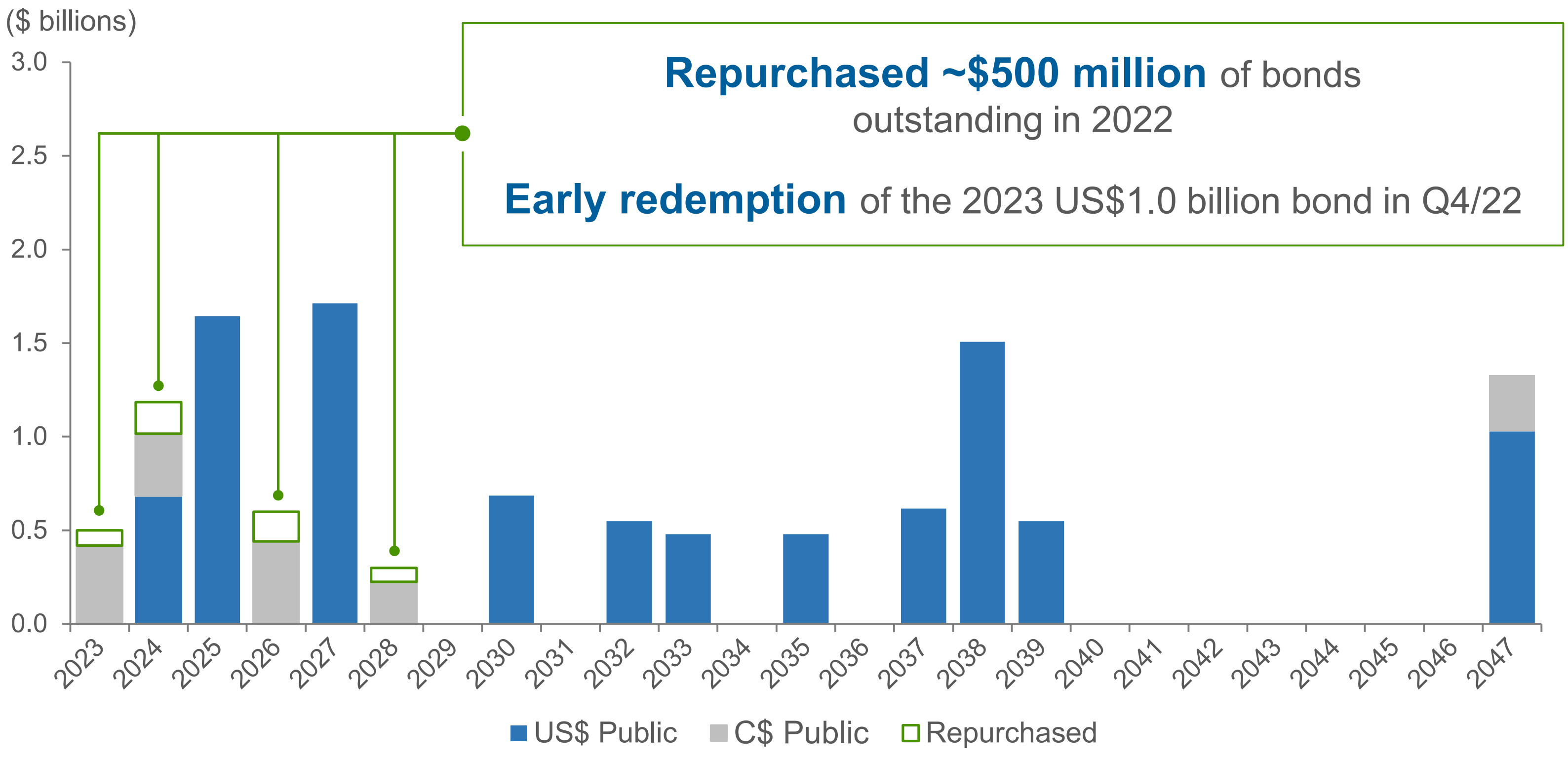
Support from **14 banks** diversified by location

15+ year relationships with 12 banks

(1) Financial covenant on Credit Facilities is based on consolidated debt to book capital ratio to not exceed 0.65:1.00.
Note: As at September 30, 2023.

LARGE & DIVERSE BANKING GROUP SUPPORTS STRONG LIQUIDITY

Canadian Natural
Debt maturity profile

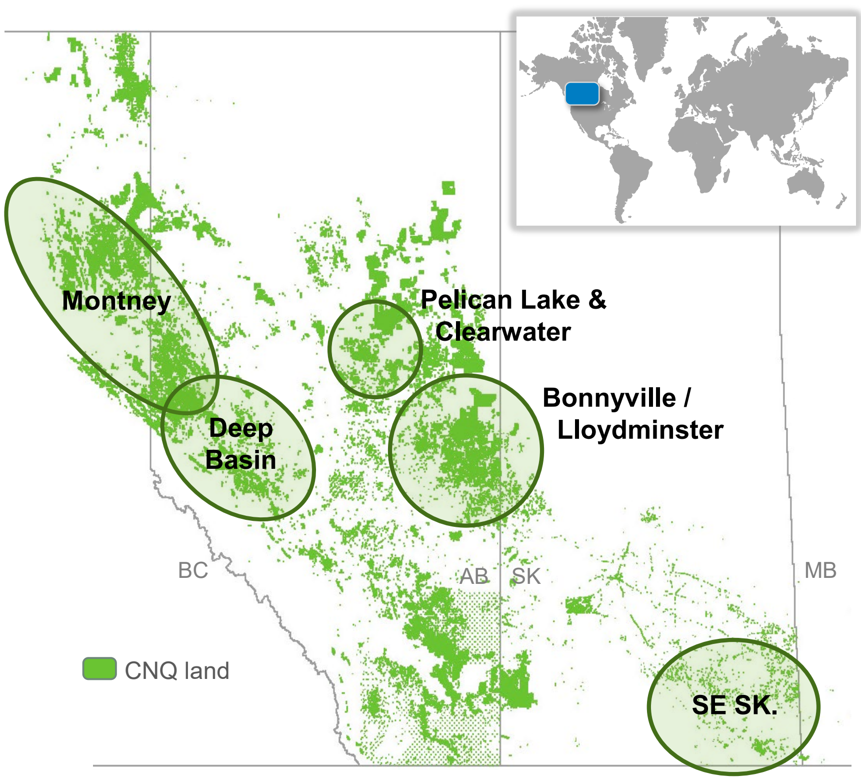


STRATEGICALLY BALANCED MATURITY PROFILE

Canadian Natural

Asset Overview

Conventional E&P
Overview



~574,000 BOE/d of production(1)

Largest conventional E&P reserves in Canada
~5.3 billion BOE total proved plus probable(2)

