human energy®

Chevron 2019

Investor Presentation

November 2019

Cautionary statement

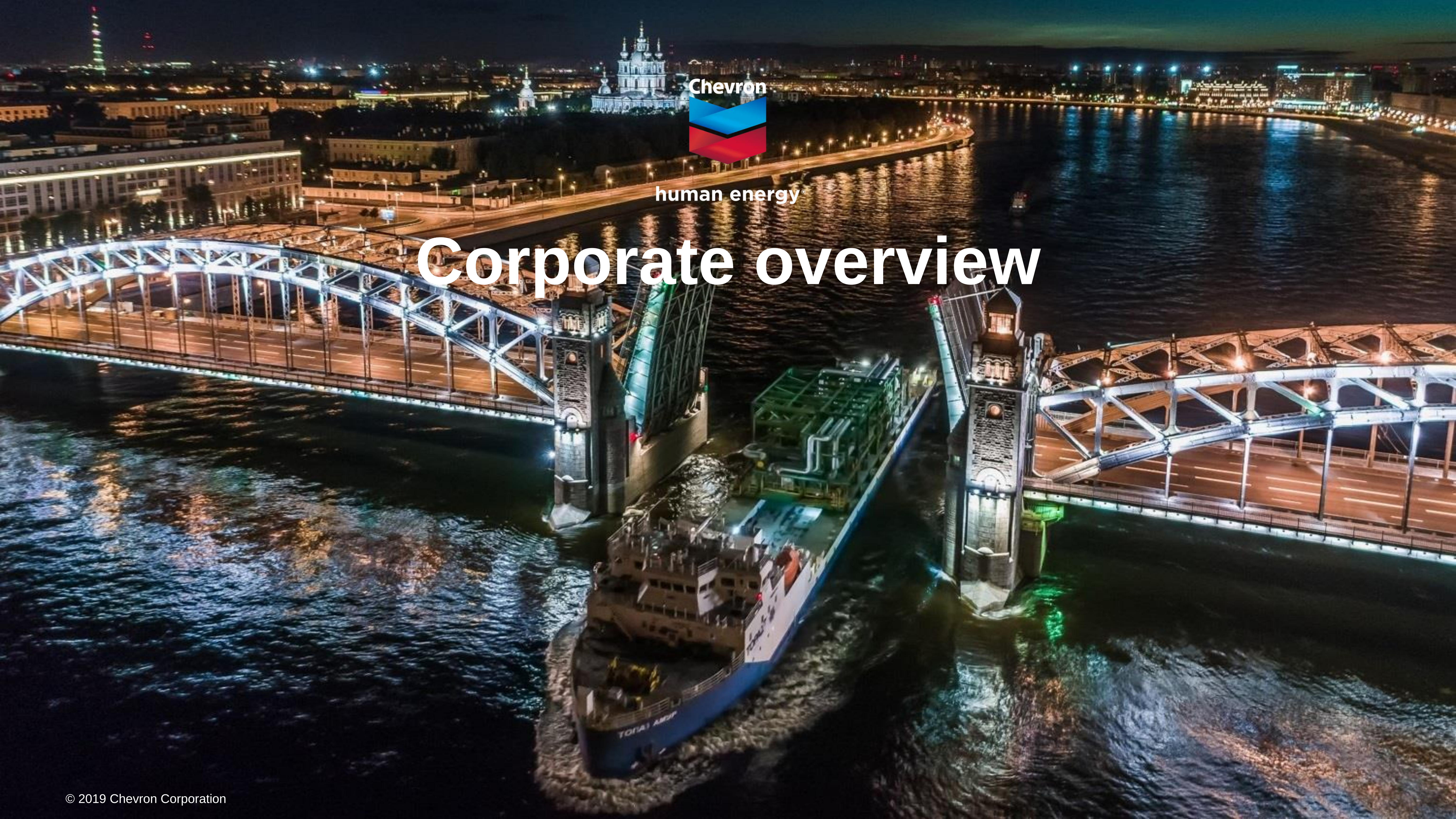
CAUTIONARY STATEMENTS RELEVANT TO FORWARD-LOOKING INFORMATION
FOR THE PURPOSE OF "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This presentation of Chevron Corporation contains forward-looking statements relating to Chevron's operations that are based on management's current expectations, estimates and projections about the petroleum, chemicals and other energy-related industries. Words or phrases such as "anticipates," "expects," "intends," "plans," "targets," "forecasts," "projects," "believes," "seeks," "schedules," "estimates," "positions," "pursues," "may," "could," "should," "will," "budgets," "outlook," "trends," "guidance," "focus," "on schedule," "on track," "is slated," "goals," "objectives," "strategies," "opportunities," "poised," and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, many of which are beyond the company's control and are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. The reader should not place undue reliance on these forward-looking statements, which speak only as of the date of this presentation. Unless legally required, Chevron undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Among the important factors that could cause actual results to differ materially from those in the forward-looking statements are: changing crude oil and natural gas prices; changing refining, marketing and chemicals margins; the company's ability to realize anticipated cost savings and expenditure reductions; actions of competitors or regulators; timing of exploration expenses; timing of crude oil liftings; the competitiveness of alternate-energy sources or product substitutes; technological developments; the results of operations and financial condition of the company's suppliers, vendors, partners and equity affiliates, particularly during extended periods of low prices for crude oil and natural gas; the inability or failure of the company's joint-venture partners to fund their share of operations and development activities; the potential failure to achieve expected net production from existing and future crude oil and natural gas development projects; potential delays in the development, construction or start-up of planned projects; the potential disruption or interruption of the company's operations due to war, accidents, political events, civil unrest, severe weather, cyber threats and terrorist acts, crude oil production quotas or other actions that might be imposed by the Organization of Petroleum Exporting Countries and other producing countries, or other natural or human causes beyond the company's control; changing economic, regulatory and political environments in the various countries in which the company operates; general domestic and international economic and political conditions; the potential liability for remedial actions or assessments under existing or future environmental regulations and litigation; significant operational, investment or product changes required by existing or future environmental statutes and regulations, including international agreements and national or regional legislation and regulatory measures to limit or reduce greenhouse gas emissions; the potential liability resulting from pending or future litigation; the company's future acquisitions or dispositions of assets or shares or the delay or failure of such transactions to close based on required closing conditions; the potential for gains and losses from asset dispositions or impairments; government-mandated sales, divestitures, recapitalizations, industry-specific taxes, tariffs, sanctions, changes in fiscal terms or restrictions on scope of company operations; foreign currency movements compared with the U.S. dollar; material reductions in corporate liquidity and access to debt markets; the effects of changed accounting rules under generally accepted accounting principles promulgated by rule-setting bodies; the company's ability to identify and mitigate the risks and hazards inherent in operating in the global energy industry; and the factors set forth under the heading "Risk Factors" on pages 18 through 21 of the company's 2018 Annual Report on Form 10-K and in subsequent filings with the U.S. Securities and Exchange Commission. Other unpredictable or unknown factors not discussed in this presentation could also have material adverse effects on forward-looking statements.

Certain terms, such as "unrisked resources," "unrisked resource base," "recoverable resources," and "oil in place," among others, may be used in this presentation to describe certain aspects of the company's portfolio and oil and gas properties beyond the proved reserves. For definitions of, and further information regarding, these and other terms, see the "Glossary of Energy and Financial Terms" on pages 54 through 55 of the company's 2018 Supplement to the Annual Report and available at chevron.com. As used in this presentation, the term "project" may describe new upstream development activity, including phases in a multiphase development, maintenance activities, certain existing assets, new investments in downstream and chemicals capacity, investment in emerging and sustainable energy activities, and certain other activities. All of these terms are used for convenience only and are not intended as a precise description of the term "project" as it relates to any specific government law or regulation.

As used in this presentation, the term "Chevron" and such terms as "the company," "the corporation," "our," "we," "us," and "its" may refer to Chevron Corporation, one or more of its consolidated subsidiaries, or to all of them taken as a whole. All of these terms are used for convenience only and are not intended as a precise description of any of the separate companies, each of which manages its own affairs.



Corporate overview

Positioned to win in any environment

Advantaged portfolio delivers strong cash flow

Unmatched balance sheet and **low breakeven**

Disciplined, returns-driven capital allocation

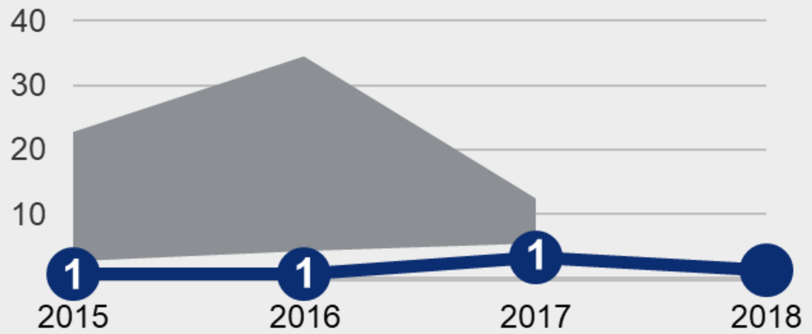
Superior cash returns to shareholders

Chevron repositioned to deliver long-term value

Leading operational excellence

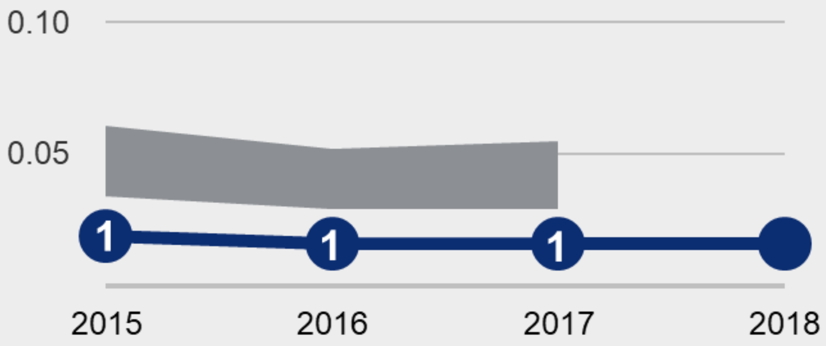
Industry leading
workforce safety

Oil spills to land or water[2]
Thousands of barrels



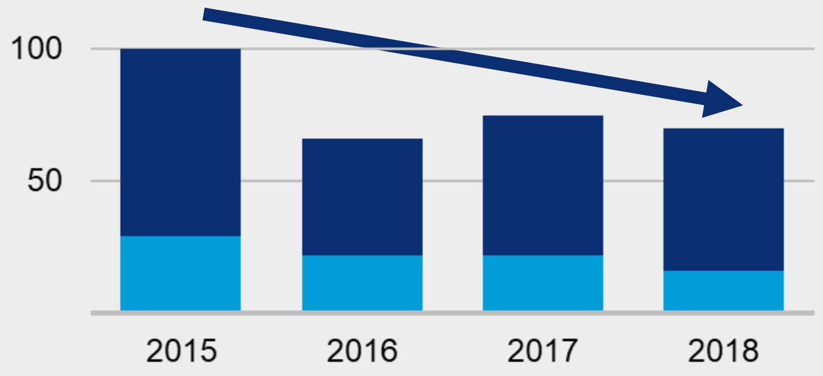
Process safety
improvement

Days away from work rate[1]



Industry leading
spill performance

Loss of containment events[3]

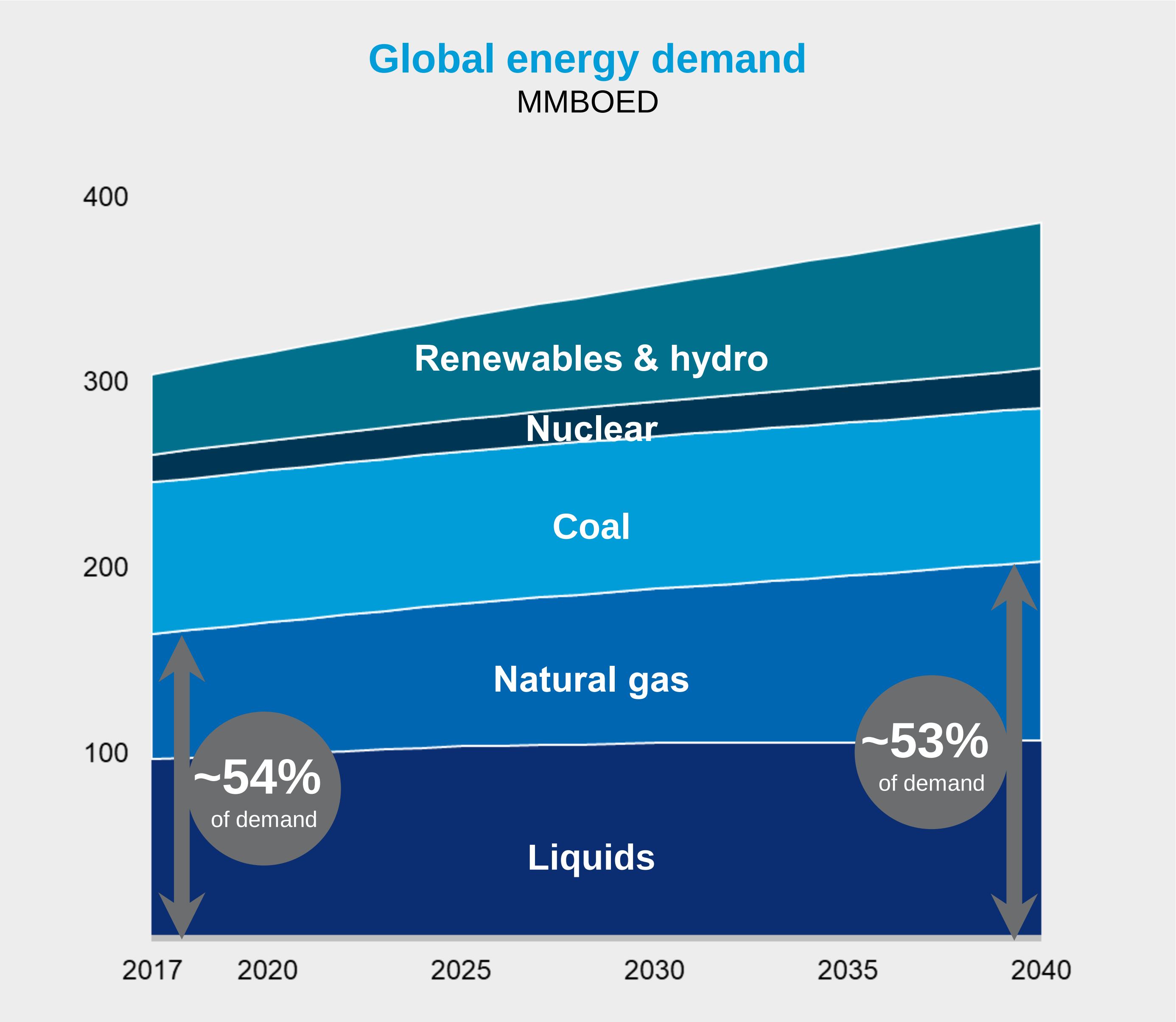


[1] Source: Annual company sustainability reports. XOM and BP are lost time incident rates; RDS is lost time incident rates for injuries only; TOT is not included in competitor range due to reporting differences.

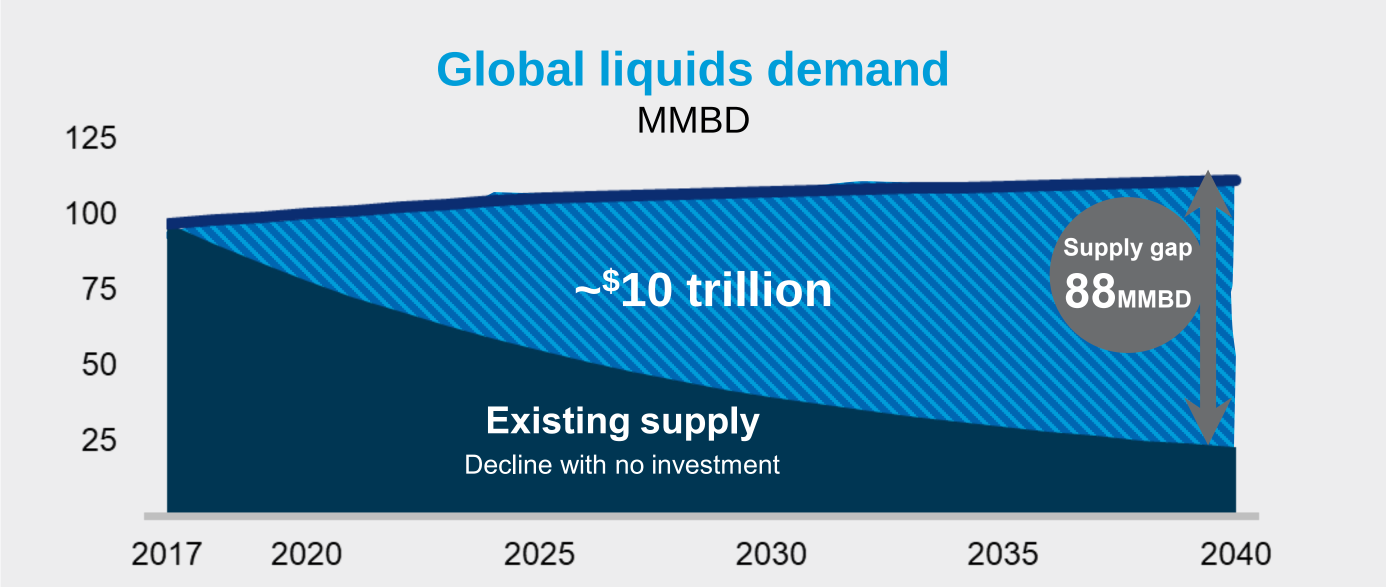
[2] Source: Annual company sustainability reports. Oil spills greater than one barrel (excluding secondary containment). Includes sabotage events. TOT is not included in competitor range due to reporting differences. When needed, units converted to thousand bbl.

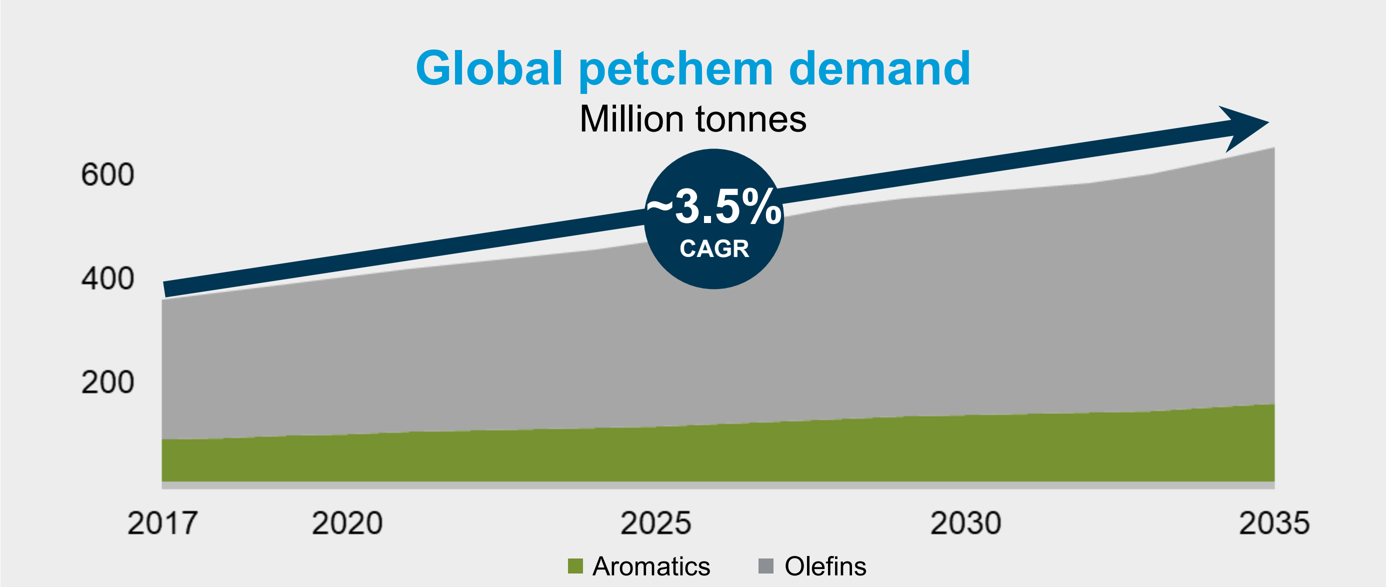
[3] Source: Company data. American Petroleum Institute Recommended Practice (RP) 754 defines Tier 1 loss-of-primary-containment (LOPC) incident as an unplanned or uncontrolled release of any material, including non-toxic and nonflammable materials from a process that results in an injury, shelter in place or evacuation, fire, or material release that meets the thresholds as defined in RP 754. A Tier 2 process safety event is an LOPC with lesser consequence.

Growing demand for our products



Source: IEA New Policies Scenario, *World Energy Outlook 2018*





Source: IEA New Policies Scenario, *World Energy Outlook 2018*
Source: Nexant, Inc. Medium Oil Scenario; Olefin demand data as of April / May 2018; Aromatics data as of Sep / Oct 2018

Advantaged portfolio a key differentiator

Upstream

Leading adjusted EPB $14.45[1]

7.4% production growth

Unit production cost ~$10.50/BOE[2]

Downstream & Chemicals

Leading adjusted EPB $2.66[1]

Highest complexity refinery system (NCI: 12.7)

Growing petchem position with advantaged feedstock (>80% ethane)[3]

Note: Actual numbers on the slide pertain to 2018.

[1] Adjusted Earnings Per Barrel (EPB) – See Appendix: reconciliation of non-GAAP measures. Source: Public information presented on a consistent basis and Chevron estimates. Excludes special items.

Nelson Complexity Index (NCI) source: *Oil and Gas Journal*

[2] Production costs per barrel sourced from Supplemental Information on Oil and Gas Producing Activities in Form 10-K, 20-F. Includes production expense, non-income taxes, and other income/expense. Excludes asset sales gains, LNG liquefaction, transportation and other non-oil & gas activities reported under the upstream segment. Includes affiliates.

[3] Ethane feedstock percentage reflects CPChem worldwide ethylene production.

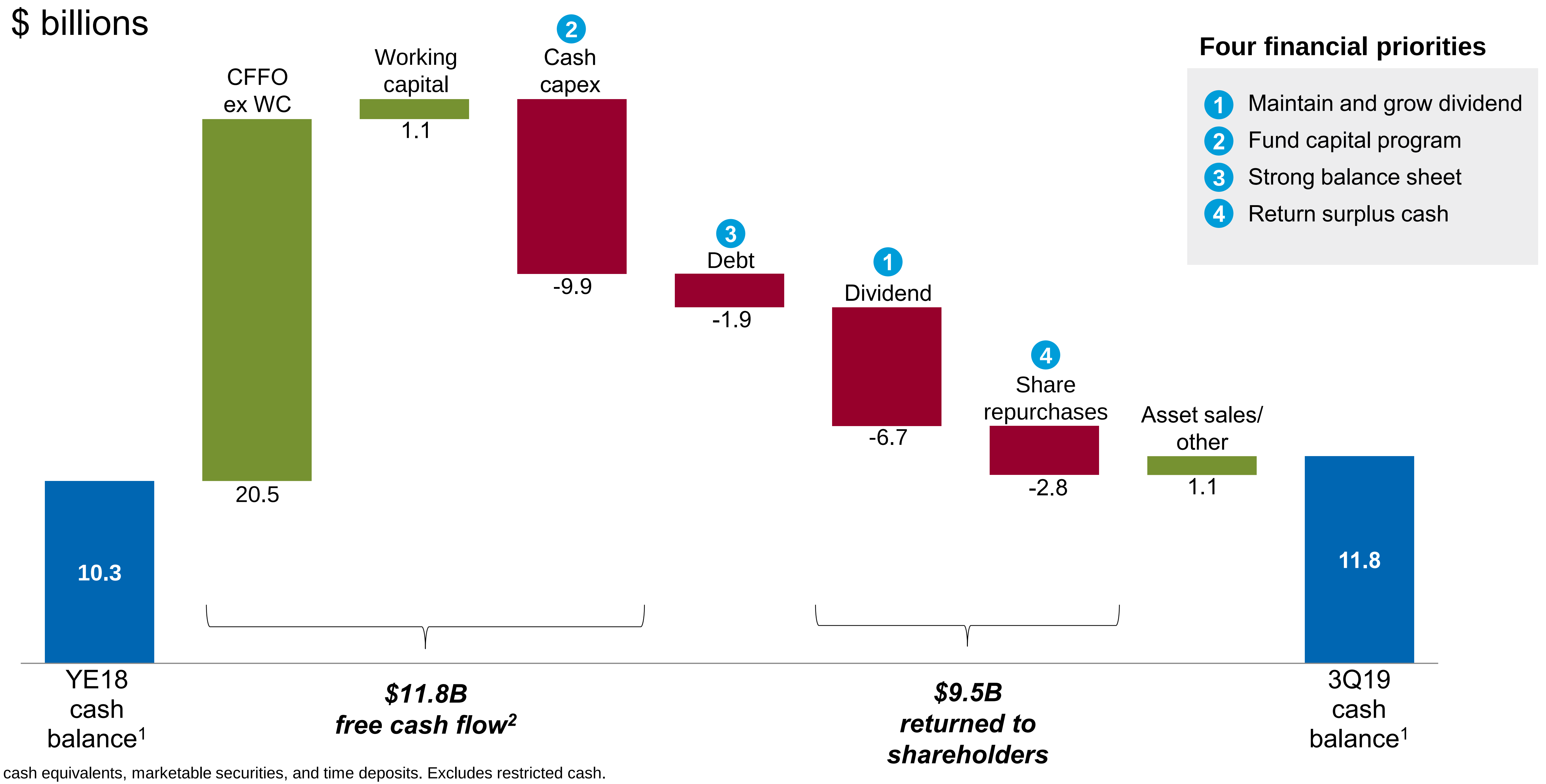
Financial highlights

	3Q19
Earnings	$2.6 billion
Earnings per diluted share	$1.36
Earnings / EPS (excluding special items and FX)[1]	$2.9 billion / $1.55
Cash flow from operations / excl. working capital[1]	$7.8 billion / $6.4 billion
Debt ratio / Net debt ratio[2]	17.4% / 11.9%
Dividends paid	$2.2 billion
Share repurchases	$1.25 billion
YTD total C&E / YTD organic C&E	$15.0 billion / $14.5 billion

[1] Reconciliation of special items, FX, and other non-GAAP measures can be found in the appendix.

[2] As of 09/30/2019. Net debt ratio is defined as debt less cash equivalents, marketable securities and time deposits divided by debt less cash equivalents, marketable securities and time deposits plus stockholders' equity.

Delivering on all four financial priorities



¹ Includes cash, cash equivalents, marketable securities, and time deposits. Excludes restricted cash.
² Free cash flow is defined as cash flow from operations less cash capital expenditures.
Note: Numbers may not sum due to rounding.

Looking ahead

4Q 2019 outlook

UPSTREAM	• Full year 2019 production growth (excluding asset sales) in the middle of the 4-7% range • Full year asset sales production impact (~30 MBOED) • Turnarounds (>70 MBOED) • Exploration related inorganic C&E (~$120 million) • Full year TCO co-lending (<$2 billion)
DOWNSTREAM	• "High" refinery turnaround activity, includes SPRC refinery wide turnaround (once every five years)
CORPORATE	• $430 million tax payment related to cash repatriation • $1.25 billion of share repurchases

Upside leverage and downside resilience

High
price environment

Competitive dividend growth

Disciplined C&E

Surplus cash returned to shareholders

Liquids weighted portfolio

Grow production & sustain margins

Returns-driven capital allocation

Lower our cost structure

Get more out of assets

High-grade portfolio

Low
price environment

Competitive dividend growth

Flexible C&E

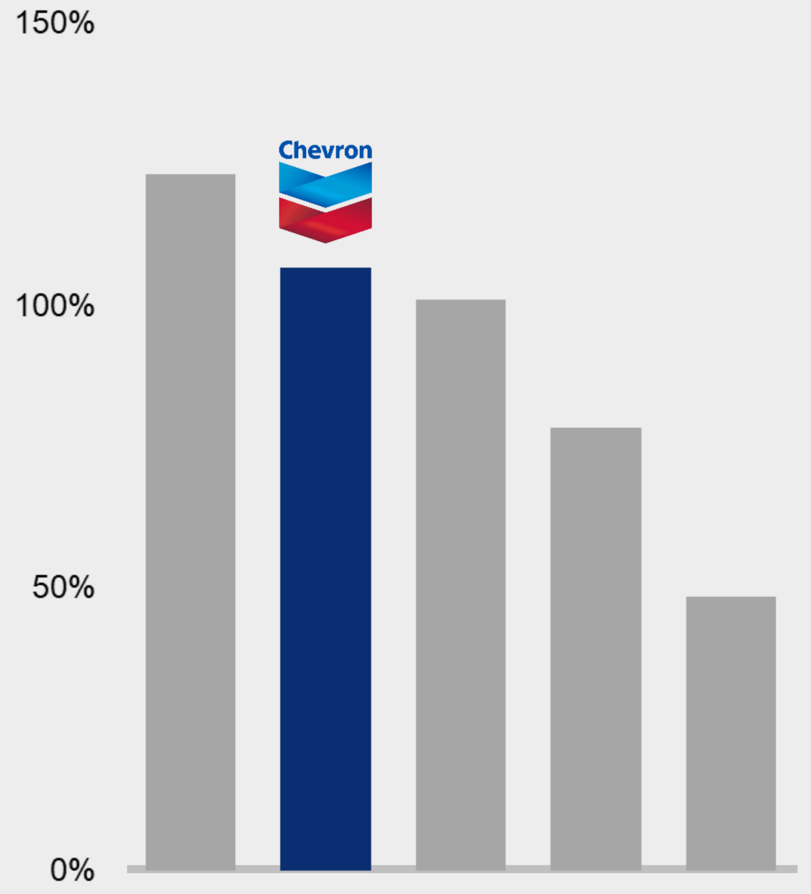
Balance sheet supports cash returns

Low cost of supply

Shareholder returns through the price cycle

Strong reserves replacement

Five-year reserve replacement ratio
2013-2017



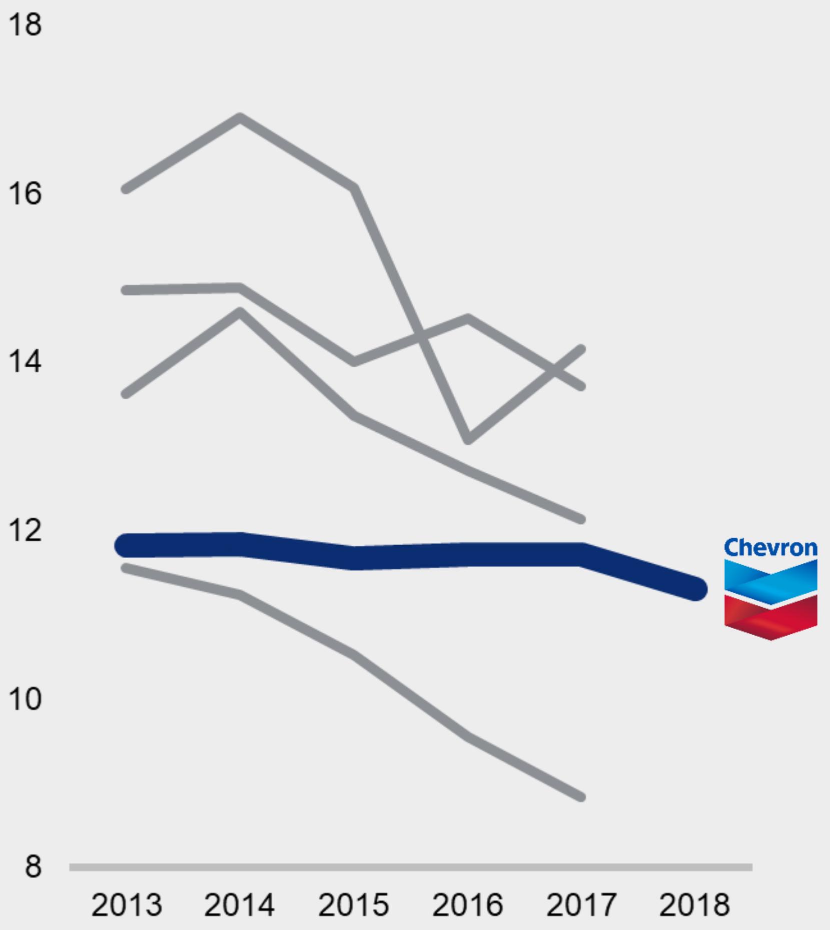
■ Competitors: BP, RDS, TOT, XOM

Source: Public information presented on a consistent basis.

Reserves replacement
through the price cycle

Prudent and stable
reserves to production

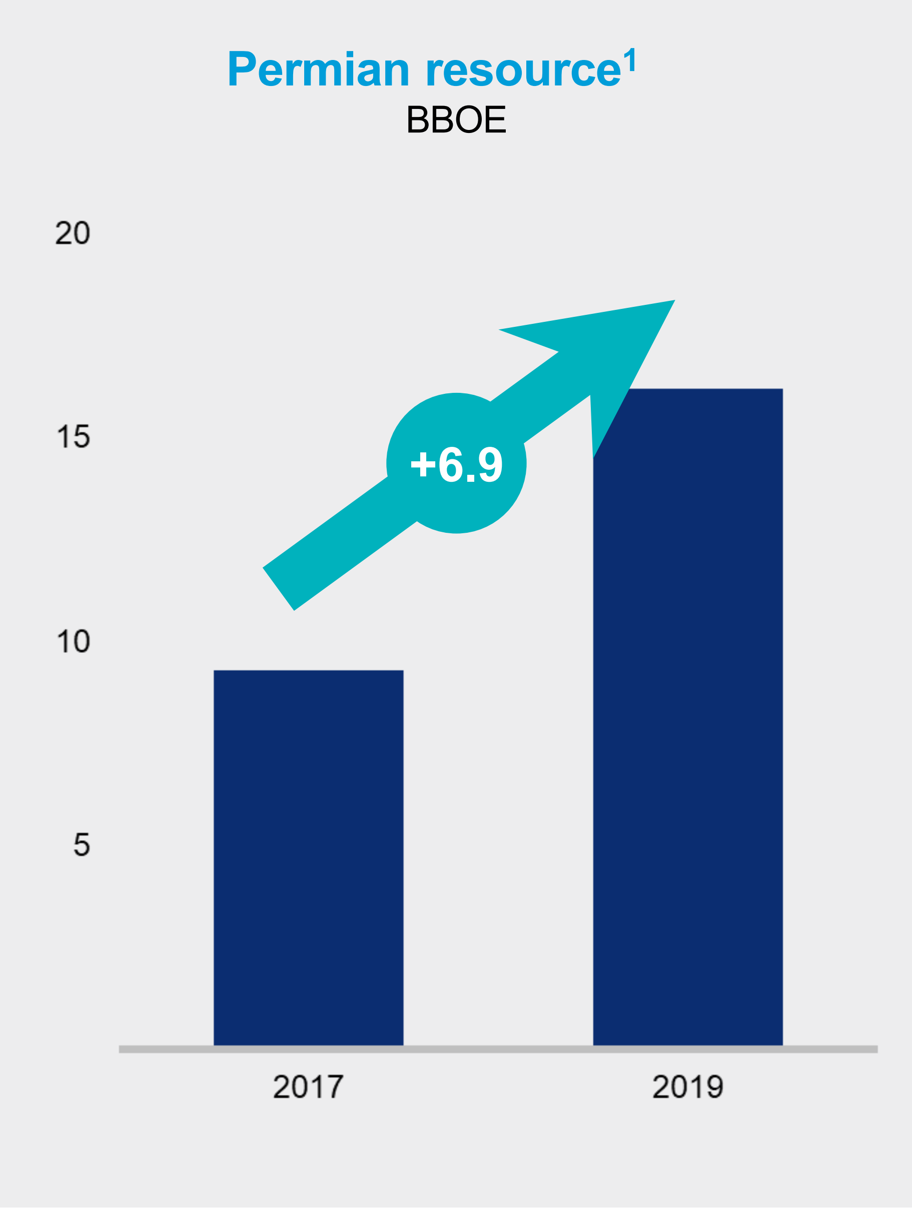
Reserves to production ratio
Years



■ Competitors: BP, RDS, TOT, XOM

Source: Public information presented on a consistent basis and Chevron estimates.

