ExxonMobil Upstream

In a league of our own

December 11, 2024

Cautionary statement

This presentation was delivered as part of ExxonMobil Corporation's Corporate Plan update on December 11, 2024 and should be read in conjunction with those Corporate Plan materials.

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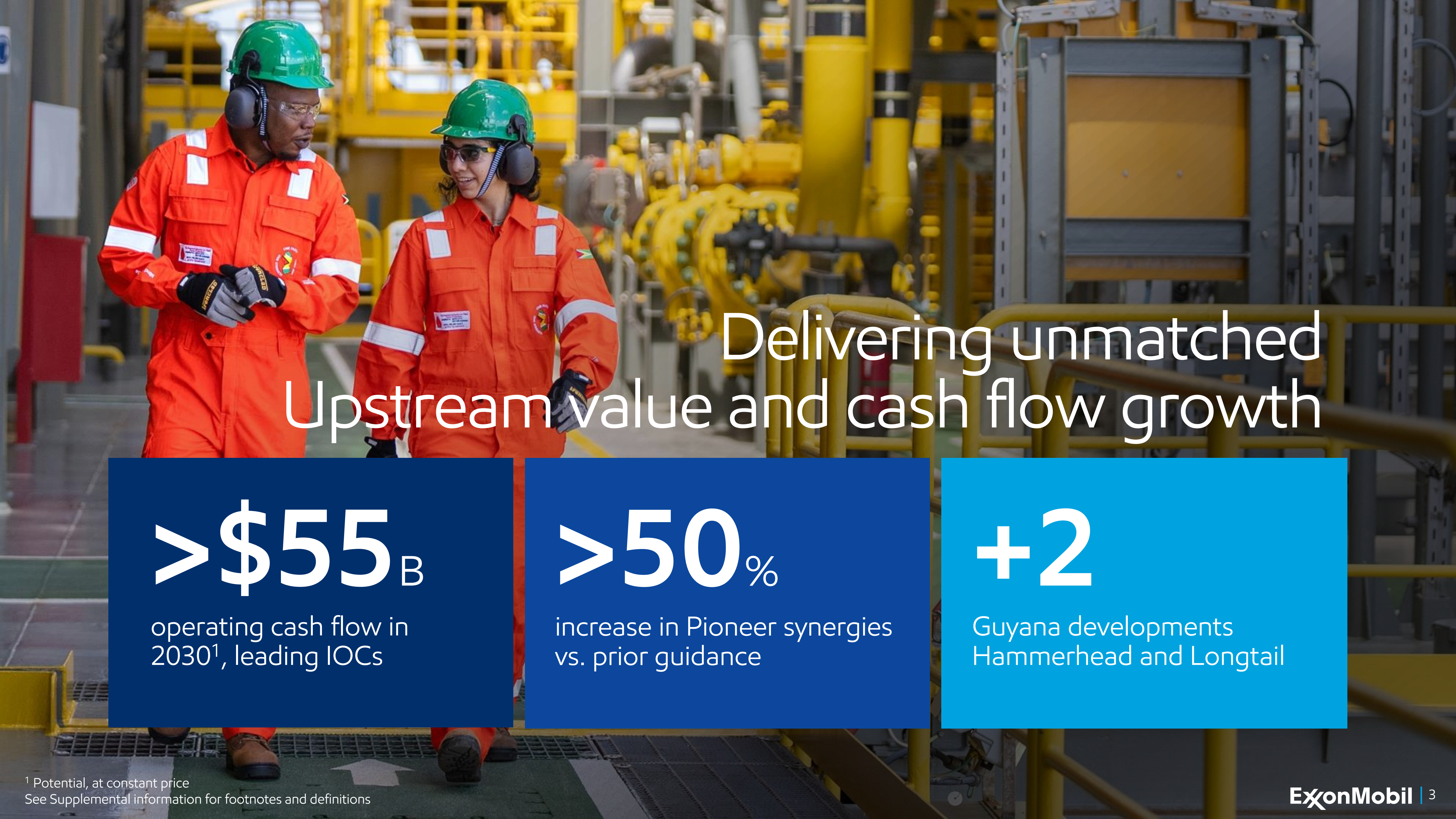
SUPPLEMENTAL INFORMATION. See the Supplemental Information starting on page 39 through the end of this presentation for additional important information required by Regulation G for non-GAAP measures or that the company considers useful to investors as well as definitions of terms used in the materials, including cash capex; cash opex excluding energy and production taxes; earnings ex. identified items and adjusted to 2024 $65/bbl real Brent; operating costs; structural cost savings; and operating cash flow. Supplemental Information also includes information on the assumptions used in these materials, including assumptions on future crude oil prices and product margins used to develop outlooks regarding future potential outcomes of current management plans.



Delivering unmatched Upstream value and cash flow growth

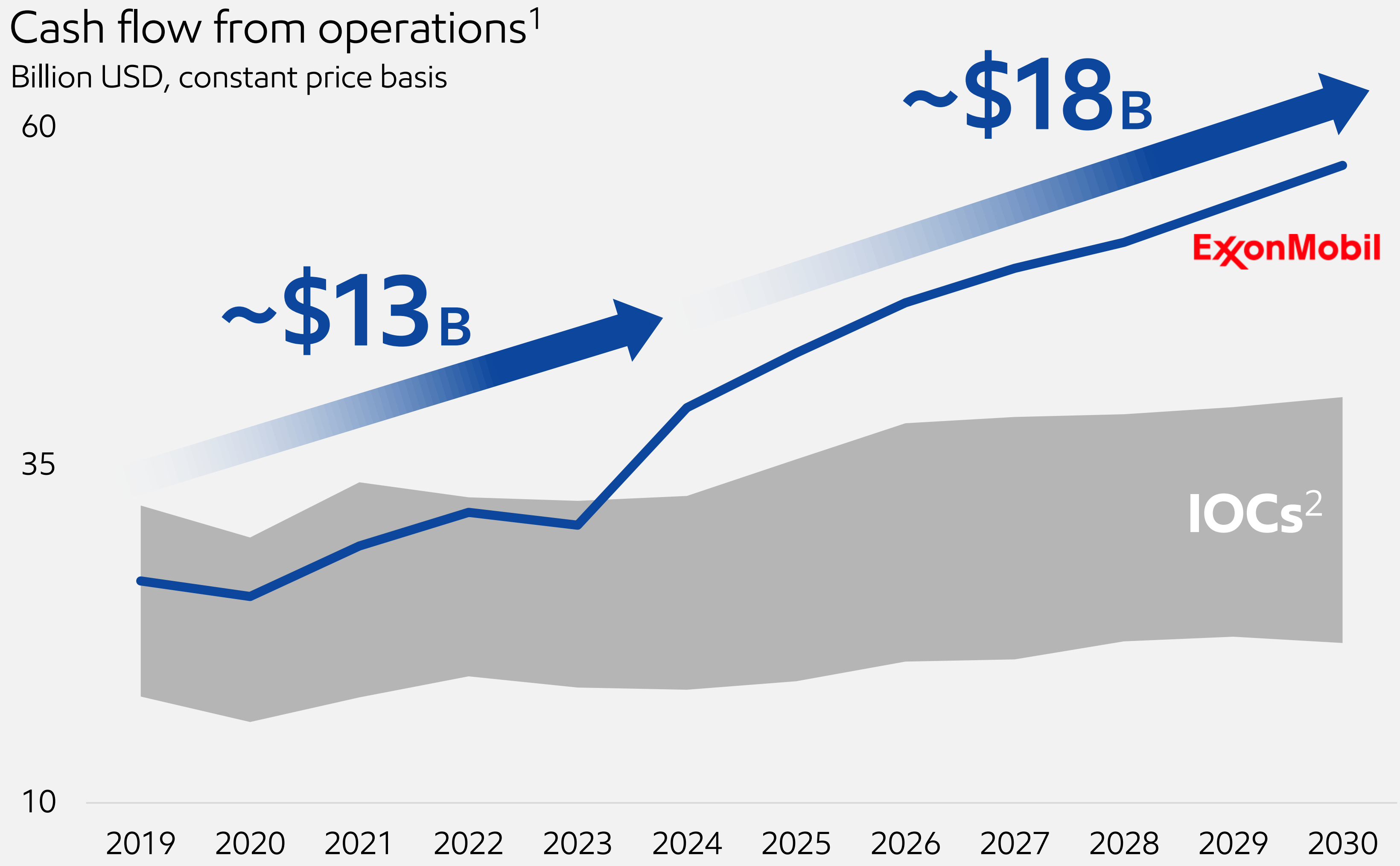
>$55B
operating cash flow in 2030[1], leading IOCs

>50%
increase in Pioneer synergies vs. prior guidance

+2
Guyana developments Hammerhead and Longtail

[1] Potential, at constant price
See Supplemental information for footnotes and definitions

Cash flow far exceeding competition



>$55B
by 2030

Source: Wood Mackenzie

See Supplemental information for footnotes and definitions.

LOOKING BACK

Developed the strongest portfolio in industry

Divested >$15 billion of lower value assets

Added ~1.2 Moebd of advantaged production

Removed >$6 billion of structural costs

Deployed a growing technology advantage

1st cube developments at scale and drilled 1st 4-mile laterals in the Permian

Achieved **production 100 Kbd above investment basis** in Guyana

>30% improvement in Kearl unit cost while growing production to 280 Kbd

Demonstrated unrivaled execution excellence

Delivered **3 Guyana FPSOs at 1st quartile** cost and schedule

Record-setting[1] Permian drilling performance

Closed Pioneer transaction **in record time**[2]

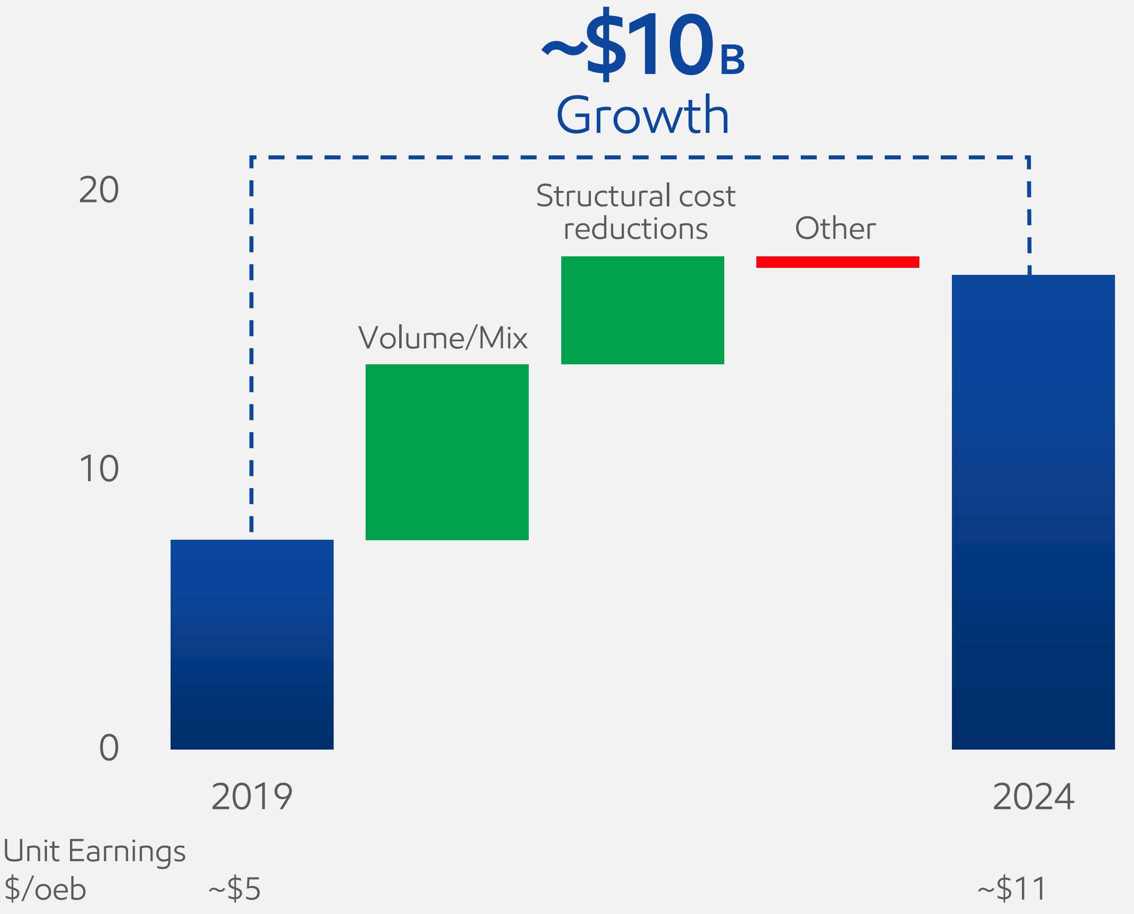
Developed our highest return, most capital efficient project portfolio in 25 years

See Supplemental information for footnotes, definitions, and reconciliations.

>2x earnings and 2x unit earnings since 2019

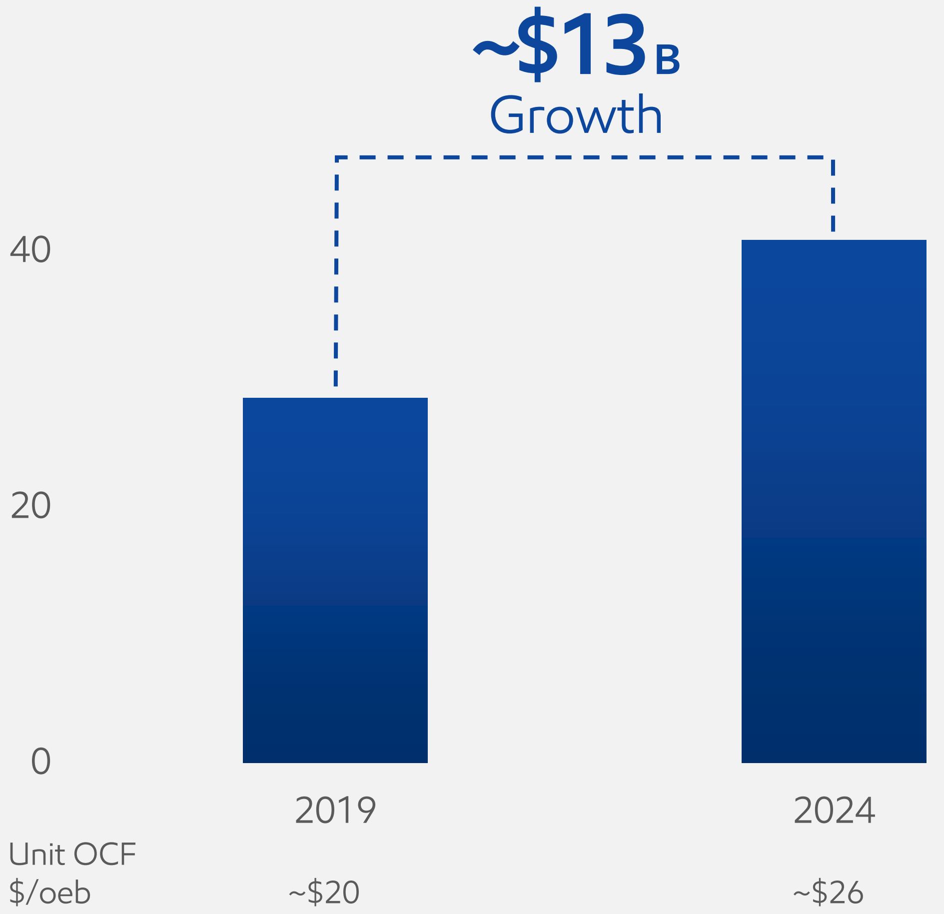
Earnings CAGR of ~18%

Billion USD, constant price basis



Operating cash flow CAGR of ~8%

Billion USD, constant price basis



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LOOKING AHEAD

Best portfolio in industry[1]	Growing technology advantage	Unrivaled execution excellence
Adding another **~1.2 Moebd of advantaged production**	Next generation cube delivers **additional 15% NPV**	Pioneer acquisition synergies **>50% above prior guidance**
Additional **$3 billion** of structural cost savings; **>30% unit cost reduction**[2]	**Up to 15% higher recovery so far**[3] with low-cost lightweight proppant in Permian	**2 additional developments** in Guyana
Portfolio of **>80% liquids and LNG**; **~50% short-cycle** production	Deploying **4D seismic** to increase value capture of >$1 billion in Guyana	**>10 major-project start-ups** in plan