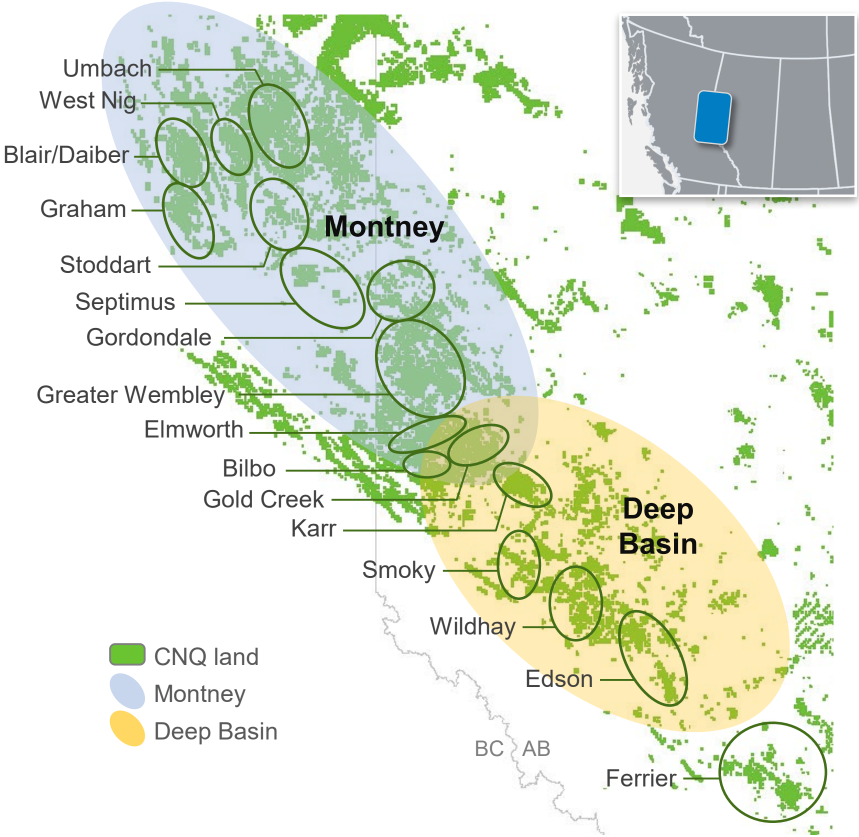
Significant infrastructure in place for drill to fill strategy with **~305,000 BOE/d** of **net available capacity**

- Natural Gas
  - ~22.2 Tcf 2P reserves(2)
  - ~2.1 Bcf/d of production(1) – 2nd largest in Canada
- NGLs, light crude oil and heavy crude oil
  - ~1.6 billion barrels 2P reserves(2)
  - ~228,000 bbl/d of production(1) – largest in Canada
- Extensive land base with significant inventory
- Leverage owned and operated infrastructure
- Drill to fill strategy

(1) Annual 2022 production.
(2) Company gross total proved plus probable reserves at December 31, 2022.

Natural Gas, NGLs & Light Crude Oil: Montney & Deep Basin

Overview



~1.5 million net acres of Montney rights
~1.8 million net acres of Deep Basin rights

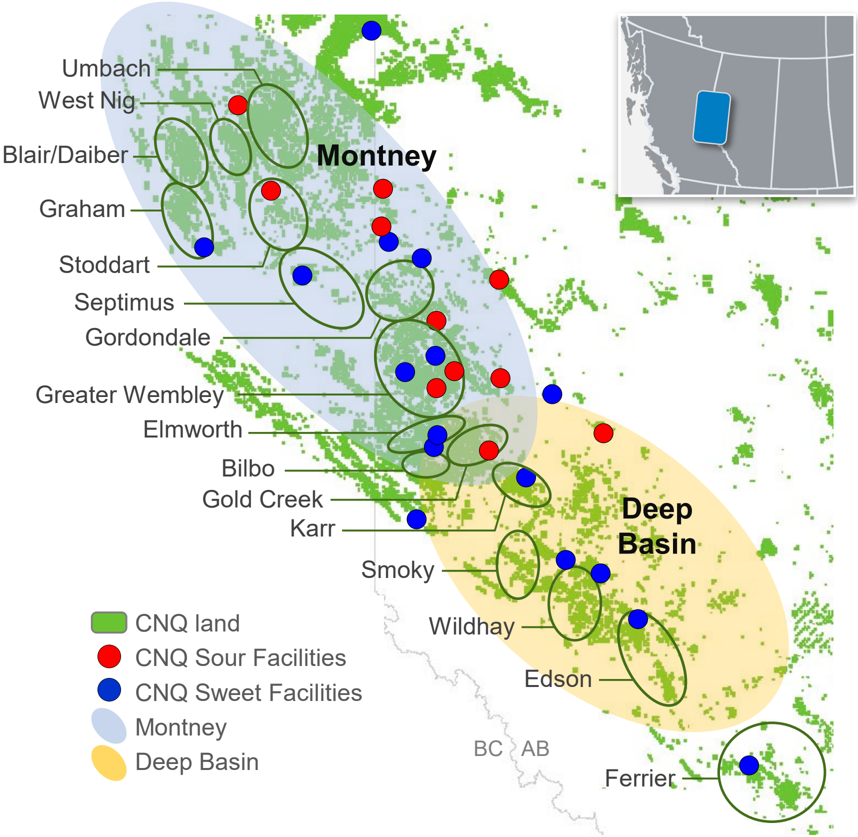
Significant high value **drill to fill** opportunities

~4,000 premium locations(1)

- Low capital exposure drill to fill strategy
  - Flexible timing in response to market conditions
- Applying technology and innovation to reduce costs and maximize value

(1) Assumes US$70/bbl WTI, C$3.25/GJ AECO and US$1.00 to C$1.30 foreign exchange.
Note: See Advisory for cautionary statements.

Natural Gas, NGLs & Light Crude Oil: Montney & Deep Basin
Infrastructure advantage



Significant high value **drill to fill** growth opportunities

~2.8 Bcf/d net facility design capacity
~1.1 Bcf/d net available facility capacity

- Extensive owned and controlled infrastructure
  - Higher utilization drives lower operating costs
- Strategic infrastructure proximal to premium land base
- Control pace of development

INFRASTRUCTURE ADVANTAGE SIGNIFICANTLY IMPROVES MARGINS

International Light Crude Oil
Overview

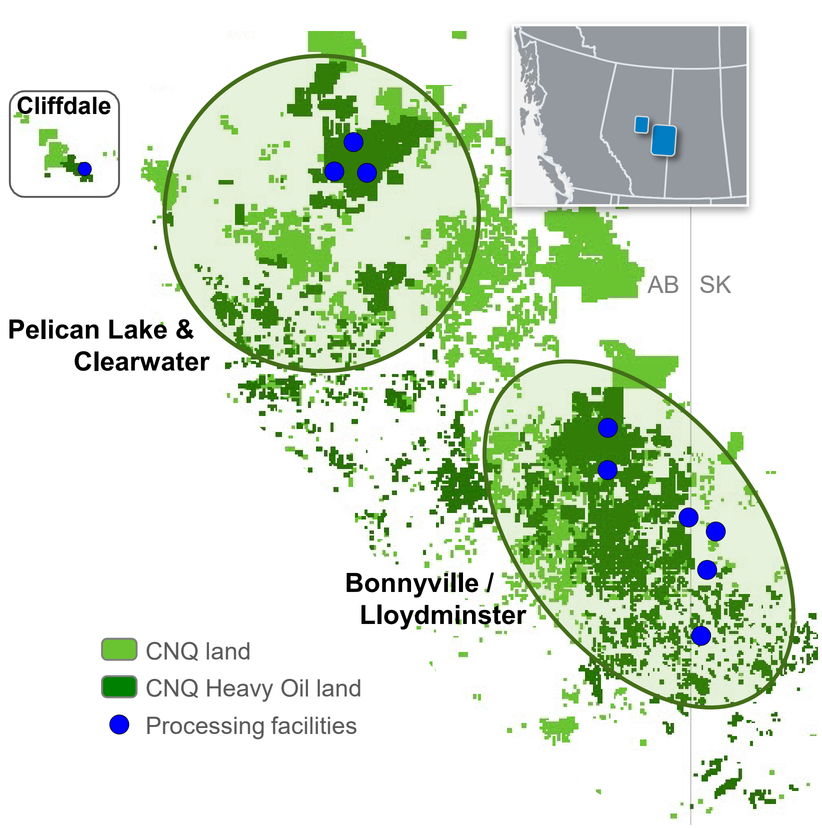
~27,300 bbl/d of light crude oil production[1]

High return international light crude oil, with exposure to Brent pricing

- North Sea
  - Leveraging expertise to manage costs in a mature basin
  - Industry leading abandonment and decommissioning results
- Côte d'Ivoire
  - Capturing high return, low risk development opportunities
    - Targeting Phase 5 development at Baobab in 2026/2027
- South Africa
  - Exploration upside with significant gas condensate resource of ~3.8 Tcfe (~0.76 Tcf net)
  - Operator applied for Production Right status in September 2022

(1) Annual 2022 production.