Permian value has more than doubled



Resource 16.2 BBOE

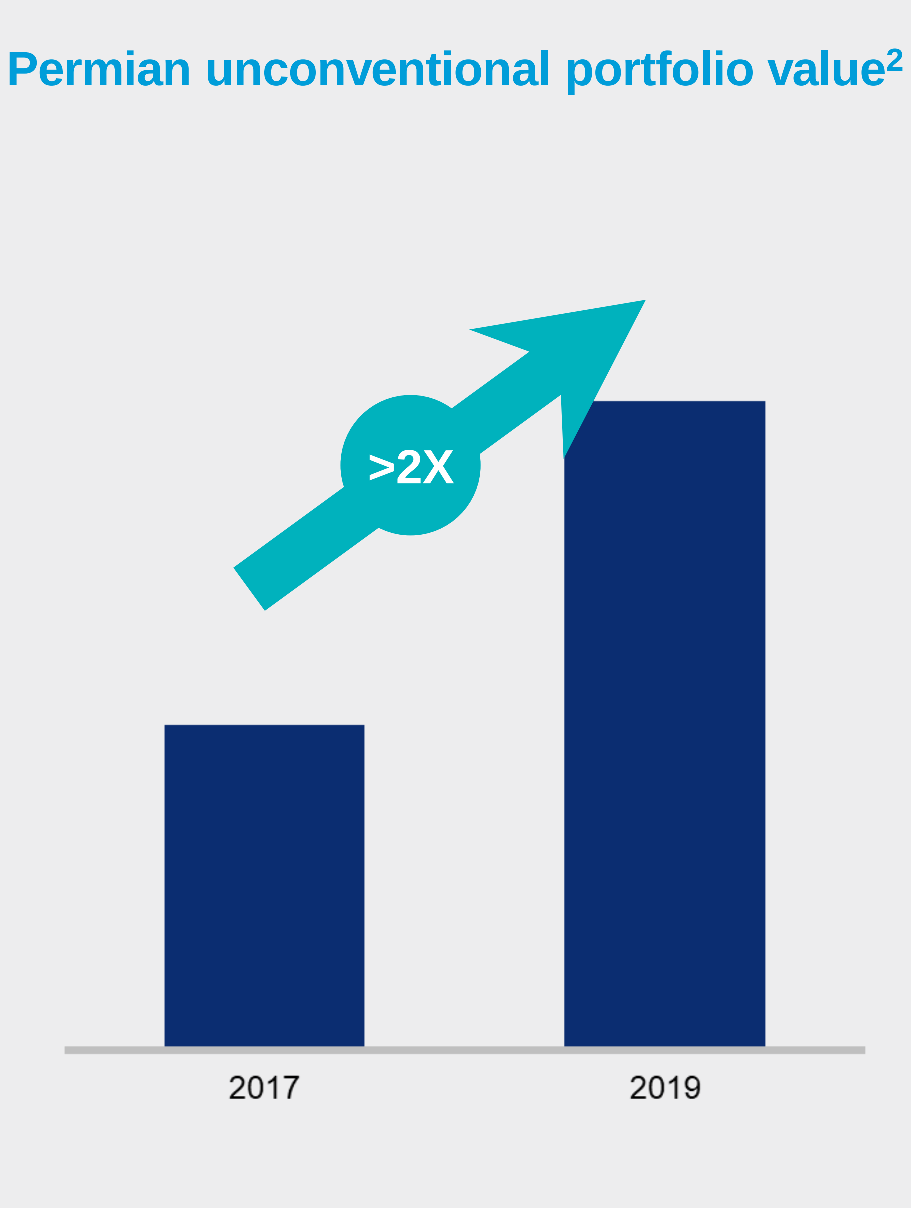
up from 9.3 BBOE

Value drivers

Land optimization

Well performance

Technology

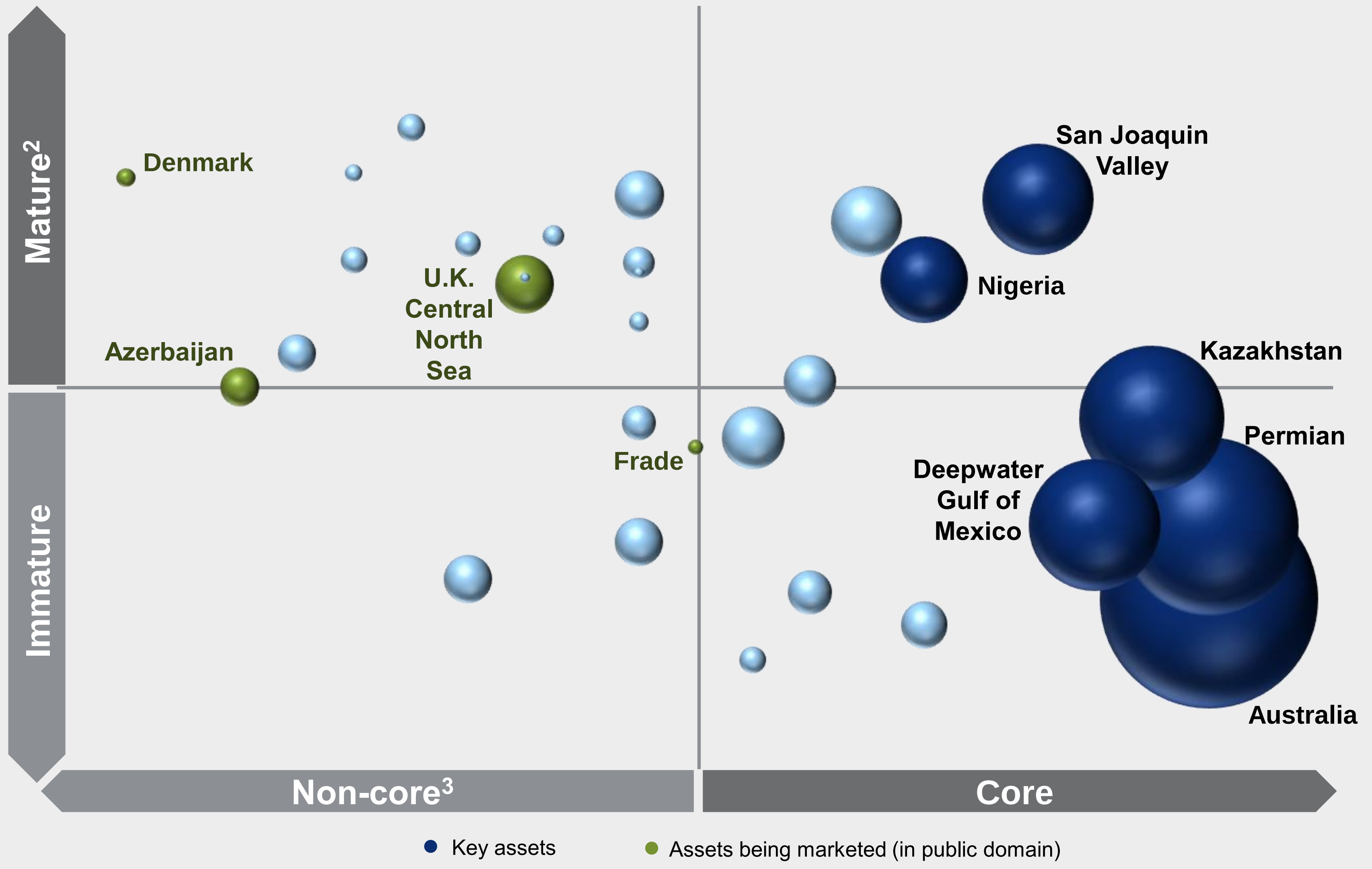


[1] Net unrisked resource as defined in the 2018 Supplement to the Annual Report. "Permian" resource refers to Permian Basin.

[2] Value of portfolio determined using Chevron internal methodology and the same price assumptions for 2017 and 2019.

Portfolio high-grading continues

Upstream assets[1]



Divestment criteria

Strategic alignment

Resource potential

Relative economics

Attractive value

2018-2020 asset sale target

~$5-$10B

~$2B

proceeds in 2018

[1] Wood Mackenzie: Bubble Size - Remaining NPV10. The present value of approximated cash inflows minus outflows discounted using a yearly discount rate of 10%.

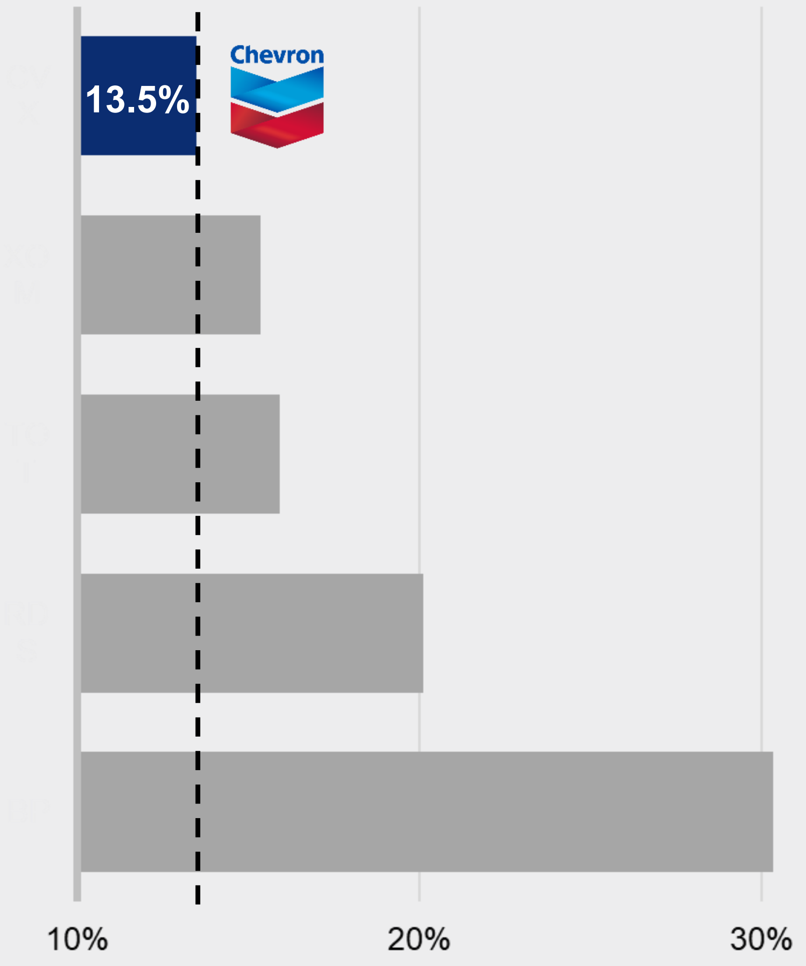
[2] Wood Mackenzie: Immature / Mature – Remaining Reserves / Total Recoverable Reserves. Total Recoverable less Production = Remaining Reserves. Wood Mackenzie then assigns ranking 1 (just discovered) to 20 (~95% produced) to each asset.

[3] Wood Mackenzie: Non-core / Core – Low external activity / upside, announced sale, low remaining NPV, assigned ranking 1-10 and essential to Chevron strategy, external activity / upside potential, high remaining NPV, assigned ranking 10-20.

Best positioned for price uncertainty

Net debt ratio[1]

2018



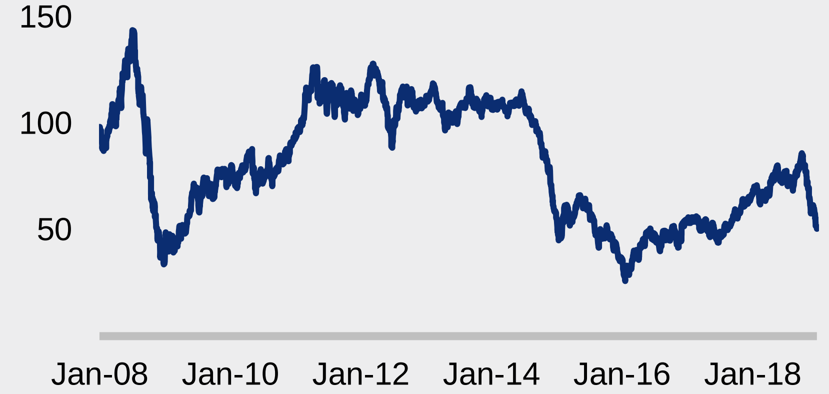
Competitors: BP, RDS, TOT, XOM

Industry-leading
balance sheet

Lowest breakeven

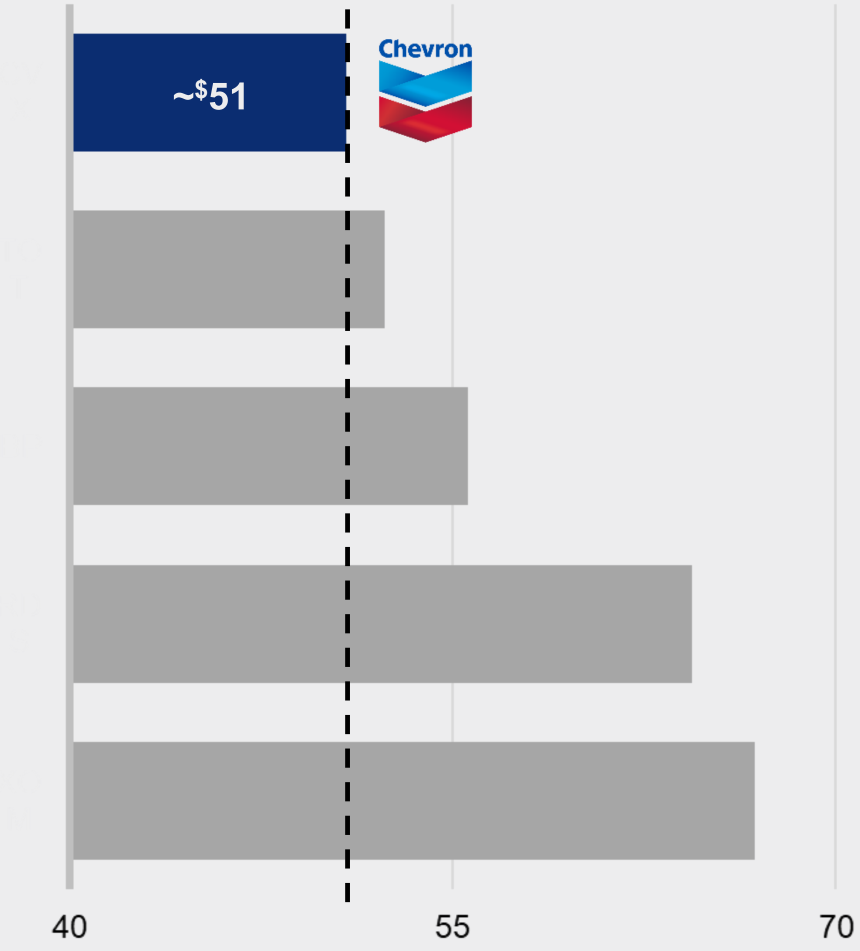
Brent volatility

$/bbl



2019 cash flow breakeven[2]

$/bbl Brent

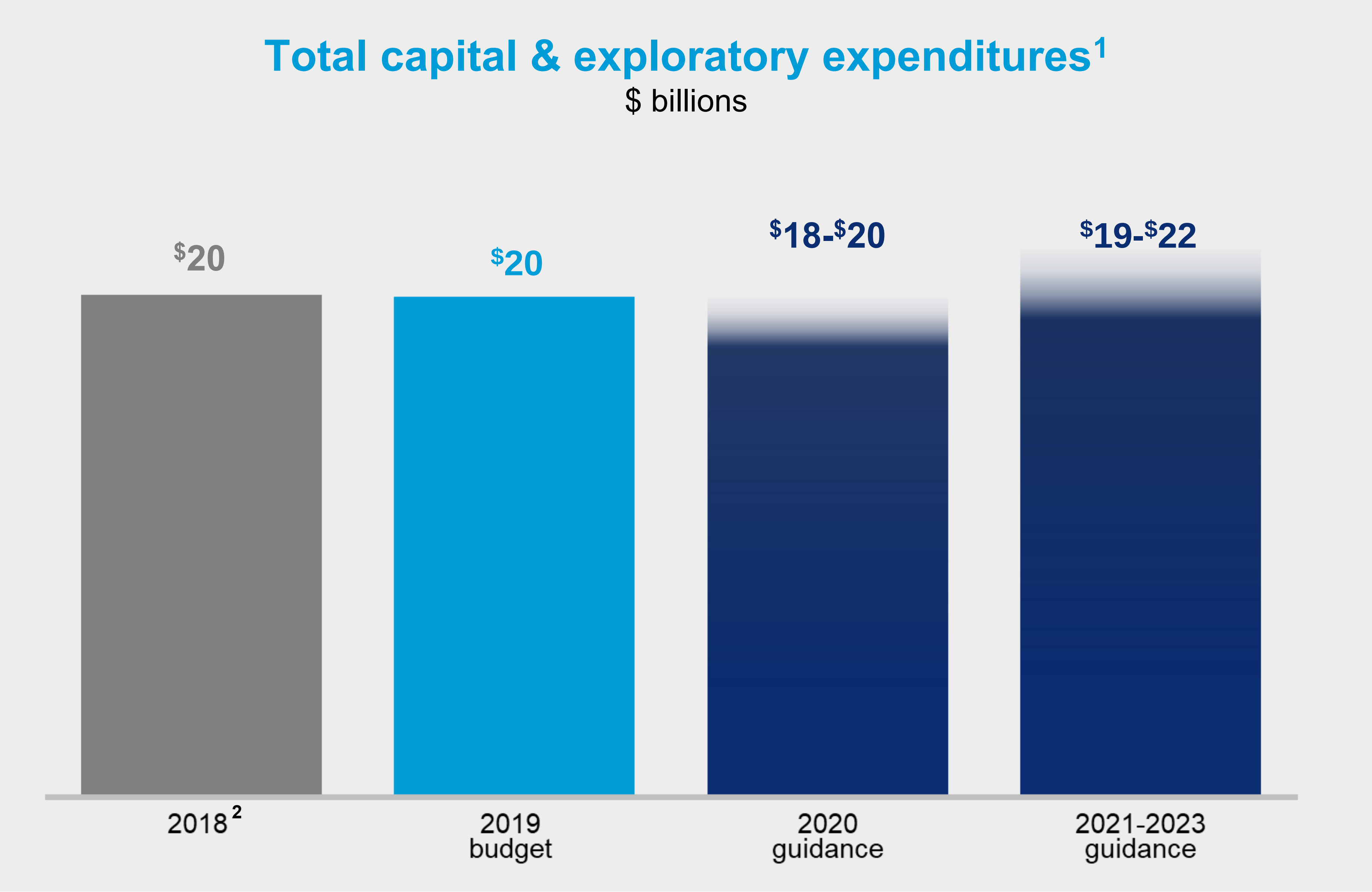


Competitors: BP, RDS, TOT, XOM

[1] As of 12/31/2018. Net debt ratio is defined as debt less cash, cash equivalents, marketable securities and time deposits divided by debt less cash, cash equivalents, marketable securities and time deposits plus stockholders' equity.

[2] Source: Wood Mackenzie Corporate Benchmarking Tool (Q4 2018) – reflects estimate of the Brent oil price required for a company to end a year with the same net-debt position as it started (cash flow neutral). Includes downstream cash flow, full corporate costs and distributions, buybacks, and exceptional items (asset sales, M&A, Macondo cash payments, other).

Disciplined and ratable C&E



Ratable

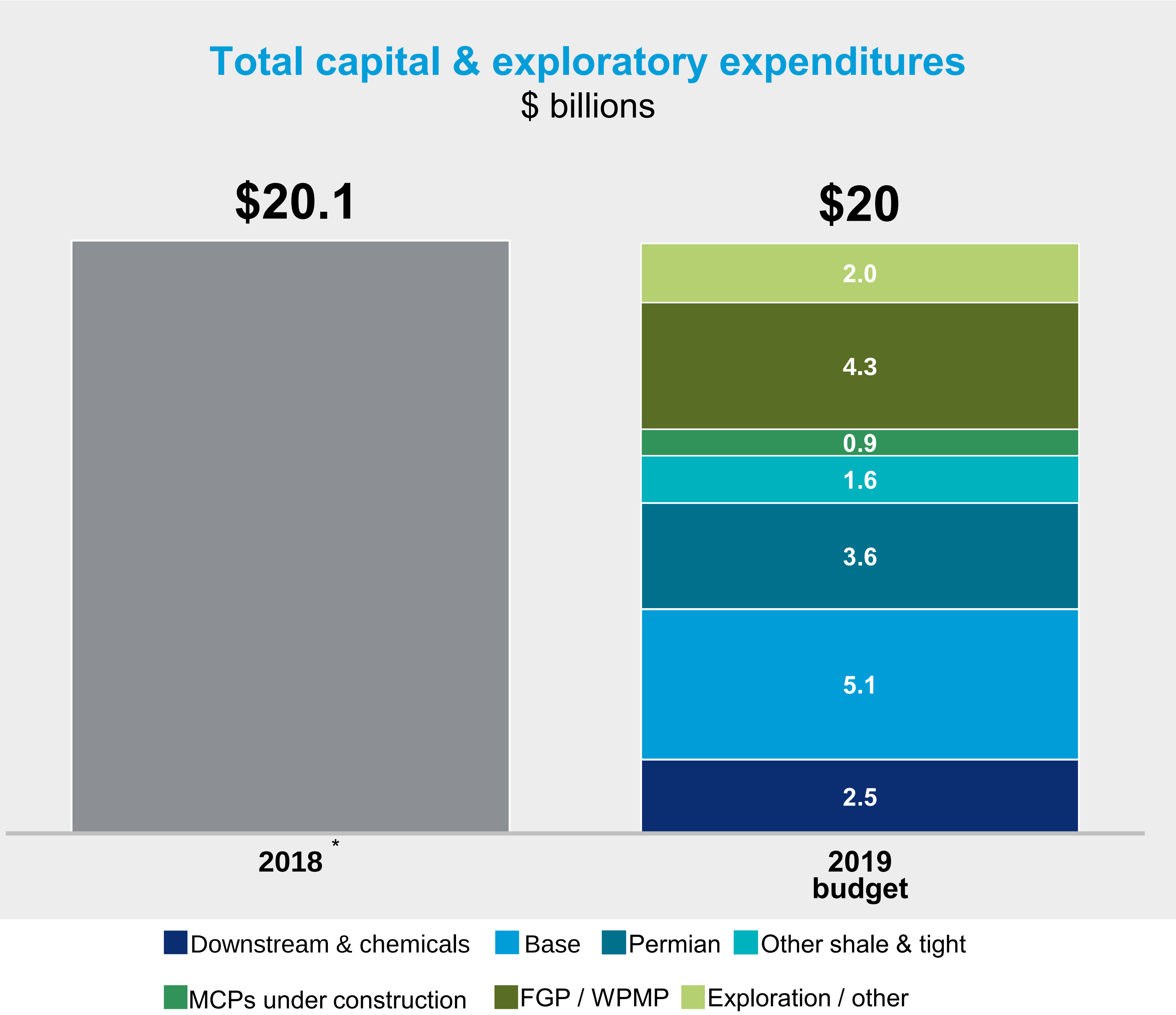
Short-cycle, high return

Low execution risk

~70% of 2019 spend delivers cash flow within 2 years

[1] Assumes average annual $60/bbl Brent, 2019-2023.
[2] Includes ~$0.6B of inorganic spend, which was not budgeted.
Note: $60/bbl Brent is for illustrative purposes only and not necessarily indicative of Chevron's price forecast.

Disciplined C&E program



* Includes ~$0.6B inorganic spend

Flat with 2018

Increases in shale & tight

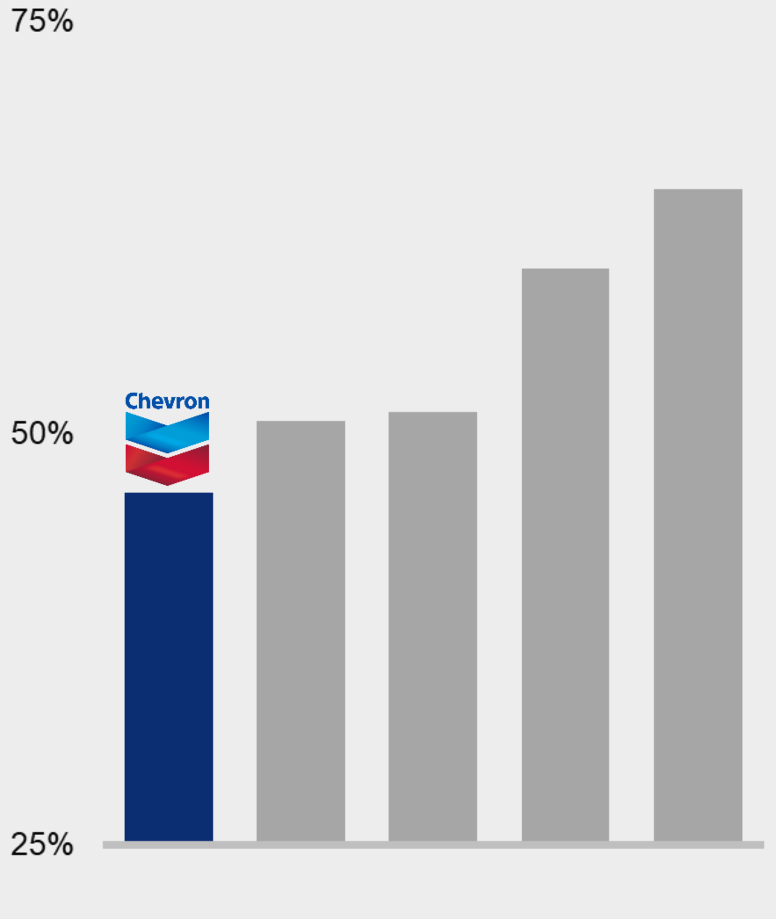
Low execution risk

~70% of spend delivers cash within 2 years

Efficient capital deployment generates superior returns

Cash capex over CFFO[1]

Average % 2018-2021

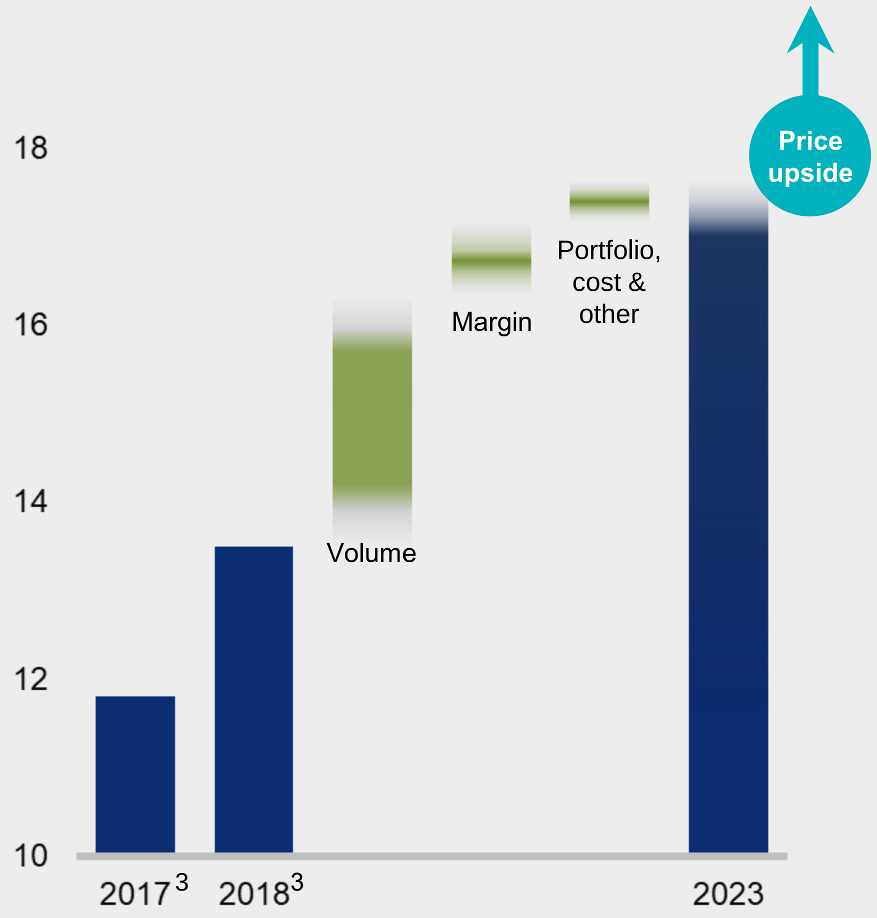


Low capital intensity

Improving returns

CFFO ROCE[2] at $60/bbl

% 2017-2023



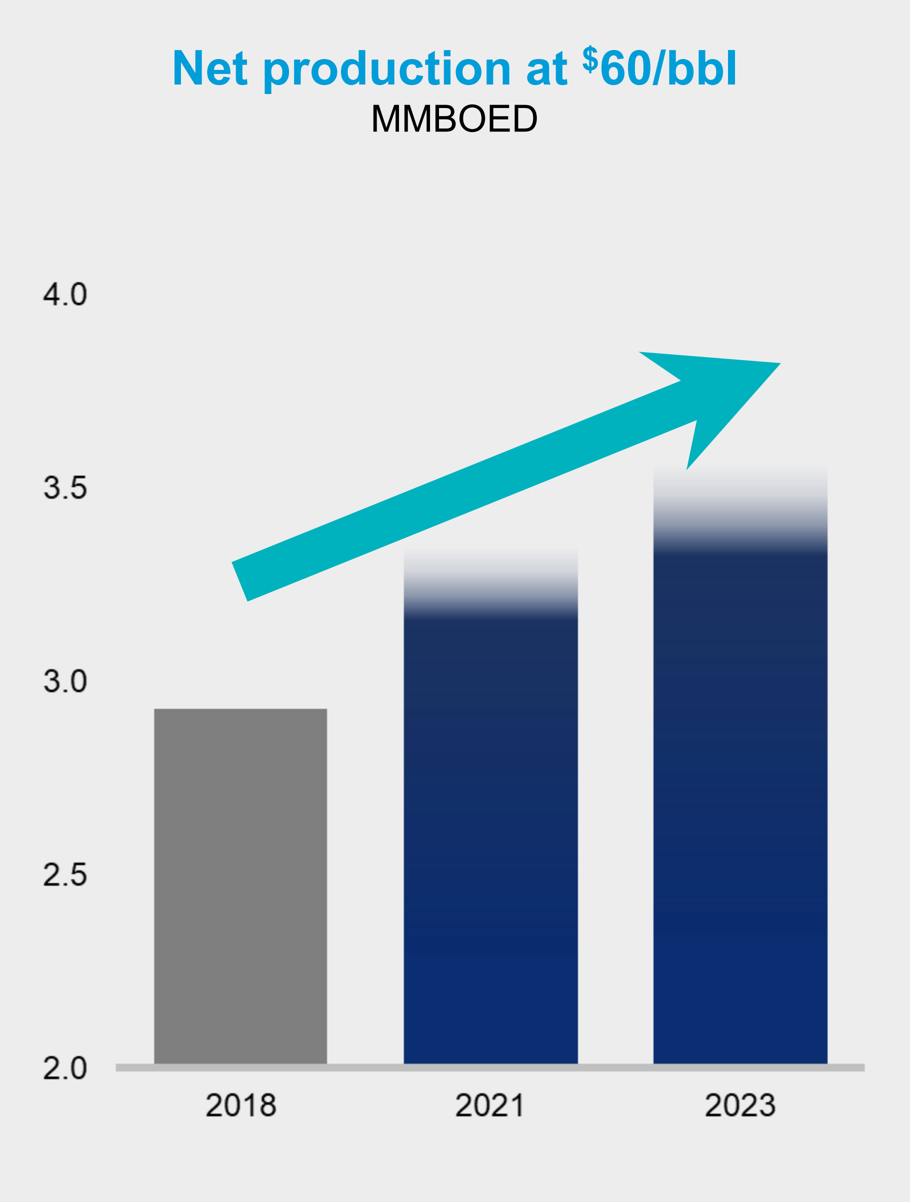
[1] Source: For all companies including CVX is third-party analyst reports (chosen for recent and relevant data): Barclays, Exane BNP Paribas, Goldman Sachs, JPMorgan, and UBS.

[2] Source: Public information and Chevron internal estimates. "CFFO ROCE" is cash flow from operations return on capital employed; this metric is defined as cash generated from operations as a % of average annual capital employed.

[3] 2017 - 2018 cash flow from operations is normalized to $60/bbl, assuming historical sensitivity of $350MM cash flow impact per $1/bbl change in Brent price for 2017 and $450MM cash flow impact per $1/bbl change in Brent price for 2018.

Note: $60/bbl Brent is for illustrative purposes only and not necessarily indicative of Chevron's price forecast.