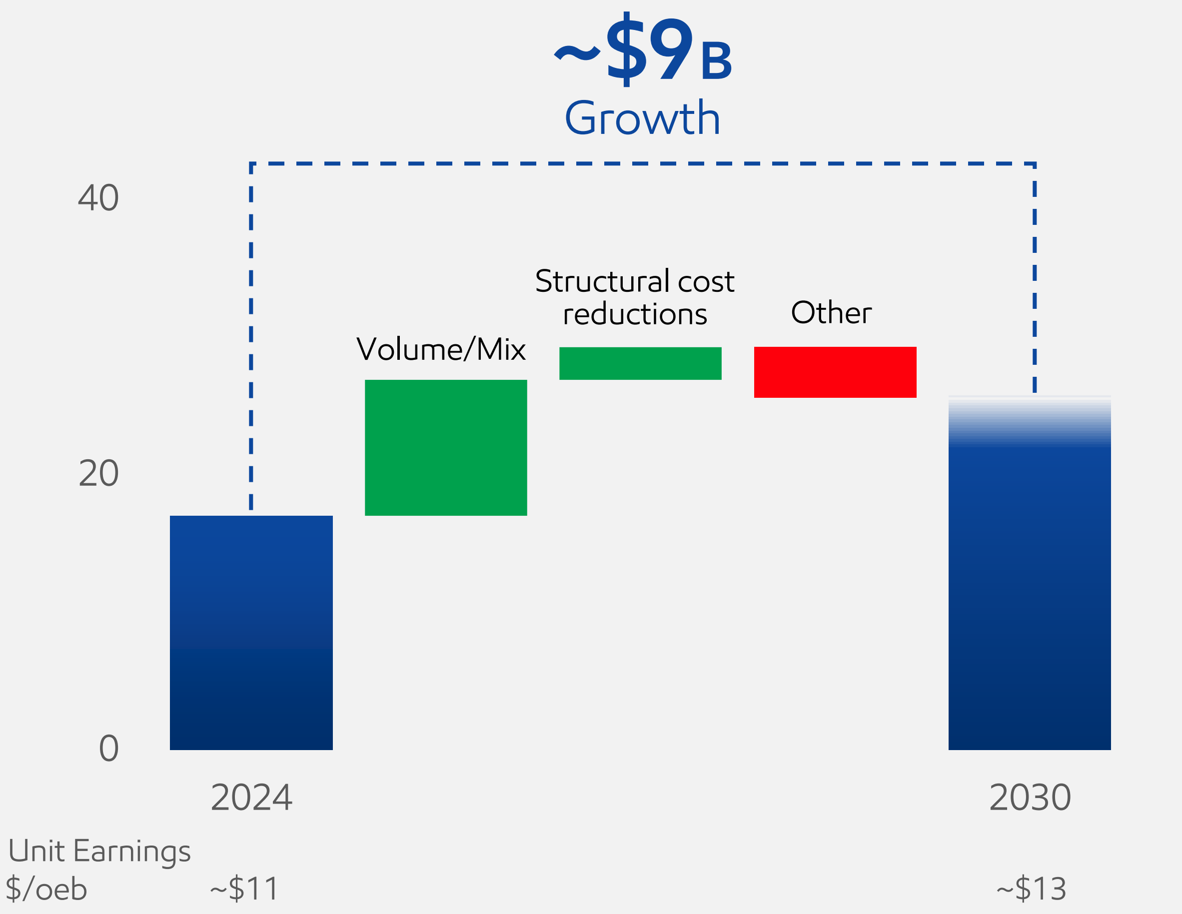
Significantly growing the gap to competition through 2030

See Supplemental information for footnotes and definitions.

~50% earnings growth by 2030

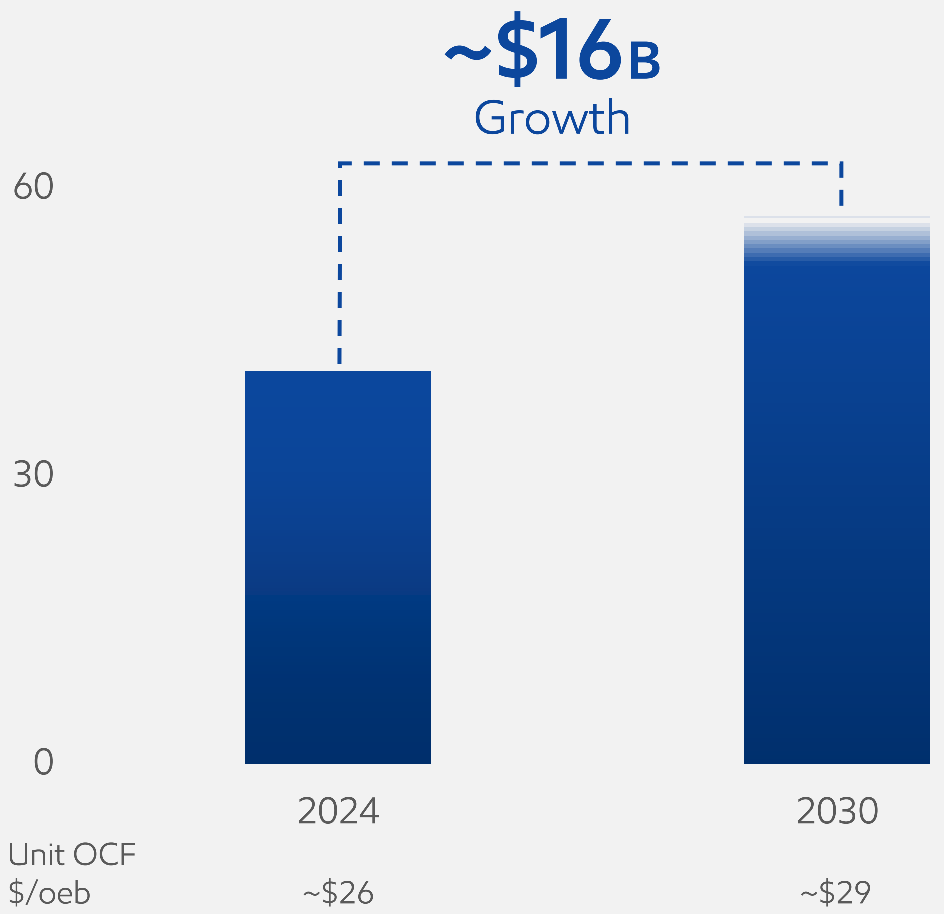
Earnings potential CAGR of ~7%

Billion USD, constant price basis



Operating cash flow potential CAGR of ~6%

Billion USD, constant price basis

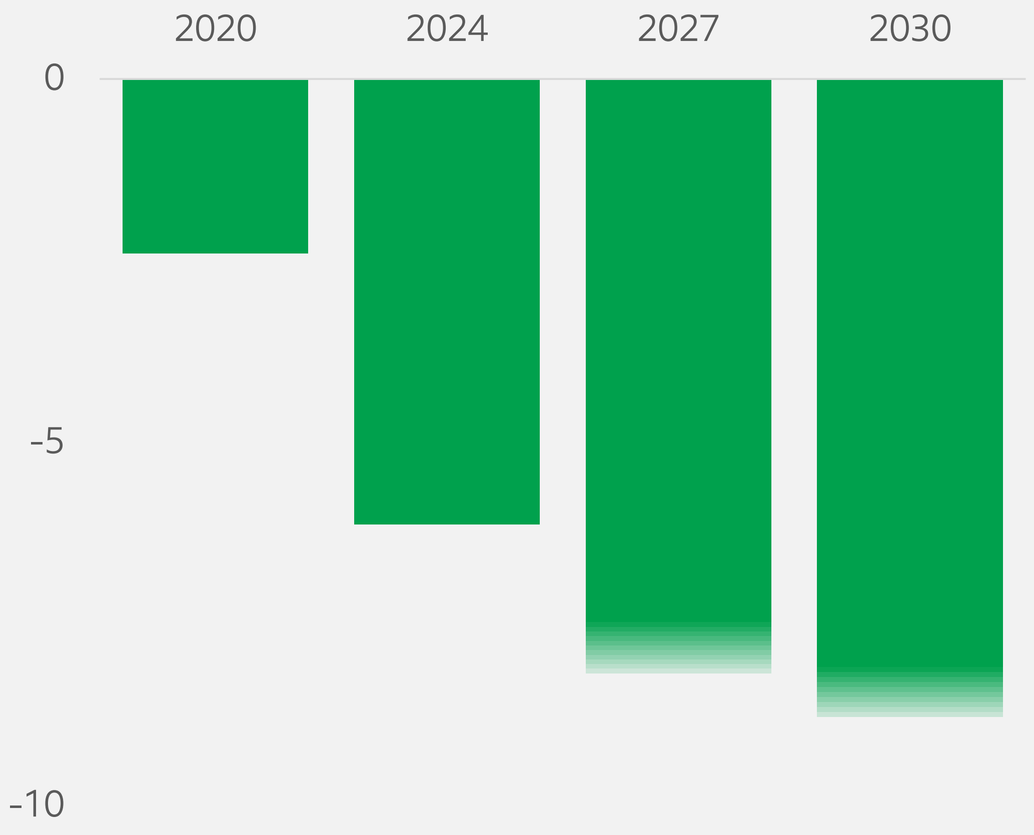


See Supplemental information for definitions and reconciliations.

Transformational reduction in costs

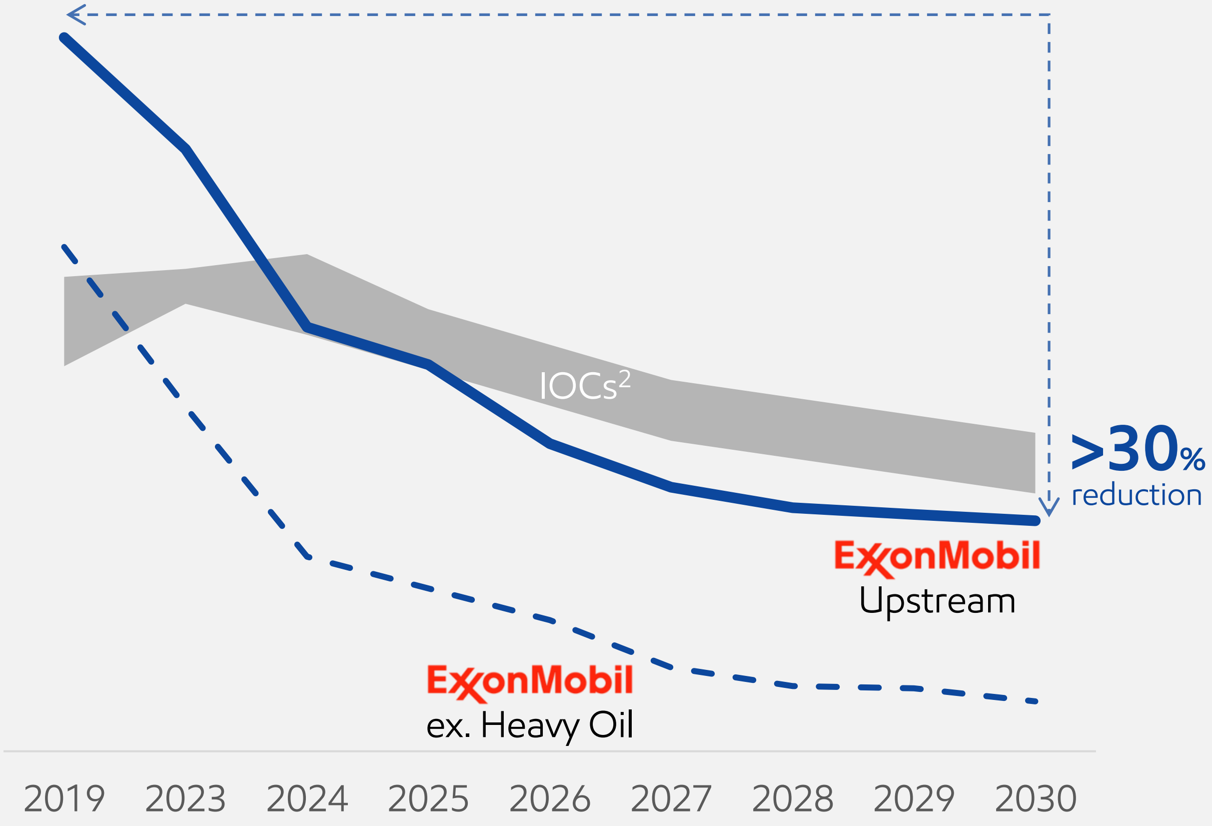
$9B/year structural savings

Billion USD vs. 2019



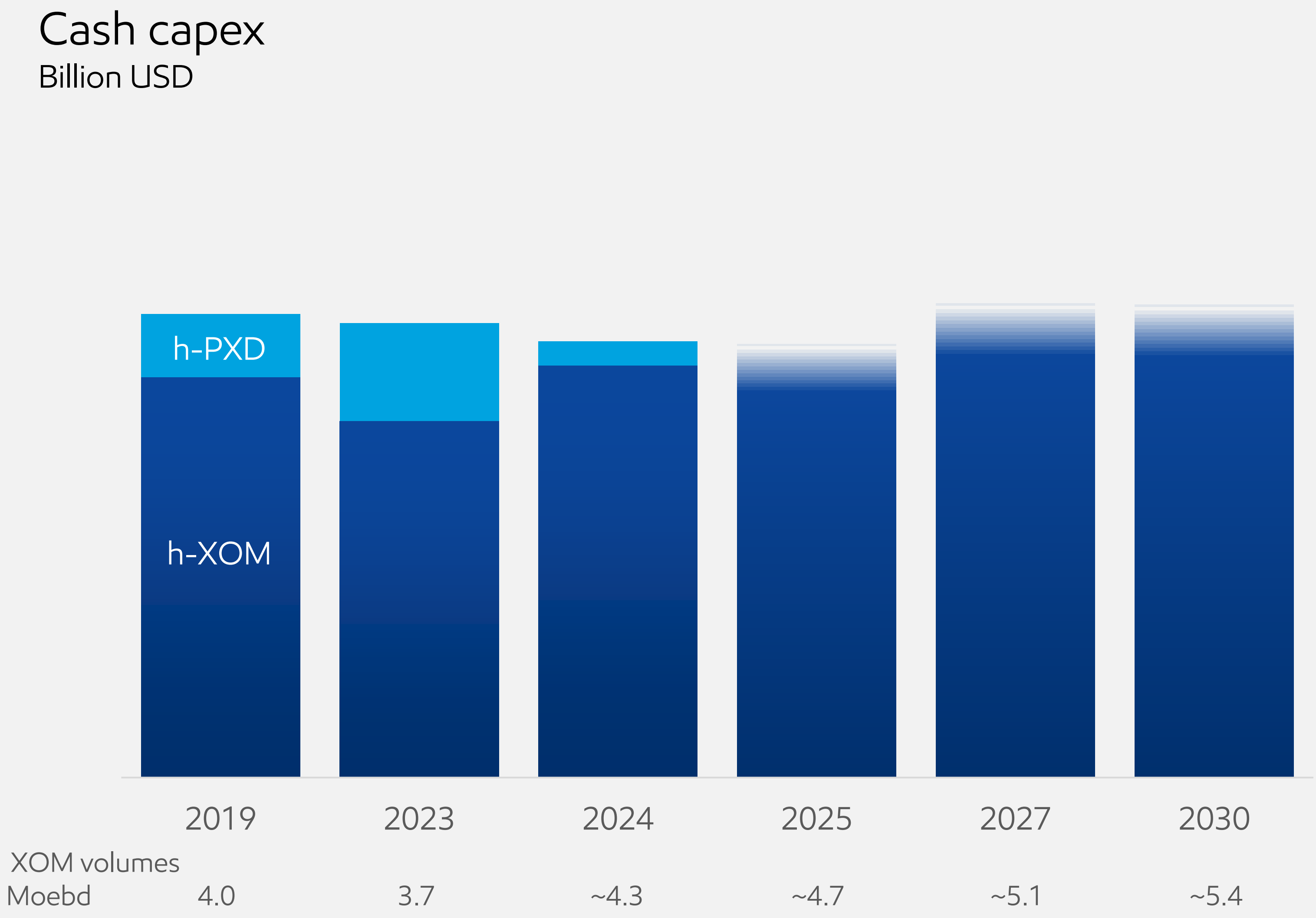
>30% reduction plan for unit cash operating expenses[1]