Heavy Crude Oil
Overview



Large land base
~3.2 million net acres

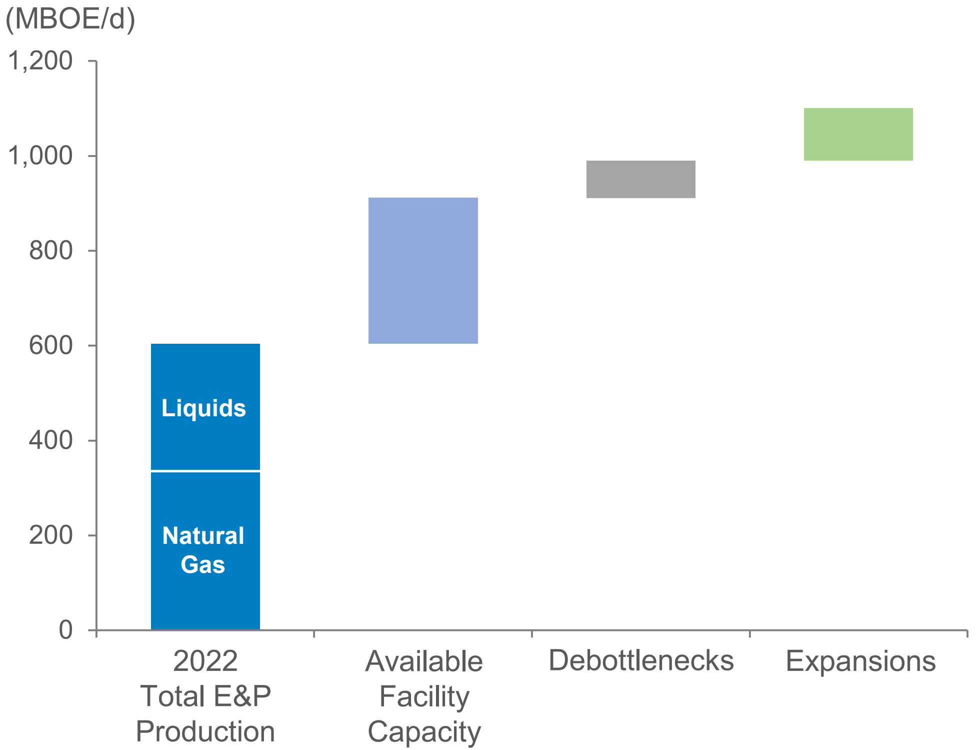
~1,570 defined multilateral locations(1)
~1,600 defined slant locations(1)

High value **drill to fill** opportunities
~67,000 BOE/d available facility capacity

- Largest primary and polymer flood heavy crude oil producer in Canada
  - Production of ~118,000 bbl/d in 2022
- Economies of scale with extensive infrastructure advantage
  - Large, concentrated land base
  - ~940,000 net Clearwater acres with exploration upside
  - Repeatable, scalable programs
- Leveraging technology to reduce costs, increase productivity and reduce environmental footprint

(1) Assumes US$70/bbl WTI, 22% WCS differential, C$3.25/GJ AECO and US$1.00 to C$1.30 foreign exchange.
Note: See Advisory for cautionary statements.

Total Conventional E&P
Near-, mid- & long-term development potential



Production of
~2.1 Bcf/d & **~255 Mbbl/d**
in 2022

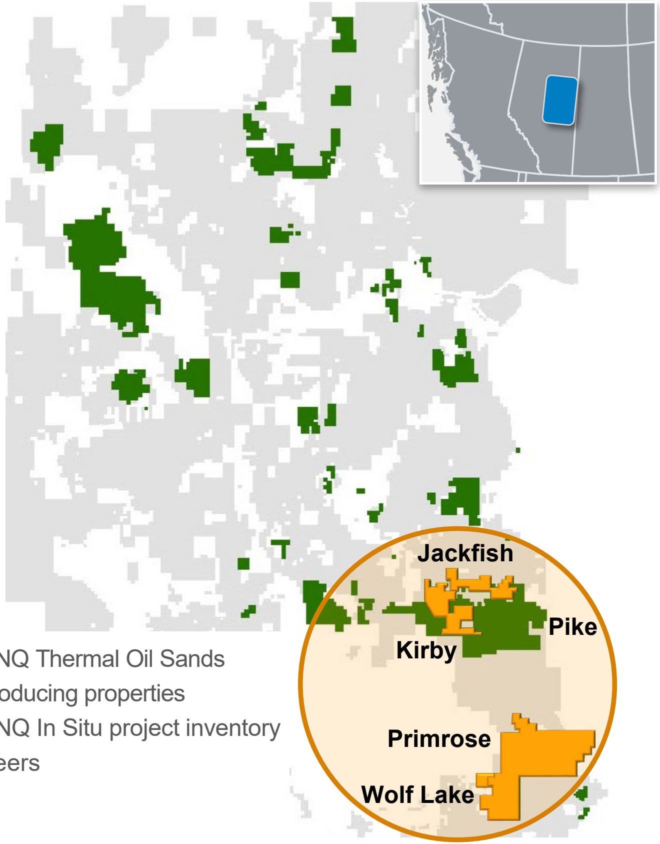
Potential to leverage available facility capacity of
~305 MBOE/d

Potential debottleneck & expansion opportunities
~190 MBOE/d

~7,500 defined locations(1)

(1) Assumes US$70/bbl WTI, 22% WCS differential, C$3.25/GJ AECO and US$1.00 to C$1.30 foreign exchange.
Note: See Advisory for cautionary statements.

Thermal In Situ Oil Sands
Asset overview



- CNQ Thermal Oil Sands producing properties
- CNQ In Situ project inventory
- Peers

Long life low decline assets producing **~252,000 bbl/d** in 2022

Second largest total proved plus probable bitumen reserves in Canada with **~5.2 billion barrels**(1)

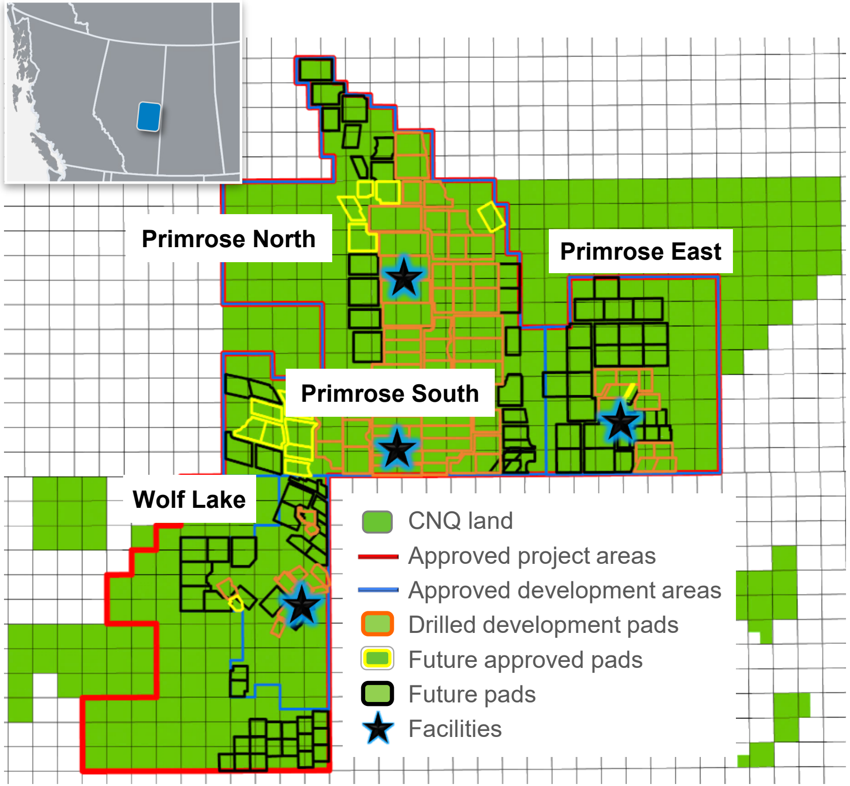
Facility capacity of ~340,000 bbl/d(2) with **~95,000 bbl/d** of **available capacity**