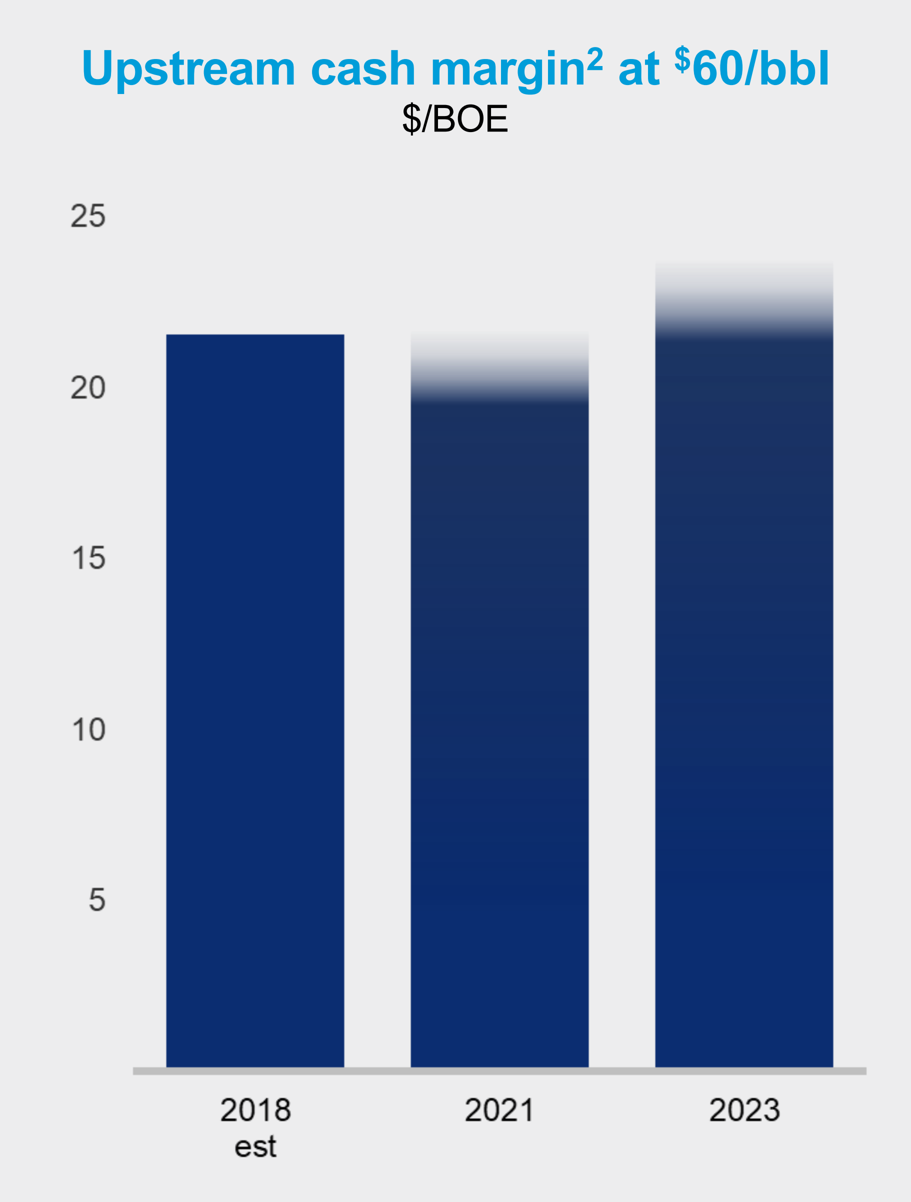
Growing upstream cash generation



Production growth

5-year: 3-4% CAGR[1]

Sustained cash margins

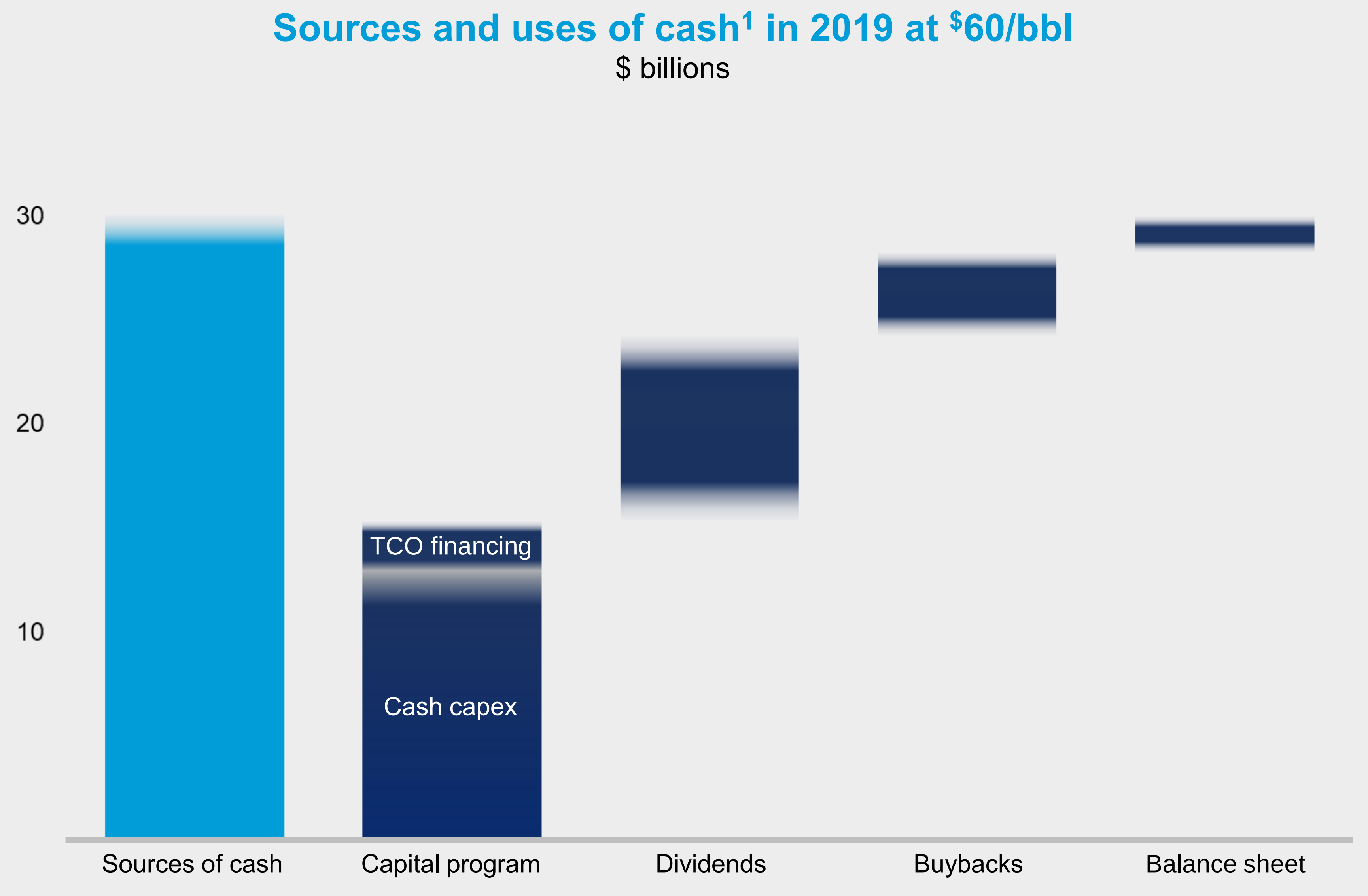


[1] 3-4% CAGR reflects 2018-2023. Includes the effect of expected asset sales in the public domain. Range factors: PZ and Venezuela, asset sales, other
Note: $60/bbl Brent is for illustrative purposes only and not necessarily indicative of Chevron's price forecast.

[2] Upstream cash margin is an operating measure. Estimated after-tax upstream cash flow from operations margin based on Chevron's internal analysis. 2018 cash flow from operations is normalized to $60/bbl, assuming historical sensitivity of $450MM cash flow impact per $1/bbl change in Brent price.

Chevron

2019 cash generation covers all financial priorities



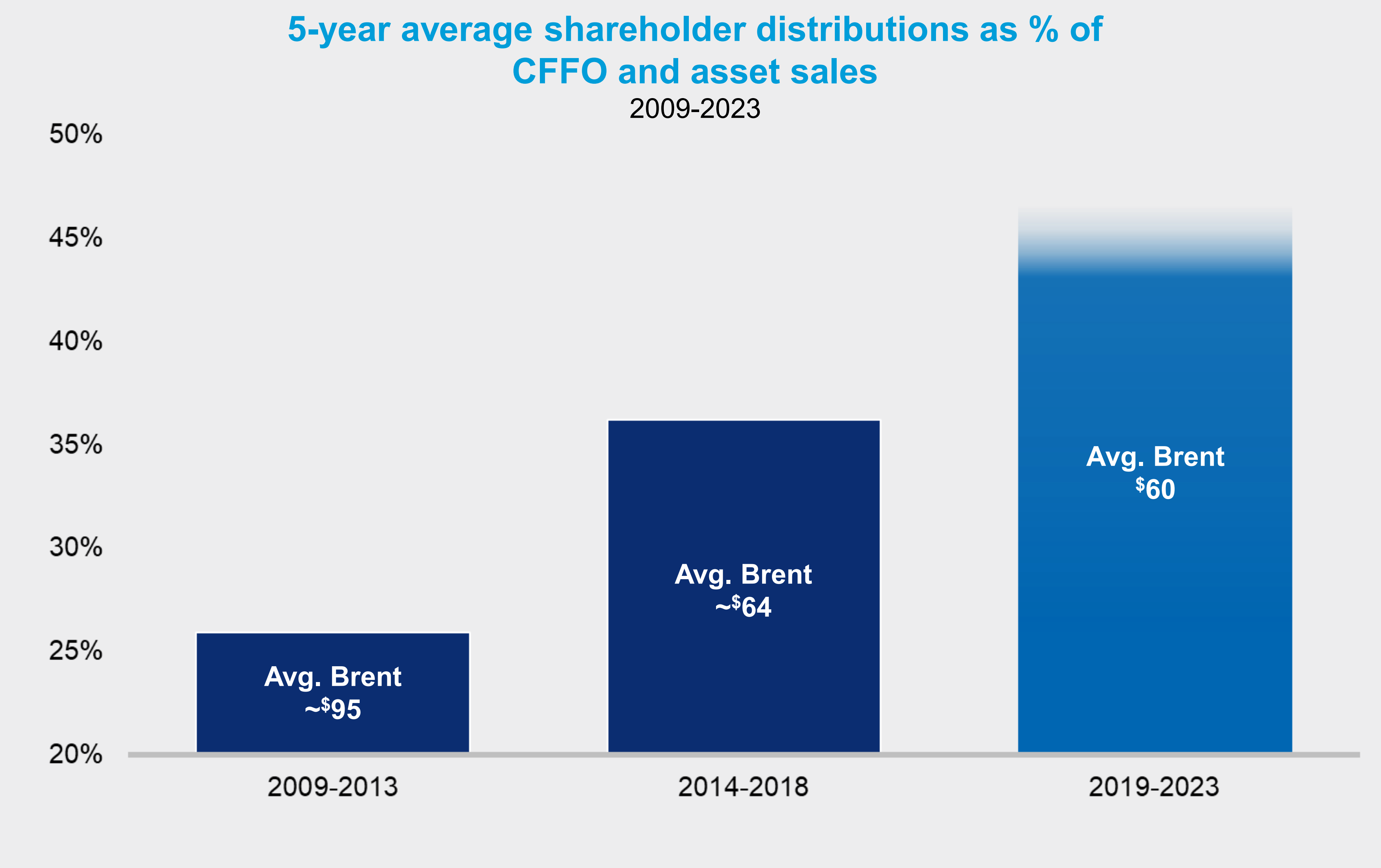
Cash framework
balanced at <$60/bbl

Cover **cash capex and dividends at ~$52/bbl[2]**

$4B share repurchases

[1] Includes cash flow from operations, proceeds from asset sales, and other.
[2] Uses only CFFO as basis for breakeven calculation.
Note: $60/bbl Brent is for illustrative purposes only and not necessarily indicative of Chevron's price forecast.

Returning more cash to shareholders



Returning
higher percentage of cash flow to shareholders

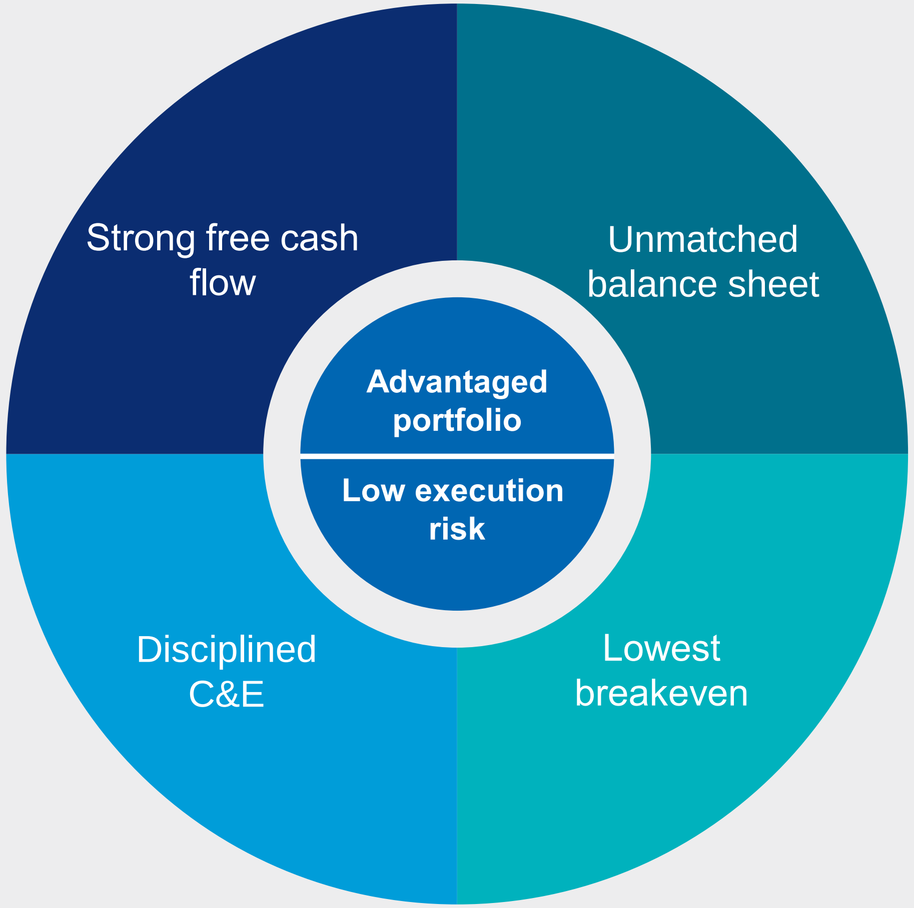
Note: $60/bbl Brent is for illustrative purposes only and not necessarily indicative of Chevron's price forecast.

Chevron offers a winning value proposition

Disciplined financial priorities

- Maintain and grow dividend
- Fund capital program
- Strong balance sheet
- Return surplus cash

Competitive advantage



Shareholder returns

>6% dividend increase in 1Q 2019

+

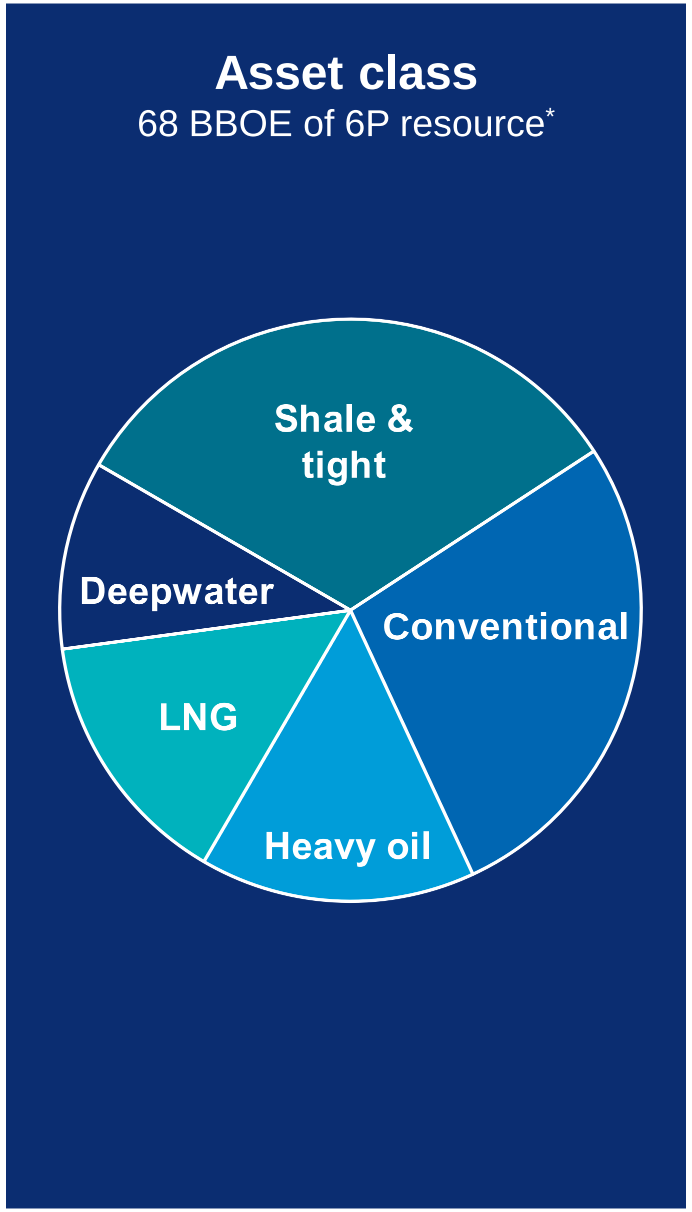
$4B share buybacks in 2019

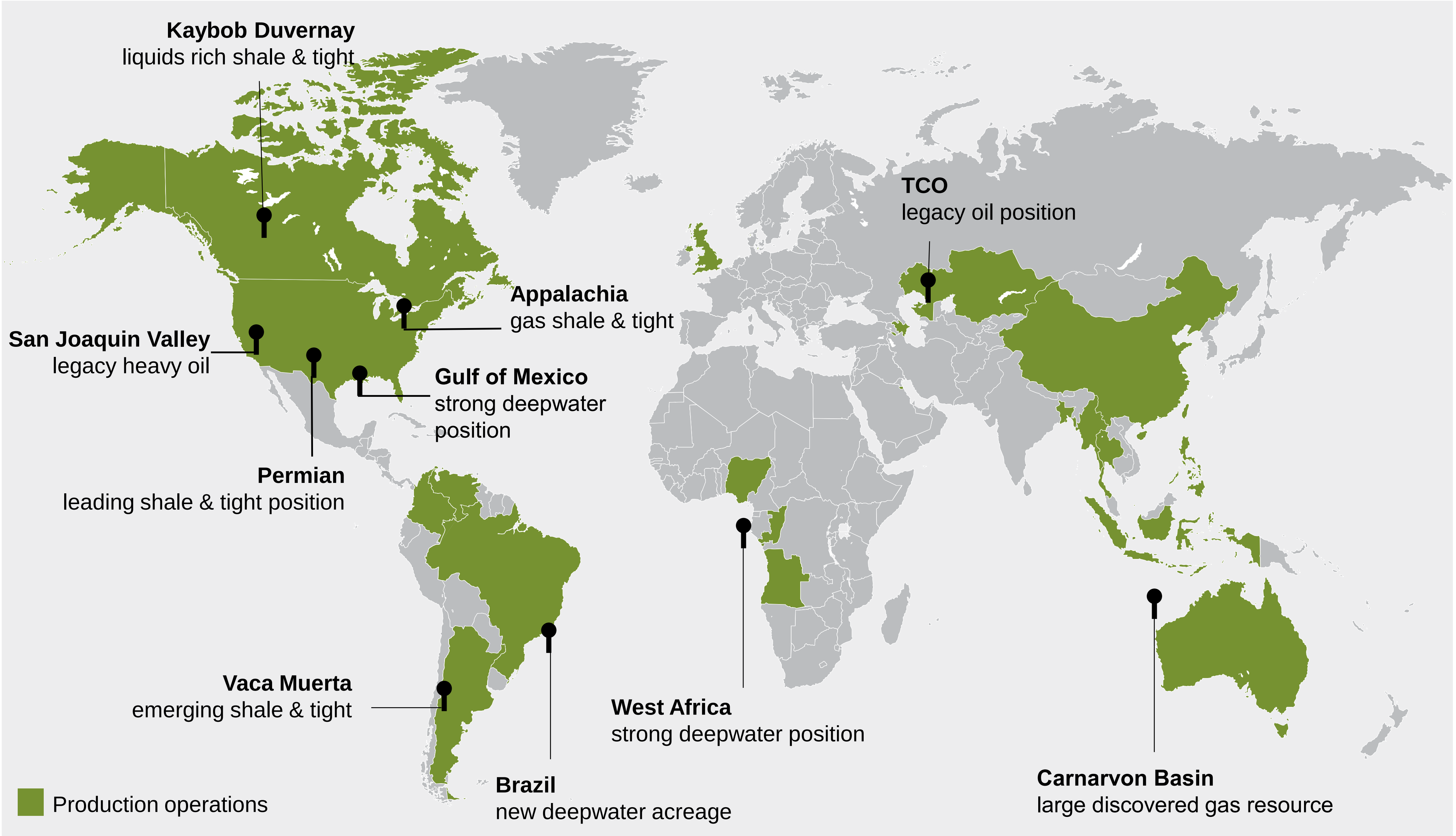
Total shareholder yield of ~6% in 2019*

* Total shareholder yield calculated as total dividend + buyback payments divided by market capitalization. Share price assumed in calculation is not necessarily indicative of Chevron's share price forecast.

Upstream overview

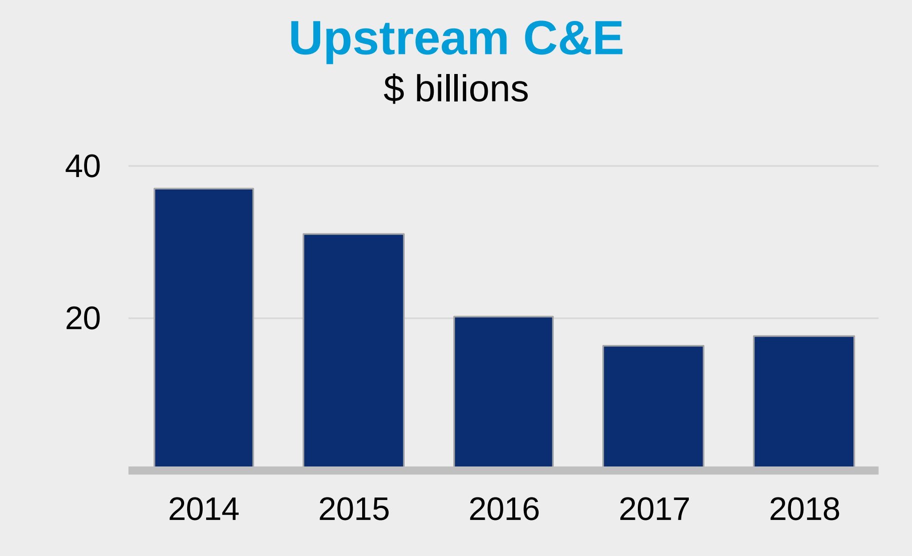
Diverse and advantaged portfolio

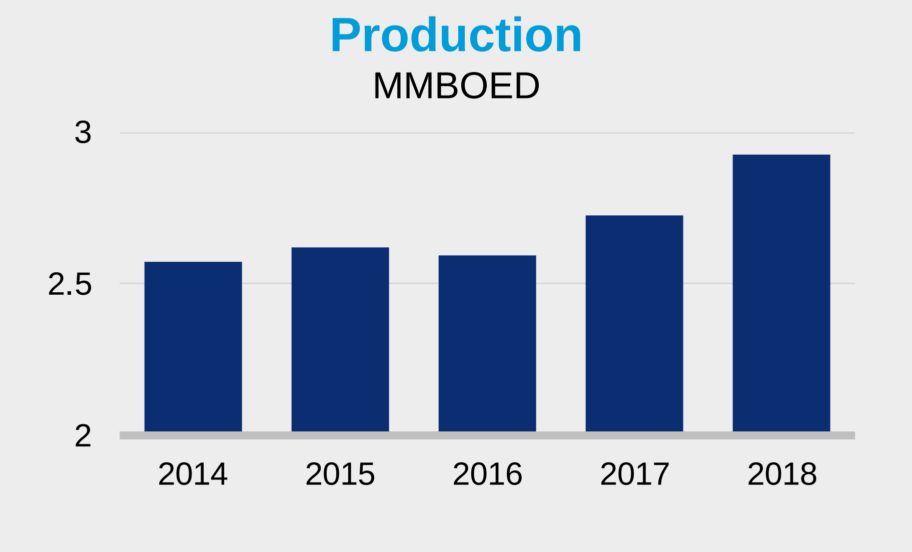




* 2018 net unrisked resource as defined in the 2018 Supplement to the Annual Report.

Industry leading performance

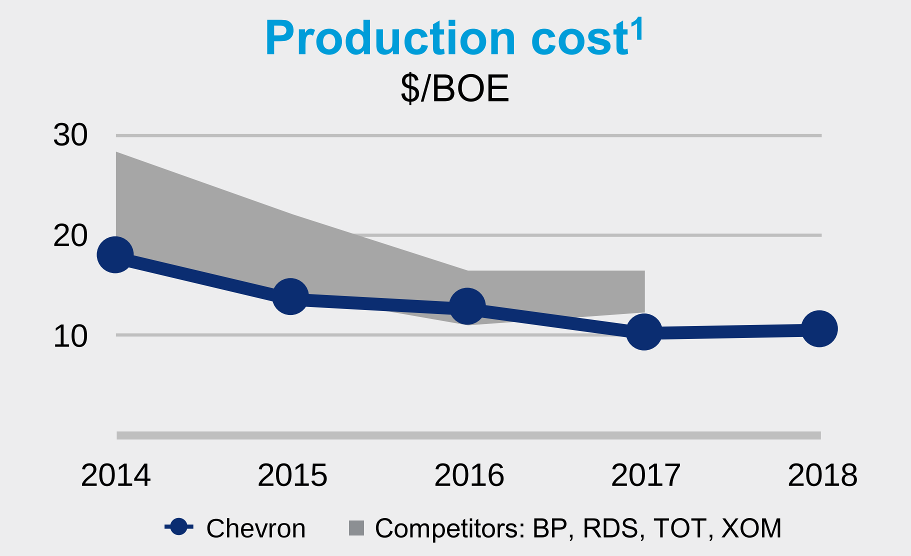


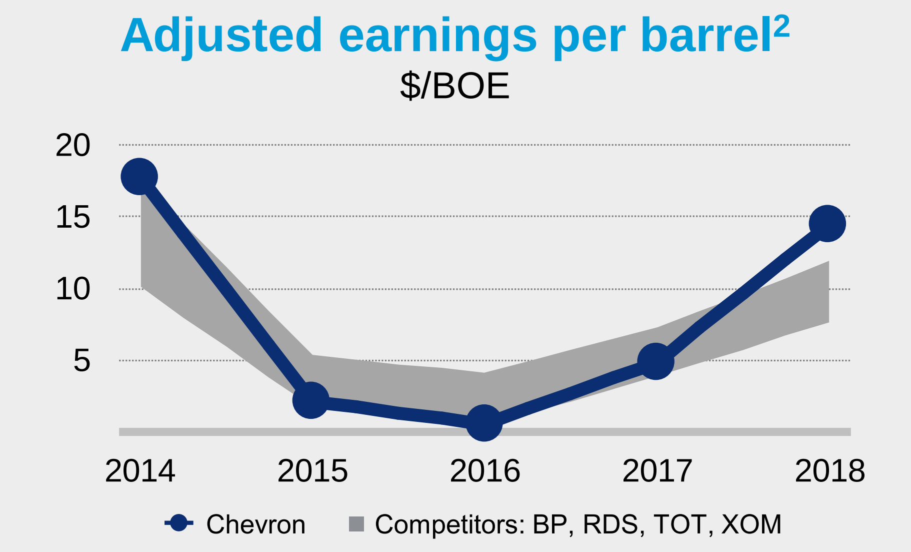


Capital discipline

Growing production

Industry leading results





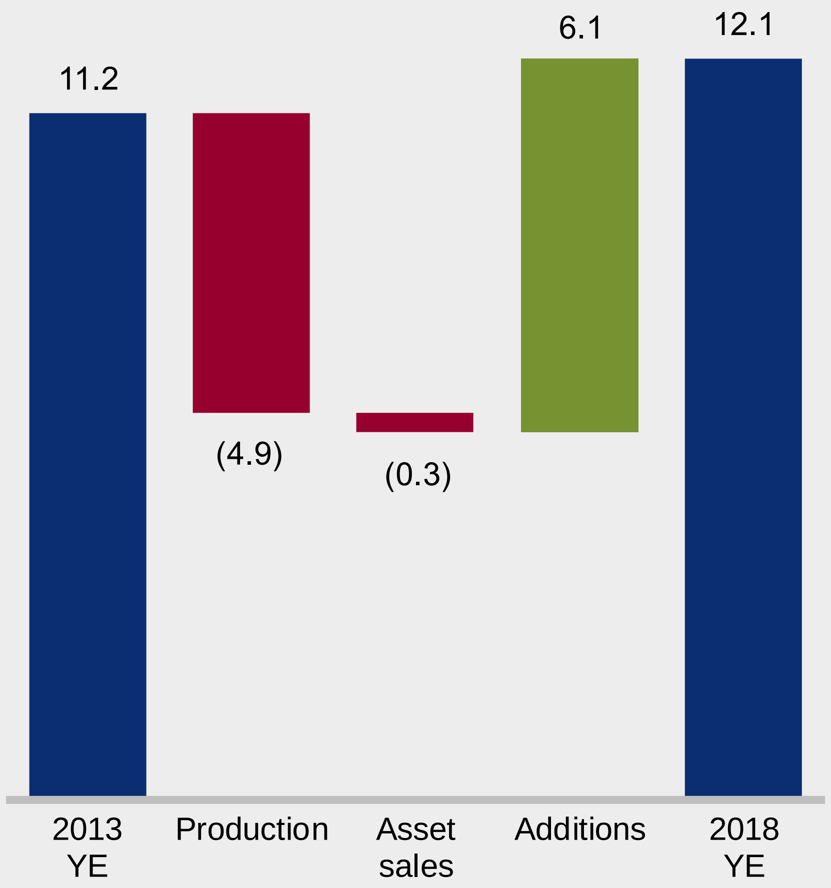
[1] Production costs per barrel sourced from Supplemental Information on Oil and Gas Producing Activities in Form 10-K, 20-F. Includes production expense, non-income taxes, and other income/expense. Excludes asset sales gains, LNG liquefaction, transportation and other non-oil & gas activities reported under the upstream segment. Includes affiliates.

[2] Source: Public information presented on a consistent basis and Chevron estimates. Excludes special items. See Appendix: reconciliation of non-GAAP measures.

Growing reserves and resources

Reserves[1]

5-year reserve replacement
BBOE



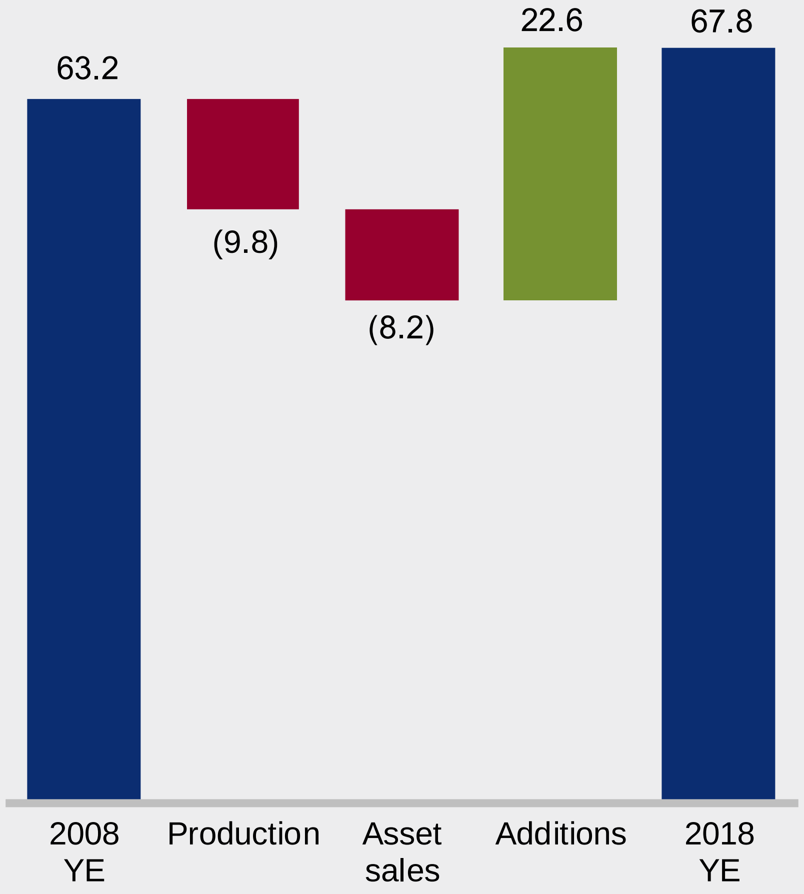
136% RRR
in 2018

117% RRR
five-year

147% resource replenishment
ten-year

Resources[2]

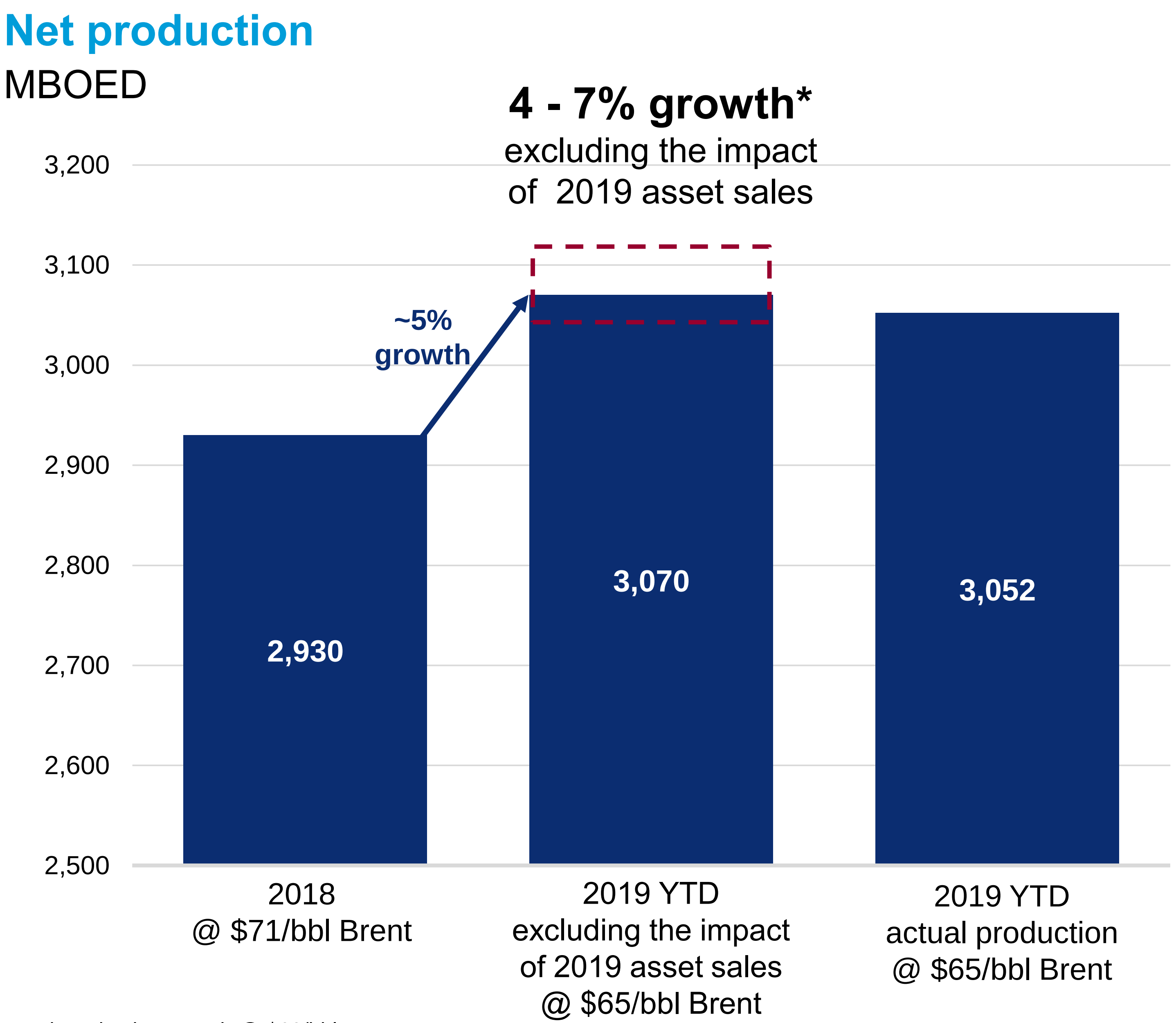
10-year resource replenishment
BBOE



[1] Net proved reserves as defined in the 2018 Supplement to the Annual Report.