$/oeb



See Supplemental information for footnotes and definitions

Higher capital efficiency enables flat capex with higher volume growth

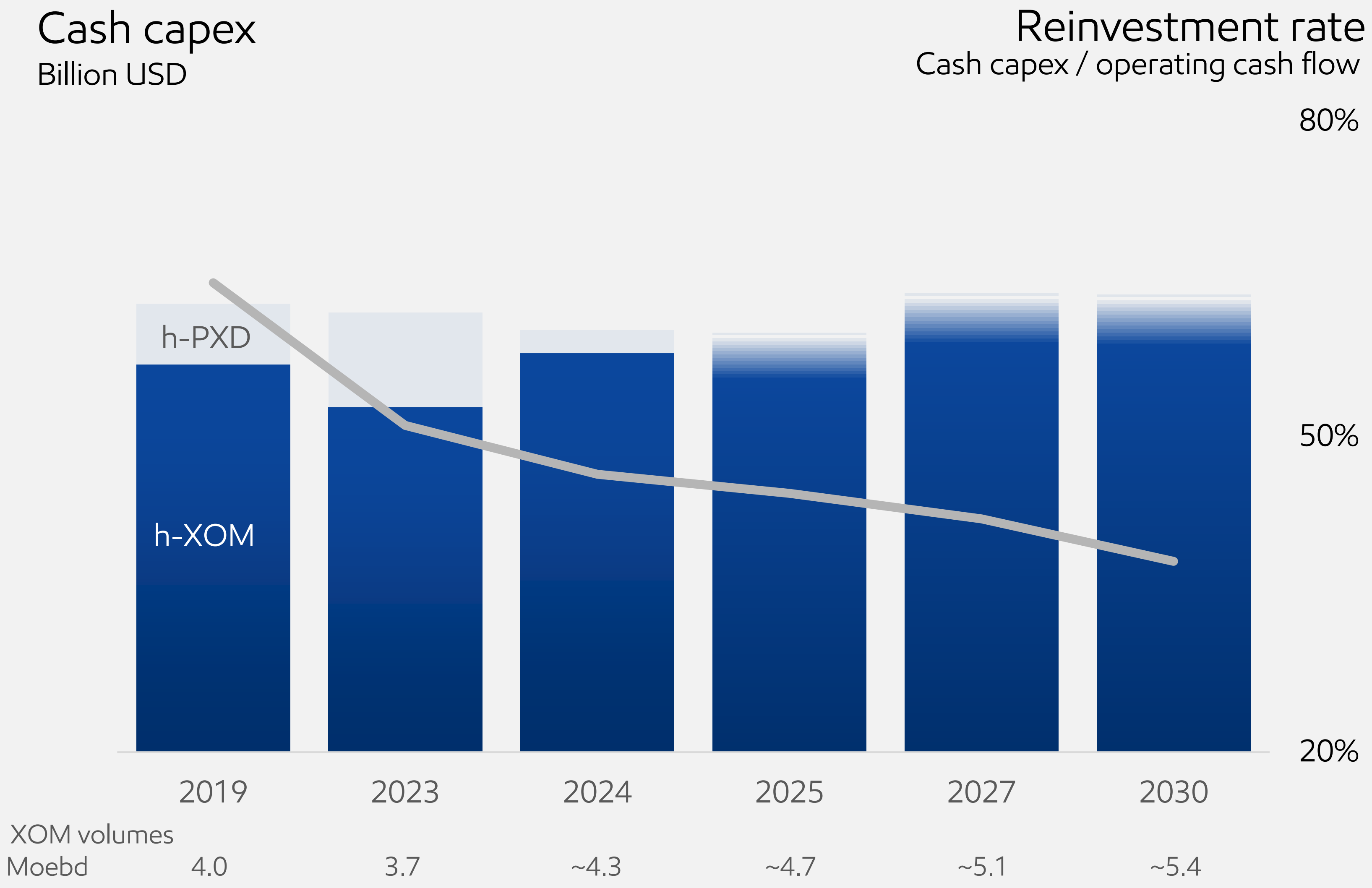


See Supplemental information for definitions.

>70% of capital spend on advantaged projects (Permian, Guyana, LNG)

Increasing capital efficiency

Higher capital efficiency enables flat capex with higher volume growth



>70% of capital spend on advantaged projects (Permian, Guyana, LNG)

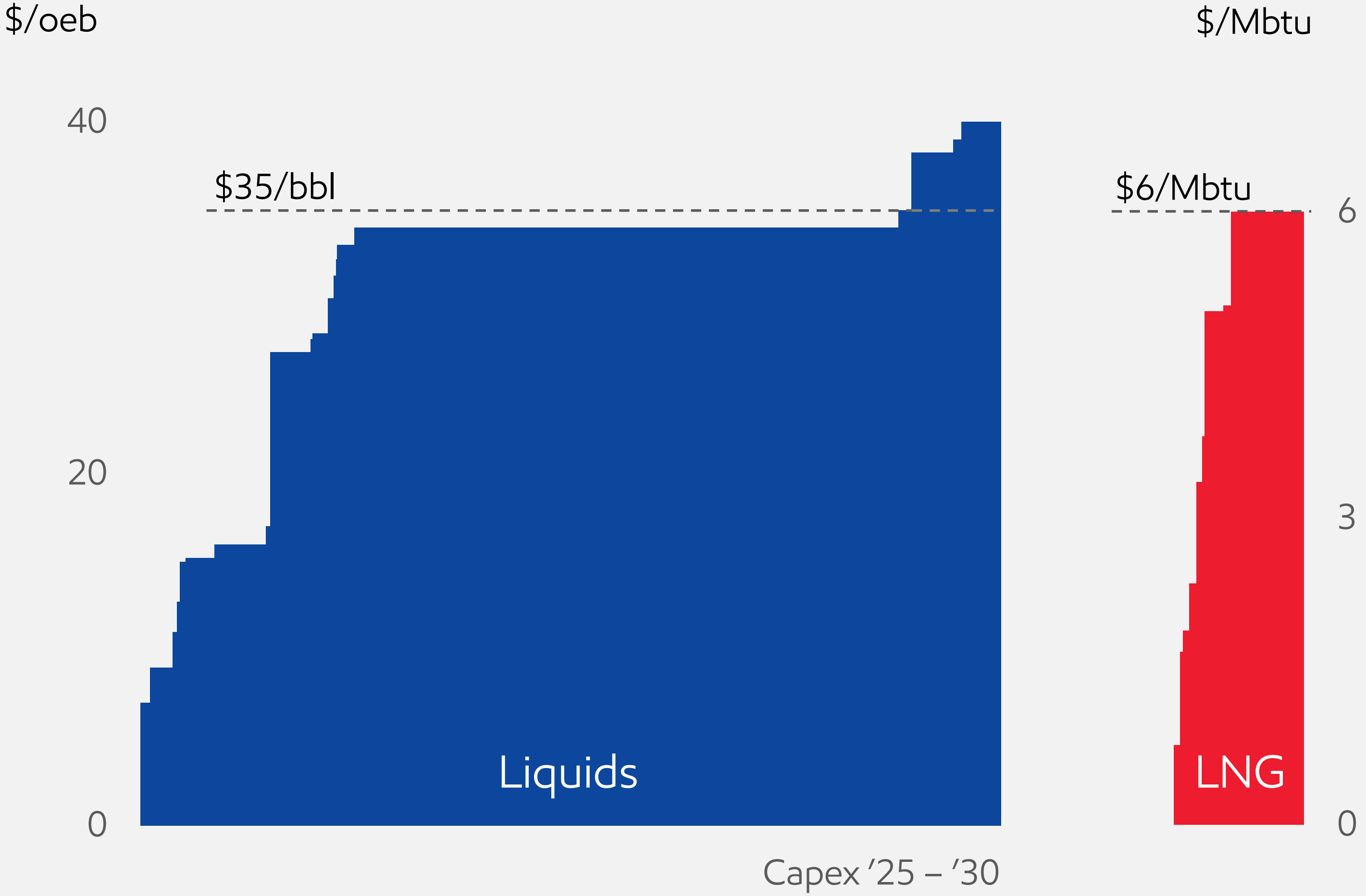
Increasing capital efficiency

~30% reduction in reinvestment rate (cash capex / operating cash flow)

See Supplemental information for definitions.

High return threshold for investments

Cost of supply of '25-'30 investment program



Average 2025 - 2030 capex investments deliver >40% return

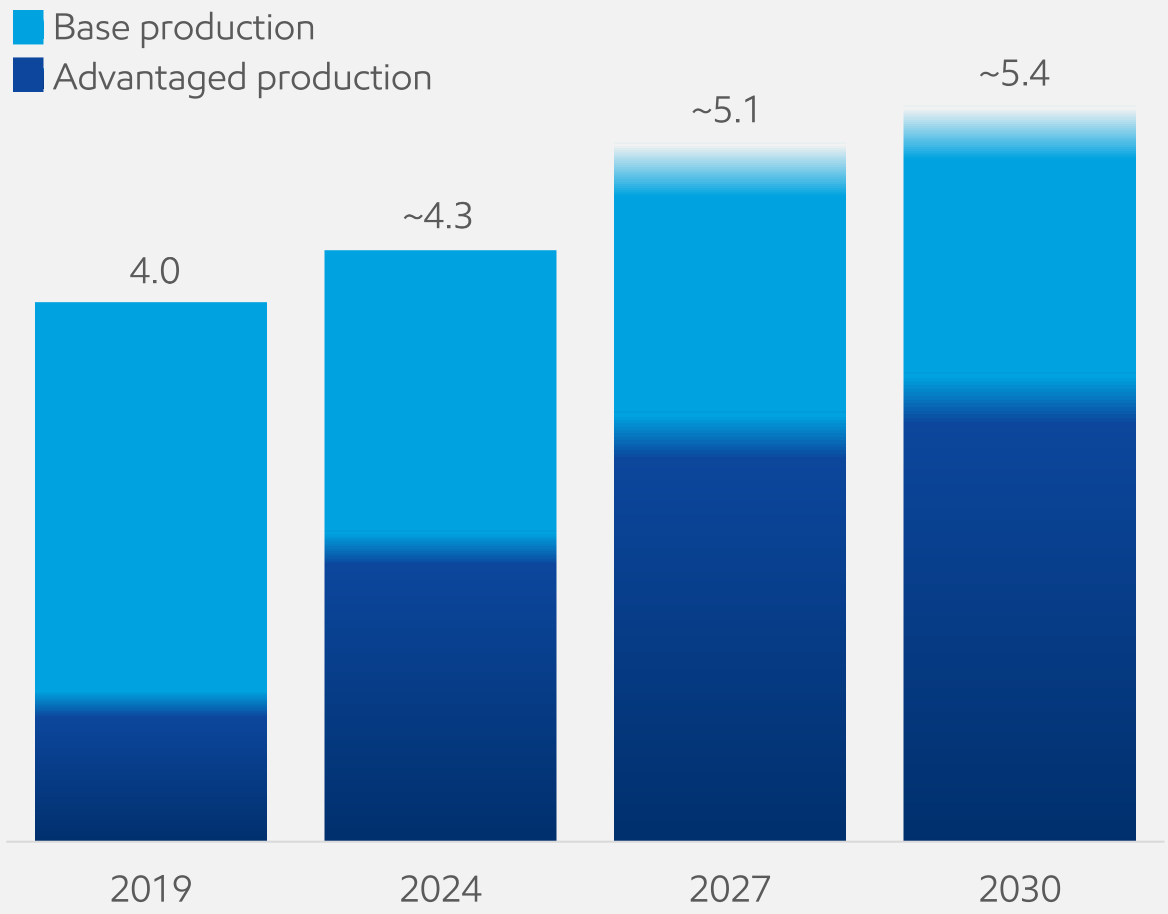
90% of investments generate >10% returns at <$35/bbl and <$6/Mbtu[1]

Investments >$35/bbl are early stage projects; anticipate improvements as projects are matured

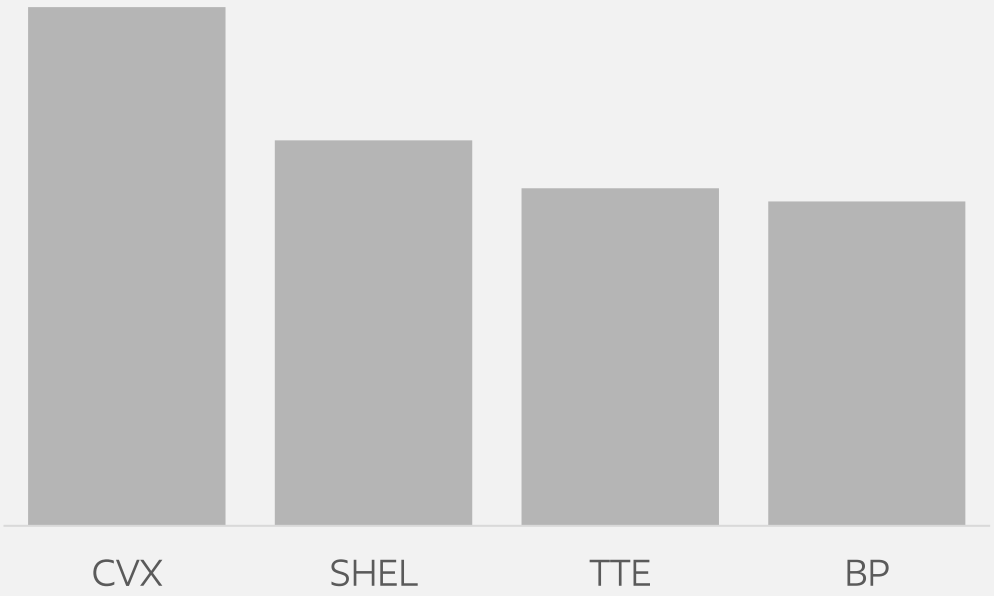
See Supplemental information for footnotes and definitions.