- 100% working interest and operatorship of developed properties
- Leverage technology and innovation to enhance recovery and optimize costs
  - Expertise in: Cyclic Steam Stimulation (CSS), Steam Assisted Gravity Drainage (SAGD), Steam Flood and Solvents
  - Progressing commercial scale solvent SAGD at Kirby North
  - Aligned potential GHG reduction projects with Pathways Alliance

(1) Company gross total proved plus probable reserves at December 31, 2022.
(2) Includes Jackfish, Kirby & Primrose/Wolf Lake facility capacities.

Thermal In Situ Oil Sands

Primrose / Wolf Lake overview



Total facility capacity **~140,000 bbl/d**

Leverage **available** facility capacity of **~65,000 bbl/d**

~307 net sections of undeveloped land

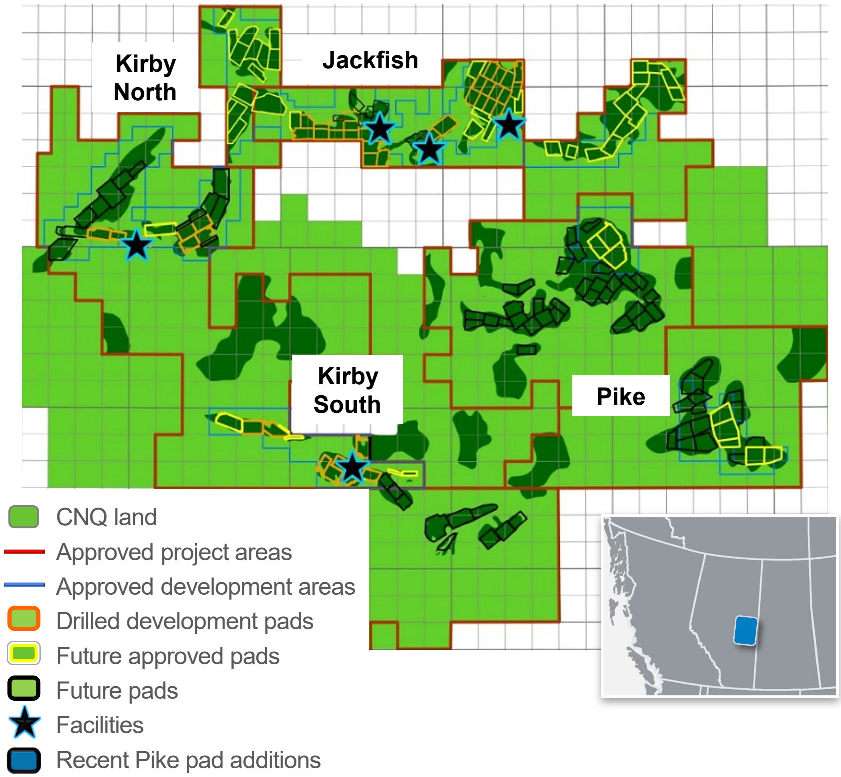
~2,000 locations[(1)]

- Low cost, low risk and repeatable CSS pad development
- Steam Flood, a follow up to CSS, increases recovery factor by ~20%
- Solvent enhanced technology steam flood upside
- Potential SAGD development opportunities

(1) At US$70/bbl WTI, 22% WCS differential, C$3.25/GJ AECO and US$1.00 to C$1.30 foreign exchange.

Thermal In Situ Oil Sands

Kirby / Jackfish / Pike SAGD overview



Total facility capacity of **~200,000 bbl/d**(1)

Leverage **available** facility capacity of **~30,000 bbl/d**

Consolidated land base **~432 net sections** of undeveloped land

~1,000 locations(2)

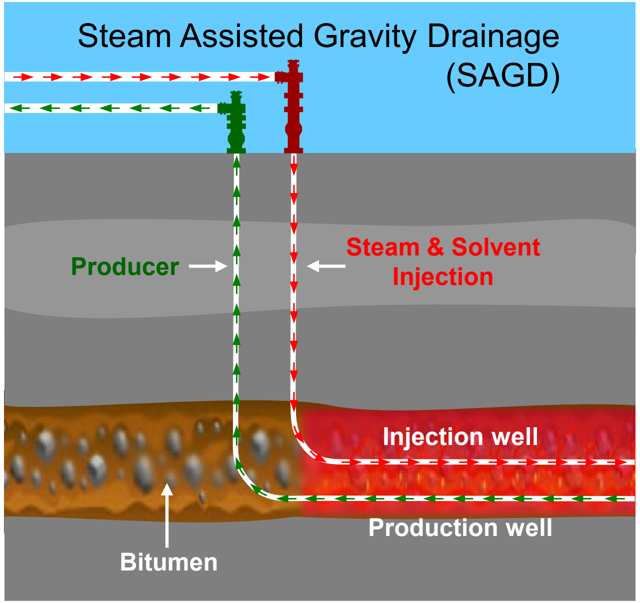
- Acquired remaining 50% working interest of Pike in Q1/22
  - Significant future development opportunities at Pike
- Economies of scale
  - Commercial scale solvent pilot progressing at Kirby
  - Synergies drive lower operating costs
  - Leverage operating and technical expertise across land base

(1) Includes Jackfish, Kirby South and Kirby North facilities.
(2) At US$70/bbl WTI, 22% WCS differential, C$3.25/GJ AECO and US$1.00 to C$1.30 foreign exchange.