[2] Net unrisked resource as defined in the 2018 Supplement to the Annual Report.

Worldwide net oil & gas production
In line with guidance



3Q production 3,033 MBOED
- Turnarounds (129) MBOED
- Asset sales (27) MBOED

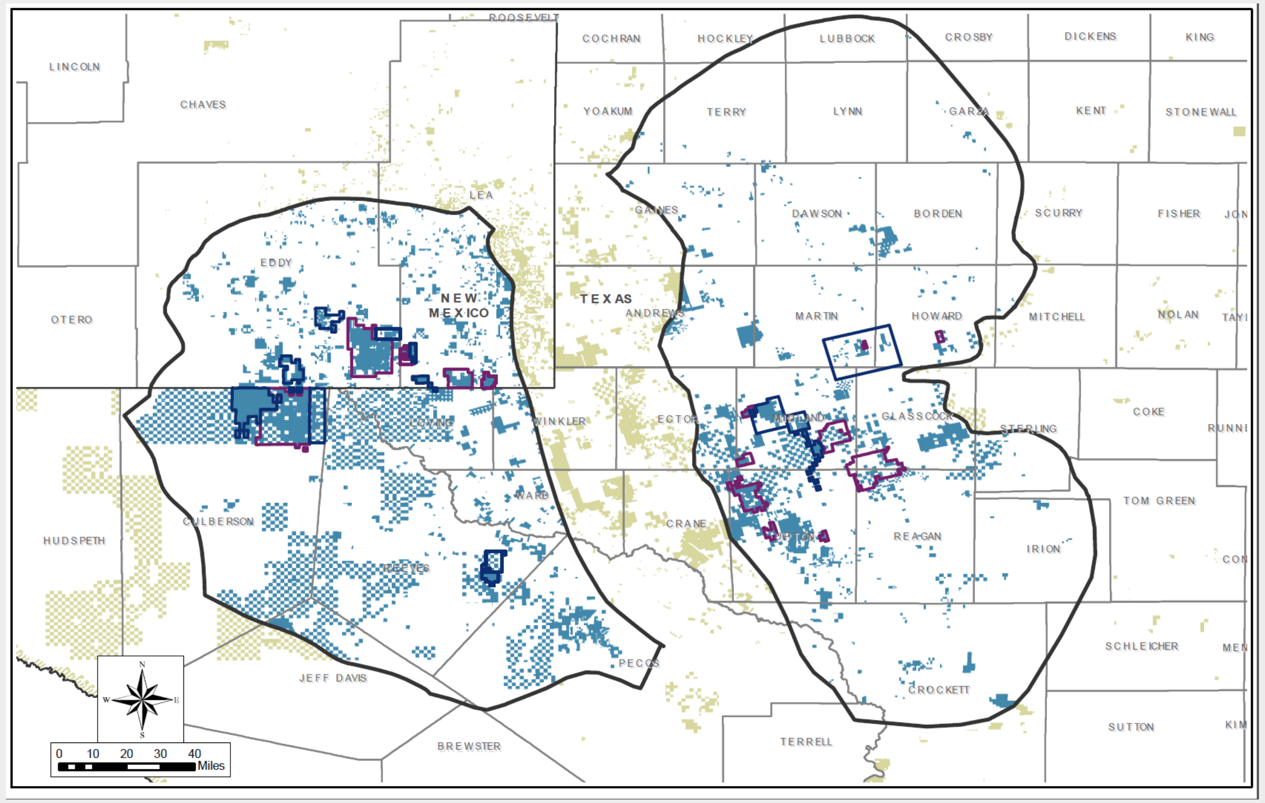
4Q growth drivers:
- Permian
- Other shale & tight
- Hebron ramp-up

* Estimated production growth @ $60/bbl Brent.

Permian…bigger resource, better value

Quality position

2.2 million total net acres / 1.7 million unconventional net acres[1]
>80% no or low royalty



Chevron acreage
Chevron operated development
Chevron non-operated development

Portfolio value increased >2X[2]
since 2017

Resource increased ~5 BBOE[3]
in 2018

1,600 additional long laterals
from 2017-2018 acreage transactions

Continuing to core-up
development areas

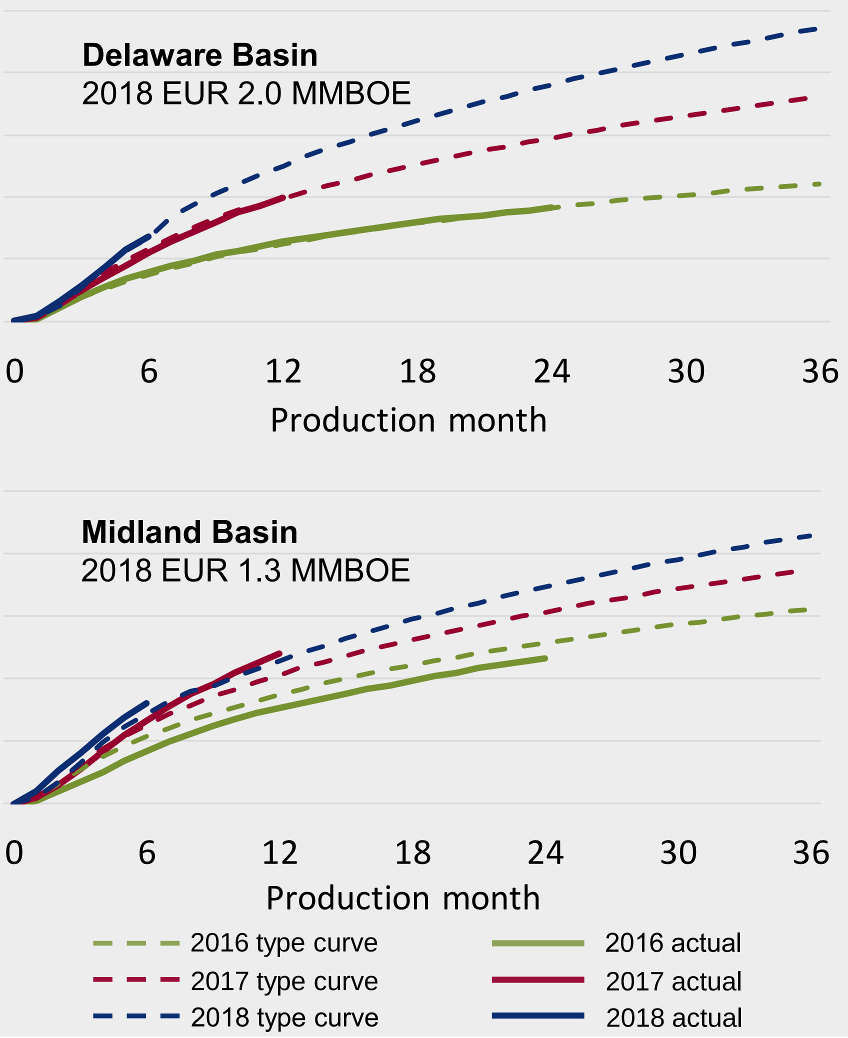
[1] Net acres are net mineral acres.

[2] Portfolio value: Value of portfolio determined using Chevron internal methodology and the same price assumptions for 2017 and 2019.
[3] Net unrisked resource as defined in the 2018 Supplement to the Annual Report.

Driving value in the Permian

Production versus type curves[1]

Average well cumulative production



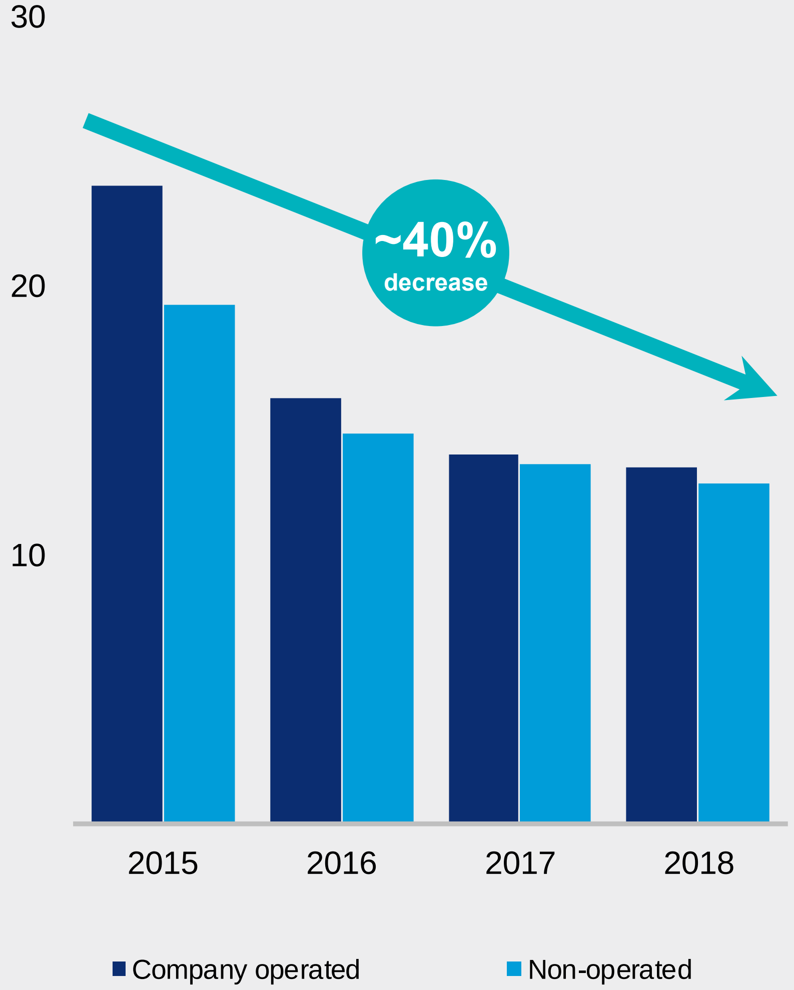
Well performance
increasing & predictable

Unit costs
decreasing

Continuing to
innovate and adopt best practices

Development & production costs[2]

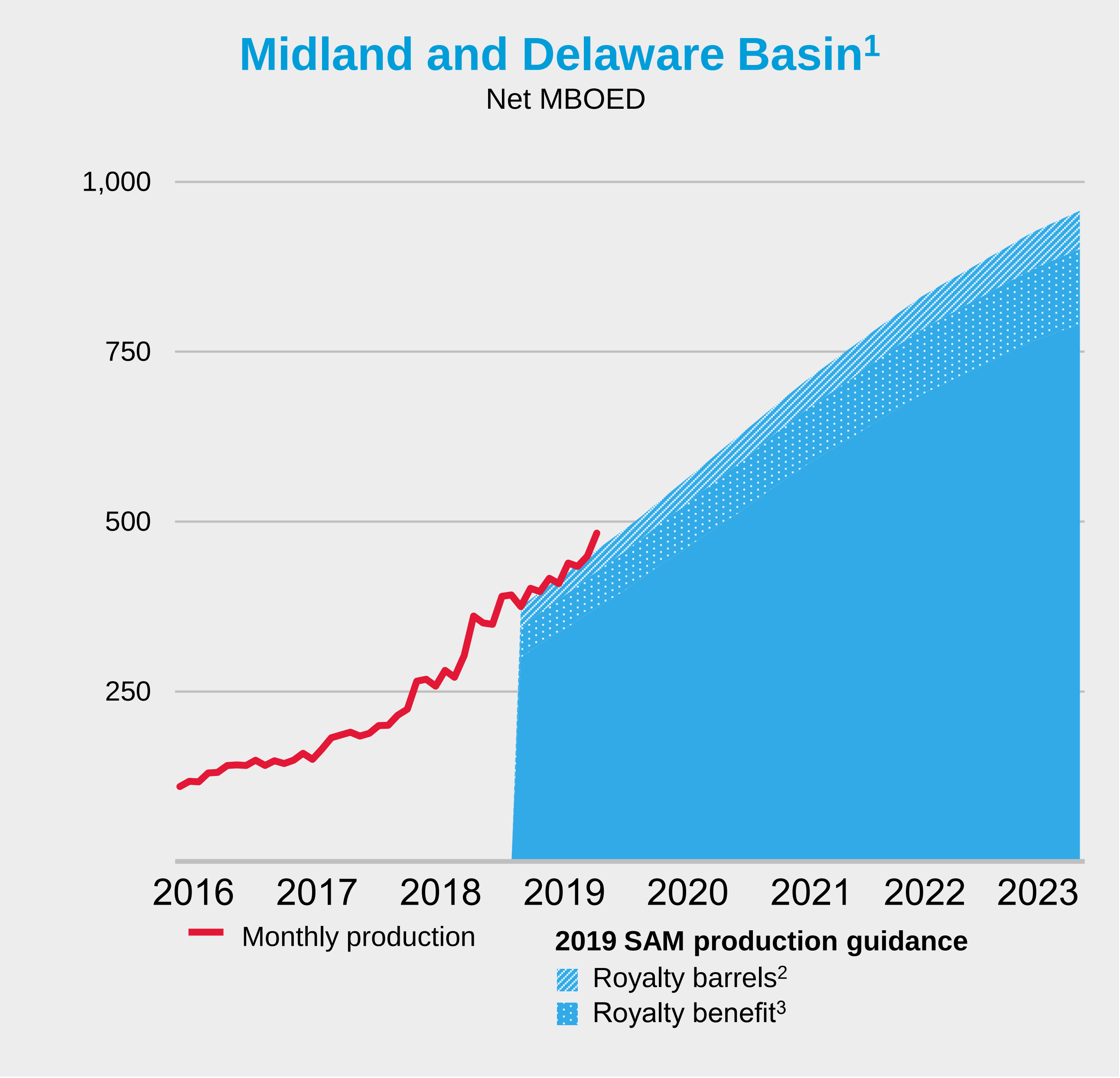
$/BOE



[1] Production curves represent the cumulative average actual well production for all Chevron wells put on production during the year. Type curves represent the expected value cumulative production forecast for all wells completed in a given basin in a given year.

[2] 2015-2018 total costs per BOE are calculated as the sum of actual operating costs per BOE produced plus development costs per BOE expected ultimate recovery (EUR) for wells put on production 2015-2018. Development costs are $/BOE, gross capital excluding G&A and gross three-stream expected ultimate recovery (EUR) BOE. Operating costs are $/BOE, net operating costs and net 3-stream production. Three-stream production refers to oil/condensate, dry gas, and NGL production.

Permian production
On track with steady rig count

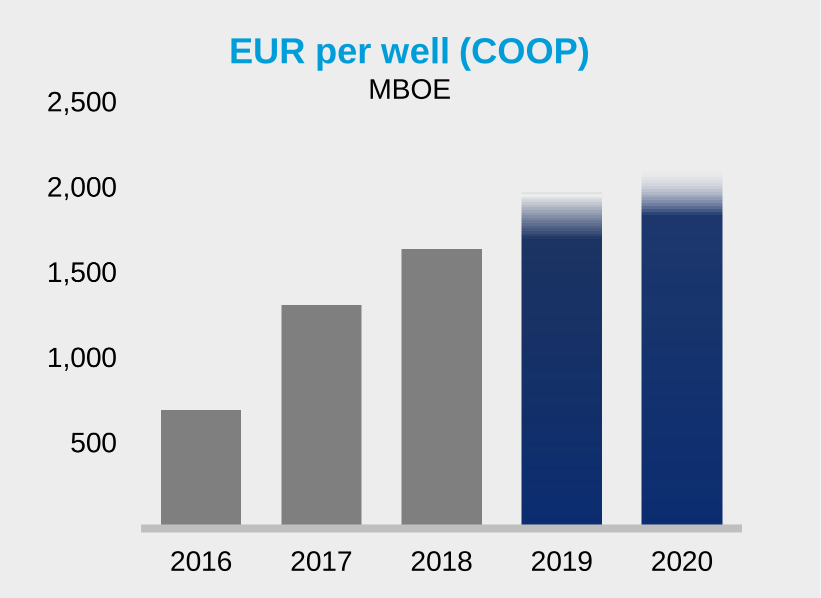


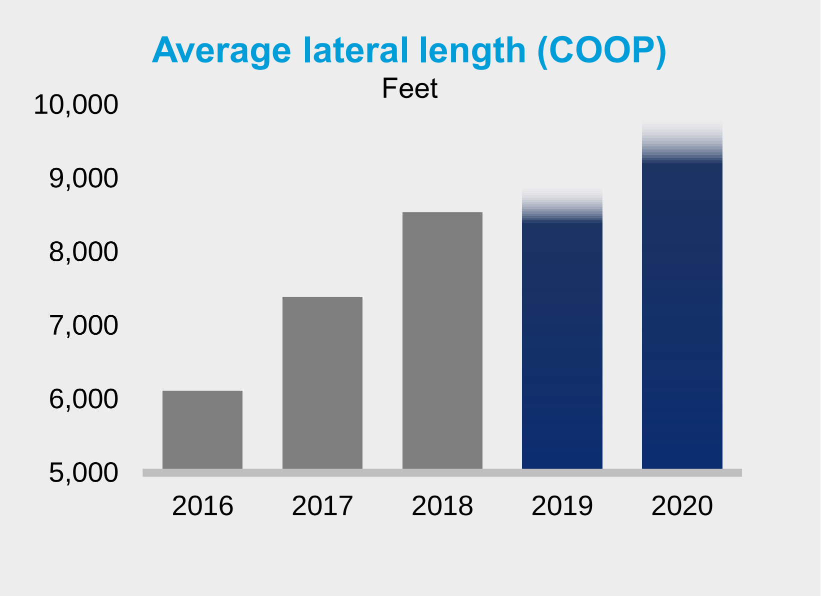
3Q production 455 MBOED up 117 MBOED from 3Q 2018

[1] Midland and Delaware Basin production reflects shale & tight production only.
[2] Royalty barrels are received by Chevron from owned acreage that has been leased to others and requires no capital investment.
[3] Royalty benefit calculation based on Chevron's lower effective royalty rate versus an assumed royalty rate of 25%.

Optimizing the Permian factory

Capital efficient execution



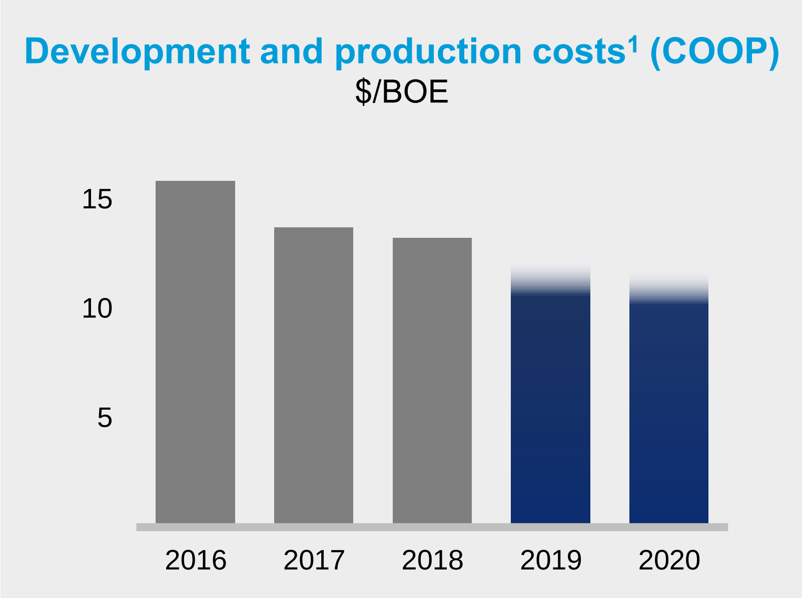


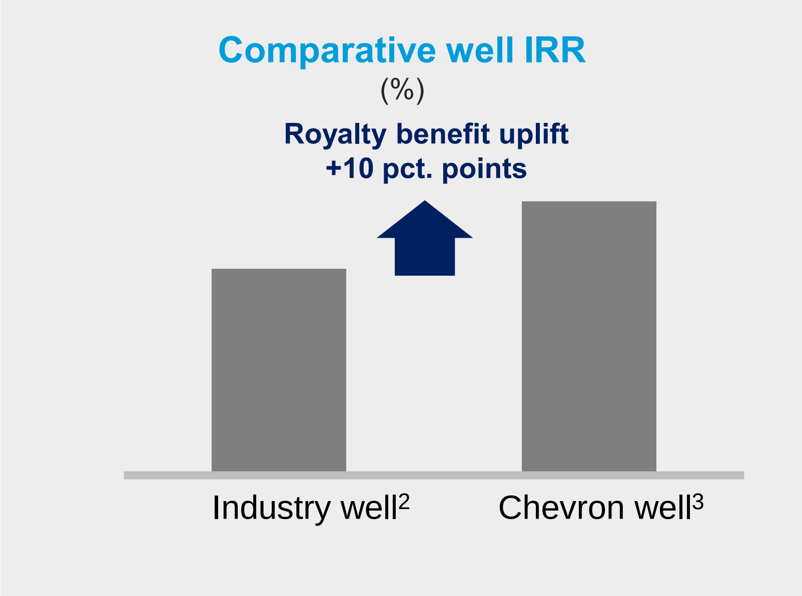
Enhancing EURs

Coring-up to lengthen laterals

Improving unit costs

Increasing returns through royalty benefit





[1] 2016-2020 total costs per BOE are calculated as the sum of operating costs per BOE produced plus development costs per BOE expected ultimate recovery (EUR) for wells put on production 2016-2020. Development costs are $/BOE, gross capital excluding G&A and gross three-stream EUR BOE. Operating costs are $/BOE, net operating costs and net three-stream production. Three-stream production refers to oil/condensate, dry gas, and NGL production.

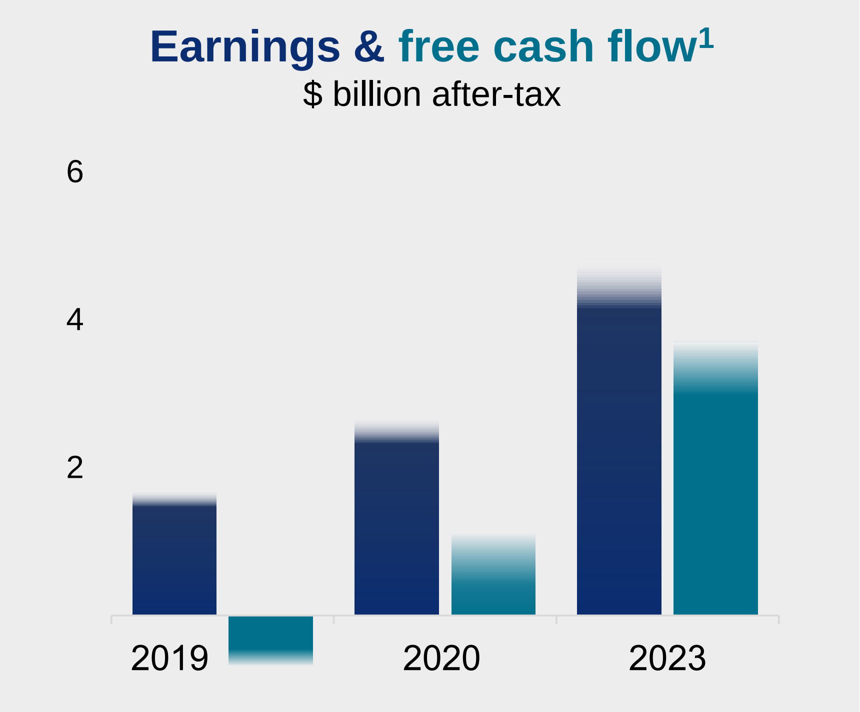
[2] Calculation assumes same type curve, development cost and ~25% royalty burden. Assumes no lease bonus cost.

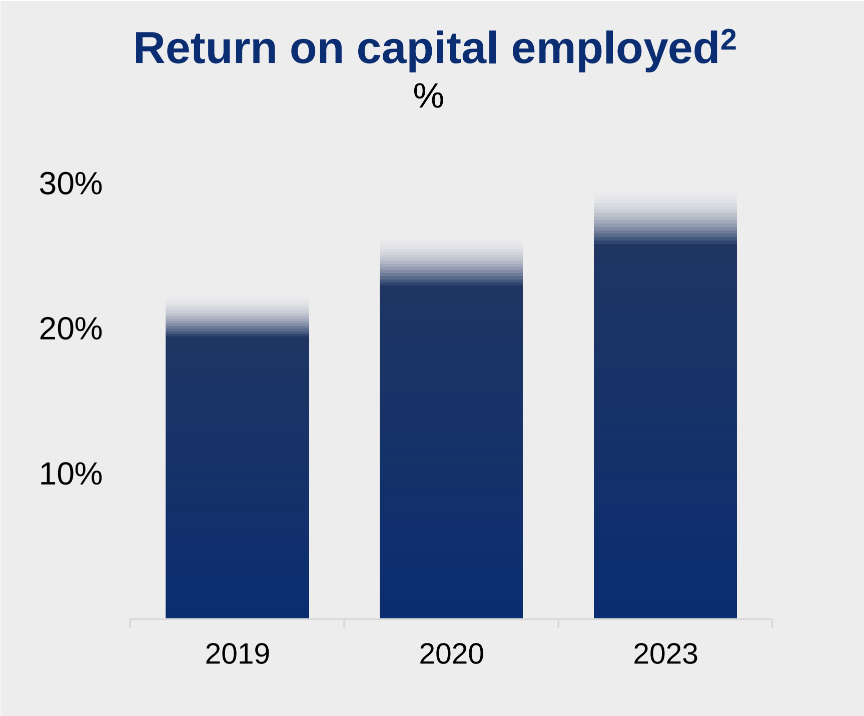
[3] Calculation assumes ~12.5% royalty burden.

Note: All data on this slide is based on Chevron actuals and Chevron outlook estimates.

Strong Permian financial performance

Building a high-return business while growing free cash flow





Free cash flow positive next year

Sustained CFFO ~2x C&E

Strong and growing returns

All results are normalized to 2019 Security Analyst Meeting (SAM) prices.

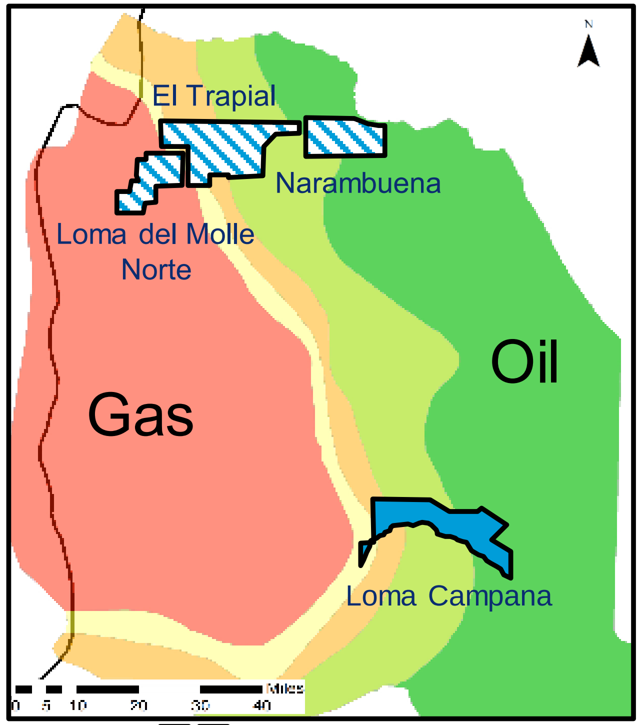
[1] Free cash flow is defined as estimated cash flow from operations less cash capital expenditures.
[2] Capital employed calculation is based on PP&E less estimated liabilities.

Other emerging shale & tight assets*

Argentina

Loma Campana

~48,000 net acres
0.4 BBOE resource
EUR ~1.0 MMBOE/well
500 potential well locations

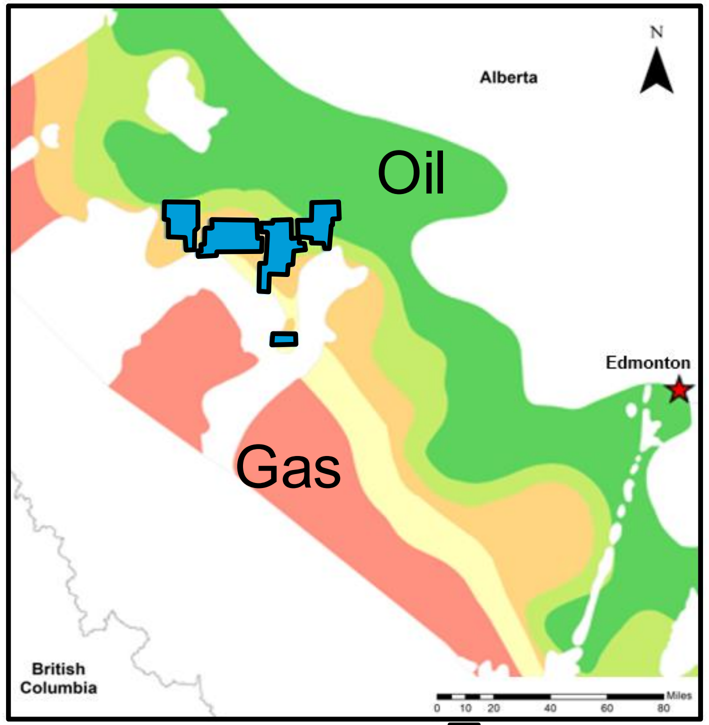


Chevron acreage

Canada

Duvernay

~215,000 net acres
1.4 BBOE resource
EUR ~1.7 MMBOE/well
1,500 potential well locations

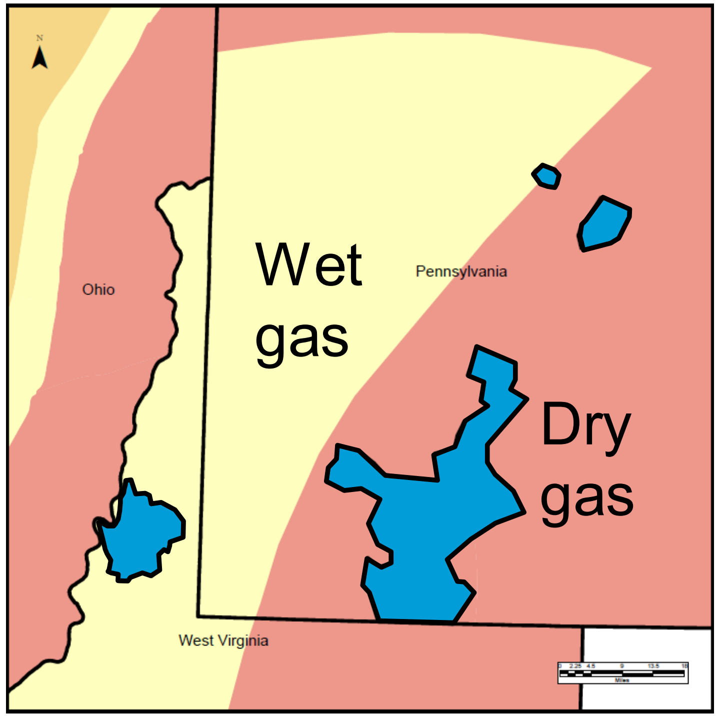


Chevron acreage

Appalachia

Marcellus / Utica

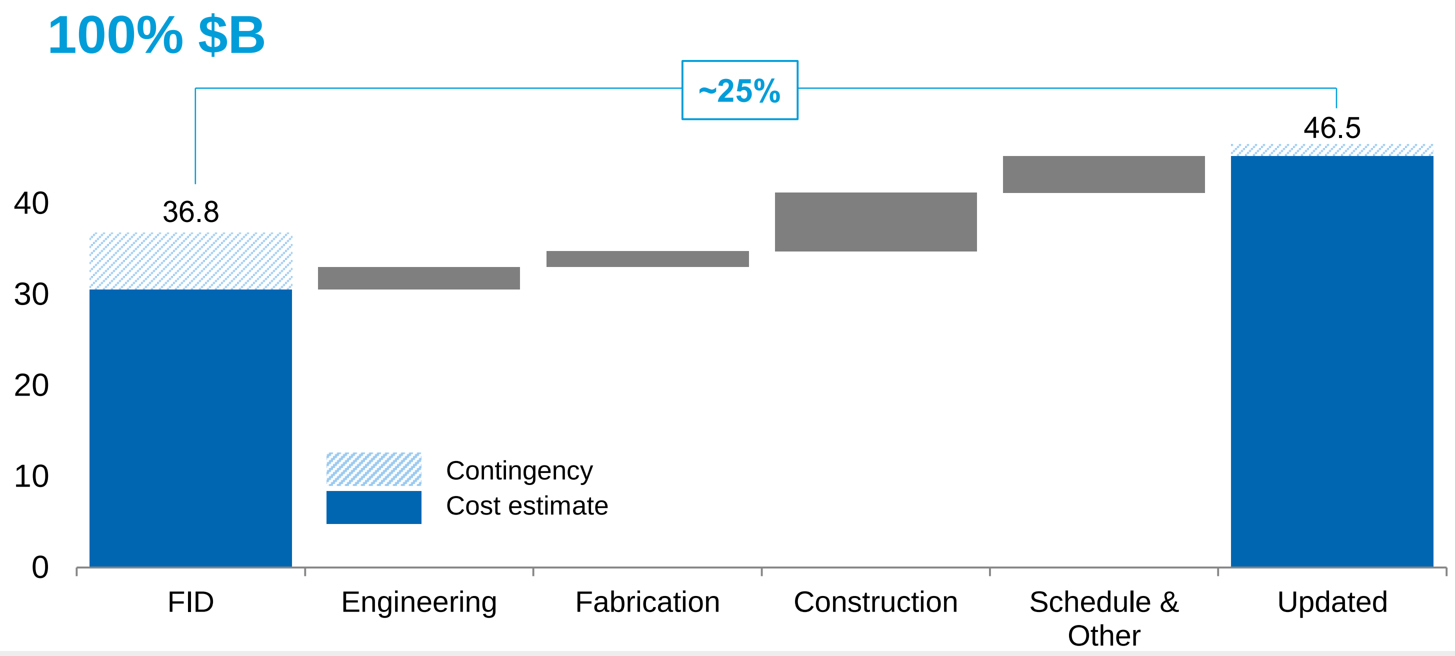
~890,000 net acres
2.4 BBOE resource
EUR ~2.6 MMBOE/well
1,300 potential well locations

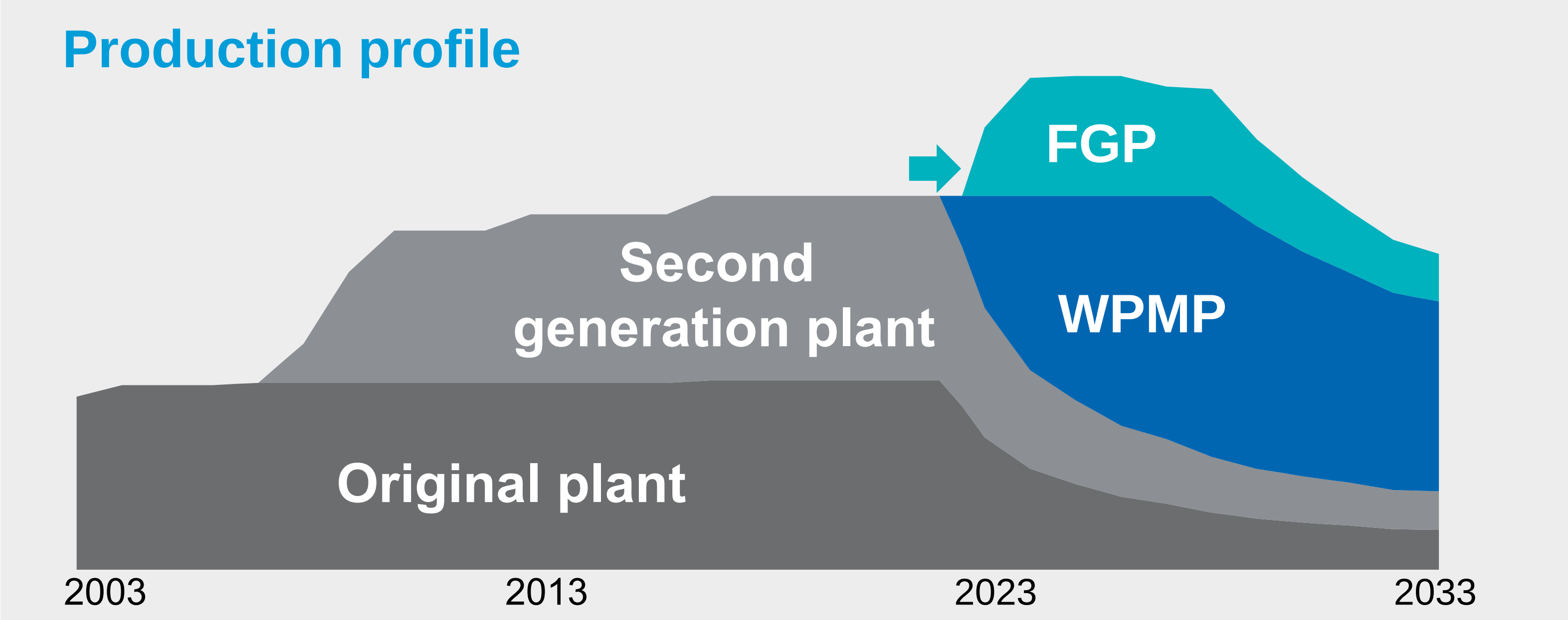


Chevron acreage

* *Net acres* are net mineral acres. *Resource:* 2018 net unrisked resource as defined in the 2018 Supplement to the Annual Report. *EUR:* 8/8ths expected ultimate recovery. Gross well locations at breakeven <$50/bbl Brent (Argentina), <$50/bbl WTI (Canada), and <$3/MCF (Appalachia).