>200% growth in advantaged production by 2030

Production
Moebd



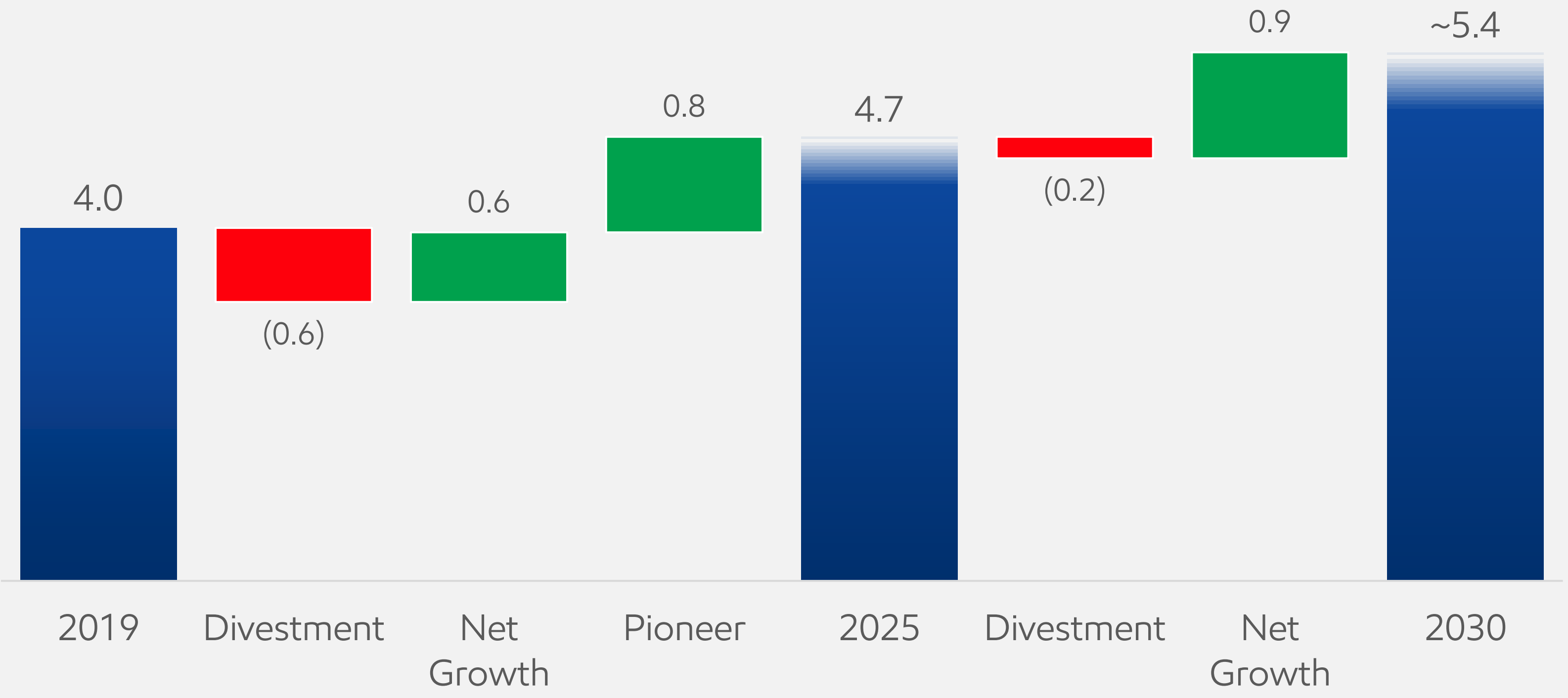
2030 competitor production
Moebd



Source: Wood Mackenzie

Demonstrated and consistent growth

Production
Moebd



2019 – 2025

Net growth offset by divestments

2025 – 2030

Future growth underpinned by established positions in Permian and Guyana

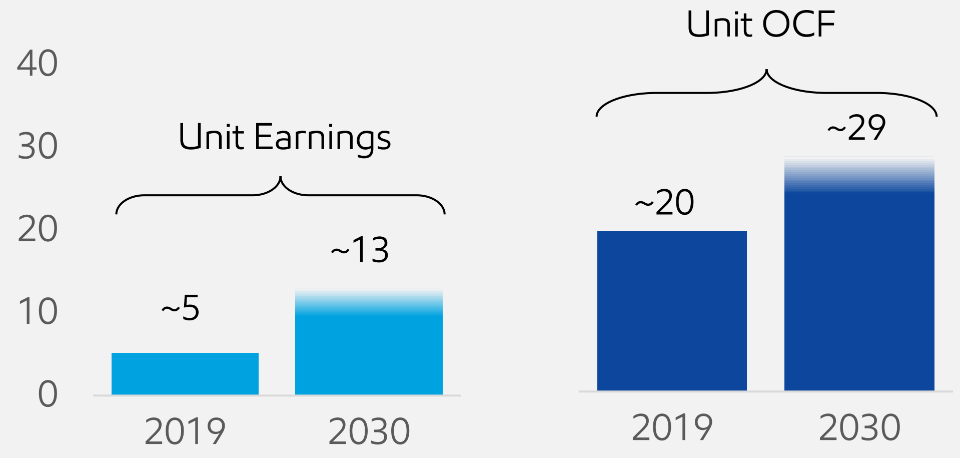
Lower divestments

Divestment includes the Sakhalin exit and minor volume impacts due to price entitlement and government mandates

Transformational portfolio change in ~10 years

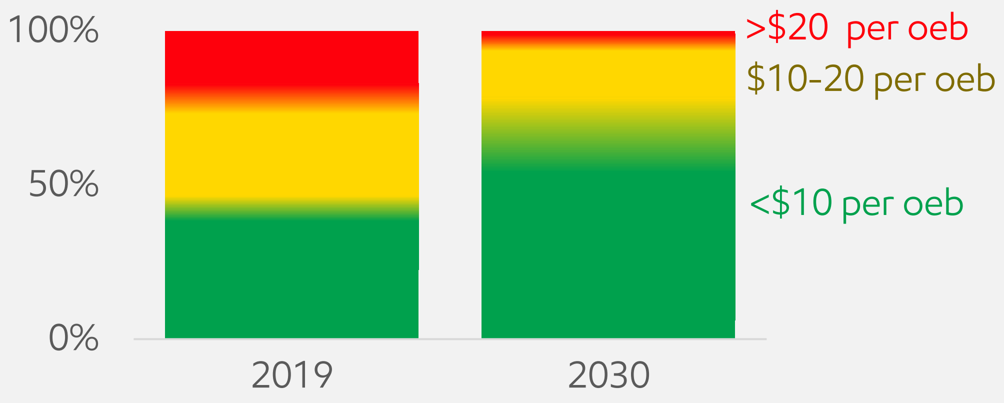
Growing unit profitability

$/oeb



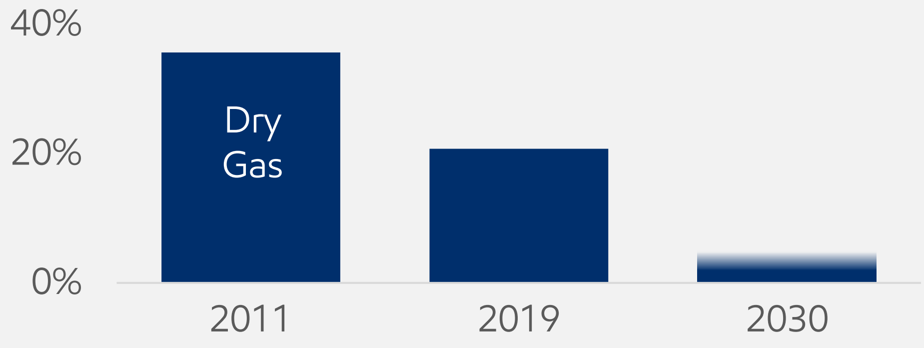
Decreasing portfolio production costs[1]

% of Upstream production



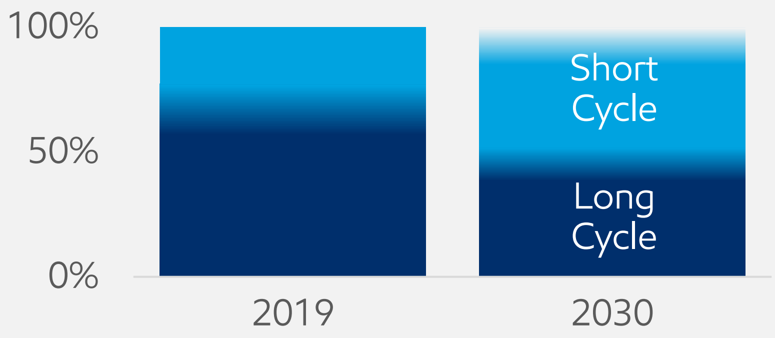
Reducing dry (non-associated) gas production

% of Upstream production



Increased flexibility: ~50% short cycle production

% of Upstream production



See Supplemental information for footnotes and definitions.

Permian

ExxonMobil and Pioneer merger
created an unmatched industry-leading position

>50%
increase in synergies vs. prior guidance

Up to **15** % so far[1]
higher recovery from low-cost lightweight proppant

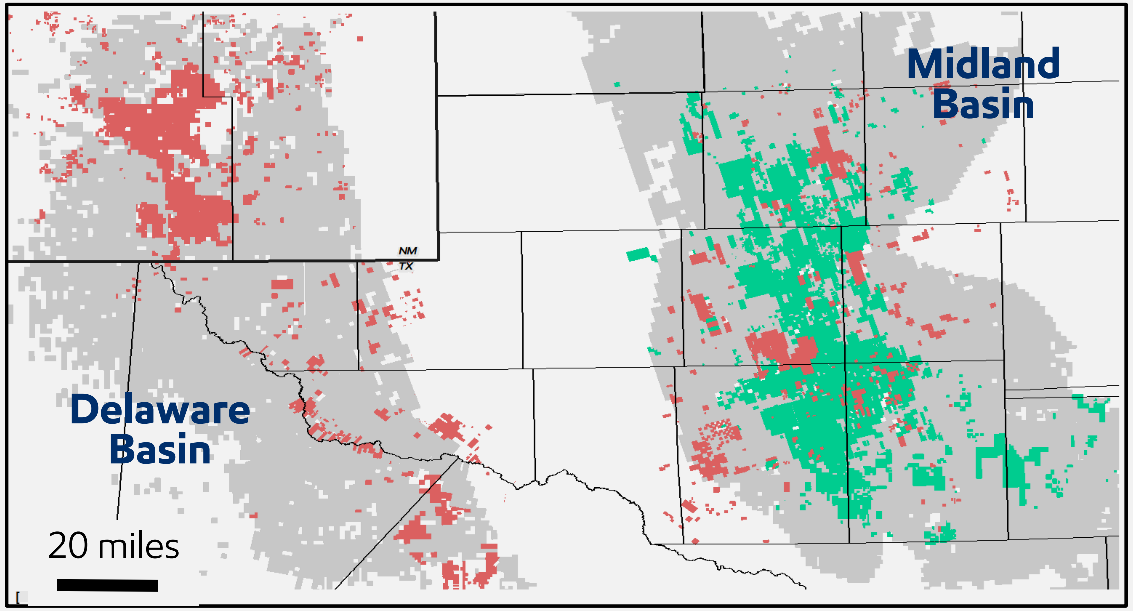
~2 Boeb greater
recoverable resource; ~18 Boeb total recoverable resource

~2.3 Moebd
Permian production by 2030; ~2 Moebd by 2027

See Supplemental information for footnotes and definitions.

Unmatched Permian position

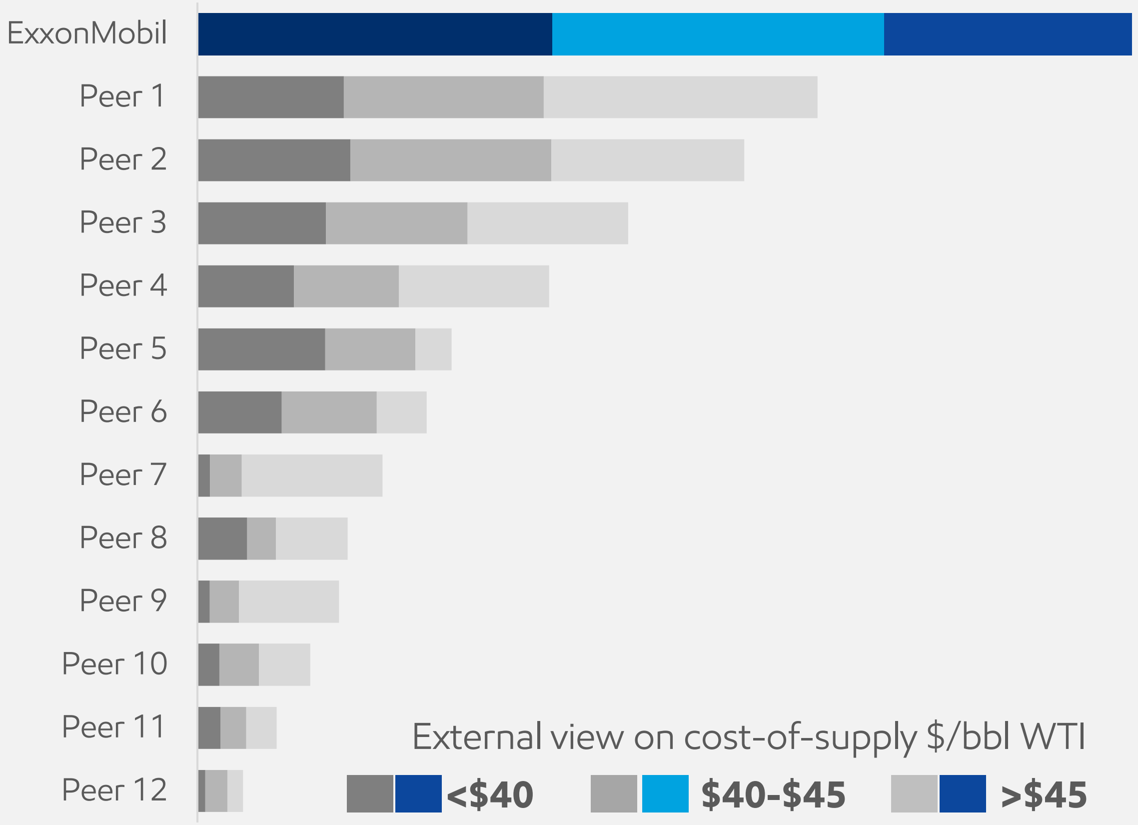
Largest contiguous acreage in the Permian



ExxonMobil Acreage | Pioneer Acreage | Others' Acreage

2x low-cost inventory vs. next best competitor[1]

Net locations

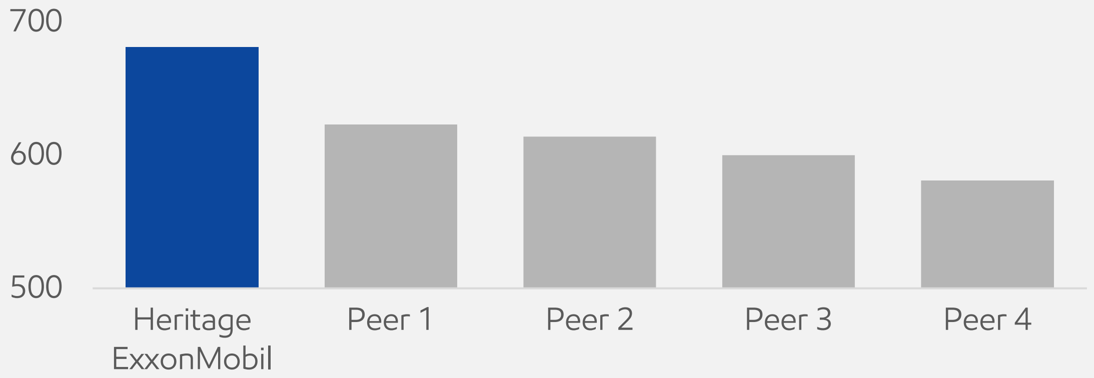


See Supplemental information for footnotes and definitions.