Technology & Innovation
Solvents: SAGD & CSS

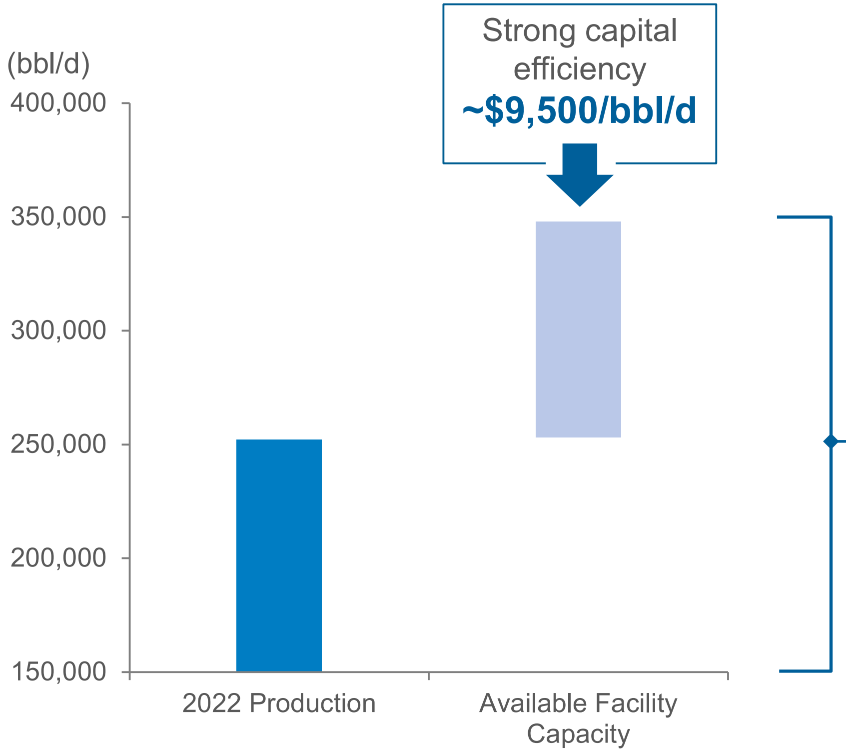
Co-injecting solvent with steam

Results to-date	• Kirby South solvent SAGD pilot was a success – SOR and GHG intensity reductions of ~45% – Solvent recovery of ~85%
Current Progress	• Completed engineering and design of a commercial scale solvent SAGD pad development at Kirby North – Begin installing facility module in Q3/23 – Targeting to commence solvent injection in mid-2024 • Primrose solvent pilot in the steam flood area – The pilot is targeted to continue into 2024 to evaluate the potential of various solvent concentrations to improve overall performance
Benefits	• Reduce SOR by up to 50% – ~$1.00/bbl in operating costs • Lower GHG emissions intensity by ~40-50% • Enhances resource recovery while reducing steam and energy required • Potential application throughout extensive thermal in situ asset base
Opportunity	**Unlocks capacity for potential production growth**



Thermal In Situ Oil Sands

Near- & mid-term potential



Thermal in situ production of **~252,000 bbl/d** in 2022

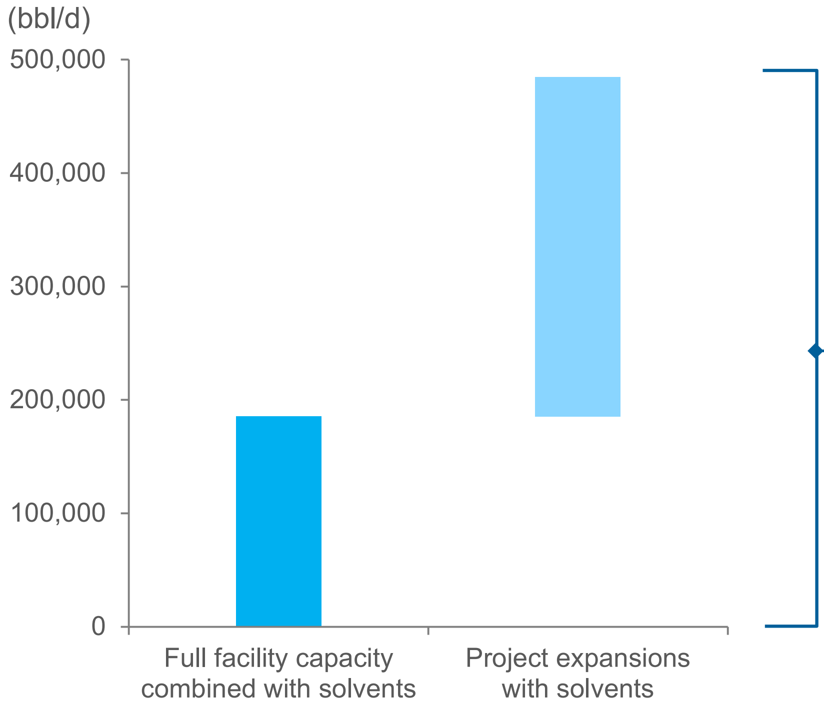
Potential to leverage **available capacity** to add **~95,000 bbl/d**(1) of production

~3,000 locations

(1) US$70/bbl WTI, 22% WCS differential, C$3.25/GJ AECO and US$1.00 to C$1.30 foreign exchange and represents incremental production to replace existing production declines and potential future capability.
Note: See Advisory for cautionary statements and definitions.

Thermal In Situ Oil Sands

Long-term potential

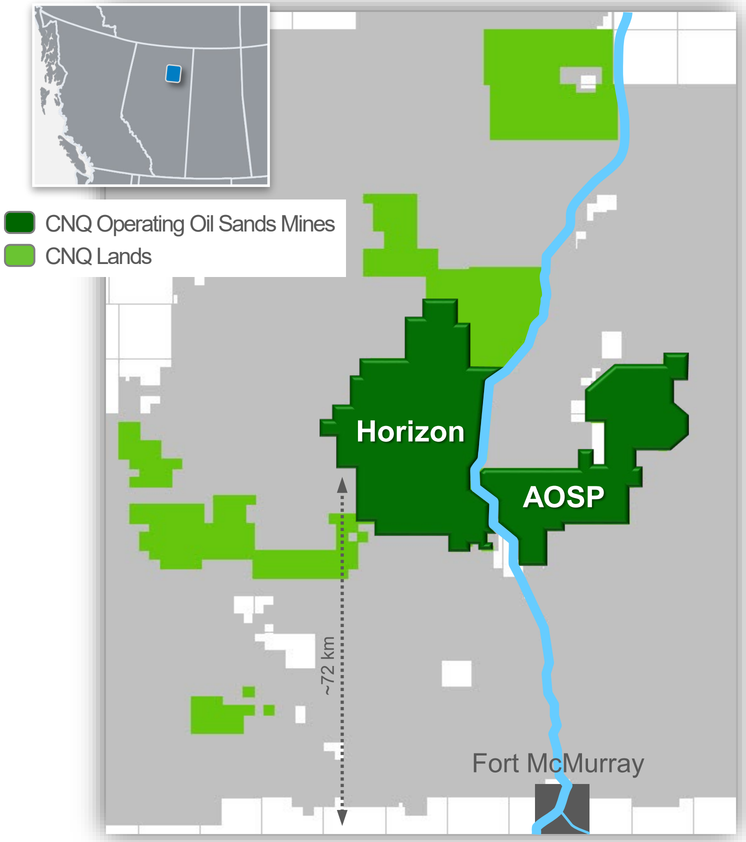


Solvents can potentially add more than **~185,000 bbl/d**(1) of **incremental** capacity

Project expansions(2), when combined with solvents, can potentially add an **~300,000 bbl/d**(1) of **incremental** capacity

(1) US$70/bbl WTI, 22% WCS differential, C$3.25/GJ AECO and US$1.00 to C$1.30 foreign exchange.
(2) Includes Primrose/Wolf Lake, Kirby and Jackfish expansions; both include the use of solvents.
Note: See Advisory for cautionary statements, definitions and pricing assumptions.