Updated FGP/WPMP cost & schedule





Cost estimate $45.2 B

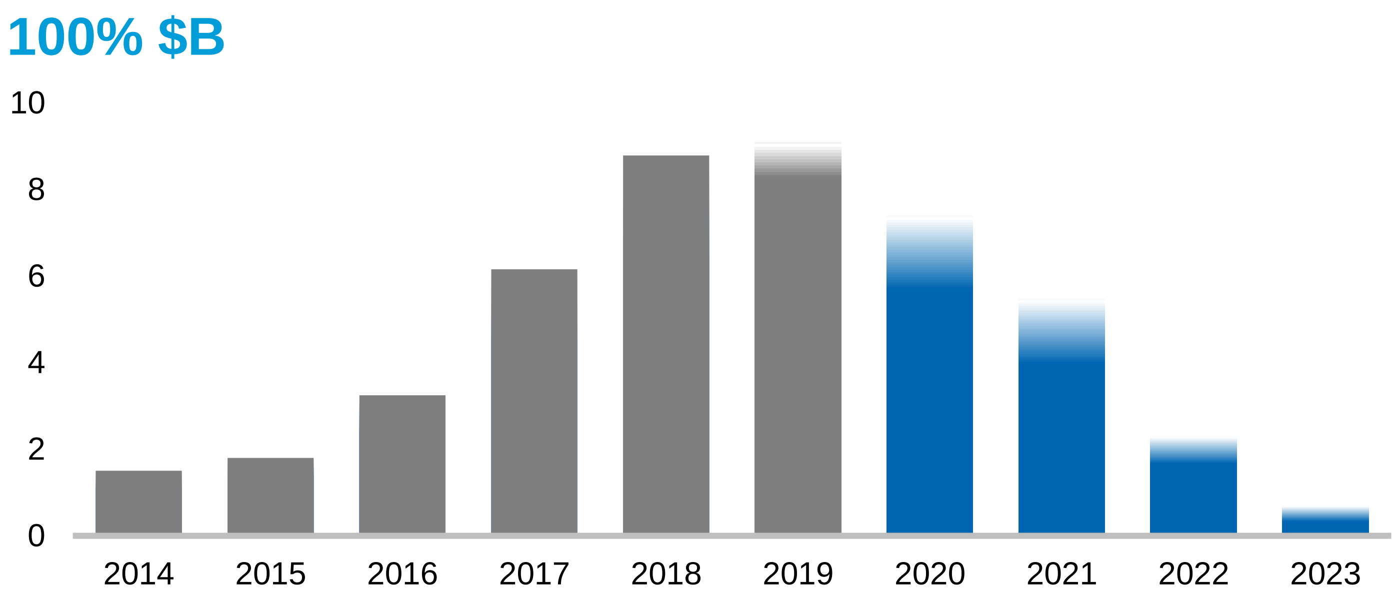
~25% cost increase

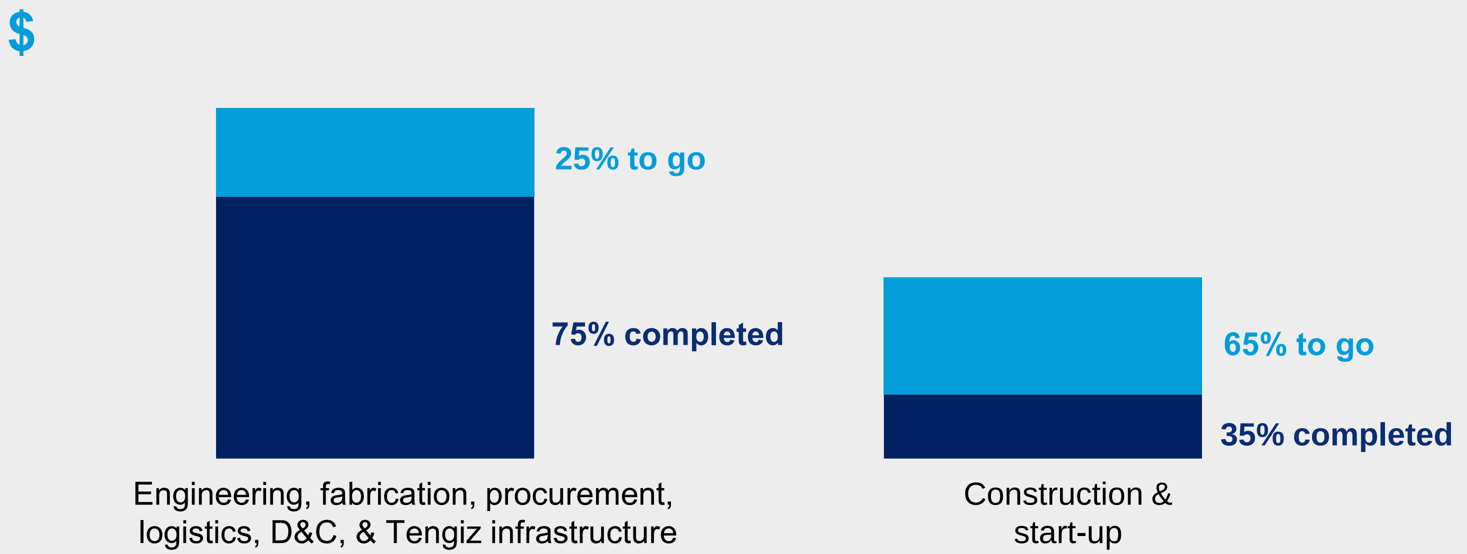
Primary drivers: engineering, quantities, unit rates & schedule

First oil from WPMP in late 2022 and FGP in mid-2023

Note: CVX share of TCO is 50%.

FGP/WPMP capital outlook





Peak spending in 2018 & 2019

Focus on construction

CVX C&E guidance unchanged

2020: $18 - $20 B

2021–2023: $19 - $22 B

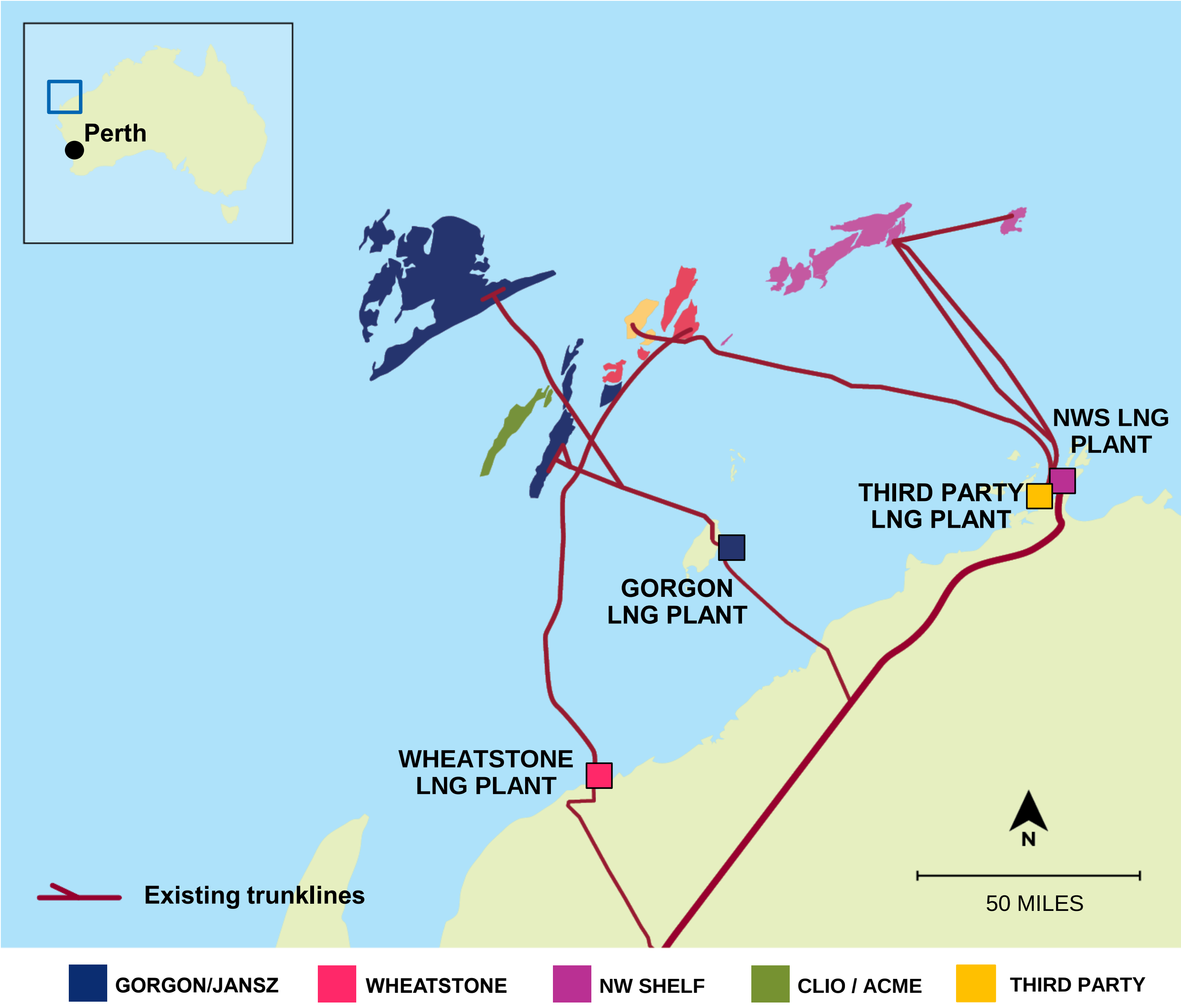
Note: CVX share of TCO is 50%.

Capital efficient resource monetization in Australia

Gorgon & Wheatstone[1]
production
in 4Q 2018

~400 MBOED

~50 TCF
of resource[2]



Maintain
reliability

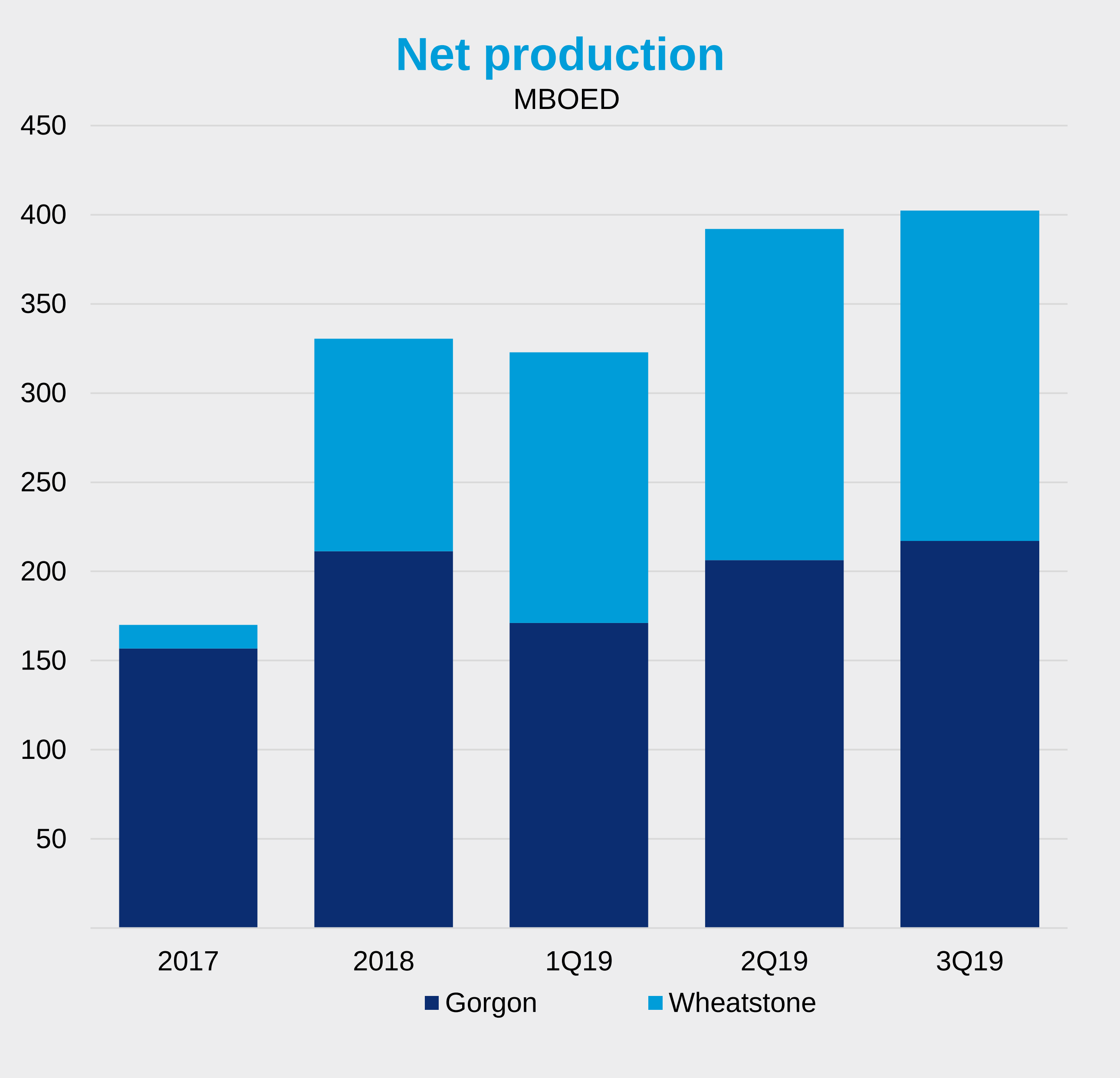
Increase
capacity

Leverage
basin infrastructure

[1] 4Q 2018 production reflects net Chevron share.
[2] 2018 net unrisked resource as defined in the 2018 Supplement to the Annual Report.

Gorgon / Wheatstone

Third quarter production > 400 MBOED



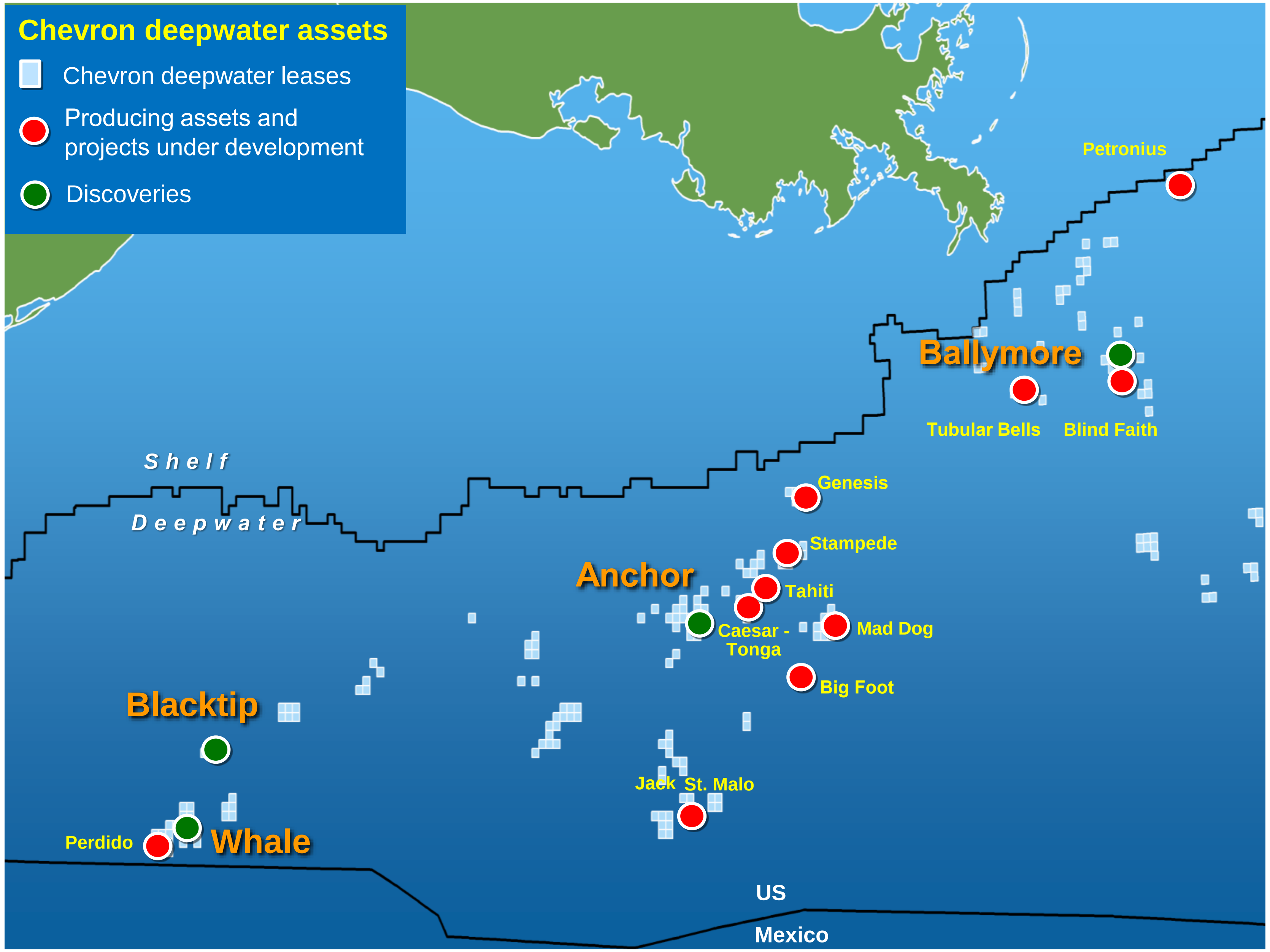
3Q19 net production

Gorgon 217 MBOED

Wheatstone 185 MBOED

Advancing our Gulf of Mexico deepwater portfolio

Attractive investment opportunities



Exploration
- Blacktip discovery

Appraisal
- Whale & Ballymore

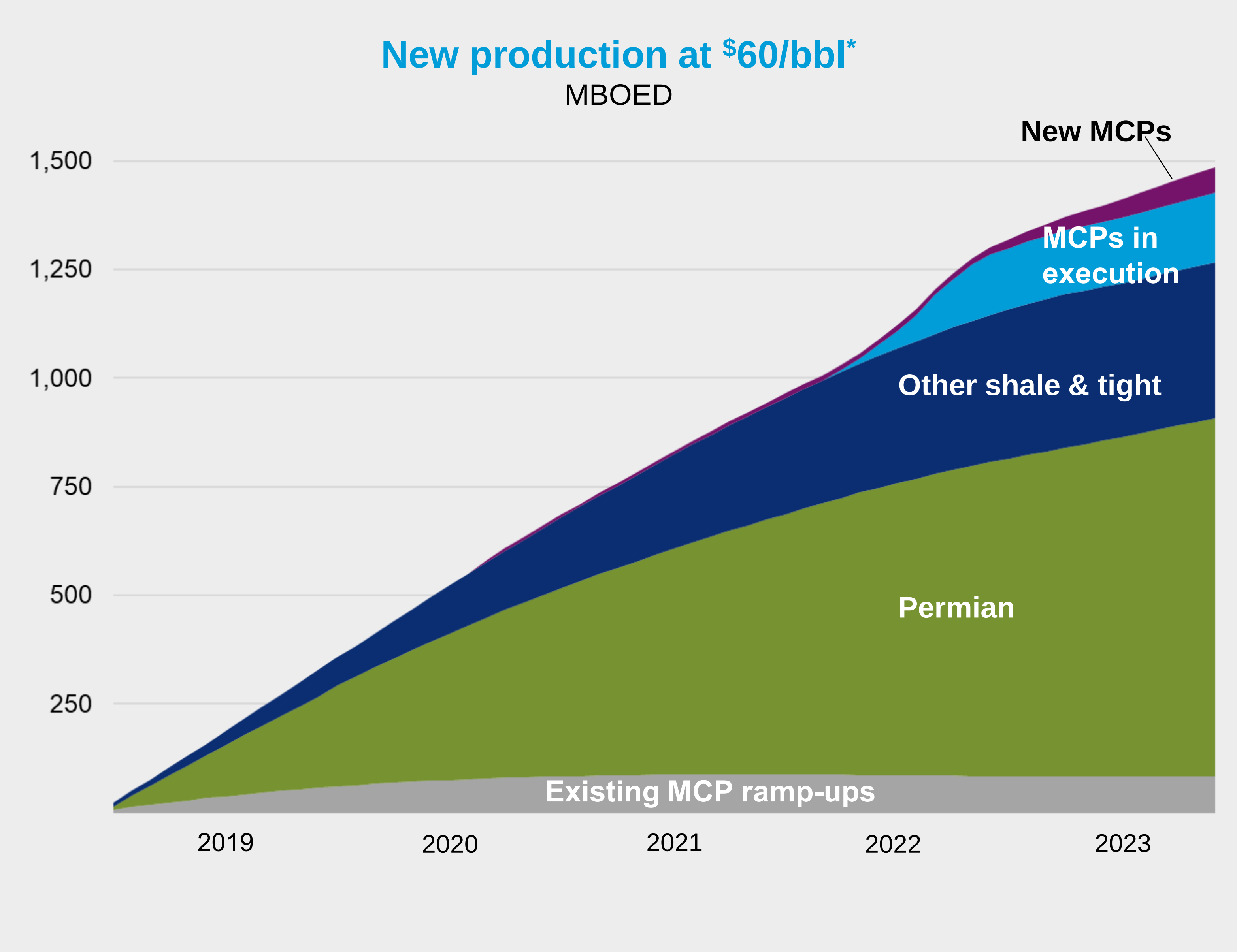
FEED
- Anchor

Under construction
- Mad Dog 2

Ramping-up
- Big Foot

Brownfield developments
- Jack St. Malo & others

Positioned for organic growth with lower risk



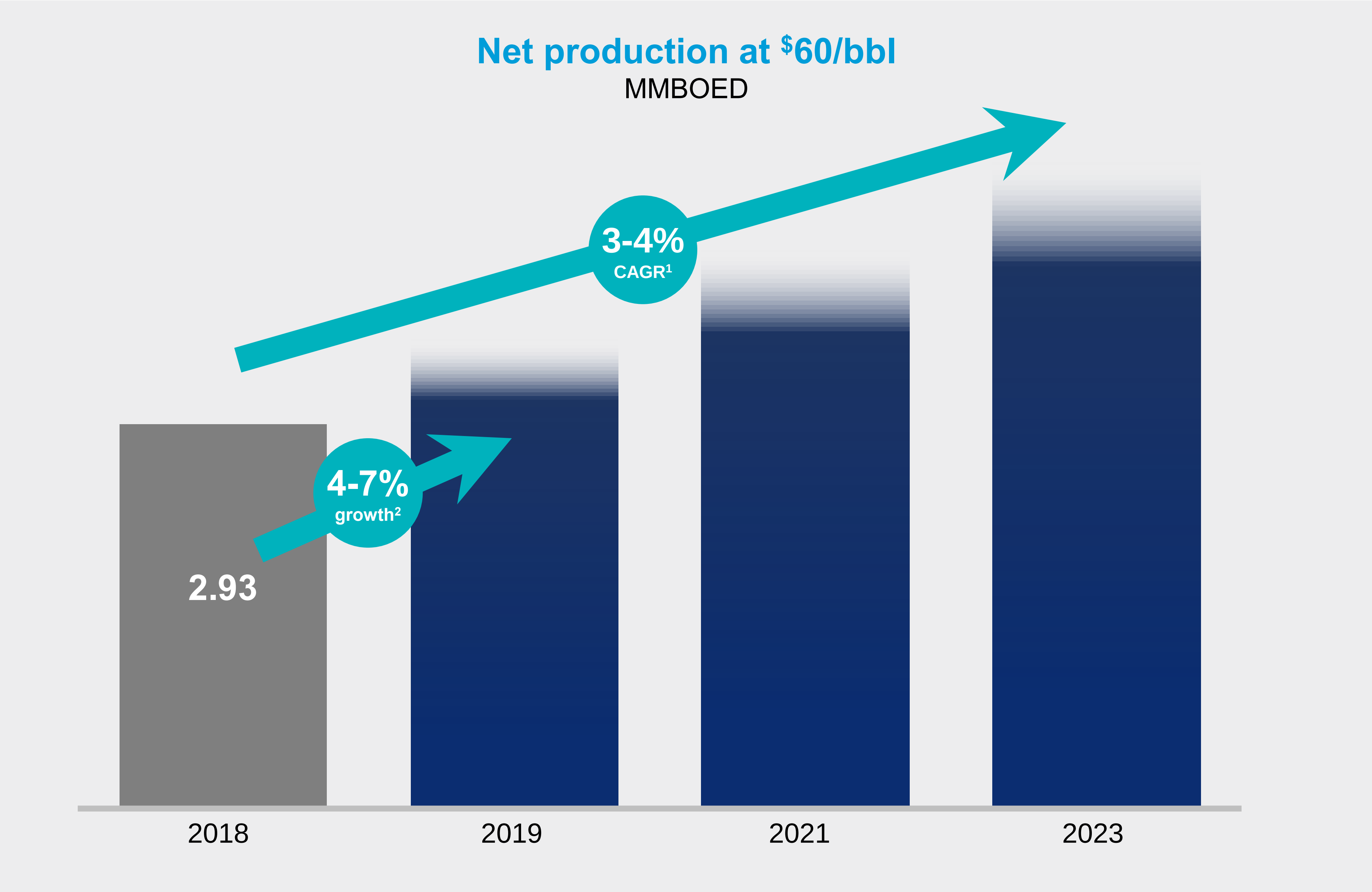
Note: $60/bbl Brent is for illustrative purposes only and not necessarily indicative of Chevron's price forecast.

~1.5 MMBOED
by year-end 2023

Primarily lower risk and short-cycle

* Oil price assumption reflects Brent crude. Projected production reflects net Chevron share of production from new investments and does not include existing production and any changes to that existing production that may occur such as brownfield project investment, decline, asset sales and contract expiration. Other shale & tight includes: Vaca Muerta, Kaybob Duvernay, Appalachia, other. Existing MCP ramp-ups includes: Clair Ridge. Big Foot, Hebron, Stampede and Sonam. MCPs in execution includes: Mad Dog 2, FGP/WPMP. New MCPs includes: Anchor, Whale, Ballymore, other.

Five-year production guidance



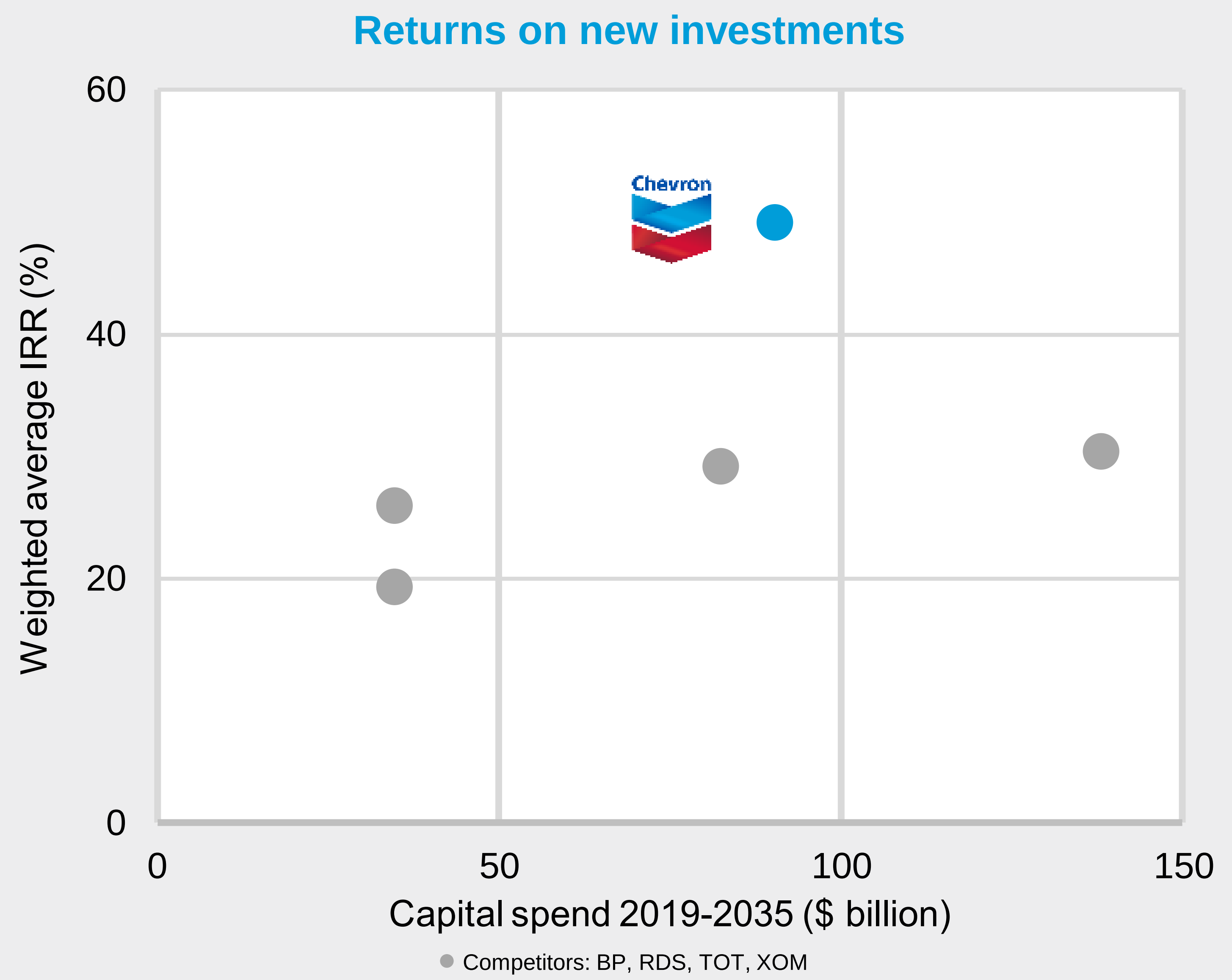
Ratable growth

Lower subsurface risk

Minimal MCP execution risk

[1] 3-4% CAGR reflects 2018-2023. Includes the effect of expected asset sales in the public domain. Range factors: PZ and Venezuela, asset sales, and other.
[2] 4-7% reflects production growth 2018-2019. Excludes the effect of 2019 asset sales.
Note: $60/bbl Brent is for illustrative purposes only and not necessarily indicative of Chevron's price forecast.