"Best of both" to deliver best in class capital efficiency

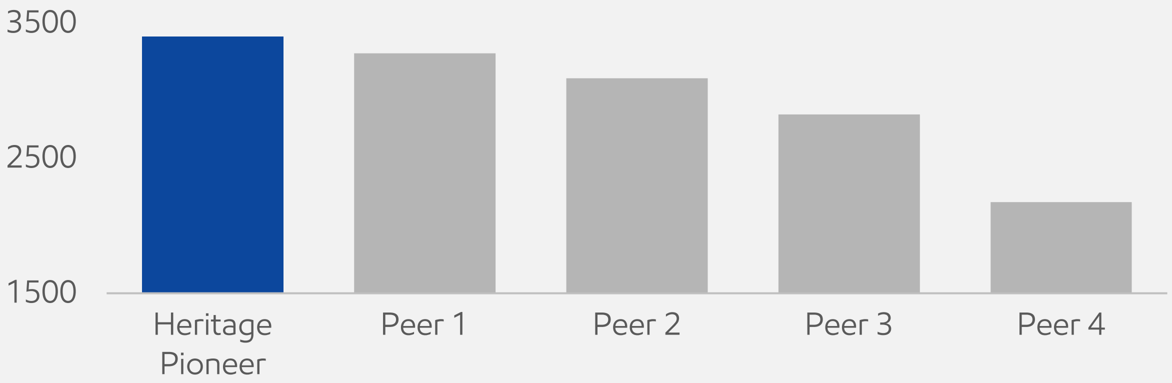
Delaware basin drilling efficiency[1]

Rolling 12 months lateral length feet drilled per day



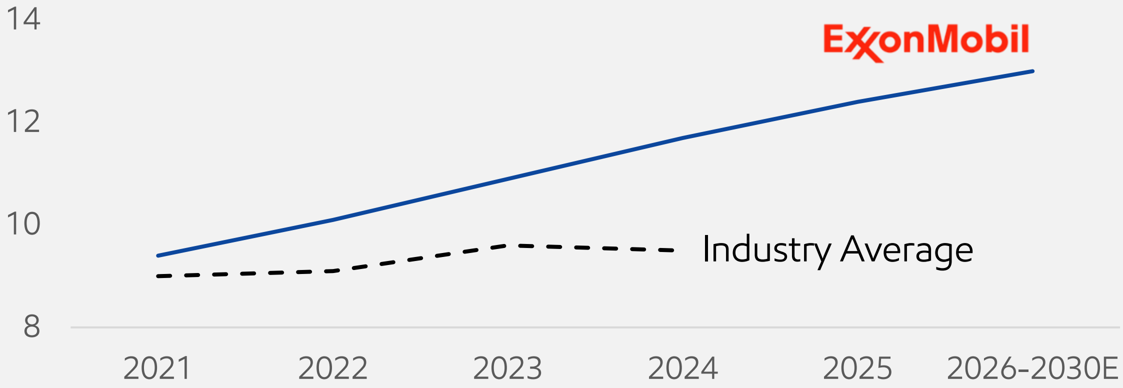
Midland basin completions efficiency[2]

Rolling 12 months lateral length feet completed per day



Delaware basin average lateral length[3]

Kft



Lowest D&C cost today built on:

ExxonMobil leading drilling capabilities and technology

Pioneer leading completions technology and deep basin knowledge

See Supplemental information for footnotes.

Unique development plan combines the "best of both" to drive higher value

Delivering additional cost savings by further leveraging scale advantage

- Longer laterals unlocked with large contiguous acreage position and extended reach drilling expertise
- Pioneer reverse synergies applied across entire Permian position

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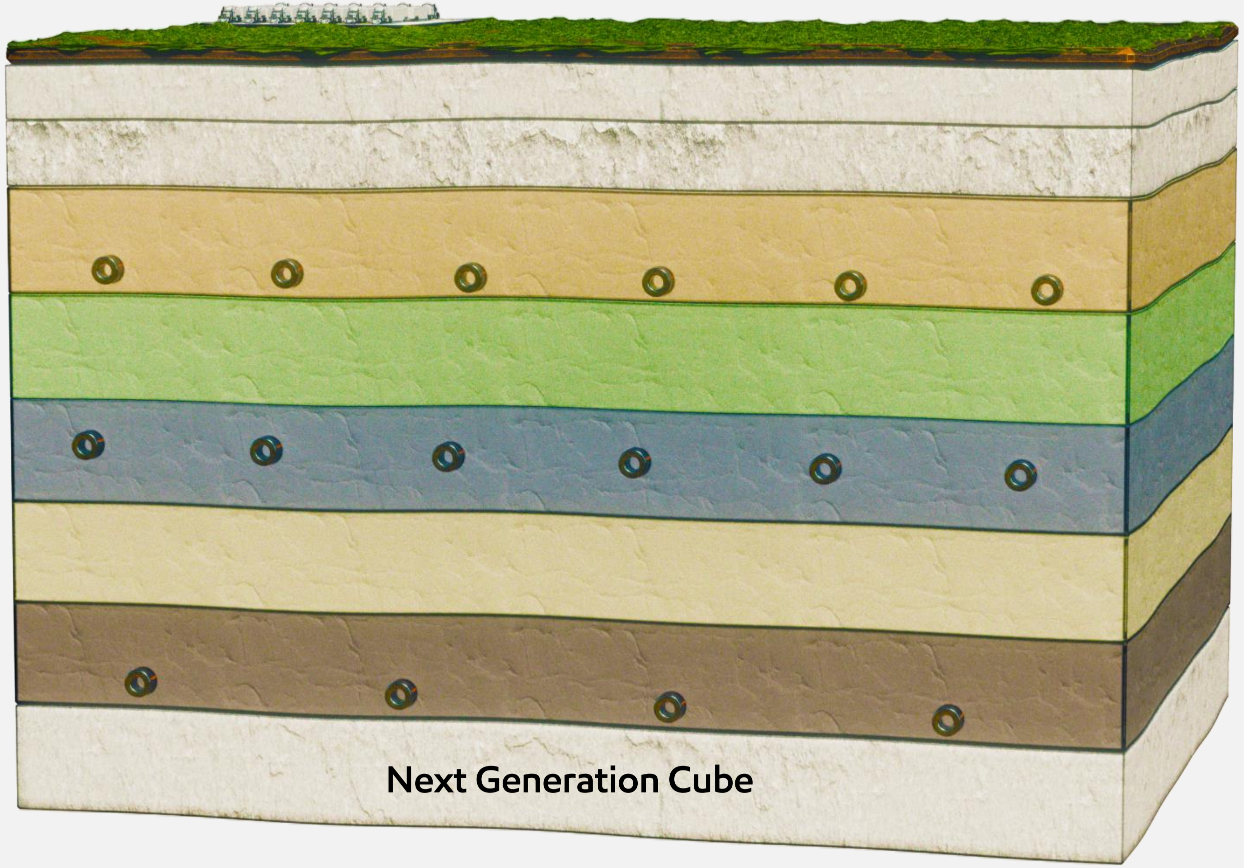
Capturing higher value from applying deep inventory of ExxonMobil technologies

- Higher capital efficiency from optimized spacing and cube design
- Higher resource recovery from low-cost lightweight proppant leveraging ExxonMobil refining integration
- Future upside from a deep pipeline of additional technology programs

Deploying the Next Generation Cube on Pioneer acreage



Higher NPV requires right balance of capital efficiency and resource recovery

- Resource quality differs by bench and by geography
- Requiring changes in spacing of wells and size of fracs

Investing in fundamental science programs to improve reservoir understanding for 8 years

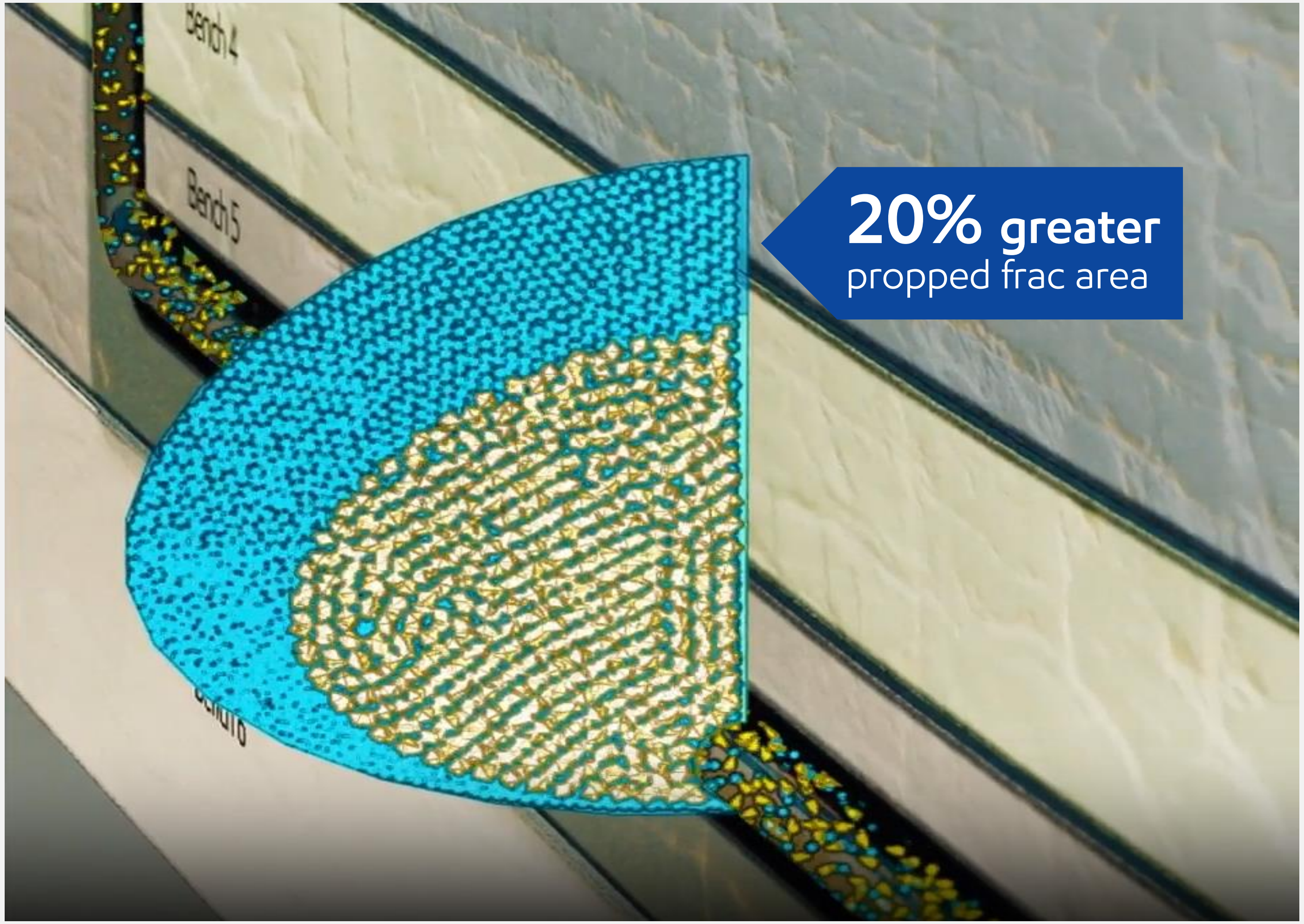
First to deploy Cube technology at scale

- Increasing NPV by 20% vs. best bench development

Now deploying Next Generation Cube improving NPV by further 15%

- Leverages unique spacing patterns, longer laterals, low-cost lightweight proppant

Patented lightweight proppant technology to improve recovery by up to ~15% so far[1]



LEGEND: **Yellow** – Sand **Blue** – Lightweight proppant

Keeps more fracture area open compared to sand

Proppant is based on low-cost refinery coke

Leverages ExxonMobil's large refinery footprint in North America

>200 wells using lightweight proppant in next 12 months

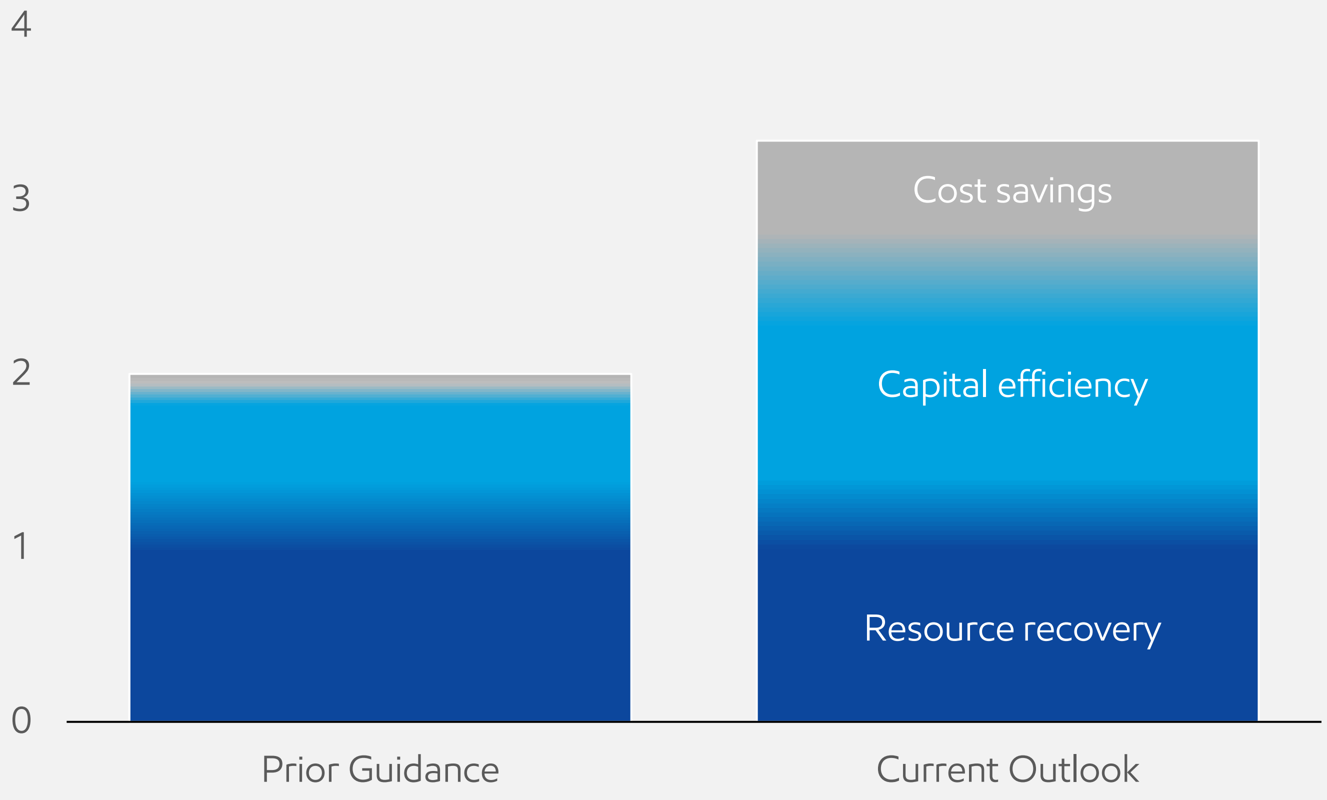
Up to 2 million tons of lightweight proppant per year at peak deployment

See Supplemental information for footnotes.