Oil Sands Mining & Upgrading
Asset overview



Industry leading oil sands operator

Net capacity increases by 5,000 bbl/d in 2023 to
~480,000 bbl/d of **high value SCO**

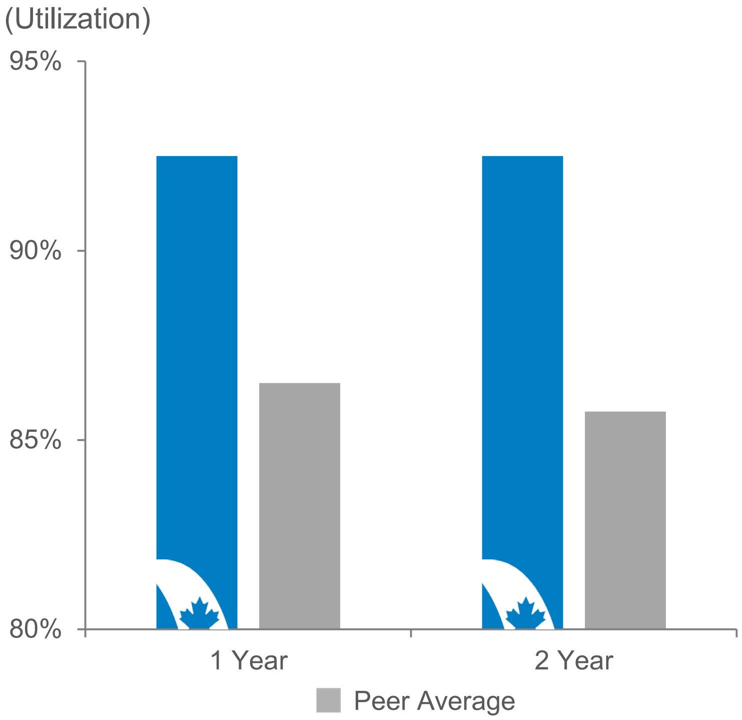
No decline, reservoir risk or reserve replacement cost

Total proved plus probable reserves of
~7.4 billion barrels with a **50+ year** reserve life(1)

- Significant resource in place
  - ~18.4 billion barrels BIIP(2)
- Top tier operating costs
- Low maintenance capital
- Focused on safety, reliability and high utilization

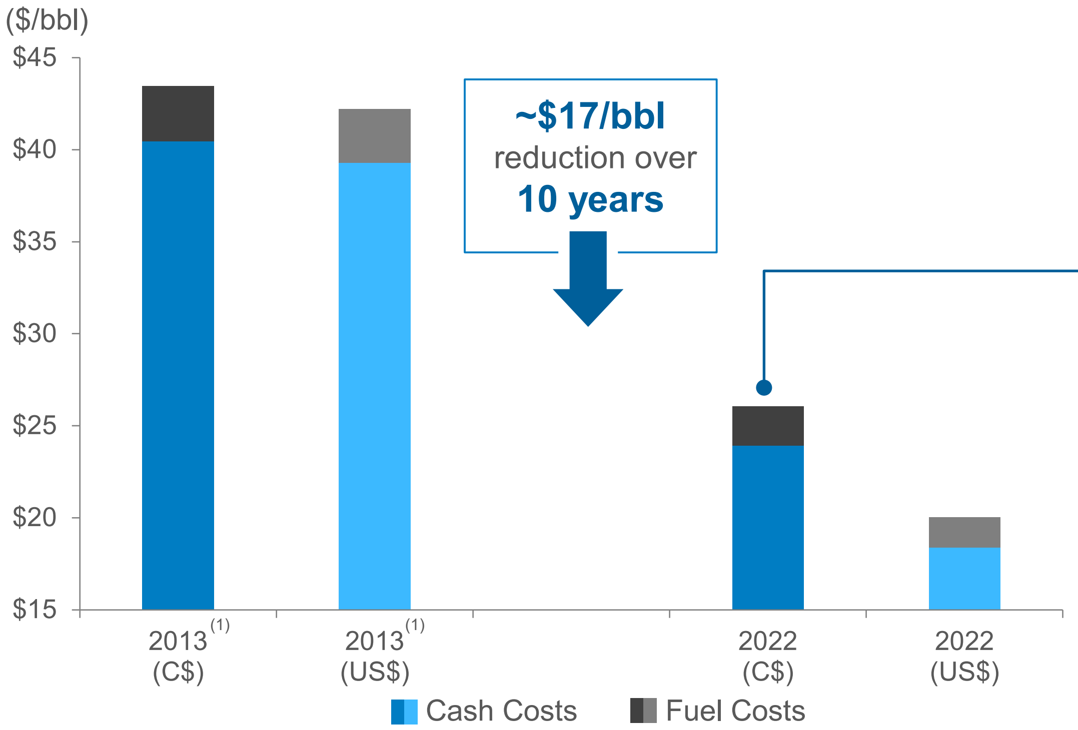
(1) Including future pit development; Company gross total proved plus probable reserves as at December 31, 2022.
(2) Mineable Bitumen Initially-in-Place (BIIP).

Oil Sands Mining & Upgrading
Top tier utilization



Peers Include: IMO Kearl, SU Base, SU Fort Hills and Syncrude.
Source:TD research: Mine your own Business report - November 9, 2023, includes trailing data as of July 2023.

Oil Sands Mining & Upgrading
Operating costs reductions over 10 years



~40% reduction in SCO operating costs (including energy costs)

Equates to a **~$2.7 billion** savings in annual operating costs in 2022

(1) 2013 operating costs are before the AOSP acquisition.
Note: Operating costs reflect production downtime for turnarounds (unadjusted). Fuel costs reflect natural gas costs used in operations.

Horizon Oil Sands

Long-term opportunity: In-Pit Extraction Process (IPEP)

IPEP is a relocatable, modular extraction plant that processes ore and separates bitumen in the mine pit.

Results & Progress to-date	• IPEP pilot was a success • Front end engineering and design (FEED) of demonstration plant is now complete
Next Steps	• Demonstration plant – Detailed design of a 750t/hour commercial unit
Benefits	• Targeted operating cost savings of $1.00/bbl - $2.00/bbl • Reduces GHG emissions by ~40% – Reduces materials transportation by truck, pipeline length and energy required to pump material • Eliminates tailings ponds, as it produces dry stackable tailings • Accelerates reclamation • Reduces and avoids fugitive emissions


IPEP Field Pilot at Horizon


Dry tailings produced in the mine pit

Horizon Oil Sands

Long-term opportunity: Paraffinic Froth Treatment (PFT)

- Potential project adds incremental production of ~75,000 bbl/d of bitumen
- Engineering and design specification work underway
  - IPEP opportunities combined with PFT to create additional capacity potential
  - Utilize excess naphtha in SCO to dilute and transport product

Horizon Oil Sands

Combine & leverage technology for cost effective expansion: IPEP & PFT

IPEP

- Reduces GHG emissions
- Eliminates / reduces need for tailings ponds
- Potential reclamation savings in future

PFT

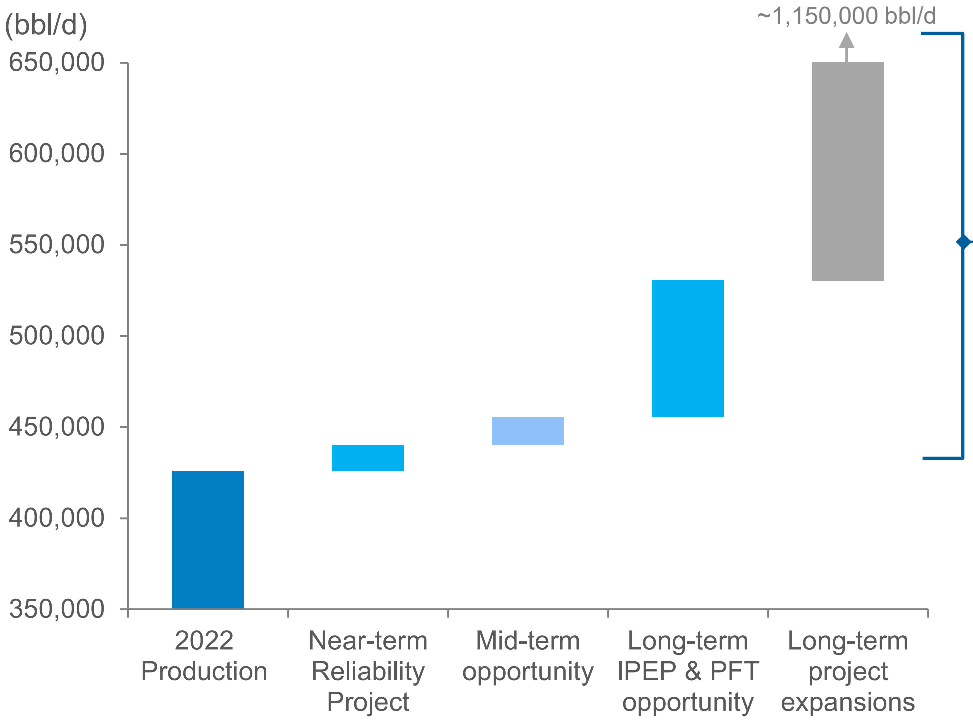
- Less energy intensive process
- Use IPEP to produce diluted bitumen