High return new investments



Superior portfolio

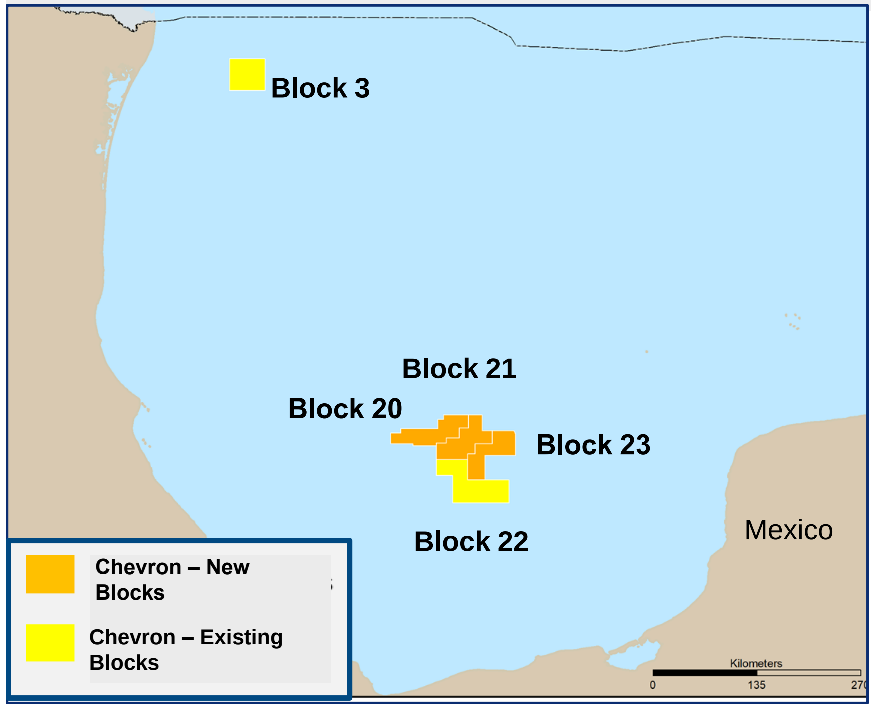
Industry leading returns

Source: Wood Mackenzie 4Q18 Corporate Benchmarking Tool. New investments comprises future wells in the U.S. lower 48 and fields which are under development and probable development. The metric does not include investment in fields which are already onstream and newfield developments that fall under tax ring fences which are already onstream.

Upstream portfolio highlights

Mexico

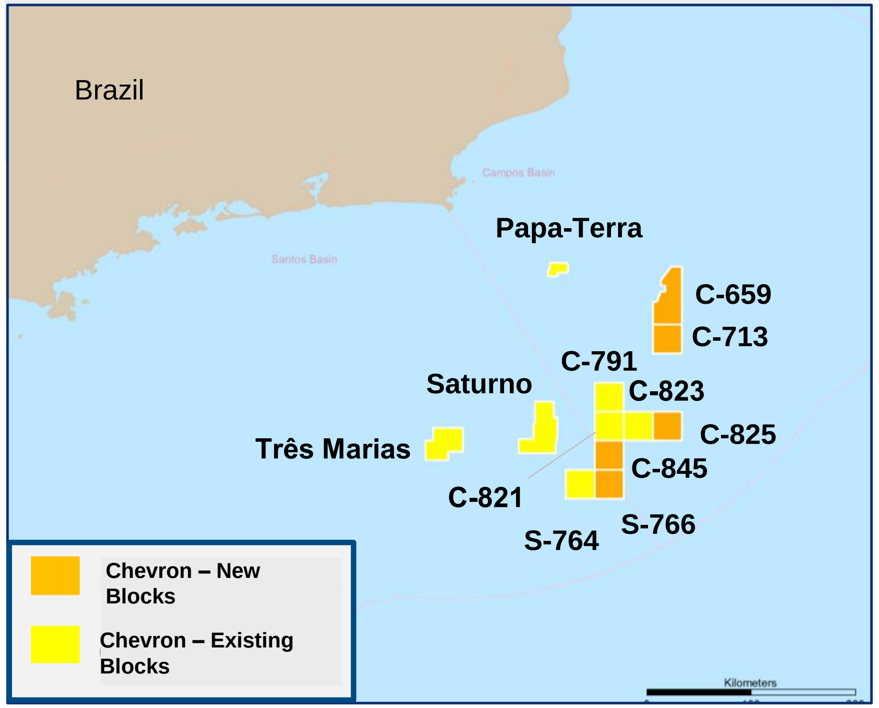
Deepwater blocks 20, 21 & 23
40% working interest



Brazil

Campos Basin
Won four blocks at ANP16
35-40% working interest

Santos Basin
Won one block at ANP16
40% working interest



Philippines

Malampaya divestment
SPA signed on October 25
Expected to close in 1H20

Delivering results

Sustainable portfolio

Ratable C&E

Lower-risk, short-cycle production growth

Industry leading returns

Growing cash flow

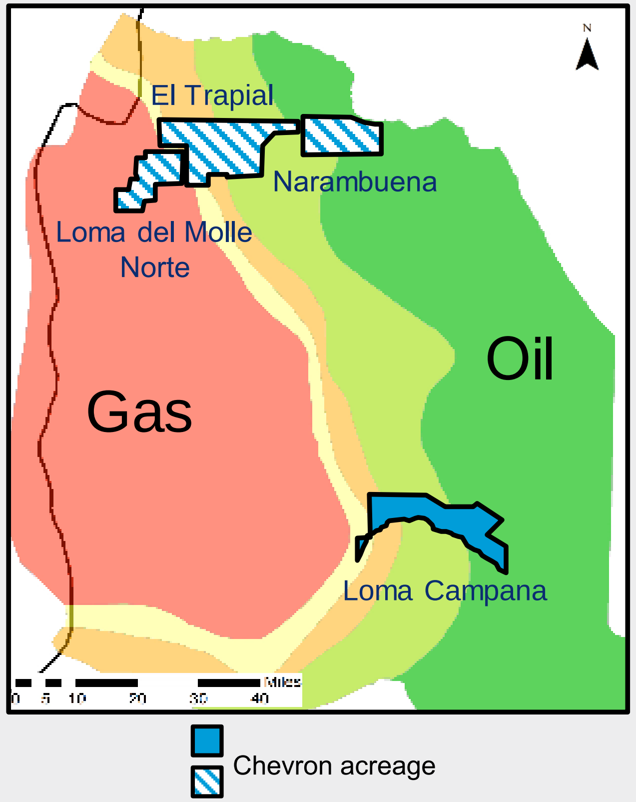
Upstream appendix

Vaca Muerta / Kaybob Duvernay / Appalachia

Vaca Muerta

Quality position

~210,000 net acres[1]



0.4 BBOE resource[2]
in Loma Campana

Three prospective development areas with ~2 BBOE potential resource

60-70 horizontal wells
planned in 2019

Loma Campana

48,000 net acres[1]

EUR 1.0 MMBOE/well[3]

Average well length 7,500 ft

Development costs $11/BOE[4]

500 potential well locations[5]

New development areas

162,000 net acres

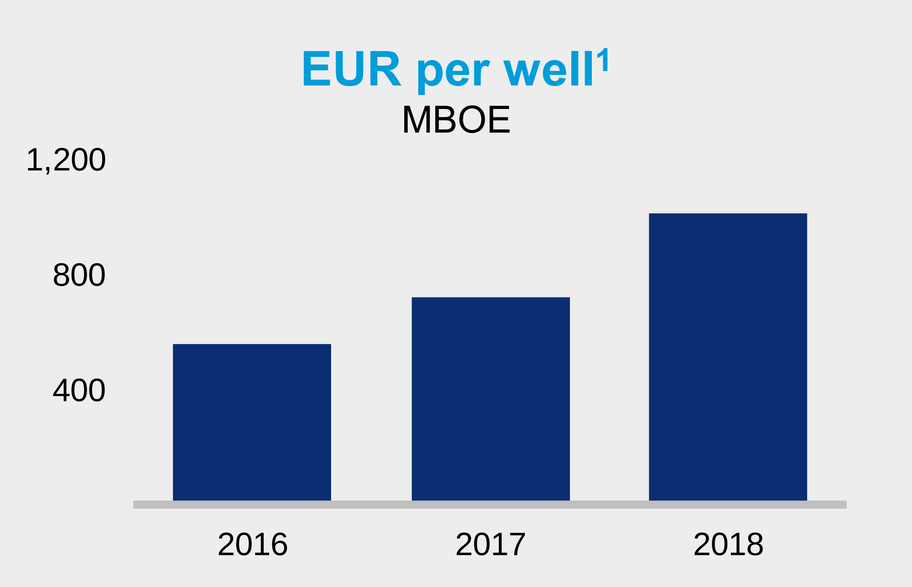
Pilot programs in 2019

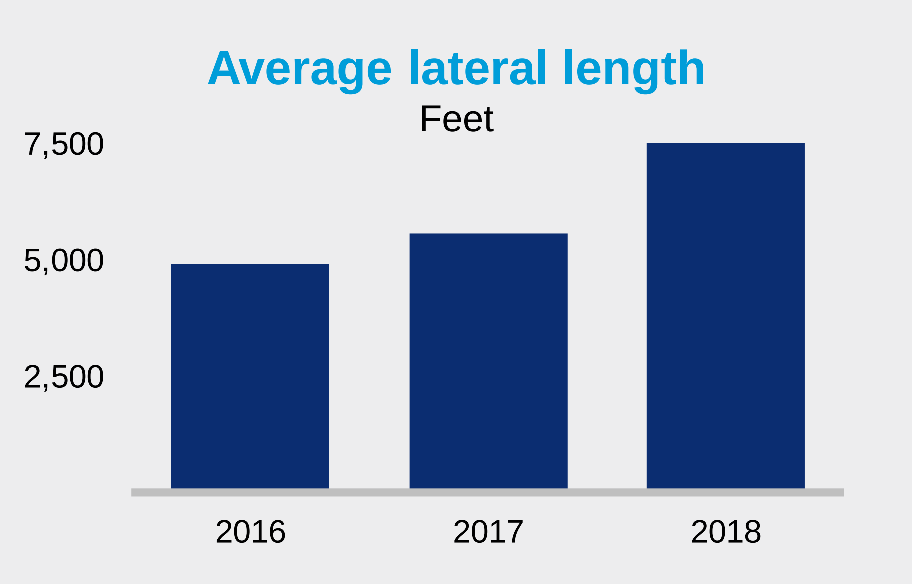
Potential for ~2,000 wells

[1] Net acres are net mineral acres.
[2] 2018 net unrisked resource as defined in the 2018 Supplement to the Annual Report.

[3] 8/8ths expected ultimate recovery.
[4] Development costs are $/BOE, gross capital excluding G&A and gross three-stream expected ultimate recovery (EUR) BOE.
[5] Gross well locations at breakeven <$50/bbl Brent.

Loma Campana performance – Vaca Muerta





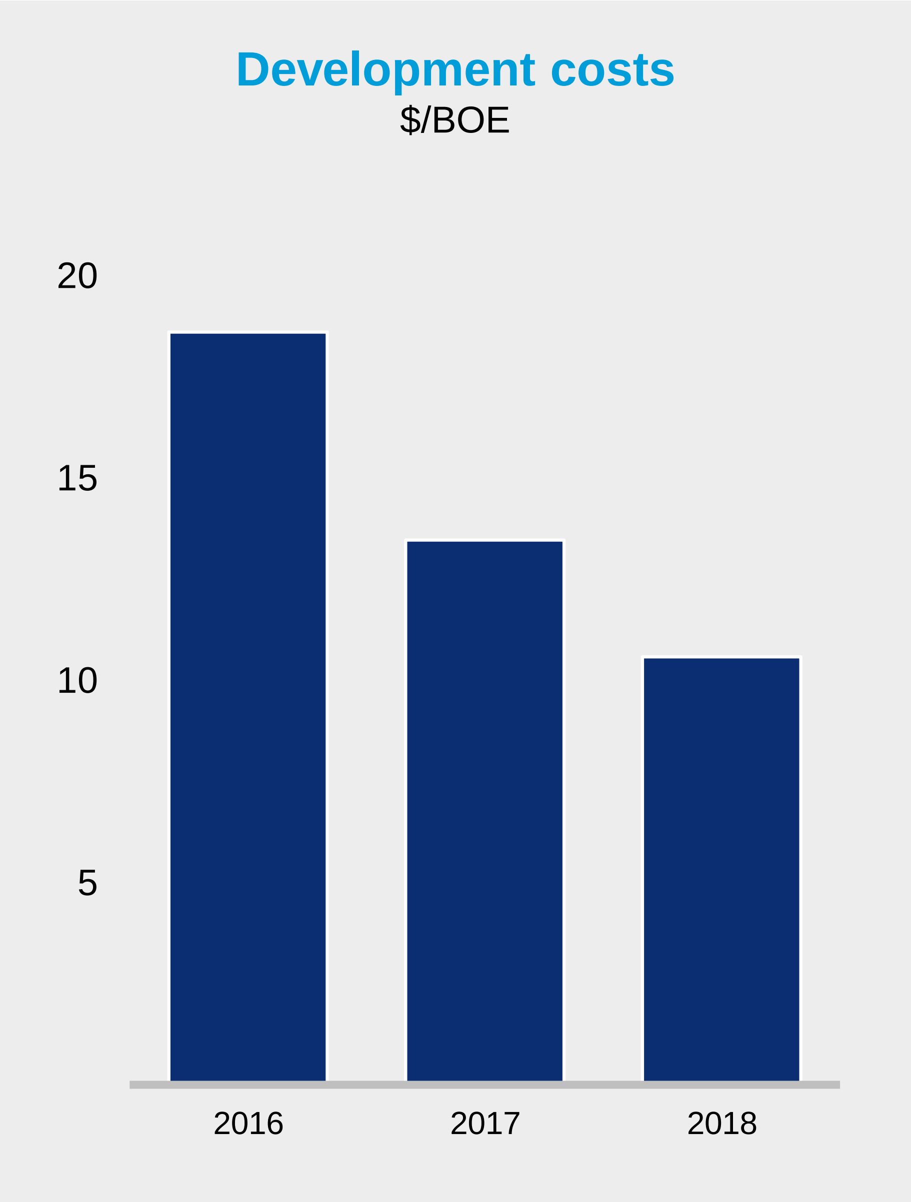
Three shale and tight benches

Well EUR increased 80%[2]

Well lateral length increased 50%[2]

Development cost decreased 45%[2,3]

2019 focus on high density completions and improving frac efficiency



[1] 8/8ths expected ultimate recovery.
[2] Well EUR, lateral length, and development cost changes reflect 2018 relative to 2016. EURs are average 8/8ths expected recoveries from wells drilled in year; lateral lengths are average drilled in year.
[3] Development costs are $/BOE, gross capital excluding G&A and gross three-stream expected ultimate recovery (EUR) BOE.

El Trapial – Vaca Muerta

94,000 net acres[1]

Legacy acreage
from conventional field

Three shale and tight benches
proven through exploration

Eight-well pilot

1,200 potential well locations[2]

[1] Net acres are net mineral acres.
[2] Gross well locations at breakeven <$50/bbl Brent.

Narambuena – Vaca Muerta

25,000 net acres[1]

Three shale and tight benches proven through exploration

Four-well pilot

600 potential well locations[2]

Adjacent to El Trapial

[1] Net acres are net mineral acres.
[2] Gross well locations at breakeven <$50/bbl Brent.

Loma del Molle Norte – Vaca Muerta

43,000 net acres[1]

Acreage acquired in 2017

Exploration planned

150 potential well locations[2]

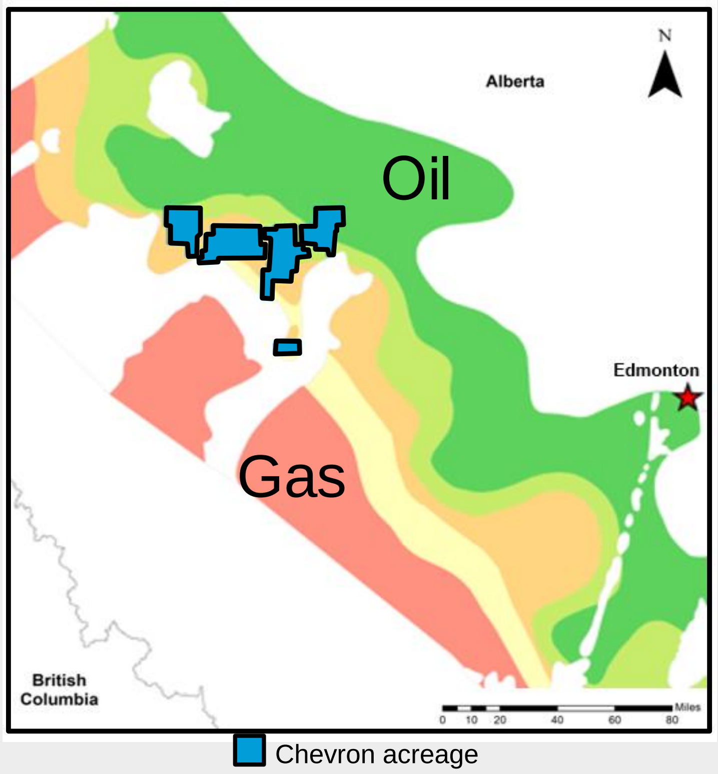
Adjacent to El Trapial

[1] Net acres are net mineral acres.
[2] Gross well locations at breakeven <$50/bbl Brent.

Kaybob Duvernay

Quality position

~215,000 net acres[1]



1.4 BBOE resource[2]

Liquids value driven

40-45 wells
planned in 2019

Well performance

EUR 1.7 MMBOE/well[3]

Average well length 8,300 ft

Development costs $9/BOE[4]

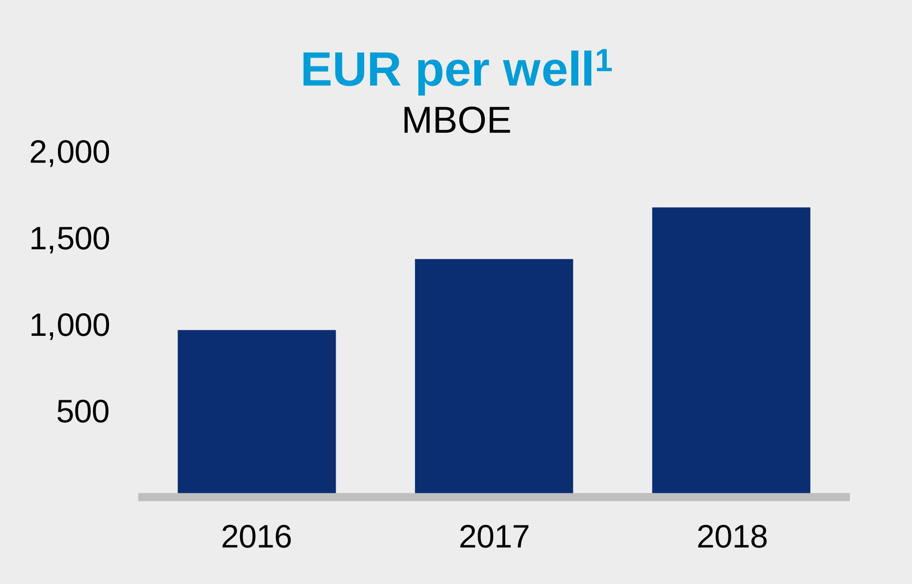
~50% liquids

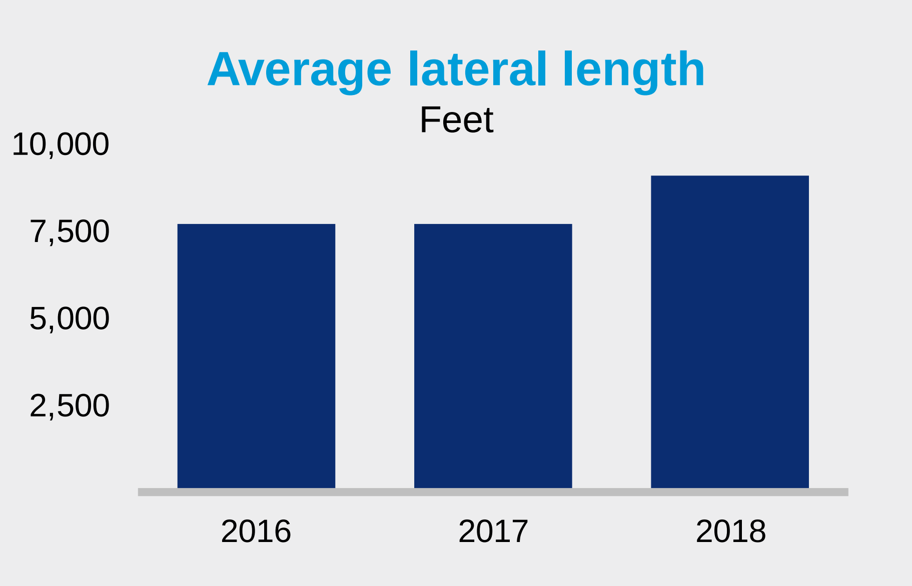
1,500 potential well locations[5]

[1] Net acres are net mineral acres.
[2] 2018 net unrisked resource as defined in the 2018 Supplement to the Annual Report.

[3] 8/8ths expected ultimate recovery.
[4] Development costs are $/BOE, gross capital excluding G&A and gross 3-stream expected ultimate recovery (EUR) BOE.
[5] Gross well locations at breakeven <$50/bbl WTI.

Kaybob Duvernay performance



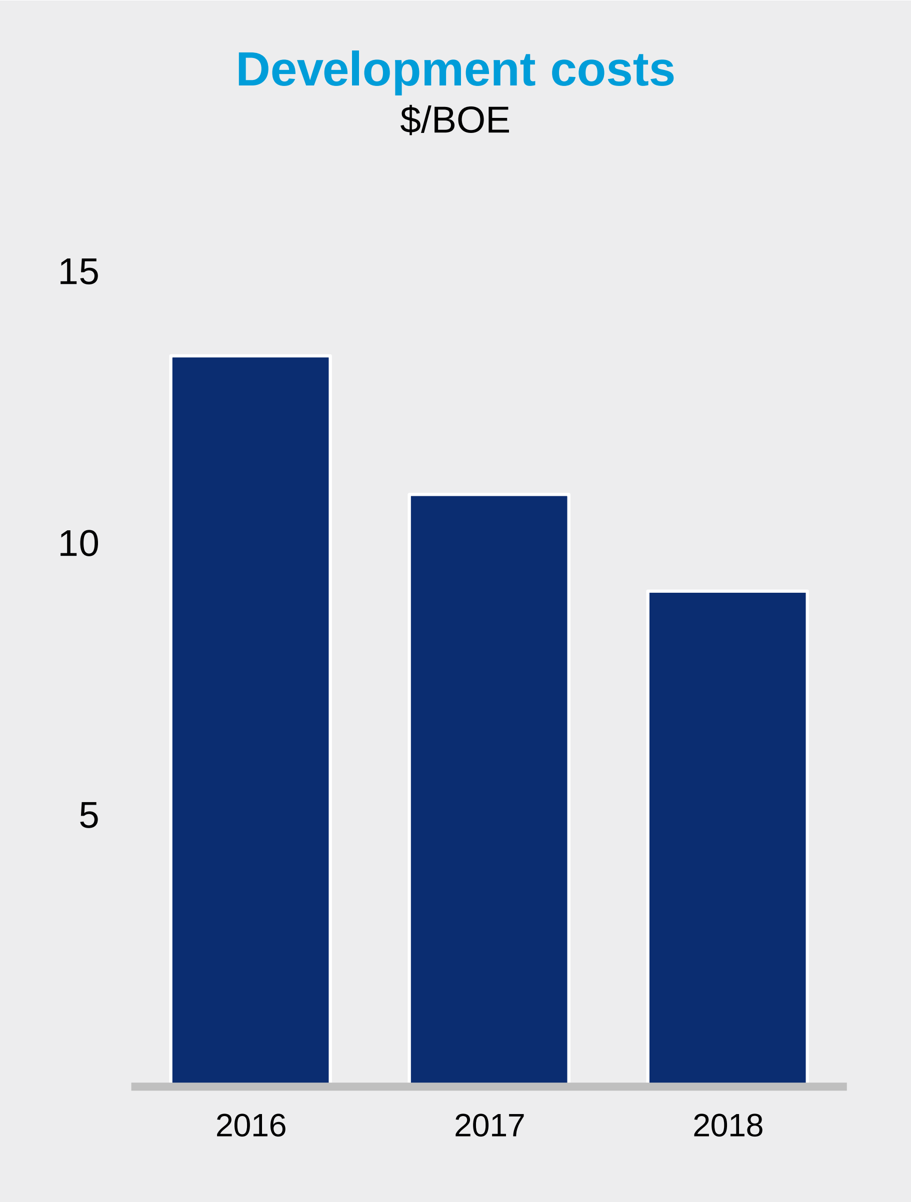


215,000 net acres[2]

Well EUR increased 70%[3]

Well lateral length increased 20%[3]

Development cost decreased 30%[3, 4]



[1] 8/8ths expected ultimate recovery.
[2] Net acres are net mineral acres.

[3] Well EUR, lateral length, and development cost changes reflect 2018 relative to 2016. EURs are average 8/8ths expected recoveries from wells drilled in year; lateral lengths are average drilled in year.
[4] Development costs are $/BOE, gross capital excluding G&A and gross three-stream expected ultimate recovery (EUR) BOE.

Kaybob Duvernay development

Began development drilling
in 2018

Scalable based on market conditions

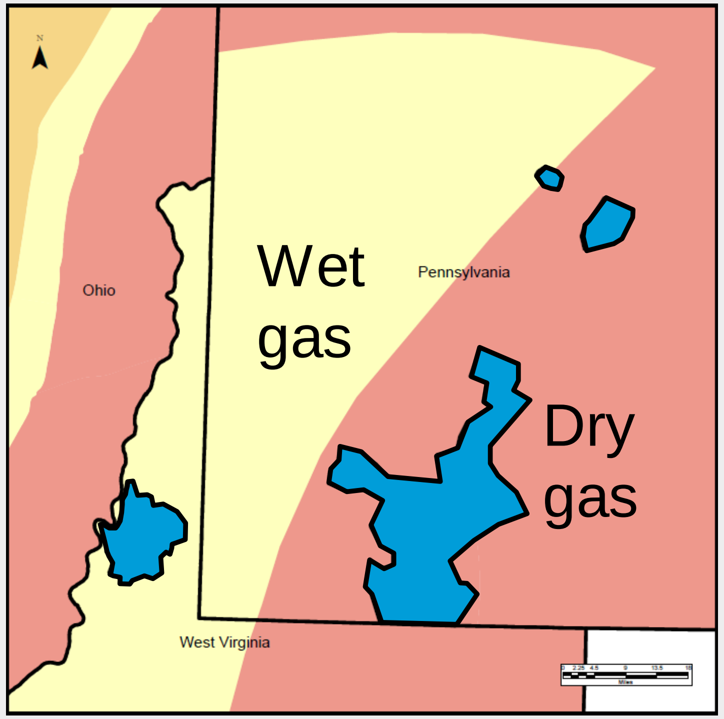
Flexible commercial infrastructure model

Local condensate market
due to oil sands diluent demand

Appalachia

Quality position

~890,000 net acres[1]



Chevron acreage

2.4 BBOE resource[2]

Two shale and tight benches

Exploration upside in deep Utica

30-40 wells planned in 2019

Well performance

EUR ~2.6 MMBOE/well[3]

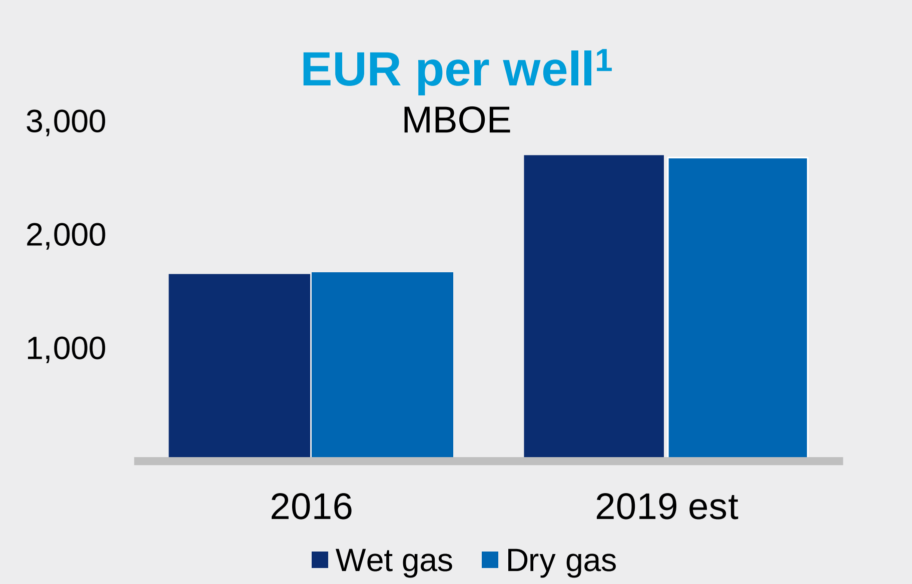
Average well length 8,600-10,000 ft

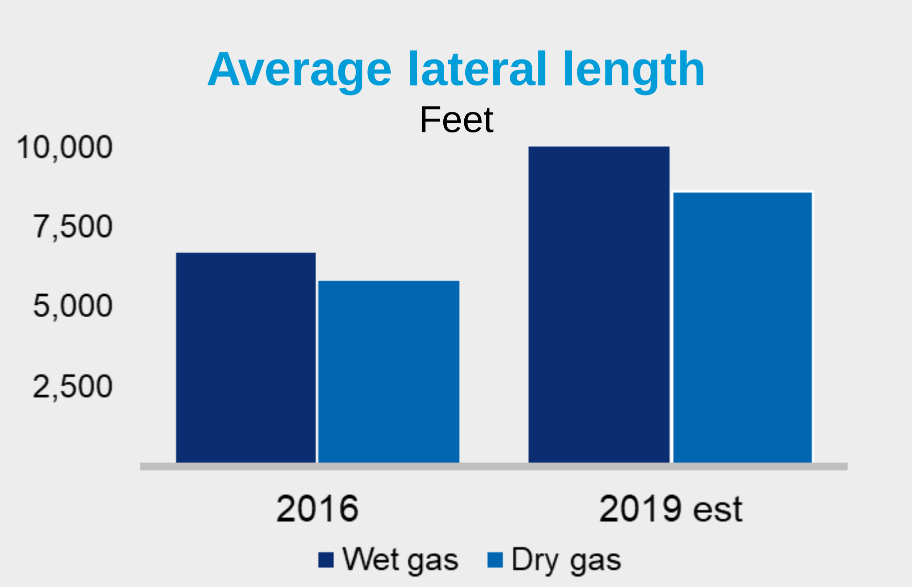
Development costs[4] $4.20- $5.70/BOE

~1,300 potential well locations[5]

[1] Net acres are net mineral acres.
[2] 2018 net unrisked resource as defined in the 2018 Supplement to the Annual Report.
[3] EUR: 8/8ths expected ultimate recovery.
[4] Development costs are $/BOE, gross capital excluding G&A and gross three-stream expected ultimate recovery (EUR) BOE.
[5] Gross well locations at breakeven <$3/MCF Henry Hub.

Appalachia performance



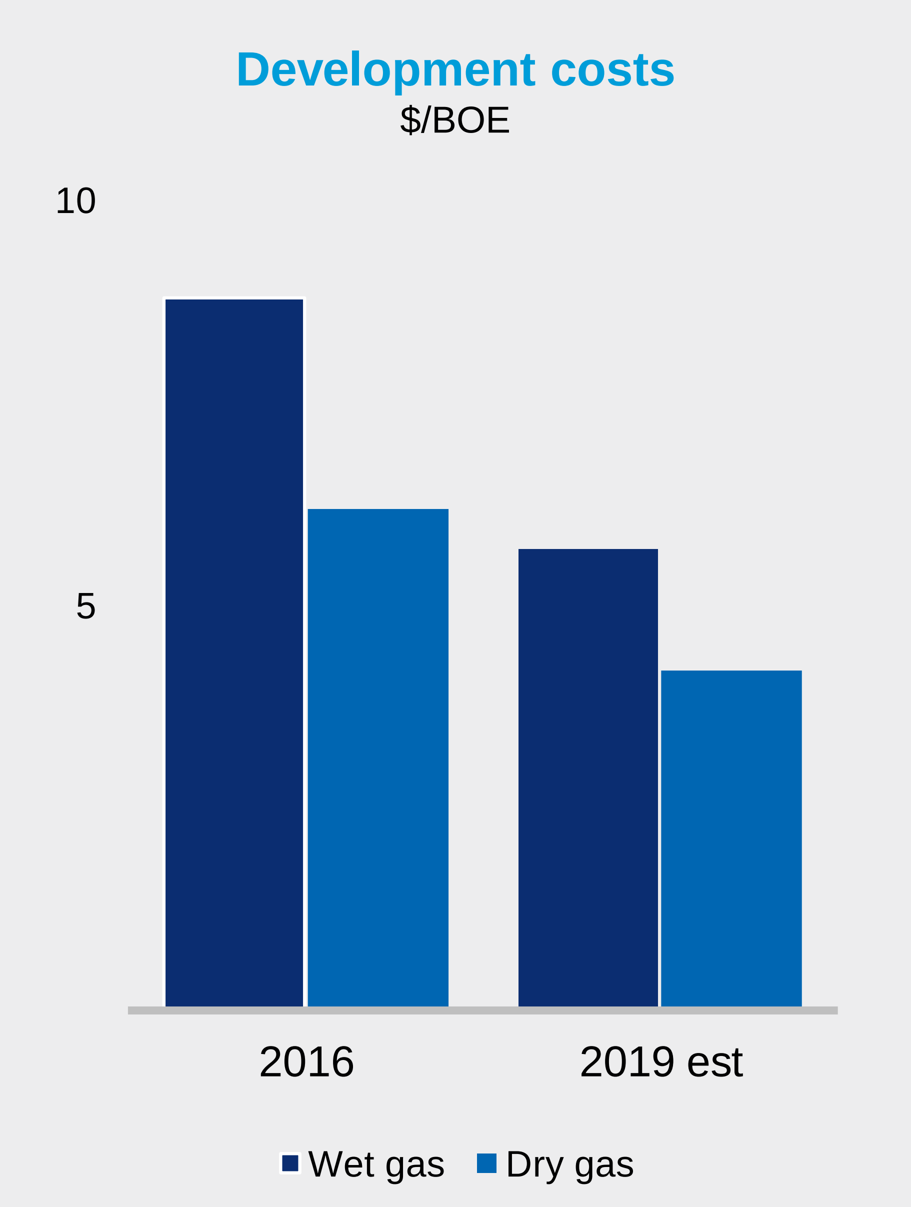


Asset optimization with factory restart

Well EUR increase ~60%[2]

Lateral length increase ~50%[2]

Development cost decrease ~30%[2, 3]



[1] 8/8ths expected ultimate recovery.
[2] Well EUR, lateral length, and development cost changes reflect 2018 relative to 2016. EURs are average 8/8ths expected recoveries from wells drilled in year; lateral lengths are average drilled in year.
[3] Development costs are $/BOE, gross capital excluding G&A and gross three-stream expected ultimate recovery (EUR) BOE.