>$3B/year of synergies significantly exceeds prior guidance

>50% increase in synergies[1]

Billion USD annual average



Cost savings

- Higher G&A savings
- Workovers and field operating cost reductions

Capital efficiency increased >150%

- Enhanced cube design maintains recovery with 20% fewer wells
- Long laterals reduces surface and drilling costs by ~25% or more
- Additional scale driving further drilling/completion efficiencies

Resource recovery

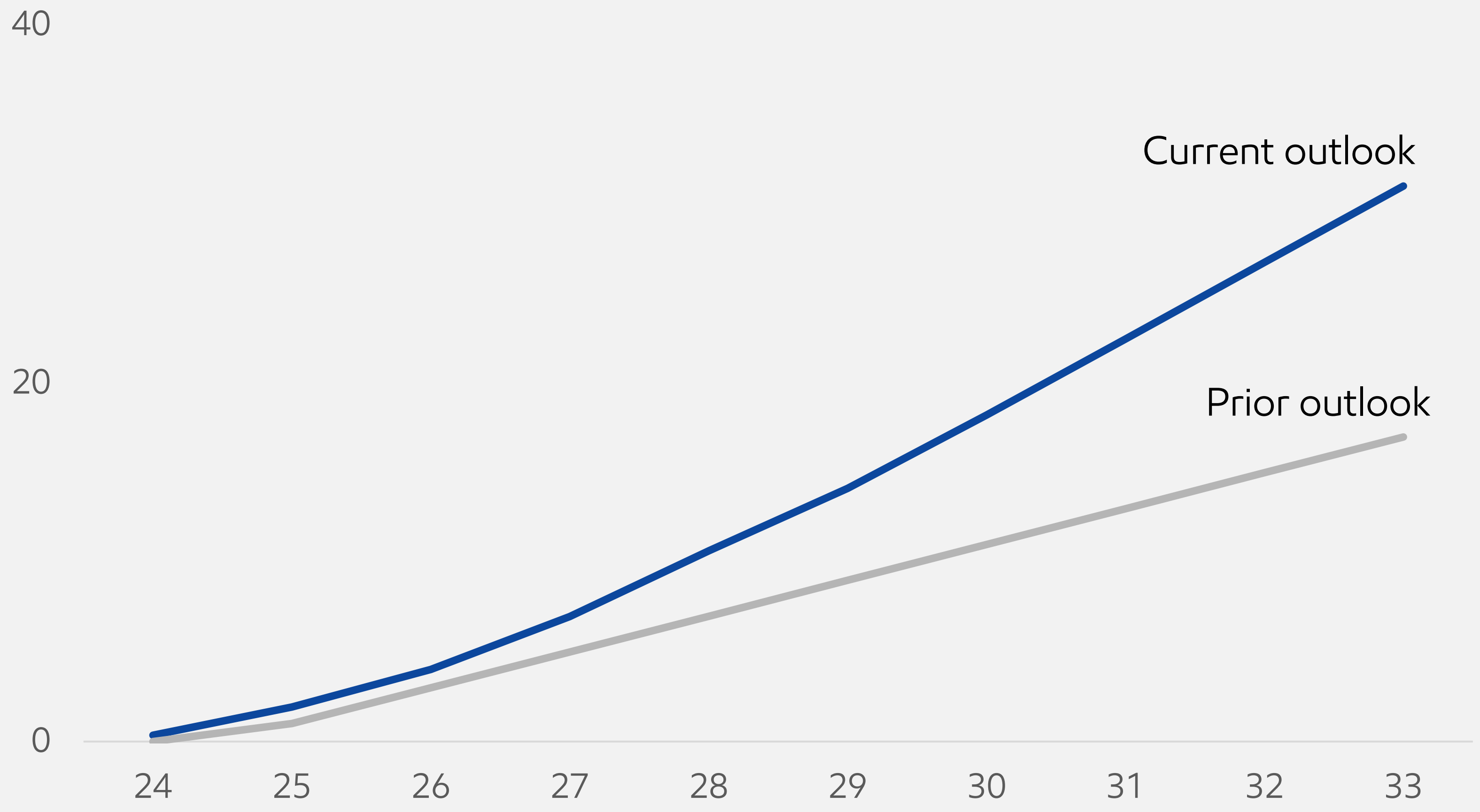
- Low-cost lightweight proppant improves recovery by up to 15% so far[2]
- Additional inventory from improved capital efficiency

See Supplemental information for footnotes and definitions.

Permian Outlook to 2030

Cumulative synergies[1]

Billion USD



>$30 B
in cumulative synergies in 10 years

~30 %
lower drilling & completions cost[2]

Up to ~30 % so far
increased resource recovery[3]

>40 %
program average rate-of-return[4]

<$35
per barrel cost of supply[5]

~2.3 Moebd
Permian volume by 2030

~$25 B
operating cash flow potential in 2030[6]

See Supplemental information for footnotes and definitions.

Guyana

Growing the most successful deepwater development in history

Industry-leading deepwater development

~11 Boeb
resource

2
additional developments; Hammerhead and Longtail

8 FPSOs
by 2030

~1.3 Moebd
estimated gross production and ~1.7 Moebd capacity by 2030

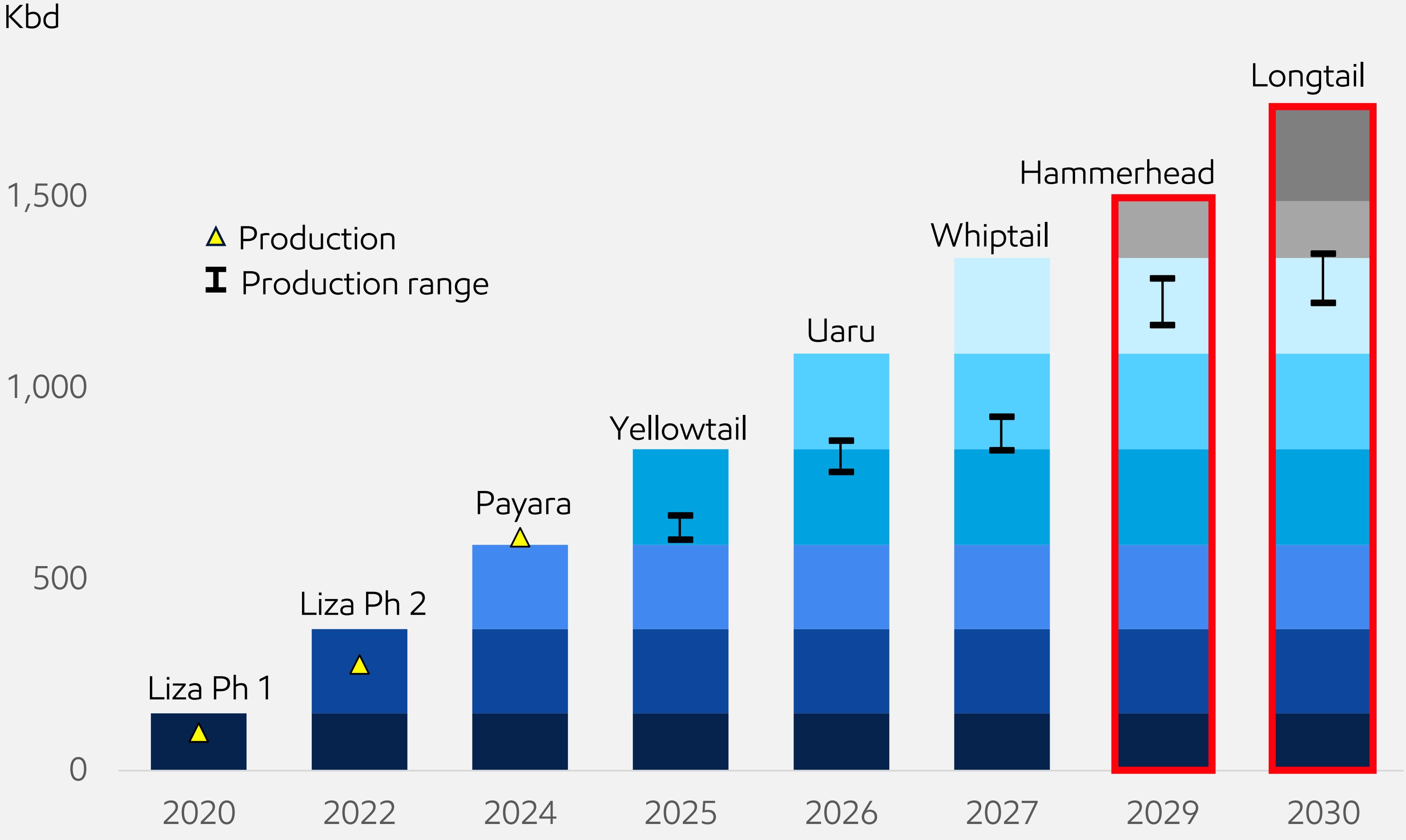
>100 Kbd
above investment basis on first 3 FPSOs

~$8 B
operating cash flow potential in 2030[1]

See Supplemental information for footnotes and definitions.

Two additional FPSOs deliver 8 developments by 2030

Growing production to 1.3 Mbd and capacity to 1.7 Mbd



Yellowtail 250 Kbd, 2025 start-up

Uaru 250 Kbd, 2026 start-up

Whiptail 250 Kbd, 2027 start-up

Hammerhead Development 7

150 Kbd, progressing to a 2029 start-up

Heavier oil resource

Longtail Development 8

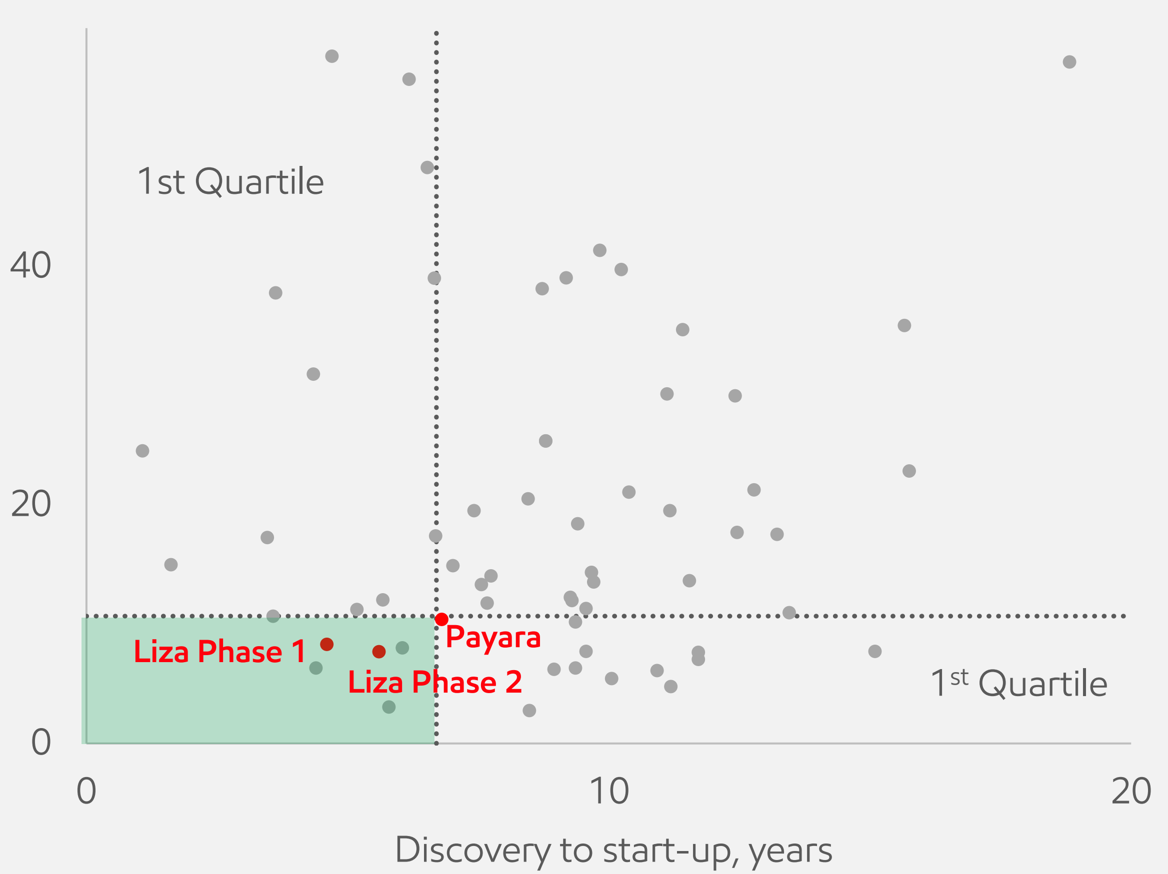
240 Kbd, progressing to a 2030 start-up

Light oil / gas condensate resource

Driving higher value from industry-leading execution

1st developments at industry-leading pace and cost[1]

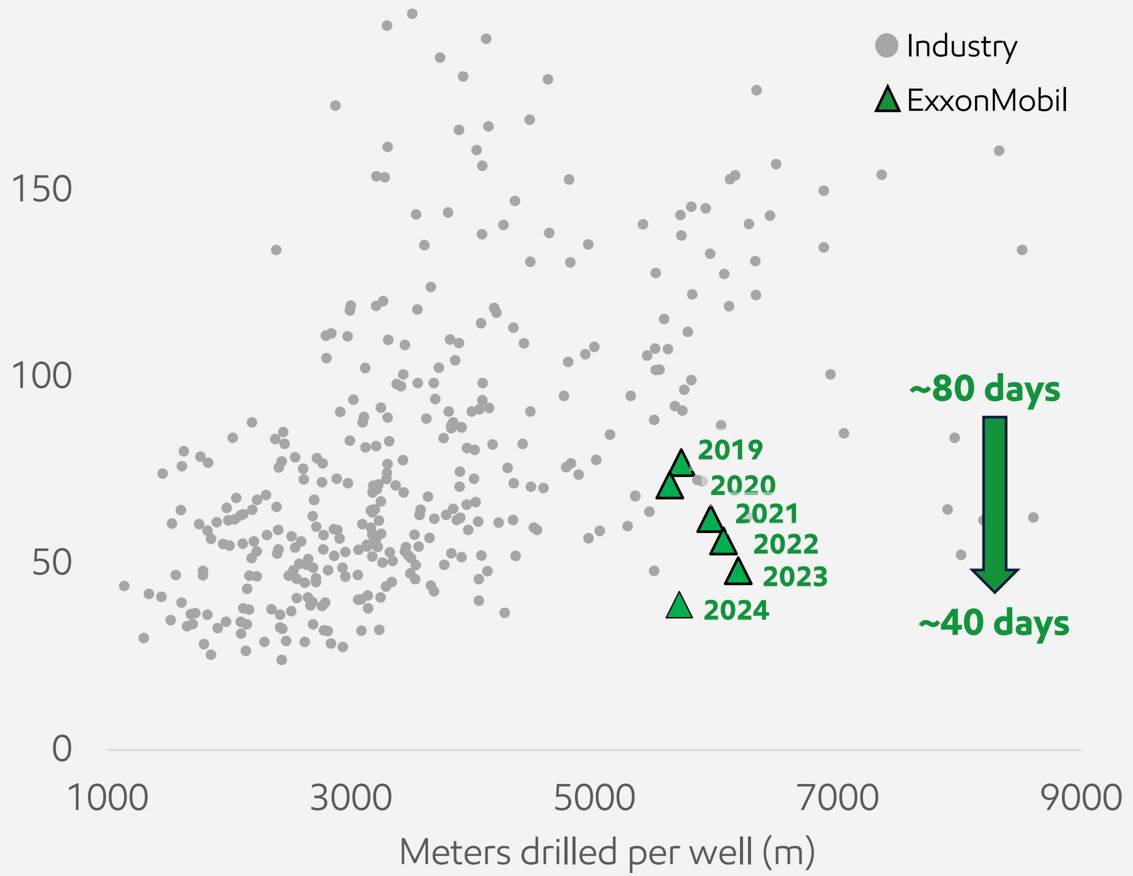
$/oeb



Source: Wood Mackenzie and ExxonMobil internal analysis
See Supplemental information for footnotes.