Combining **PFT** with **IPEP** technology targets to increase overall project returns through **incremental production** opportunity of **~75,000 bbl/d** of bitumen while lowering operating costs by **~$3.25/bbl** & reducing GHG emissions

Total potential capital estimate of **~$5.0 billion** to be invested over a 15 year period

Oil Sands Mining & Upgrading

Near-, mid- & long-term development potential



Production of **~426,000 bbl/d** in 2022

Near-term Reliability Project adds **~14,000 bbl/d**(1) of SCO production capacity

Potential mid-term opportunity of **~15,000 bbl/d**(1) of production capacity

Long-term, the **PFT** & **IPEP** combination potentially adds **~75,000 bbl/d**(1) of bitumen capacity while lowering GHG emissions

Long-term total project expansions could potentially add incremental production capacity of **~610,000 bbl/d**(1)

(1) US$70/bbl WTI, 22% WCS differential, C$3.25/GJ AECO and US$1.00 to C$1.30 foreign exchange.
Note: See Advisory for cautionary statements, definitions and pricing assumptions.


Canadian Natural
PROVEN • EFFECTIVE • STRATEGY

Special Note Regarding Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, income tax expenses, and other targets provided throughout this presentation and the Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of the Company, constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including, without limitation, those in relation to: the Company's assets at Horizon Oil Sands ("Horizon"), the Athabasca Oil Sands Project ("AOSP"), the Primrose thermal oil projects, the Pelican Lake water and polymer flood projects, the Kirby thermal oil sands project, the Jackfish thermal oil sands project and the North West Redwater bitumen upgrader and refinery; construction by third parties of new, or expansion of existing, pipeline capacity or other means of transportation of bitumen, crude oil, natural gas, natural gas liquids ("NGLs") or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market; the development and deployment of technology and technological innovations; the financial capacity of the Company to complete its growth projects and responsibly and sustainably grow in the long-term; and the impact of the Pathways Alliance ("Pathways") initiative and activities, government support for Pathways and the ability to achieve net zero emissions from oil production, also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts, and are reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and NGLs reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the earlier of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions (including as a result of the actions of the Organization of the Petroleum Exporting Countries Plus ("OPEC+") the impact of armed conflicts in the Middle East, the impact of the Russian invasion of Ukraine, continuing effects of the novel coronavirus ("COVID-19") pandemic, increased inflation, and the risk of decreased economic activity resulting from a global recession) which may impact, among other things, demand and supply for and market prices of the Company's products, the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil, natural gas and NGLs prices; fluctuations in currency and interest rates; assumptions on which the Company's current targets are based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; the ability of the Company to prevent and recover from a cyberattack and other cyber-related crime; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; the Company's ability to implement strategies and leverage technologies to meet climate change initiatives and emissions targets; the impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain, and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital expenditures and production expenses); asset retirement obligations; the sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short, medium, and long-term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by national, federal, provincial, state and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this presentation or the Company's MD&A could also have adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by applicable law, the Company assumes no obligation to update forward-looking statements in this presentation or the Company's MD&A, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or the Company’s estimates or opinions change.

Special Note Regarding Currency, Financial Information and Production

This presentation should be read in conjunction with the Company's unaudited interim consolidated financial statements (the "financial statements") and the Company's MD&A for the three and nine months ended September 30, 2023 and audited consolidated financial statements for the year ended December 31, 2022. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's financial statements and MD&A for the three and nine months ended September 30, 2023 have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

Production volumes and per unit statistics are presented throughout this presentation on a "before royalties" or "company gross" basis, and realized prices are net of blending and feedstock costs and exclude the effect of risk management activities. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("BOE"). A BOE is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio 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 comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this presentation, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and SCO. Production on an "after royalties" or "company net" basis is also presented for information purposes only.

Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2022, is available on SEDAR+ at www.sedarplus.ca and on EDGAR at www.sec.gov. Information on the Company's website does not form part of and is not incorporated by reference in the Company's MD&A.

Special Note Regarding Non-GAAP and Other Financial Measures

This presentation includes references to non-GAAP and other financial measures as defined in National Instrument 52-112 – Non-GAAP and Other Financial Measures Disclosure. These financial measures are used by the Company to evaluate its financial performance, financial position or cash flow and include non-GAAP financial measures, non-GAAP ratios, total of segments measures, capital management measures, and supplementary financial measures. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP and other financial measures. The non-GAAP and other financial measures used by the Company may not be comparable to similar measures presented by other companies, and should not be considered an alternative to or more meaningful than the most directly comparable financial measure presented in the Company's financial statements, as applicable, as an indication of the Company's performance. Descriptions of the Company's non-GAAP and other financial measures included in this presentation, and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below as well as in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and nine months ended September 30, 2023, dated November 1, 2023.

Free Cash Flow

Free cash flow is a non-GAAP financial measure that represents adjusted funds flow adjusted for base capital expenditures and dividends on common shares for 2023 and comparable periods. The Company considers free cash flow a key measure in demonstrating the Company's ability to generate cash flow to fund future growth through capital investment, pay returns to shareholders and to repay debt.

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2023**	Jun 30 2023	Sep 30 2022	**Sep 30 2023**	Sep 30 2022
Adjusted funds flow [1]	**$ 4,684**	$ 2,742	$ 5,208	**$ 10,855**	$ 15,615
Less: Base capital expenditures [2]	**$ 1,019**	$ 1,385	$ 996	**$ 3,522**	$ 3,106
Dividends on common shares	**$ 984**	$ 989	$ 2,532	**$ 2,911**	$ 4,092
Free cash flow	**$ 2,681**	$ 368	$ 1,680	**$ 4,422**	$ 8,417

(1) Refer to the descriptions and reconciliations to the most directly comparable GAAP measure, which are provided in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and nine months ended September 30, 2023, dated November 1, 2023.

(2) Item is a component of net capital expenditures. Refer to the "Non-GAAP and Other Financial Measures" section of Company's MD&A for the three and nine months ended September 30, 2023, dated November 1, 2023 for more details on net capital expenditures.

Special Note Regarding Non-GAAP and Other Financial Measures (continued)

Capital Budget

Capital budget is a forward looking non-GAAP financial measure. The capital budget is based on net capital expenditures (Non-GAAP Financial Measure) and excludes net acquisition costs. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for more details on net capital expenditures.

The 2024 capital budget reflects budgeted net capital expenditures, before abandonment expenditures of approximately $635 million related to the execution of the Company's abandonment and reclamation programs in North America and the North Sea. The Company currently carries an Asset Retirement Obligation ("ARO") liability on its balance sheet for these budgeted future expenditures. Abandonment expenditures are reported before the impact of current income tax recoveries. Current tax recoveries are refundable at a rate of approximately 23% in Canada and at a combined current income tax and Petroleum Revenue Tax ("PRT") rates approximating 70% to 75% in the UK portion of the North Sea. The Company is eligible to recover interest on refunded PRT previously paid. With our ongoing commitment to environmental stewardship, 2024 will be the third year of a program with a pace to abandon the Company's North American inactive well inventory, as of December 31, 2021, in approximately 10 years.