Appalachia development

Pipeline infrastructure build out improving price differentials vs. Henry Hub

---

Re-started development drilling in 2018

New basis of design with:

Longer laterals

Improved frac efficiency

Higher density completion

Upside potential of deep Utica

currently drilling exploration wells

Digital innovation drives business value

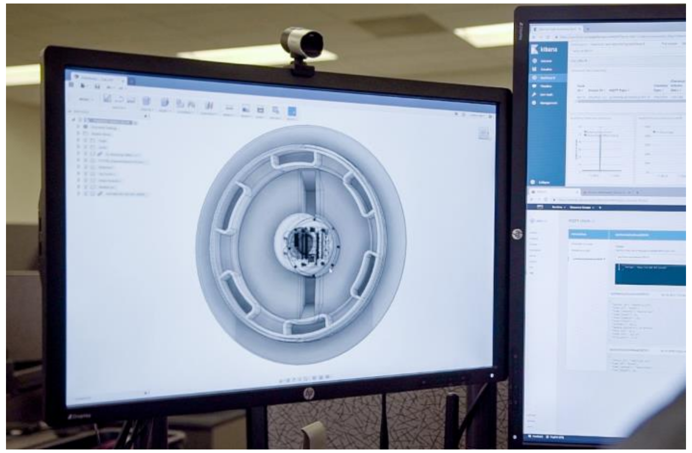
Revenue
Improve delivery
of cash and earnings

Cost
Reduce costs
and increase efficiencies

Reliability
Manage our global assets
more reliably

Safety
Improve safeguards
in high risk situations






Business | **Technology** | **Culture**

Investing in a broader energy portfolio

Future energy fund

Seed funds for breakthrough technologies

EV charging station batteries

Direct air capture of CO_2

EV station network

GHG intensity reduction

Performance tied to compensation

2016-2023

Upstream oil net GHG emission intensity 5 – 10%

Upstream natural gas net GHG emission intensity 2 – 5%

Reduce flaring 25-30%

Reduce methane emissions 20-25%

Partnerships

Collaborative industry efforts; investment in technology

Partners to reduce manmade greenhouse gas emissions

OGCI
OIL AND GAS CLIMATE INITIATIVE

Renewables

Lowering the carbon intensity of our operations

Renewable base oil

Renewable diesel sales

Renewable power purchase agreements

Chevron

Lowering the carbon intensity

GHG emission reduction targets

		Targeted reduction 2016 – 2023
New	Upstream **oil** net GHG emission intensity	5% - 10%
New	Upstream **natural gas** net GHG emission intensity	2% - 5%
Existing	Upstream **flaring** intensity	25% - 30%
Existing	**Methane** emissions	20% - 25%

Carbon sequestration

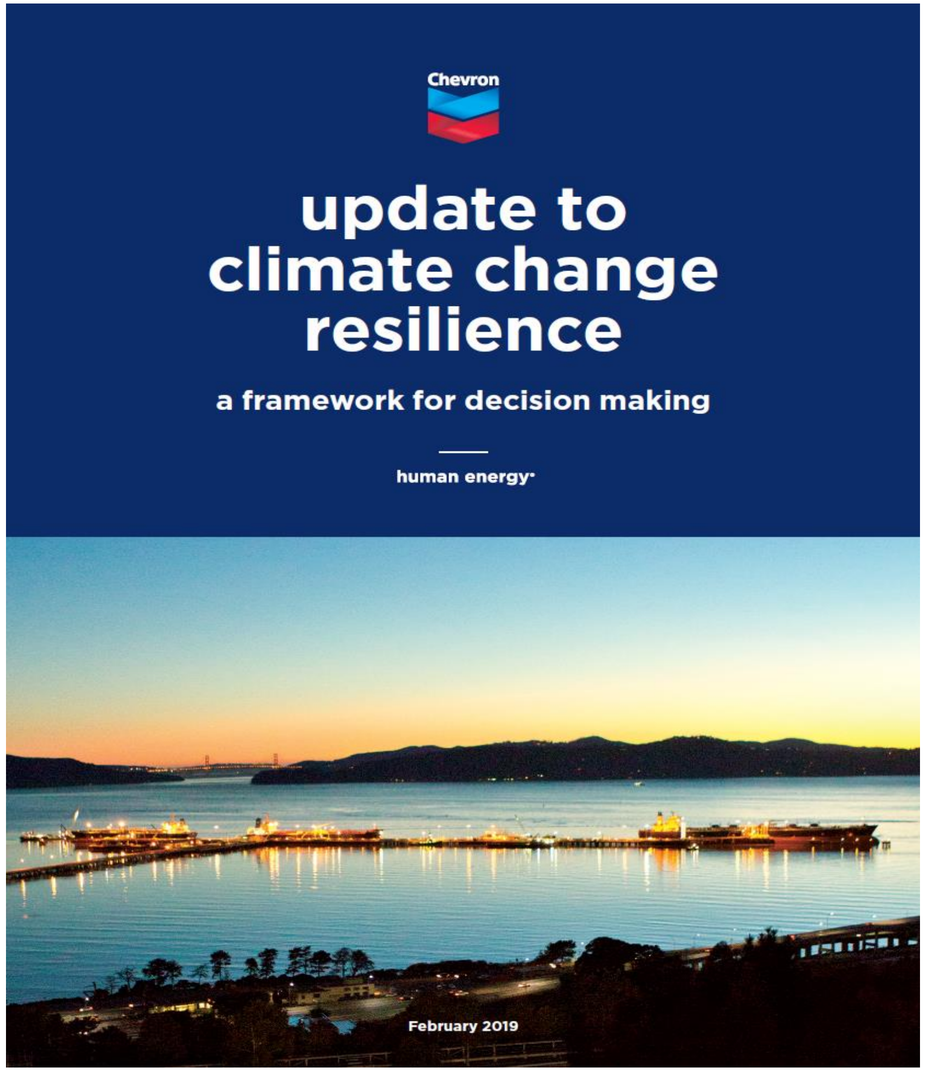
Began operation of Gorgon CO_2 Injection Project

Renewables

Solar project to support California upstream operations

Results the right way

TCFD-aligned report



Robust disclosure

Diversity and inclusion

Effective Human Capital Management

Human energy

vision

At the heart of The Chevron Way is our vision … to be *the* global energy company most admired for it's people, partnership and performance.

enabling human progress

We develop the energy that improves lives and powers the world forward.

The Chevron way

strategies

Our strategies guide our actions to deliver industry-leading results and superior shareholder value in any business environment.

values

Our company's foundation is built on our values, which distinguish us and guide our actions to deliver results

Chevron poised to deliver winning performance

Advantaged portfolio	Production growth with low execution risk	Cash flow expansion	Return cash to shareholders
Increased Permian resources from 9.3 BBOE to **16.2 BBOE**[1]	Grow 2018-2023 production at **3-4% CAGR**[3]	Updated C&E range of **$19-$22B** 2021-2023[5]	**6%** dividend increase
Permian portfolio value **increased >2X**[2]	Permian production **900 MBOED** in 2023[4]	CFFO ROCE improves **>3%** 2018-2023	**$4B** annual share buybacks

Note: Guidance pertains to 2019 unless otherwise indicated. Assumes average annual $60/bbl Brent, 2019-2023. $60/bbl Brent is for illustrative purposes only and not necessarily indicative of Chevron's price forecast.

[1] 2018 net unrisked resources as defined in the 2018 Supplement to the Annual Report. Increase relative to year-end 2016 net unrisked resources.

[2] Value of portfolio determined using Chevron internal methodology and the same price assumptions for 2017 and 2019.

[3] 3-4% CAGR reflects 2018-2023. Includes the effect of expected asset sales in the public domain. Range factors:PZ and Venezuela, asset sales, other.

[4] Permian production is Midland and Delaware Basin and reflects shale & tight production only.

[5] 2019 cash generation – includes cash flow from operations, proceeds from asset sales, and other.

Chevron

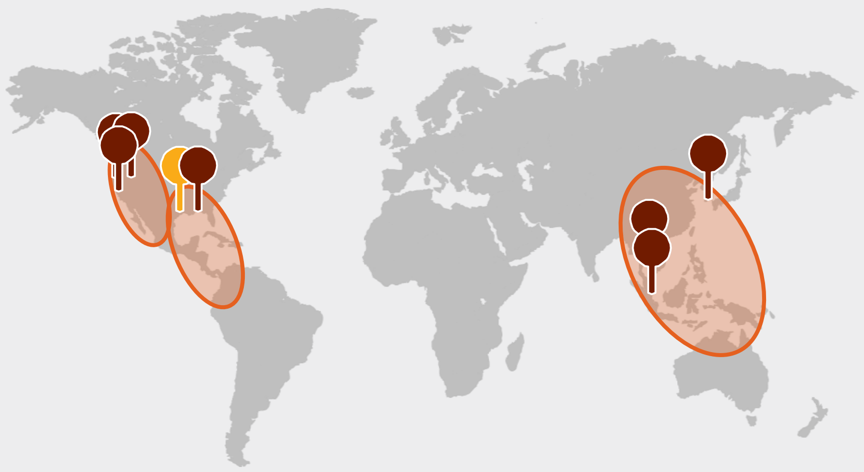
human energy®

Downstream & Chemicals

Downstream & chemicals portfolio

Fuels refining & marketing*

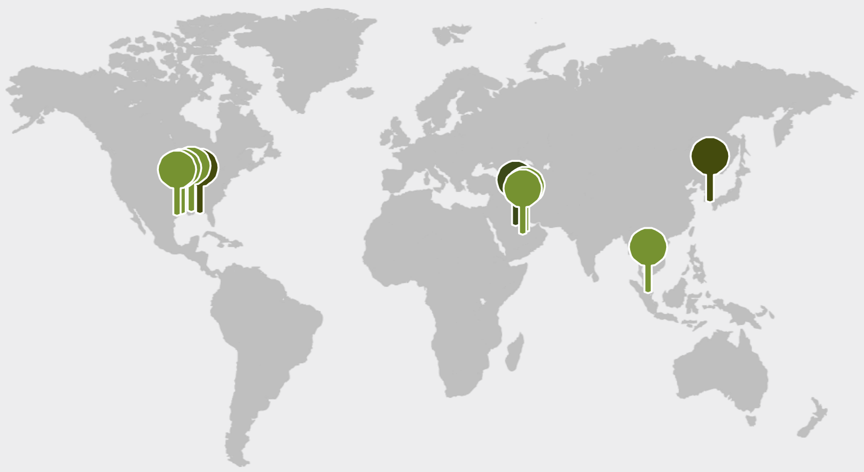
Focused,
regional optimization



Refinery
Refinery acquisition
Integrated fuels value chain

Petrochemicals

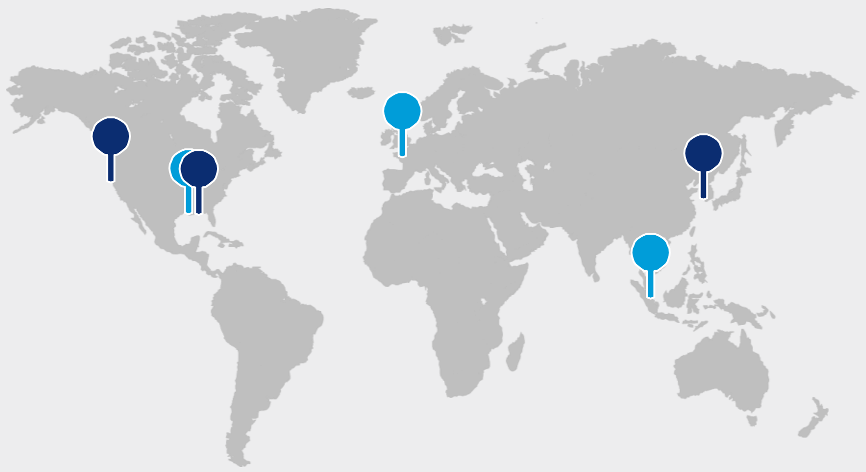
Advantaged feed,
scale and technology



Olefins / Polyolefins complex
Aromatics complex

Lubricants & additives

Strategic positions serving
global markets



Premium base oil plant integrated with refinery
World-scale additives plant

* Pasadena, TX refinery acquisition expected close 1H19.

Strategy focused on leading returns

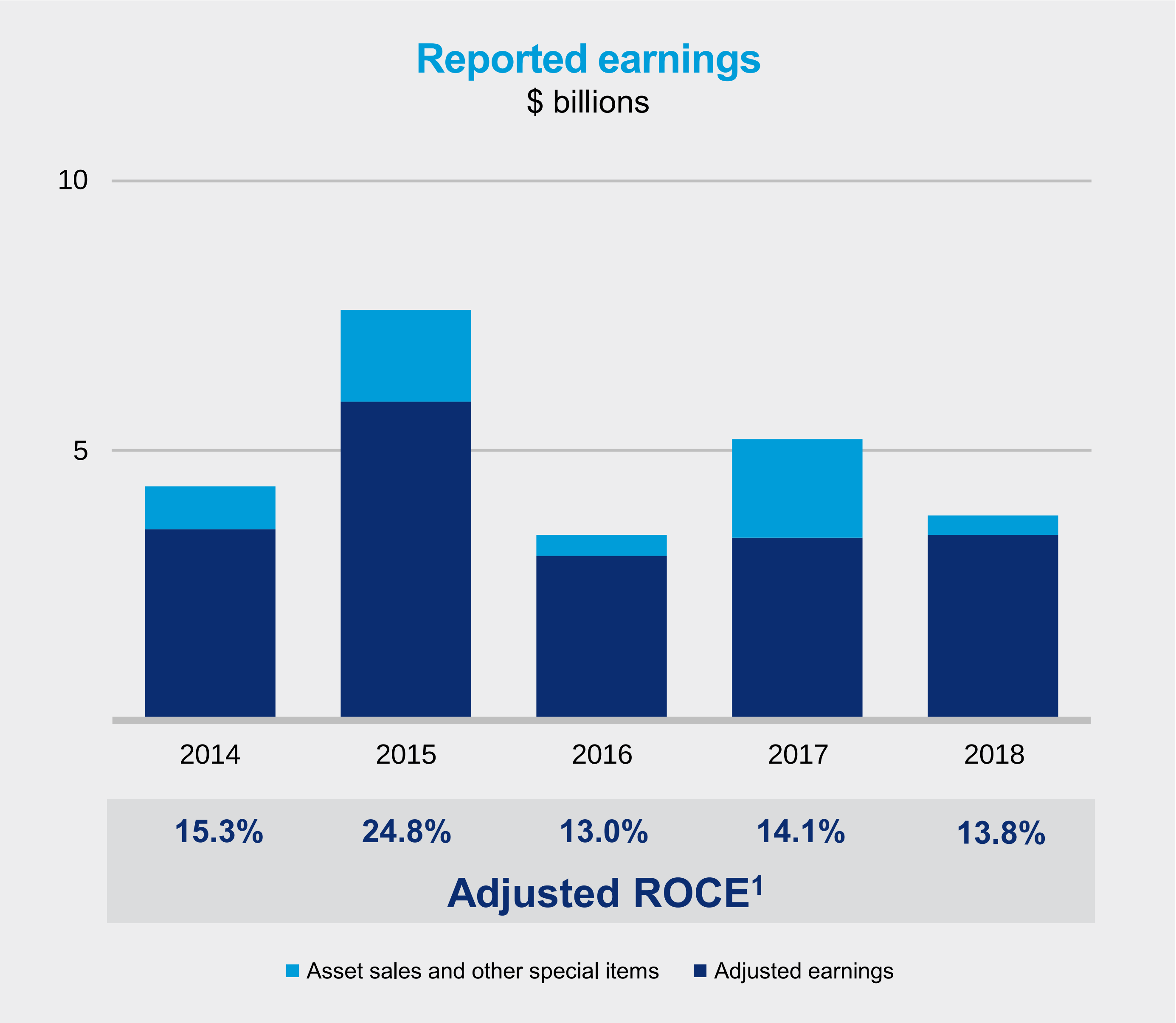
Sustain
world-class operational excellence

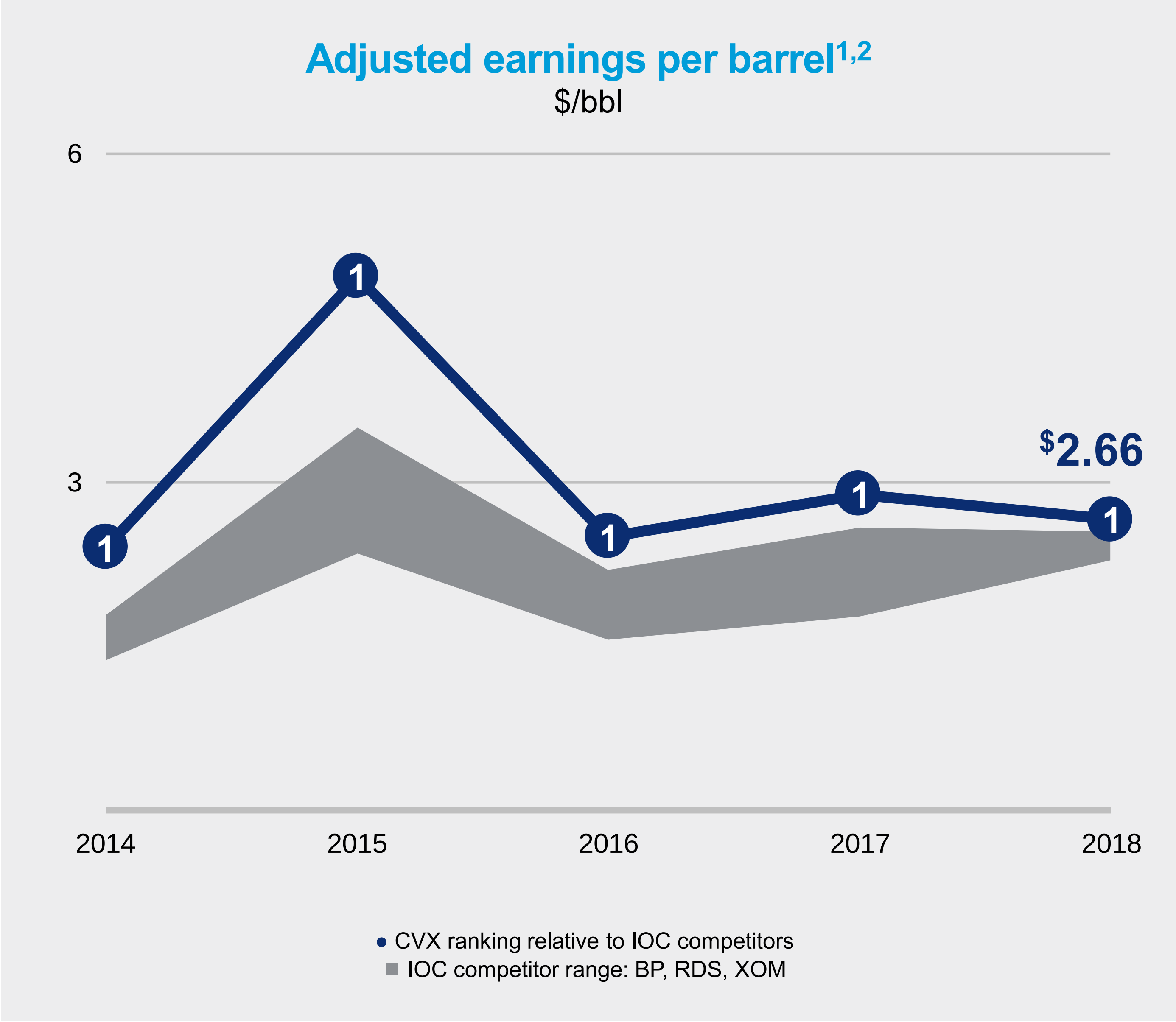
Grow
earnings across the value chain

Target
investments

Lead
the industry in returns

Strong financial performance

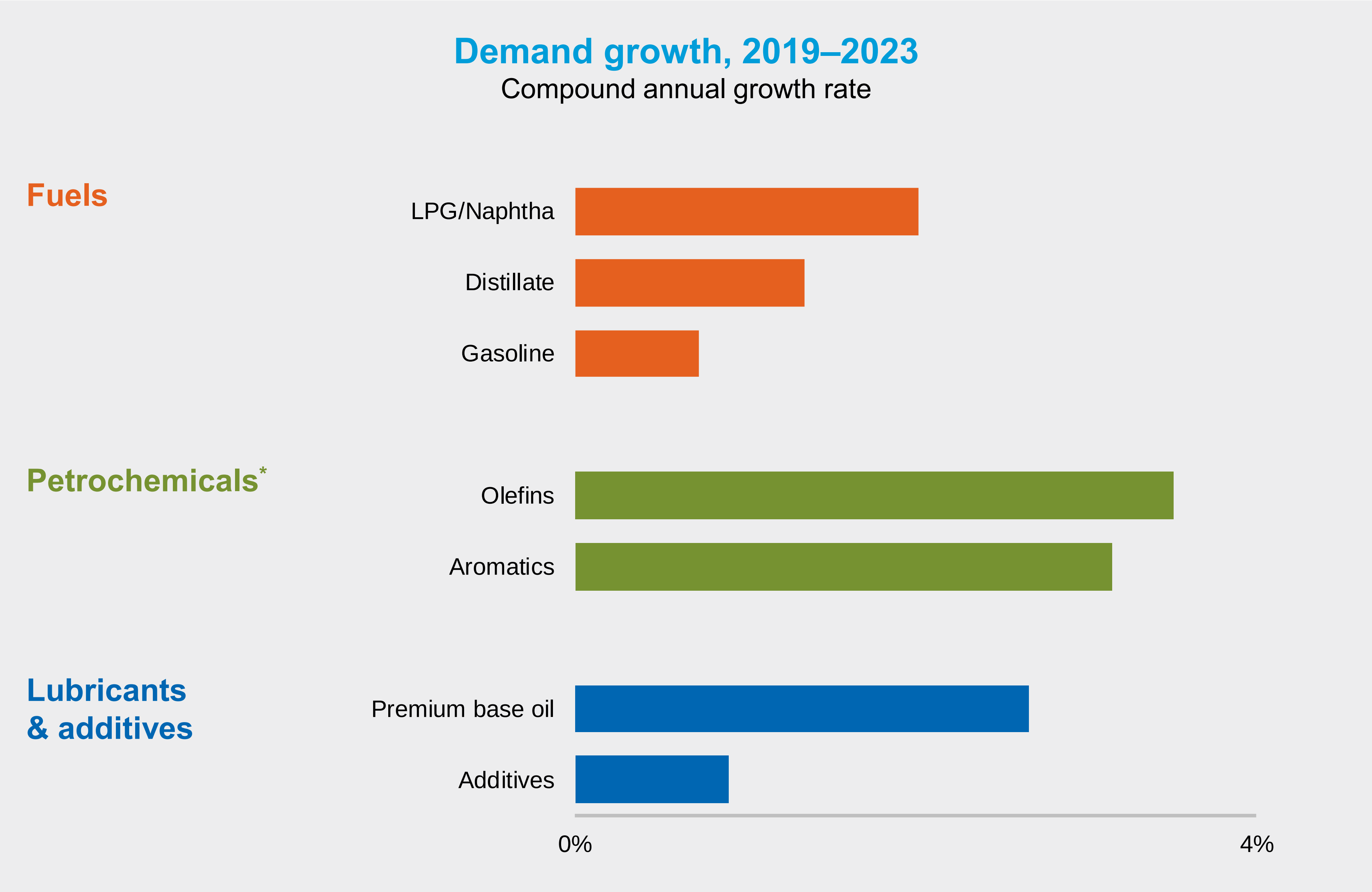




[1] See Appendix: reconciliation of non-GAAP measures.
[2] Total downstream, excluding petrochemicals.

Chevron

Global product demand



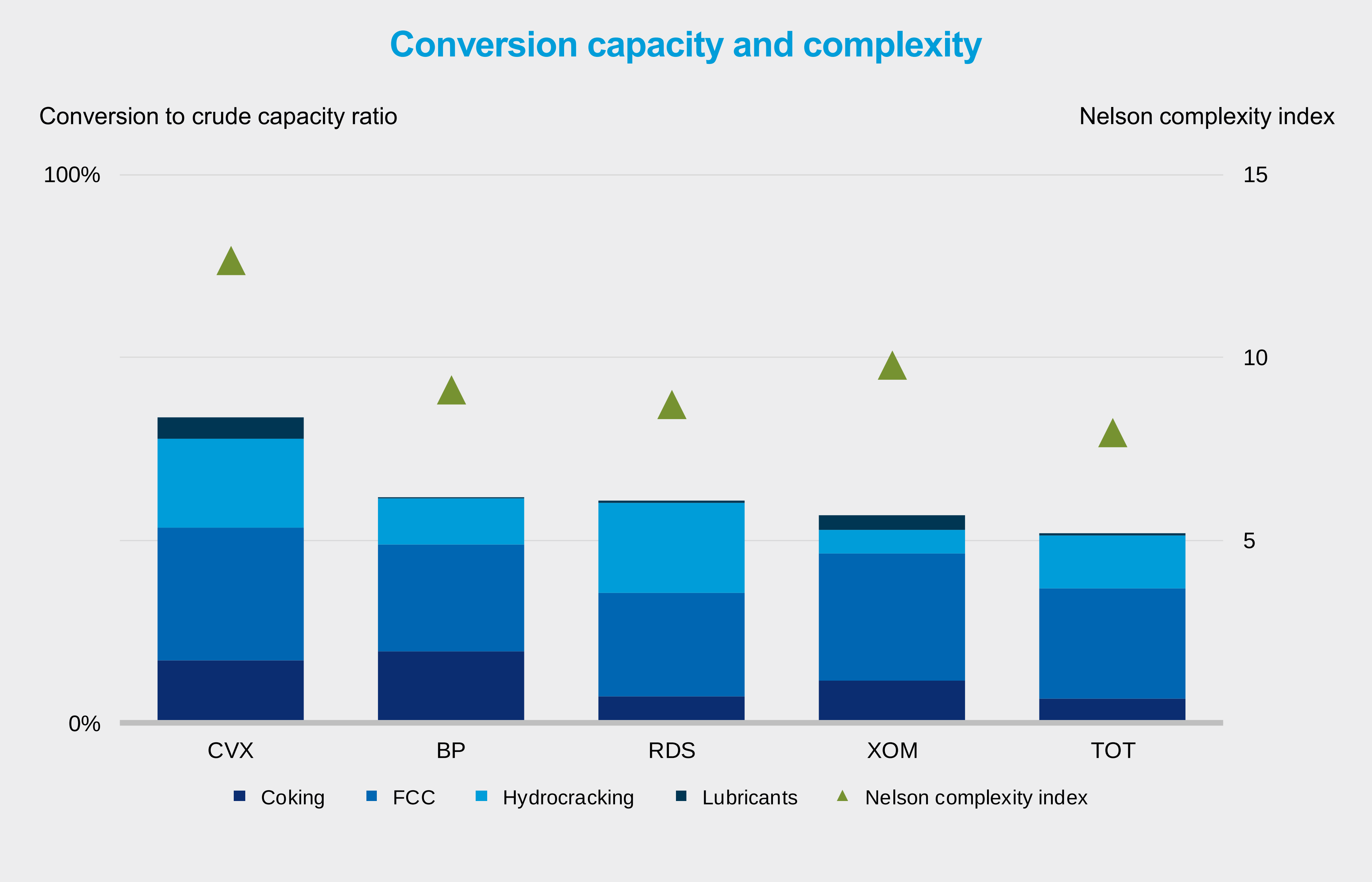
Global economic growth
drives product demand

Petrochemicals
grow faster than fuels

IMO
supports light product margins

Sources: Wood Mackenzie, NexantThinking™ Petroleum and Petrochemicals Economics program, Klein & Company
* Olefins includes ethylene, propylene and butadiene. Aromatics includes paraxylene and benzene.

Well positioned for IMO 2020



Complex refiners advantaged

Highest Nelson complexity

Nelson Complexity Index (NCI) source: *Oil and Gas Journal;* Conversion to crude capacity source: IHS Markit.

Major capital projects

Evaluation / FEED

Chevron Phillips Chemical Co.
USGC II

Chevron Phillips Chemical Co.
Middle East growth

Singapore Refining Co.
Resid upgrading

Under construction

Salt Lake refinery
ISOALKY™ plant

Oronite
China blending & shipping

GS Caltex
Olefins project

Commission / start-up

Richmond refinery
Modernization

Pasadena refinery acquisition

Scope

110 MBD

Houston Ship Channel terminal

5.6 MM bbls storage tanks

143 acres vacant land

Strategic fit

Enables light crude processing

Integrates and optimizes with Pascagoula

Supplies equity fuels to Texas / Louisiana

Transaction

$350MM, plus working capital

Closed 2Q19

Integrated fuels value chains

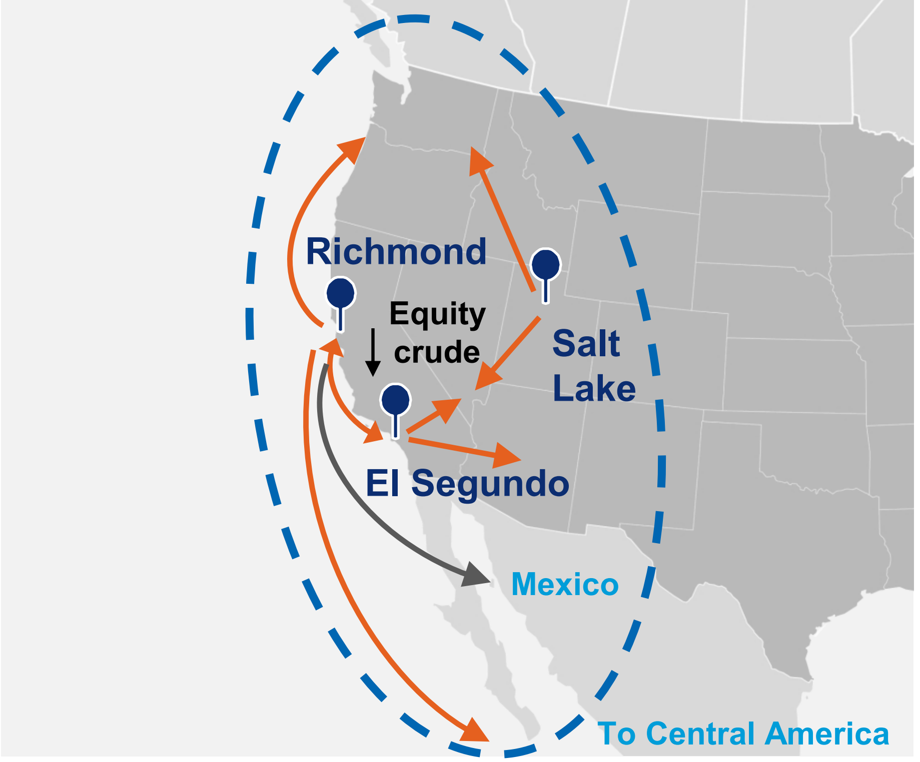
U.S. West Coast

#1 brand share in Western U.S.