Industry-leading deepwater drilling pace[2]

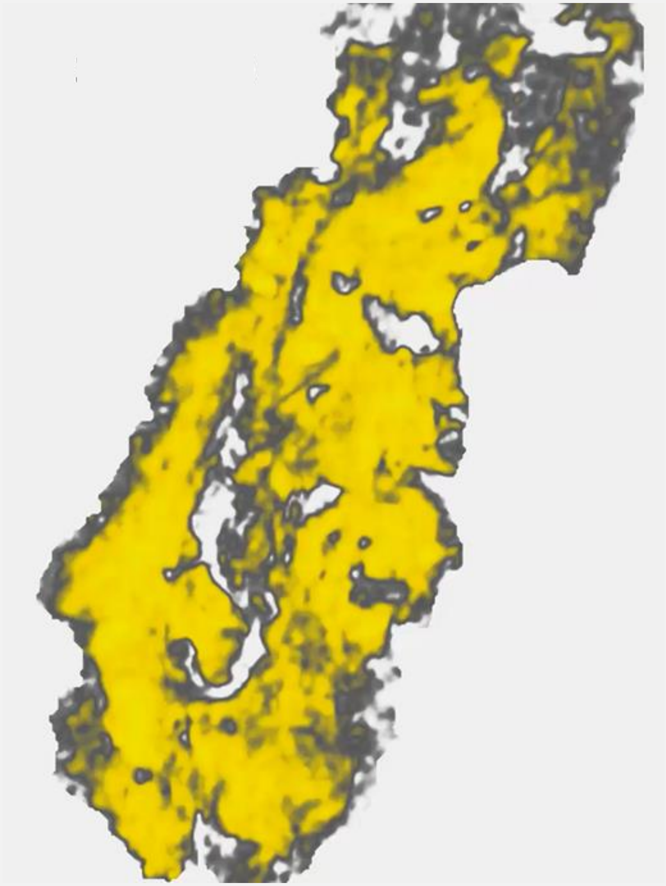
Days to drill 2019 - 2024



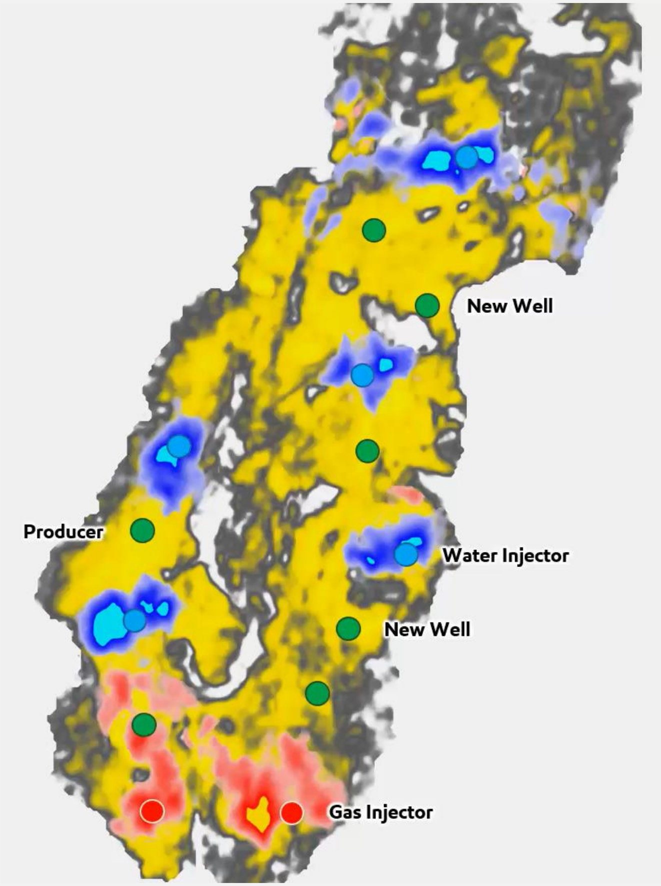
Source: External S&P Rushmore Industry

4D seismic technology unlocks >$1B in value

Guyana 3D Seismic



Guyana 4D Seismic



LEGEND:
Yellow – Oil saturated sand **Blue** – Oil displaced by water **Red** – Oil displaced by gas

Deployed 4D seismic to more accurately map movement of oil, water and gas in the reservoir

- Significantly increases resource recovery with less capital; adding >$1 billion in value

Additional High-Performance Computing capacity will unlock 4x greater computing speeds by 2026

- Further >$1 billion potential value capture

Stabroek is still early in development: considerable future potential

8 foundational projects

- Significant future in-field and tie-back opportunities

Continuing exploration and appraisal programs

- 30% of Stabroek block inaccessible

Working closely with the government of Guyana on potential gas developments

Partnering to deliver a positive impact in Guyana

Growing Guyana's economy

#1

in GDP Growth 2024 YTD; highest in the world

Greater Guyana Initiative

$100M

supporting economic diversification, advancing education and improving healthcare

Workforce

>6K

Guyanese currently supporting offshore and onshore activities

Transformational Gas-to-energy project

50%

reduction in price of electricity expected with government's power plant

Developing a low-cost-of-supply

LNG portfolio

Increasing LNG sales

>40 MTA

by 2030

Attractive LNG Portfolio

4

world-class projects
under development

Strong LNG cash flow

~$8 B

operating cash flow potential
in 2030[1]

See Supplemental information for footnotes and definitions.

Growing with world-class LNG project additions

U.S. Golden Pass
16 MTA Gross

Train 1: 85% complete; 1st LNG by ~year-end 2025

PNG Papua
6 MTA Gross

Driving competitive investment cost before FID; targeting FID 2025

Qatar NFE
32 MTA Gross

Construction underway; 1st LNG by ~year-end 2025

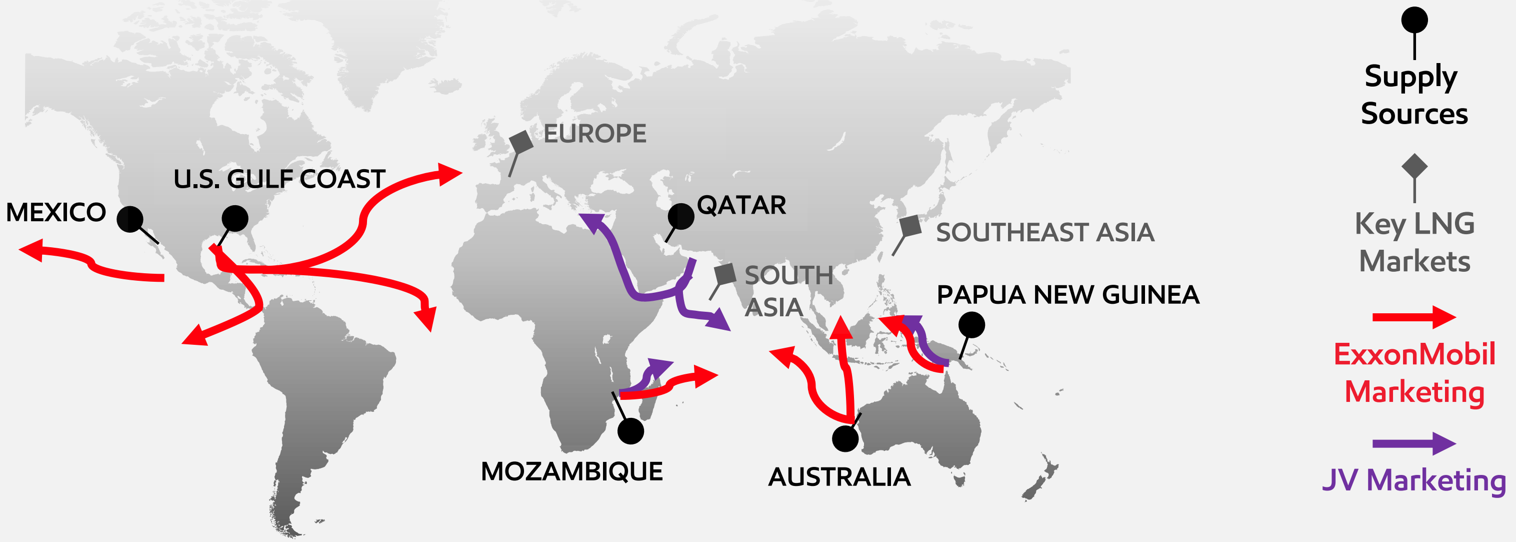
Mozambique Rovuma
18 MTA Gross

Unique modular design; targeting FID 2026

Expanding LNG global footprint and market access

LNG Sales

MTA



Extracting more value out of existing assets

PNG producing >20% above investment basis

Expanding portfolio of ExxonMobil-marketed volumes

PNG, Mozambique, Golden Pass and >5 MTA from U.S. Gulf Coast and Mexico 3rd party suppliers

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Generating additional value from increased supply source flexibility and trading

Relentlessly improving the

Base portfolio

Transformation of the base portfolio

First startup in Brazil (Bacalhau)

~70 Kbd

net production, start-up in 2025

Tengiz expansion growing value

~65 Kbd

incremental net production, FGP start-up in 2025

Progressing additional near-term divestments

>$2 B

proceeds including Nigeria JV and Argentina unconventional

Deploying technology at scale

100 %

autonomous heavy haul trucks at Kearl

Pursuing Canada in-situ breakthrough technology

>4 Boeb

potential resource at <$35/bbl cost-of-supply[1]

Significantly reducing emissions

70-80 % lower

methane intensity by 2030[2]

See Supplemental information for footnotes and definitions.

Delivering unmatched Upstream value and cash flow growth

>$55B
operating cash flow in 2030[1], leading IOCs

>50%
increase in Pioneer synergies vs. prior guidance

+2
Guyana developments Hammerhead and Longtail

[1] Potential, at constant price
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Q&A

Supplements and footnotes

Supplemental information

Forward-looking statements contained in this presentation regarding the potential for future earnings, cash flow, cash flow from operations, cash flow from operations (ex. working capital), operating cash flow, returns, structural cost savings, cash capital expenditures, synergies, and volumes, including statements regarding future earnings potential, cash flow potential, and returns in the Upstream segment and in our low emissions investments, are not forecasts of actual future results. These figures are provided to help quantify for illustrative purposes management's view of the potential future results and goals of currently-contemplated management plans and objectives over the time periods shown, calculated on a basis consistent with our internal modeling assumptions. Management plans discussed in this presentation include objectives to invest in new projects, plans to replace natural decline in Upstream production, continued high grading of ExxonMobil's portfolio through our ongoing asset management program, both announced and continuous initiatives to improve efficiencies and reduce costs, capital expenditures, operating costs, and other efforts within management's control to impact future results as discussed in this presentation. We have assumed future demand growth in line with our internal planning basis, and that other factors including factors management does not control such as applicable laws and regulations (including tax and environmental laws), technology advancements, interest rates, and exchange rates remain consistent with current conditions for the relevant periods. These assumptions are not forecasts of actual future market conditions. Capital investment guidance in low emissions investments is based on plan, however actual investment levels will be subject to the availability of the opportunity set and focused on returns.

All references to production rates, project capacity, resource size, and acreage are on a net basis, unless otherwise noted. All references to tons refer to metric tons, unless otherwise noted.

Non-GAAP and other measures. With respect to historical periods, reconciliation information is provided on page 41 and in the Frequently Used Terms available under the "Modeling Toolkit" tab on the Investor Relations page of our website at www.exxonmobil.com for certain terms used in this presentation including cash capex; cash opex excluding energy and production taxes; earnings ex. identified items and adjusted to 2024 $65/bbl real Brent; operating costs; structural cost savings; and operating cash flow. For future periods, we are unable to provide a reconciliation of forward-looking non-GAAP or other measures to the most comparable GAAP financial measures because the information needed to reconcile these measures is dependent on future events, many of which are outside management's control as described above. Additionally, estimating such GAAP measures and providing a meaningful reconciliation consistent with our accounting policies for future periods is extremely difficult and requires a level of precision that is unavailable for these future periods and cannot be accomplished without unreasonable effort. Forward-looking non-GAAP measures are estimated in a manner consistent with the relevant definitions and assumptions noted above.

Supplemental information

Important information and assumptions regarding certain forward-looking statements. For all price point comparisons, unless otherwise indicated, we assume $65/bbl Brent crude prices, $3/mmbtu Henry Hub gas prices, and $6.5/mmbtu TTF gas prices. Unless otherwise specified, crude prices are Brent prices. These are used for clear comparison purposes and are not necessarily representative of management's internal price assumptions. Crude and natural gas prices for future years are adjusted for inflation (assumption of 2.5%) from 2024. Operating costs and capex are also inflated consistent with plans done on a country-by-country basis.

These prices are not intended to reflect management's forecasts for future prices or the prices we use for internal planning purposes.

Unless otherwise indicated, asset sales and proceeds are aligned with our internal planning.

Actions needed to advance ExxonMobil's 2030 greenhouse gas emission-reductions plans are incorporated into its medium-term business plans, which are updated annually. The reference case for emission-reduction planning beyond 2030 is based on the Company's Global Outlook research and publication. The Outlook is reflective of the existing global policy environment and an assumption of increasing policy stringency and technology improvement to 2050. However, the Global Outlook does not attempt to project the degree of required future policy and technology advancement and deployment for the world, or ExxonMobil, to meet net zero by 2050. As future policies and technology advancements emerge, they will be incorporated into the Outlook, and the Company's business plans will be updated accordingly. References to projects or opportunities may not reflect investment decisions made by the corporation or its affiliates. Individual projects or opportunities may advance based on a number of factors, including availability of supportive policy, permitting, technological advancement for cost-effective abatement, insights from the company planning process, and alignment with our partners and other stakeholders. Capital investment guidance in lower-emission investments is based on our corporate plan; however, actual investment levels will be subject to the availability of the opportunity set, public policy support, and focused on returns.