Long-term Debt, net (Net Debt)

Long-term debt, net (also referred to as net debt) is a capital management measure that is calculated as current and long-term debt less cash and cash equivalents.

Capital Efficiency

Capital efficiency is a supplementary financial measure that represents the capital spent to add new or incremental production divided by the current rate of the new or incremental production. It is expressed as a dollar amount per flowing volume of a product ($/bbl/d or $/BOE/d). The Company considers capital efficiency a key measure in evaluating its performance, as it demonstrates the efficiency of the Company's capital investments.

Break-even WTI Price

The break-even WTI price is a supplementary financial measure that represents the equivalent US dollar WTI price per barrel where the Company's adjusted funds flow is equal to the sum of maintenance capital and dividends. The Company considers the break-even WTI price a key measure in evaluating its performance, as it demonstrates the efficiency and profitability of the Company's activities. The break-even WTI price incorporates the non-GAAP financial measure adjusted funds flow as reconciled in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A. Maintenance capital is a supplementary financial measure that represents the capital required to maintain annual production at prior period levels.

Cautionary Statement

Project progress and financial results are dependent upon economic and regulatory conditions, commodity prices, global economic factors, project sanction and capital allocation.

Thermal In Situ Oil Sands Overview – Clearwater, McMurray, Bluesky, Grand Rapids and Grosmont Formations

~126 billion barrels of Discovered Bitumen Initially-in-place is comprised of:

- 5.2 billion barrels of total proved plus probable reserves at December 31, 2022 that were evaluated in accordance to COGEH standards by an Independent Qualified Reserves Evaluator
- 1.3 billion barrels of produced Bitumen to December 31, 2022
- Development of remaining volume is subject to company final investment decisions
- A portion of remaining volume may not be recoverable with current technology
- All values are Company gross

Oil Sands Mining & Upgrading

~18.4 billion barrels of Mineable Bitumen Initially-in-place is comprised of:

- 8.0 billion barrels of Bitumen associated with 7.4 billion barrels of total proved plus probable SCO reserves at December 31, 2022 that were evaluated in accordance with COGEH standards by an Independent Qualified Reserves Evaluator
- 1.9 billion barrels of produced Bitumen to December 31, 2022
- Development of remaining volume is subject to company final investment decisions.
- A portion of remaining volume may not be recoverable with current technology
- All values are Company gross

Definitions

CAGR – Compound Annual Growth Rate – the compounded growth rate for a specific value on an annual basis in a defined time range.

Enterprise Value – Market capitalization plus the Company's net total liabilities.

Estimated Ultimate Recovery (EUR) – Estimated Ultimate Recovery is the amount of oil and natural gas expected to be economically recovered from a well, reservoir or field by the end of its producing life.

Free Cash Flow Yield – Free Cash Flow divided by the Company's market capitalization at a given point in time.

Market Capitalization (Market Cap) – Outstanding common shares multiplied by the Company's share price at a given point of time.

Maintenance Capital – Net capital expenditures required to maintain flat production year over year.

Pricing Assumptions

		2024B		2023E
Strip				
US$ WTI/bbl	$	77.98	$	75.42
C$ AECO/GJ	$	2.77	$	2.448
SCO Diff/(Prem) US$/bbl	$	(2.02)	$	0.70
WCS Differential US$/bbl	$	18.62	$	17.08
Average FX 1.00 US$ = X C$	$	1.35	$	1.35

2024B and 2023E based on Strip pricing as at November 23, 2023.

Glossary of Terms

AECO – Alberta Energy Company (benchmark pricing)

AOSP – Athabasca Oil Sands Project

BOE – barrels of oil equivalent

BBL – barrels of oil

Bcf – billion cubic feet

CCS – carbon capture and storage

CCUS – carbon capture, utilization and storage

CSS – cyclic steam stimulation

CO_2e – carbon dioxide equivalent

E&P – exploration and production

EOR – enhanced oil recovery

ESG – Environment, Social and Governance

EUR – estimated ultimate recovery

GHG – greenhouse gas

IP365 – initial average production rate of 365 days

IPEP – in-pit extraction process

MMcf – million cubic feet

$MtCO_2e$ – million tonnes of carbon dioxide equivalent

NI 51-101 – National Standards of Disclosure for Oil and Gas Activities

NGL – natural gas liquids

NWR – North West Redwater Refinery

R&D – research and development

SAGD – steam assisted gravity drainage

SEC – U.S. Securities & Exchange Commission

SCO – synthetic crude oil

Reserves Notes:

1. Company gross reserves are working interest share before deduction of royalties and excluding any royalty interests.
2. Information in the reserves data tables may not add due to rounding. BOE values and oil and gas metrics may not calculate exactly due to rounding.
3. Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserves estimates are the 3-consultant-average of price forecasts developed by Sproule Associates Limited, GLJ Ltd. and McDaniel & Associates Consultants Ltd., dated December 31, 2022:

		2023	2024	2025	2026	2027
Crude Oil and NGLs						
WTI	US$/bbl	80.33	78.50	76.95	77.61	79.16
WCS	C$/bbl	76.54	77.75	77.55	80.07	81.89
Canadian Light Sweet	C$/bbl	103.76	97.74	95.27	95.58	97.07
Cromer LSB	C$/bbl	104.55	98.50	95.55	96.83	98.13
Edmonton C5+	C$/bbl	106.22	101.35	98.94	100.19	101.74
Brent	US$/bbl	84.67	82.69	81.03	81.39	82.65
Natural gas						
AECO	C$/MMBtu	4.23	4.40	4.21	4.27	4.34
BC Westcoast Station 2	C$/MMBtu	4.08	4.28	4.11	4.16	4.23
Henry Hub	US$/MMBtu	4.74	4.50	4.31	4.40	4.49

   All prices increase at a rate of 2% per year after 2027.
   A foreign exchange rate of 0.7450 US$/C$ for 2023, 0.7650 US$/C$ for 2024, 0.7683 US$/C$ for 2025, 0.7717 US$/C$ for 2026 and 0.7750 US$/C$ after 2026 was used in the year end 2022 evaluation.

4. A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio 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 comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.
5. Oil and gas metrics included herein are commonly used in the crude oil and natural gas industry and are determined by Canadian Natural as set out in the notes below. These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies and may be misleading when making comparisons. Management uses these metrics to evaluate Canadian Natural's performance over time. However, such measures are not reliable indicators of Canadian Natural's future performance and future performance may vary.
6. Reserves additions and revisions are comprised of all categories of Company Gross reserves changes, exclusive of production.
7. Reserves replacement or Production replacement ratio is the Company Gross reserves additions and revisions, for the relevant reserves category, divided by the Company Gross production in the same period.
8. Reserves Life Index ("RLI") is based on the amount for the relevant reserves category divided by the 2023 proved developed producing production forecast prepared by the Independent Qualified Reserves Evaluators.
9. Finding, Development and Acquisition ("FD&A") costs excluding changes in Future Development Costs ("FDC") are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2022 by the sum of total additions and revisions for the relevant reserves category.
10. FD&A costs including changes in FDC are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2022 and net changes in FDC from December 31, 2021 to December 31, 2022 by the sum of total additions and revisions for the relevant reserves category. FDC excludes all abandonment, decommissioning and reclamation costs.
11. Abandonment, decommissioning and reclamation ("ADR") costs included in the calculation of the Future Net Revenue ("FNR") consist of both the Company's total Asset Retirement Obligation ("ARO"), before inflation and discounting, for development existing as at December 31, 2022 and forecast estimates of ADR costs attributable to future development activity.