ExxonMobil has business relationships with thousands of customers, suppliers, governments, and others. For convenience and simplicity, words such as venture, joint venture, partnership, co-venturer, operated by others, and partner are used to indicate business and other relationships involving common activities and interests, and those words may not indicate precise legal relationships.

Separately from our Corporate Plan Update disclosure, competitor data in this presentation is based on publicly available information and, where estimated or derived, done so on a consistent basis with ExxonMobil data. Future competitor data, unless otherwise noted, taken from publicly available statements or disclosures by that competitor and has not been independently verified by ExxonMobil or any third party. We note that certain competitors report financial information under accounting standards other than U.S. GAAP (i.e., IFRS).

ExxonMobil reported emissions, including reductions and avoidance performance data, are based on a combination of measured and estimated data. Calculations are based on industry standards and best practices, including guidance from the American Petroleum Institute (API) and Ipieca. Emissions reported are estimates only, and performance data depends on variations in processes and operations, the availability of sufficient data, the quality of those data and methodology used for measurement and estimation. Emissions data is subject to change as methods, data quality, and technology improvements occur, and changes to performance data may be updated. Emissions, reductions and avoidance estimates for non-ExxonMobil operated facilities are included in the equity data and similarly may be updated as changes in the performance data are reported. ExxonMobil's plans to reduce emissions are good faith efforts based on current relevant data and methodology, which could be changed or refined. ExxonMobil works to continuously improve its approach to identifying, measuring and addressing emissions. ExxonMobil actively engages with industry, including API and Ipieca, to improve emission factors and methodologies, including measurements and estimates.

See the Cautionary Statement at the front of this presentation for additional information regarding forward-looking statements

Supplemental information

RECONCILIATION OF UPSTREAM UNIT EARNINGS AND OPERATING CASH FLOW

UPSTREAM EARNINGS	2019
Earnings (U.S. GAAP)	14.4
Asset management (Announced divestments)	(3.7)
Impairment	0.0
Tax / Other items (Tax items, Additional European taxes on energy sector)	(0.8)
Earnings ex. identified items	**10.0**
Adjustment to 2024 $65/bbl real Brent	(2.5)
Earnings, ex. identified items and adjusted to 2024 $65/bbl real Brent	**7.5**
Production (Koebd, $65/bbl real Brent)[1]	3,983
Unit earnings, ex. identified items ($/oeb, adjusted to 2024 $65/bbl real Brent)[2]	**$5**

OPERATING CASH FLOW	2019
Earnings, ex. identified items and adjusted to 2024 $65/bbl real Brent	**7.5**
Non-Cash primarily Depreciation[3]	18.5
Asset sales proceeds[3]	3.5
Other items[3]	(1.0)
Operating Cash Flow adjusted to 2024 $65/bbl real Brent (Non-GAAP)	**$28.5**

[1] Production adjusted to 2024 $65/bbl real Brent. Differences versus actual production include entitlements and other price-linked volume impacts.
[2] The unit earnings calculation uses total production, which is equal to Production (Koebd, $65/bbl real Brent) multiplied by the number of days in the period multiplied by 1,000.
[3] Non-cash, Asset sales proceeds, and other items are adjusted to 2024 $65/bbl real Brent
Billions of dollars unless specified otherwise.
Due to rounding, numbers may not add.

Supplemental information

DEFINITIONS AND NON-GAAP FINANCIAL MEASURE RECONCILIATIONS

Advantaged assets (Advantaged growth projects). Includes Permian (heritage Permian and Pioneer), Guyana, and LNG.

Base portfolio (Base). In our Upstream segment, refers to assets (or volumes) other than advantaged assets (or volumes from advantaged assets).

Capital and exploration expenditures (Capital expenditures, Capex). Represents the combined total of additions at cost to property, plant and equipment, and exploration expenses on a before-tax basis from the Consolidated Statement of Income. ExxonMobil's Capex includes its share of similar costs for equity companies. Capex excludes assets acquired in nonmonetary exchanges, the value of ExxonMobil shares used to acquire assets, and depreciation on the cost of exploration support equipment and facilities recorded to property, plant and equipment when acquired. While ExxonMobil's management is responsible for all investments and elements of net income, particular focus is placed on managing the controllable aspects of this group of expenditures.

Cash capital expenditures (Cash Capex) (Non-GAAP). Sum of Additions to property, plant and equipment; Additional investments and advances; and Other investing activities including collection of advances; reduced by Inflows from noncontrolling interests for major projects, each from the Consolidated Statement of Cash Flows. Prior to fourth quarter 2024, Inflows from noncontrolling interests for major projects was included within Changes in noncontrolling interests on the Consolidated Statement of Cash Flows. This measure is useful for investors to understand the current period cash impact of investments in the business.

Cash operating expenses excluding energy and production taxes (non-GAAP). Subset of total operating costs that are stewarded internally to support management's oversight of spending over time. This measure is useful for investors to understand our efforts to optimize cash through disciplined expense management for items within management's control.

Compound annual growth rate (CAGR). Represents the consistent rate at which an investment or business result would have grown had the investment or business result compounded at the same rate each year.

Divestments. Refers to asset sales; results include associated cash proceeds and production impacts, as applicable, and are consistent with our internal planning.

Earnings (loss) excluding Identified Items (Earnings ex. Ident. Items) (non-GAAP). Earnings (loss) excluding individually significant non-operational events with, typically, an absolute corporate total earnings impact of at least $250 million in a given quarter. The earnings (loss) impact of an Identified Item for an individual segment may be less than $250 million when the item impacts several periods or several segments. Earnings (loss) excluding Identified Items does include non-operational earnings events or impacts that are generally below the $250 million threshold utilized for Identified Items. When the effect of these events is significant in aggregate, it is indicated in analysis of period results as part of quarterly earnings press release and teleconference materials. Management uses these figures to improve comparability of the underlying business across multiple periods by isolating and removing significant non-operational events from business results. The Corporation believes this view provides investors increased transparency into business results and trends and provides investors with a view of the business as seen through the eyes of management. Earnings (loss) excluding Identified Items is not meant to be viewed in isolation or as a substitute for net income (loss) attributable to ExxonMobil as prepared in accordance with U.S. GAAP. A reconciliation to earnings is shown for the periods on slide X.

Estimated Operating Cash Contribution. Estimated earnings before depreciation and depletion, including non-controlling interest and abandonment, and excluding exploration expenses and trading Where applicable, pro-rata equity company earnings are net of depreciation and depletion.

Flowing gas. Refers to gas available for sale that is not marketed as liquefied natural gas.

Supplemental information

DEFINITIONS AND NON-GAAP FINANCIAL MEASURE RECONCILIATIONS

Government mandates (curtailments). Changes to ExxonMobil's sustainable production levels as a result of production limits or sanctions imposed by governments.

Heavy oil and oil sands. Heavy oil includes heavy oil, extra heavy oil, and bitumen, as defined by the World Petroleum Congress in 1987 based on American Petroleum Institute (API) gravity and viscosity at reservoir conditions. Heavy oil has an API gravity between 10 and 22.3 degrees. The API gravity of extra heavy oil and bitumen is less than 10 degrees. Extra heavy oil has a viscosity less than 10,000 centipoise, whereas the viscosity of bitumen is greater than 10,000 centipoise. The term "oil sands" is used to indicate heavy oil (generally bitumen) that is recovered in a mining operation.

Heritage Permian (h-XOM, h-Permian) Permian basin assets excluding assets acquired as part of the acquisition of Pioneer Natural Resources that closed in May 2024.

Heritage Pioneer (h-PXD, h-Pioneer) Permian basin assets acquired as part of the acquisition of Pioneer Natural Resources that closed in May 2024.

IOCs. Unless stated otherwise, IOCs include each of BP, Chevron, Shell, and TotalEnergies.

Long Cycle (long cycle production). Long cycle production describe Upstream production excluding production from our Unconventional business

Operating cash flow. Operating Cash Flow is earnings plus depreciation and depletion, including non-controlling interests and abandonment spend, plus asset sales proceeds. Where applicable, pro-rata equity company earnings are net of depreciation and depletion. Management believes this measure is useful when approximating contributions to cash available for investment and financing activities excluding working capital impacts, applied to the Upstream business. For information concerning the calculation and reconciliation of operating costs see the table on slide 41.

Operating costs (Opex) (non-GAAP). Operating costs are the costs during the period to produce, manufacture, and otherwise prepare the company's products for sale – including energy, staffing, and maintenance costs. They exclude the cost of raw materials, taxes, and interest expense and are on a before-tax basis. While ExxonMobil's management is responsible for all revenue and expense elements of net income, operating costs, as defined above, represent the expenses most directly under management's control, and therefore are useful for investors and ExxonMobil management in evaluating management's performance.

Project. The term "project" as used in this presentation can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports. Projects or plans may not reflect investment decisions made by the company. Individual opportunities may advance based on a number of factors, including availability of supportive policy, technology for cost-effective abatement, and alignment with our partners and other stakeholders. The company may refer to these opportunities as projects in external disclosures at various stages throughout their progression.

Resources, resource base, and recoverable resources. Along with similar terms, refer to the total remaining estimated quantities of oil and natural gas that are expected to be ultimately recoverable. The resource base includes quantities of oil and natural gas classified as proved reserves, as well as quantities that are not yet classified as proved reserves, but that are expected to be ultimately recoverable. The term "resource base" or similar terms are not intended to correspond to SEC definitions such as "probable" or "possible" reserves. The term "in-place" refers to those quantities of oil and natural gas estimated to be contained in known accumulations and includes recoverable and unrecoverable amounts

Returns, rate of return, investment returns, project returns, IRR. Unless referring specifically to ROCE or external data, references to returns, rate of return, IRR, and similar terms mean future discounted cash flow returns on future capital investments based on current company estimates. Investment returns exclude prior exploration and acquisition costs.

Supplemental information

DEFINITIONS AND NON-GAAP FINANCIAL MEASURE RECONCILIATIONS

Short Cycle (short cycle production). Short cycle production describe production from our Unconventional business inclusive of Permian assets

Structural cost savings (structural cost reductions, structural savings, structural cost improvements). Structural cost savings describe decreases in cash opex excluding energy and production taxes as a result of operational efficiencies, workforce reductions, divestment-related reductions, and other cost-savings measures, that are expected to be sustainable compared to 2019 levels. Relative to 2019, estimated cumulative structural cost savings totaled $11.3 billion across all business segments as of September 30, 2024 .The total change between periods in expenses will reflect both structural cost savings and other changes in spend, including market factors, such as inflation and foreign exchange impacts, as well as changes in activity levels and costs associated with new operations, mergers and acquisitions, new business venture development, and early-stage projects. Estimates of cumulative annual structural savings may be revised depending on whether cost reductions realized in prior periods are determined to be sustainable compared to 2019 levels. Structural cost savings are stewarded internally to support management's oversight of spending over time. This measure is useful for investors to understand our efforts to optimize spending through disciplined expense management.

Synergies. Synergies refer to pre-tax increases in cash flow due to factors such as higher resource recovery, lower development costs, lower operating costs, among others.

Supplemental information

Slide 3
1) Operating cash flow is adjusted to 2024 $65/bbl real Brent. See reconciliation of 2019 operating cash flow on page 41.

Slide 4
1) Cash flow from operations data from Wood Mackenzie. Wood Mackenzie estimates do not necessarily match ExxonMobil's internal plans.
2) IOCs data from Wood MacKenzie includes Chevron, Shell, TotalEnergies, and BP. All data adjusted to 2024 $65/bbl real Brent.

Slide 5
1) Based on ExxonMobil internal efficiency record in both Midland and Delaware basins.
2) Based on average duration of significant investigations as reported in Dechert Antitrust Merger Investigation Timing Tracker 2023 Annual Report.

Slide 7
1) Industry based on Wood Mackenzie data comparing ExxonMobil Upstream to other IOC's Upstream portfolio.
2) Excludes energy and production taxes.
3) Up to 15% so far based on lightweight proppant pilot conducted on ~50 wells; limited to Delaware/North Midland or areas with highest EM working interest.

Slide 9
1) Excludes energy and production taxes.
2) IOCs represent Chevron and Shell.

Slide 12
1) Investment generate returns at <$35/bbl and <$6/MBTU; Includes projects that bring on new volumes. Breakeven based on cost-of-supply to generate a minimum 10 percent return on a money-forward basis.

Slide 15
1) Excludes energy costs and production taxes.

Slide 16
1) Up to 15% so far based on lightweight proppant pilot conducted on ~50 wells; limited to Delaware/North Midland or areas with highest EM working interest.

Slide 17
1) Based on Enverus 2024 Permian Basin Play Fundamentals article with updated data as of 10/2024 | Locations normalized to 10,000-foot laterals; Peers include Apache Corporation, BP, ConocoPhillips, Coterra Energy, Chevron, Devon Energy, Diamondback Energy, EOG Resources, Matador Resources, Ovintiv, Occidental, and Permian Resources. PV-10 Breakeven @ 20:1 WTI:HH ($/bbl).

Slide 18
1) Based on ExxonMobil analysis of Kayrros database as of 09/2024. Top 4 Peers include Chevron, Devon Energy, EOG Resources, and Permian Resources.
2) Based on ExxonMobil analysis of Kayrros database as of 09/2024 normalized to 90% simulfrac fleet mix. Top 4 Peers include Chevron, ConocoPhillips, Diamondback Energy, and Ovintiv.
3) Based on ExxonMobil analysis of Enverus data as of 09/2024; Industry average includes Apache Corporation, BP, Chevron, ConocoPhillips, Coterra Energy, Devon Energy, Diamondback Energy, EOG Resources, Matador Resources, Occidental, and Permian Resources. Enverus is a self reporting system that may not include all data, but we believe best represents industry data.

Slide 21
1) Up to 15% so far based on lightweight proppant pilot conducted on ~50 wells; limited to Delaware/North Midland or areas with highest EM working interest.

Slide 22
1) >50% increase in synergies is based on a 10 year average
2) Up to 15% so far based on lightweight proppant pilot program conducted on ~50 wells; limited to Delaware/North Midland or areas with highest EM working interest.

Supplemental information

Slide 23

1) Cumulative synergies calculated based on 2024 $65/bbl real Brent.
2) 2030 compared to 2019, $/lateral foot.
3) 2030 compared to 2019. Measured on estimated recovery per typical cube.
4) Potential assuming 2024 $65/bbl real Brent on a money-forward basis.
5) Money-forward basis.
6) Potential assuming 2024 $65/bbl real Brent. See page 43 for definition of Operating Cash Flow.

Slide 25

1) Potential assuming 2024 $65/bbl real Brent. See page 43 for definition of Operating Cash Flow.

Slide 27

1) Industry and quartile data based on ExxonMobil analysis of Wood Mackenzie data; and ExxonMobil internal data for Liza Phase 1, Phase 2, and Payara.
2) Based on ExxonMobil analysis of S&P Rushmore Industry Global offshore Deepwater Drillship data as of 10/2024 for industry, and ExxonMobil internal data for Guyana.

Slide 31 (Developing a low cost-of-supply LNG portfolio)

1) Potential assuming 2024 $65/bbl real Brent. See page 43 for definition of Operating Cash Flow.

Slide 35 (Transformation of the base portfolio)

1) Money-forward basis.
2) Based on Scope 1 and 2 emissions of operated assets (versus 2016)

Slide 36 (Delivering unmatched Upstream value and cash flow growth)

1) Operating cash flow is adjusted to 2024 $65/bbl real Brent. See reconciliation of 2019 operating cash flow on page 41.