Growing retail in Mexico

San Joaquin Valley equity crude

Tightly integrated supply chain



U.S. Gulf Coast

A leading brand in Central America

Top net cash margin refinery

Equity crude integration

Optimizing across the value chain

Asia Pacific

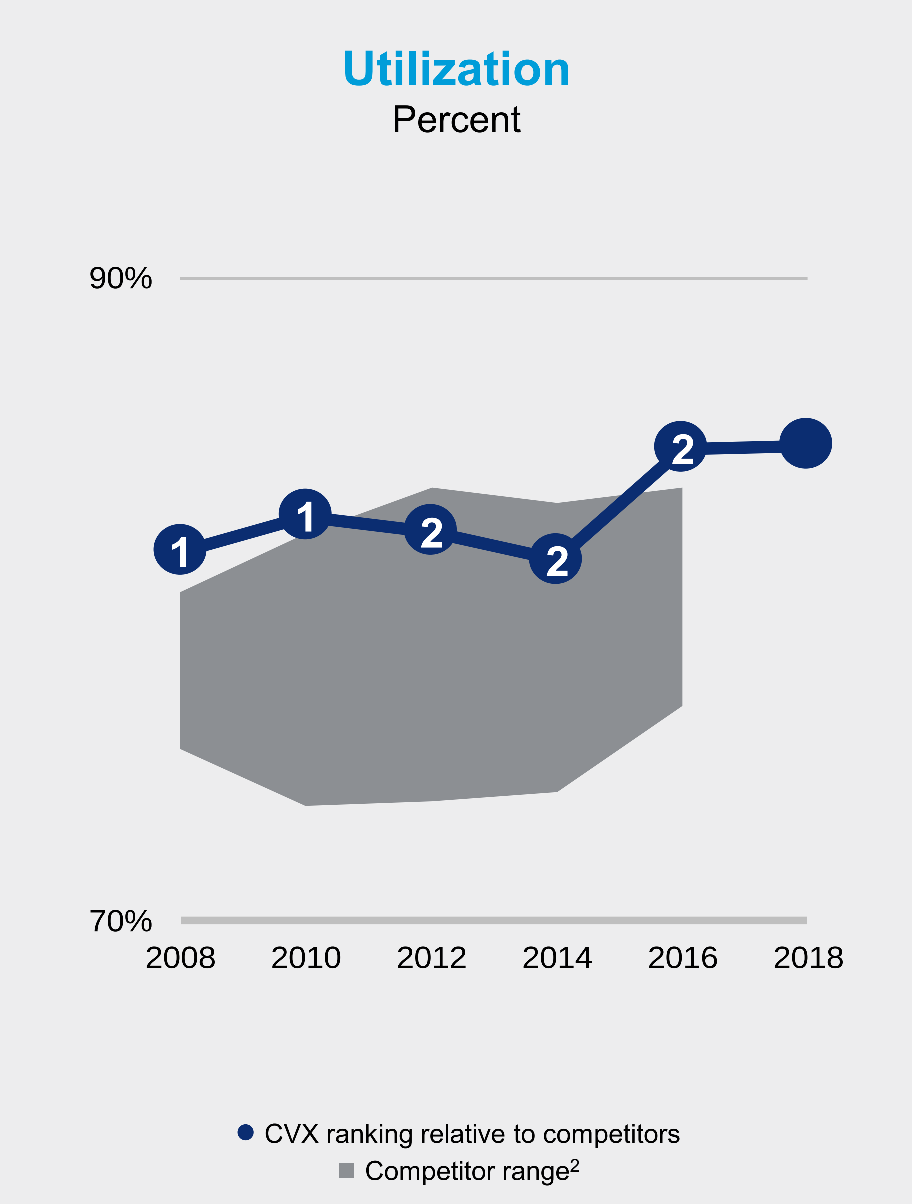
Long-standing partnerships

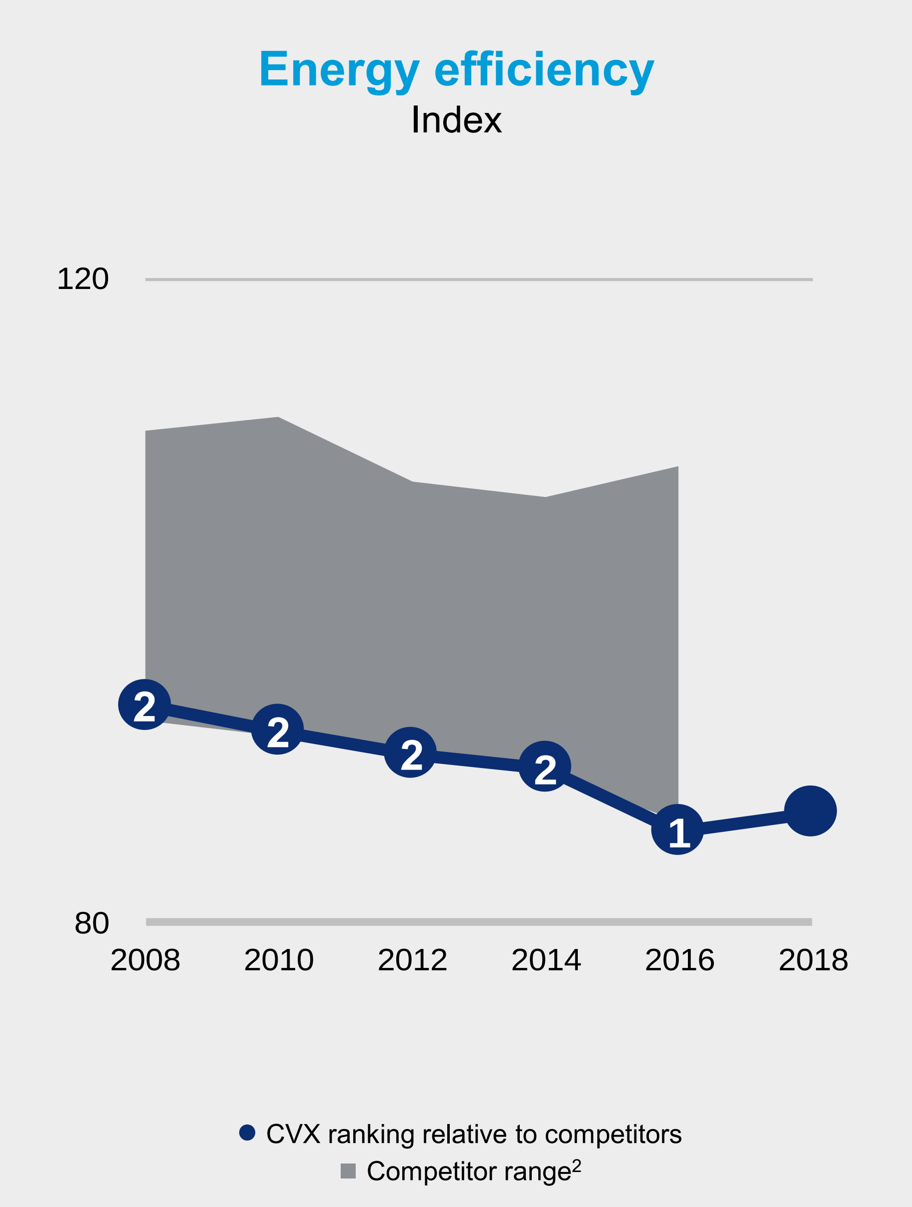
World-class manufacturing

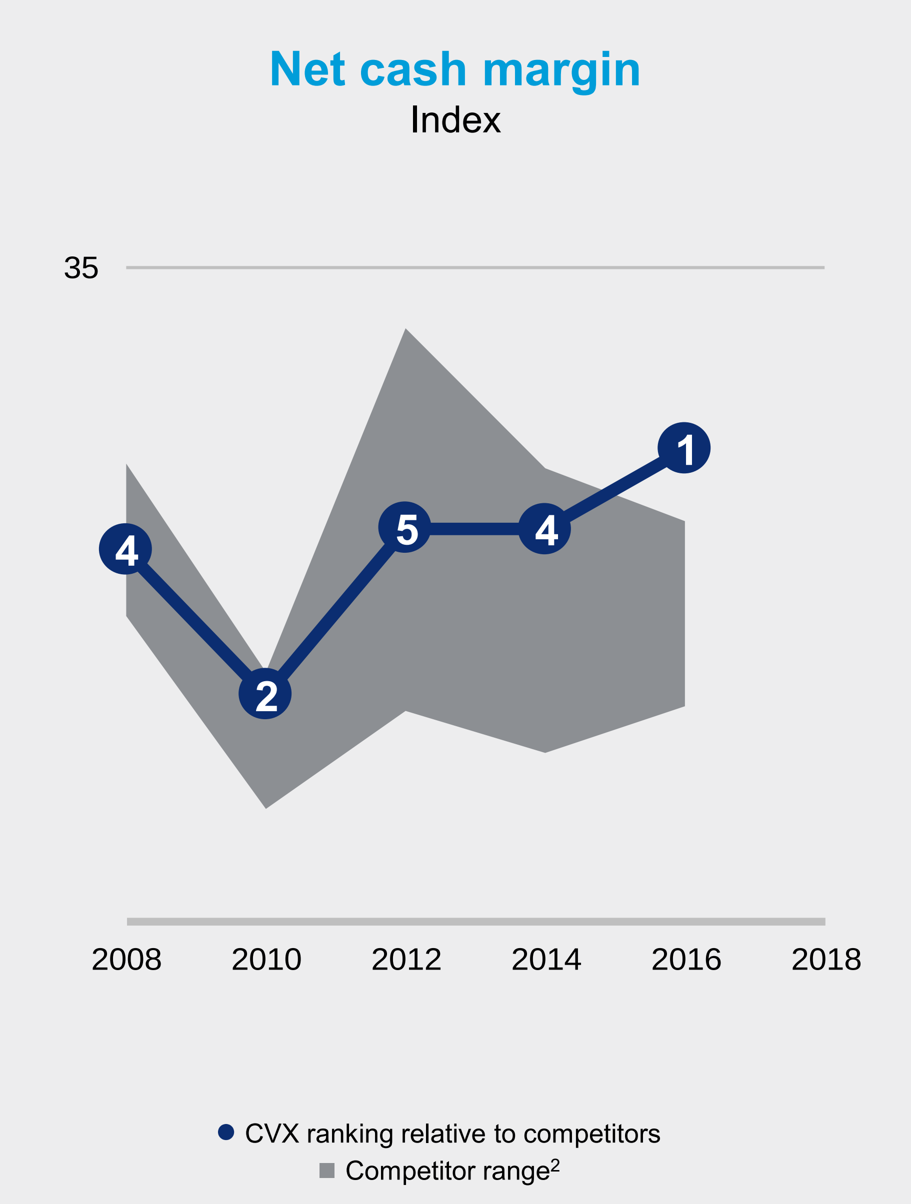
Strengthening upgrading capability and marketing positions

Future integration — Products and intermediaries — Equity crude

Leading refinery performance[1]







Source: Solomon Associates and Chevron data.
[1] Includes operated and non-operated refineries.
[2] Average for top eight international refiners excluding CVX with facilities included in at least two of the three regional Solomon biennial surveys.

Fuels marketing initiatives

Americas

On track for ~400 branded sites in Mexico by 2020

Mexico terminals expected start-up 2020

Targeting additional ~75 ExtraMile convenience stores per year

Asia

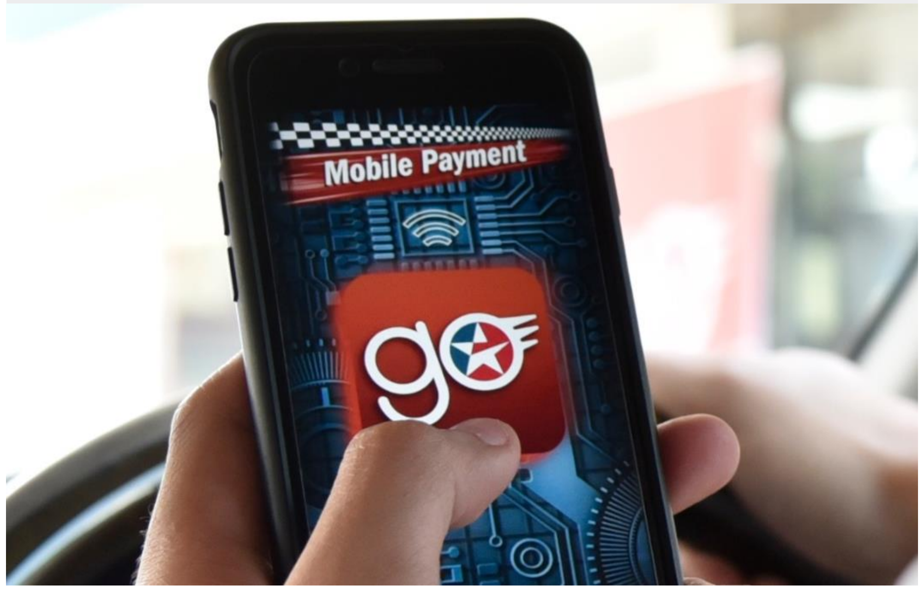
Plan to grow by up to 300 branded sites in Southeast Asia by 2022

GS Caltex equity investment in car sharing company, Green Car

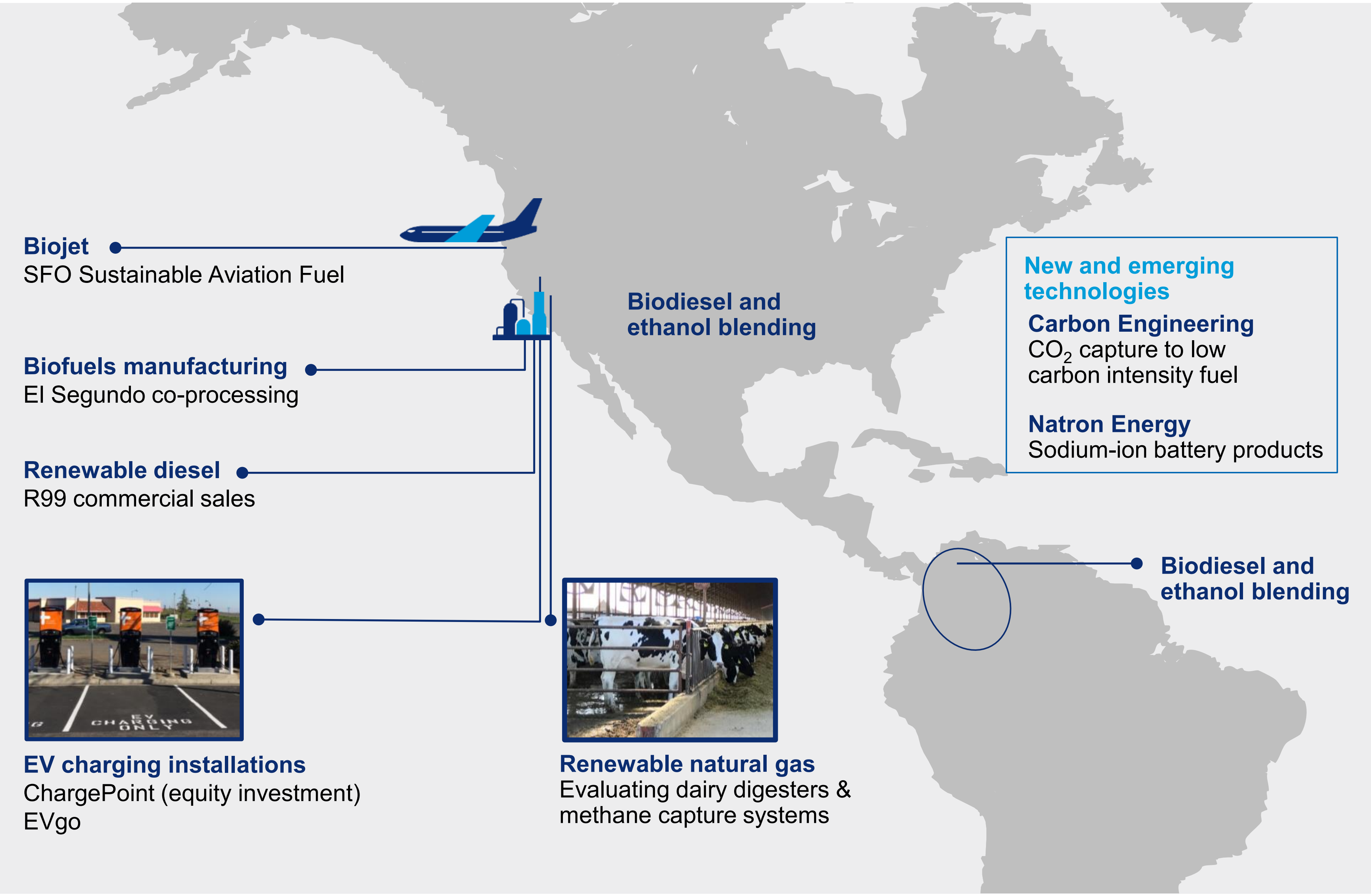
Mobile e-pay

PayPal and Honda partnerships in U.S.

CaltexGO – mobile pay in Southeast Asia



Renewable fuels



Integrated value chain

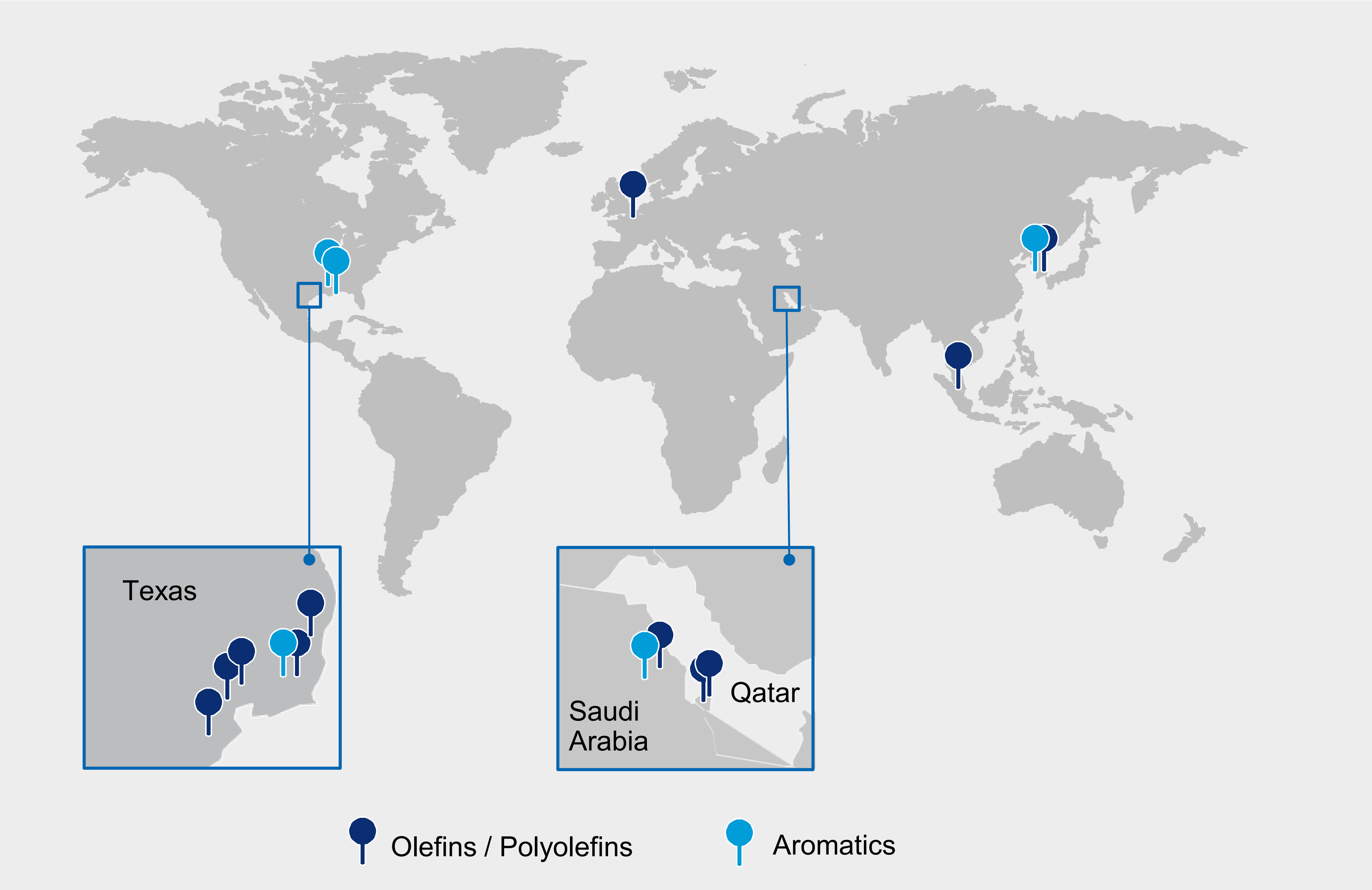
Modest investment

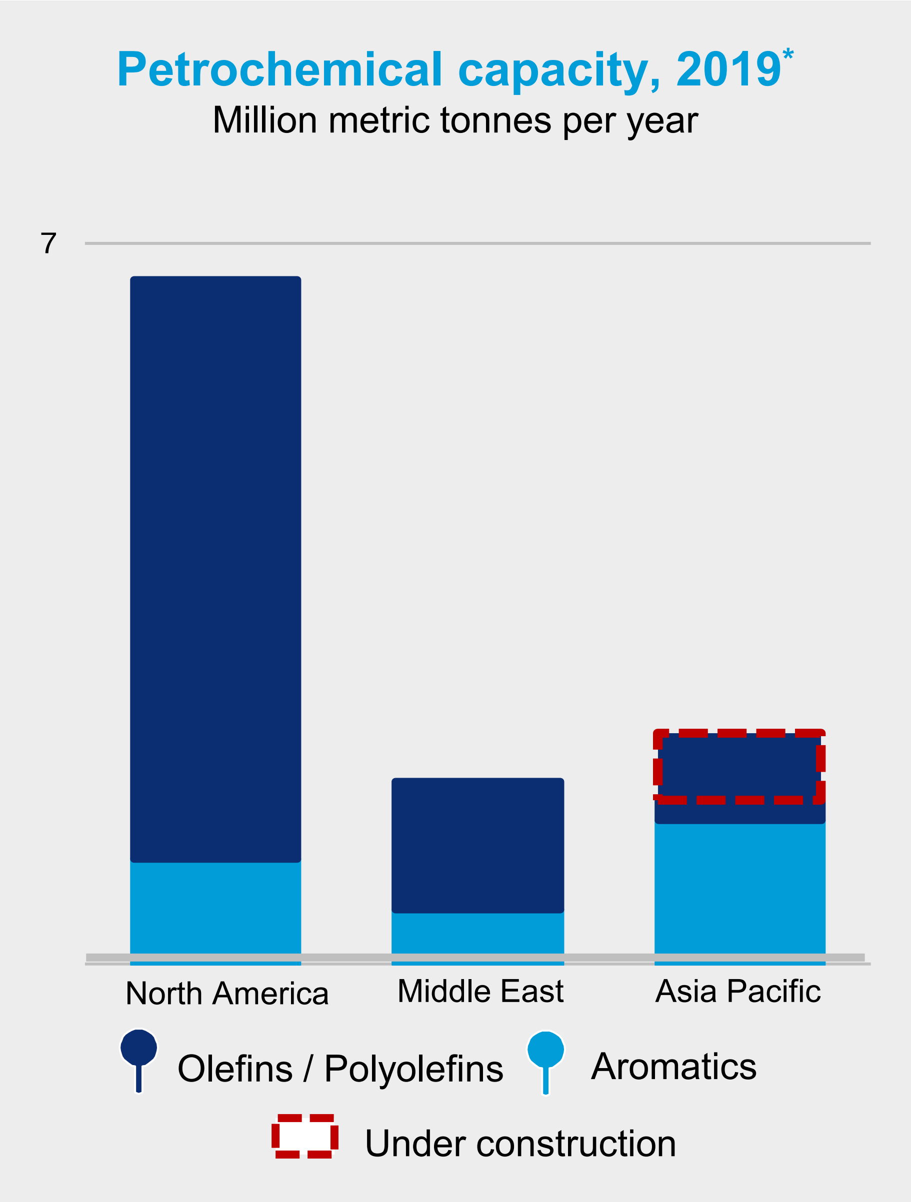
Portfolio of options

Competitive returns

Reliable supply

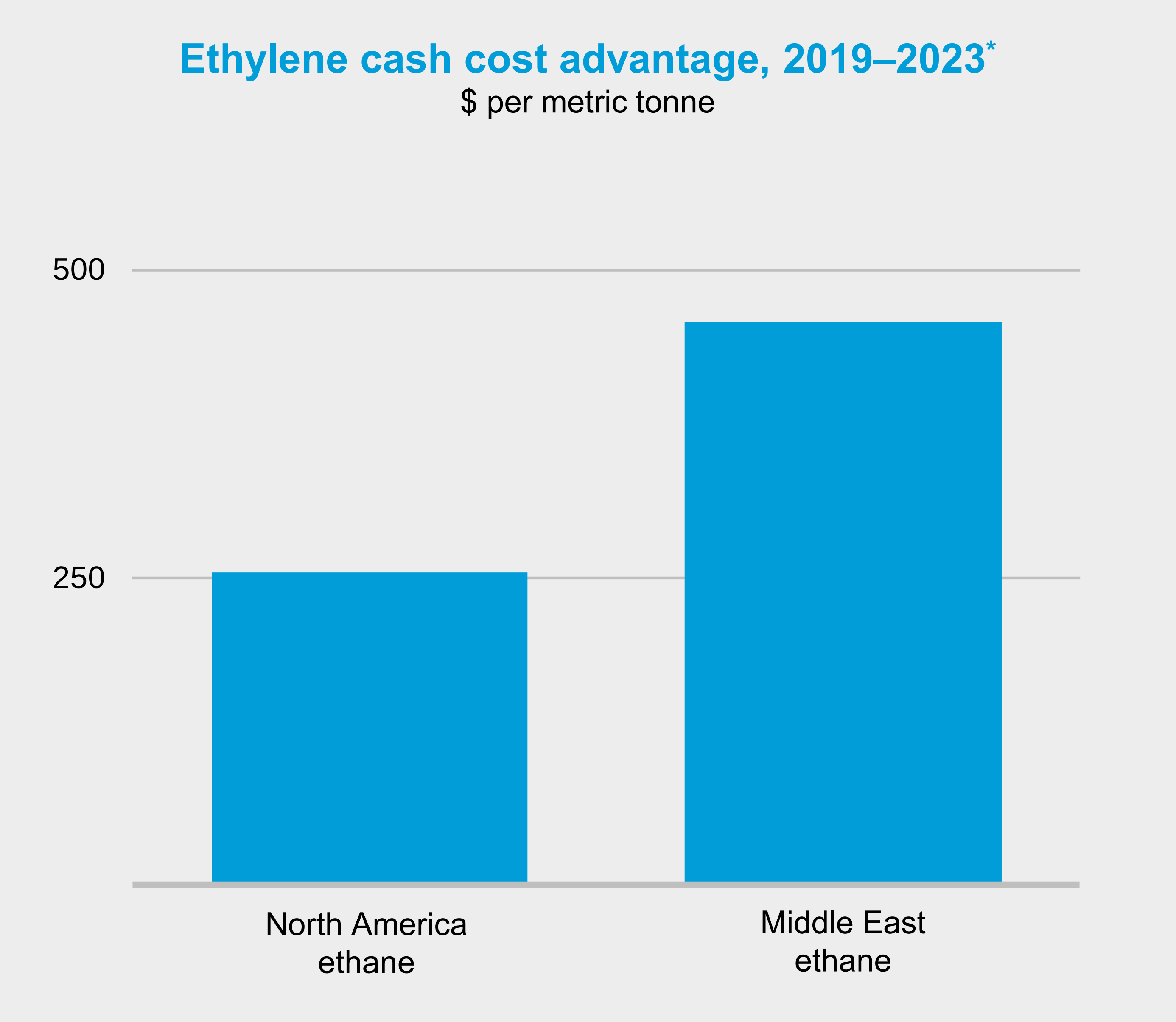
Advantaged petrochemicals portfolio

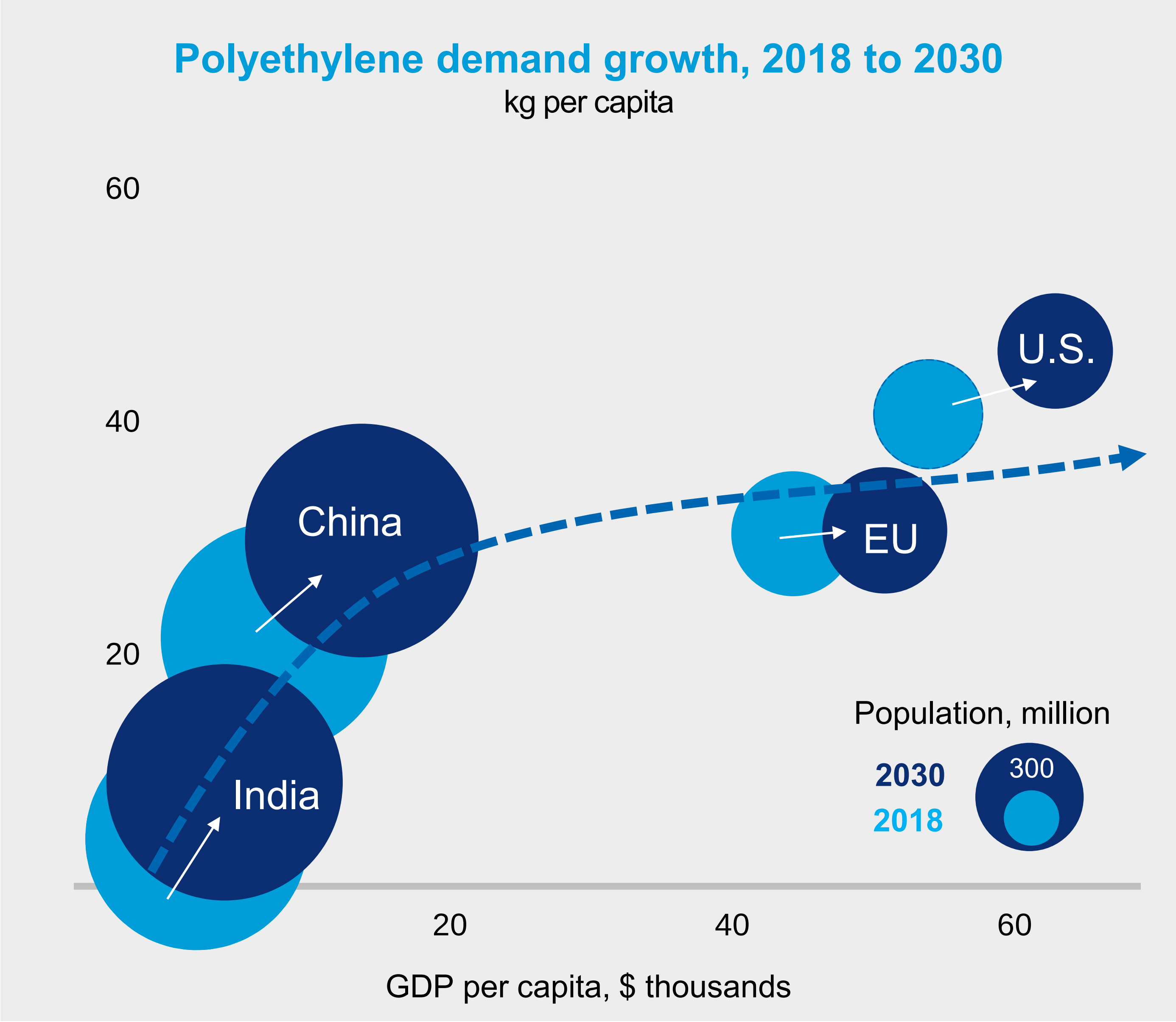




Sources: Company data and 2018 Chevron Annual Report.
* Chevron 50% share in Chevron Phillips Chemical and GS Caltex.

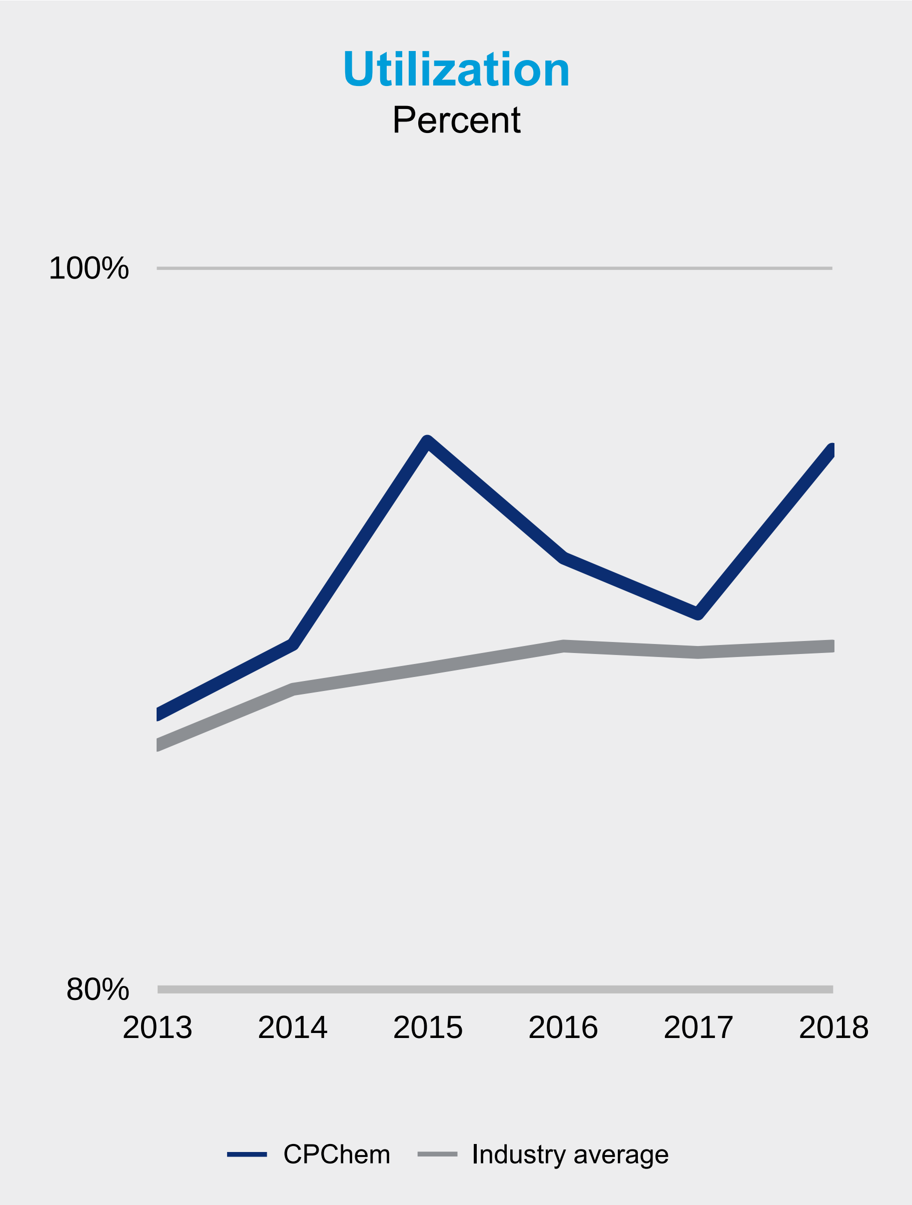
Strong petrochemical market fundamentals





Sources: NexantThinking™ Petroleum and Petrochemicals Economics program, Wood Mackenzie Chemicals
* Asia Naphtha Cracker cash cost per metric tonne – North America / Middle East Cracker cash cost per metric tonne using Nexant medium oil price scenario.

Chevron Phillips Chemical performance



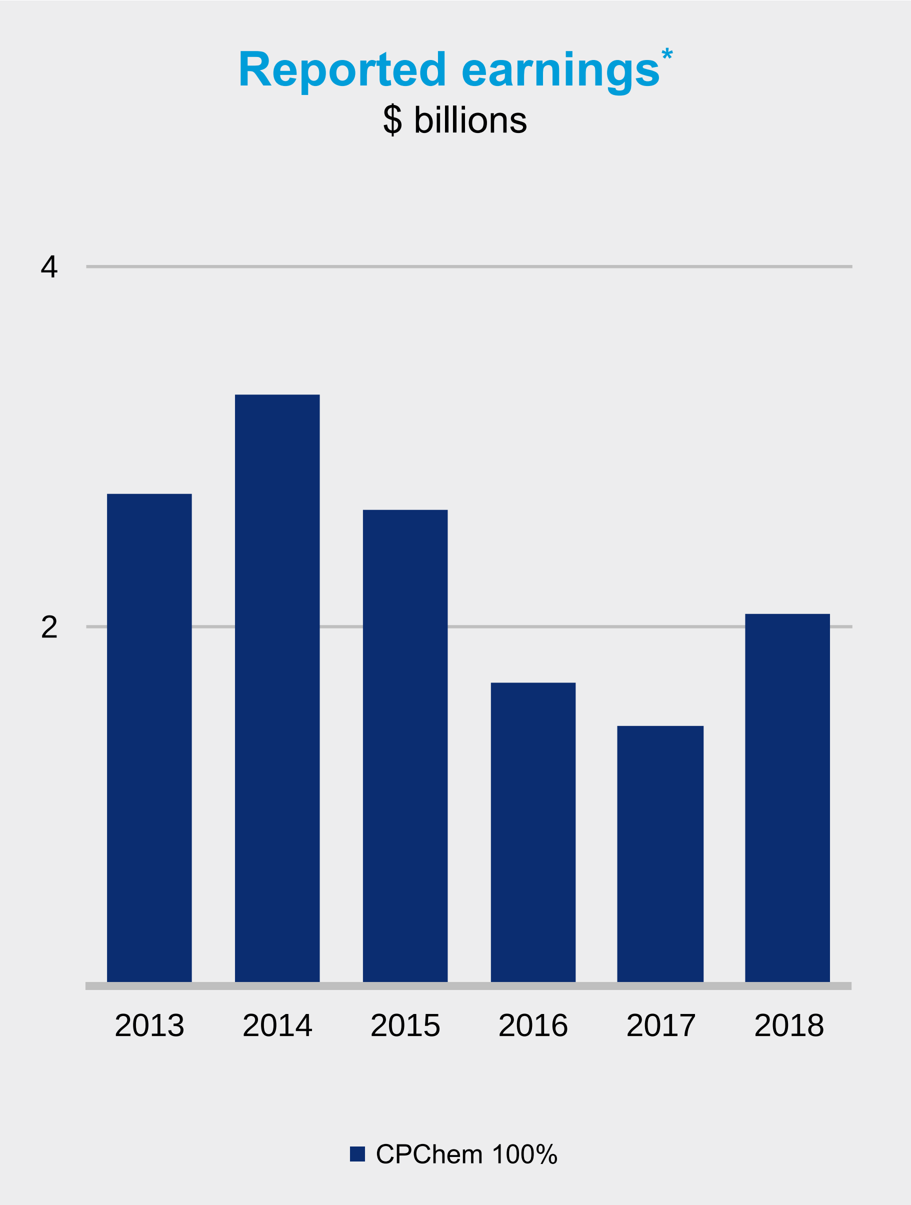
World class assets

Advantaged feedstock

Proprietary technologies

High operating rates

Sustainability focus



* 100% CPChem earnings before U.S. income tax.

Lubricants and additives activities

Renewable base oil

Equity investment in Novvi LLC

Technology partnership

Plant-based renewable feedstock

High-performance synthetic base oil

Novvi plant capital investment, expected start-up 3Q19

Finished lubricants

Delo, 67% of first fill trucks in North America

Motorcycle oil products launched in Asia / Latin America

Taro Ultra to meet IMO 2020

Additives

Portfolio to address IMO 2020

Singapore capacity expansion for next gen automotive lubricants

Solutions for latest stationary gas engine designs

Midstream overview

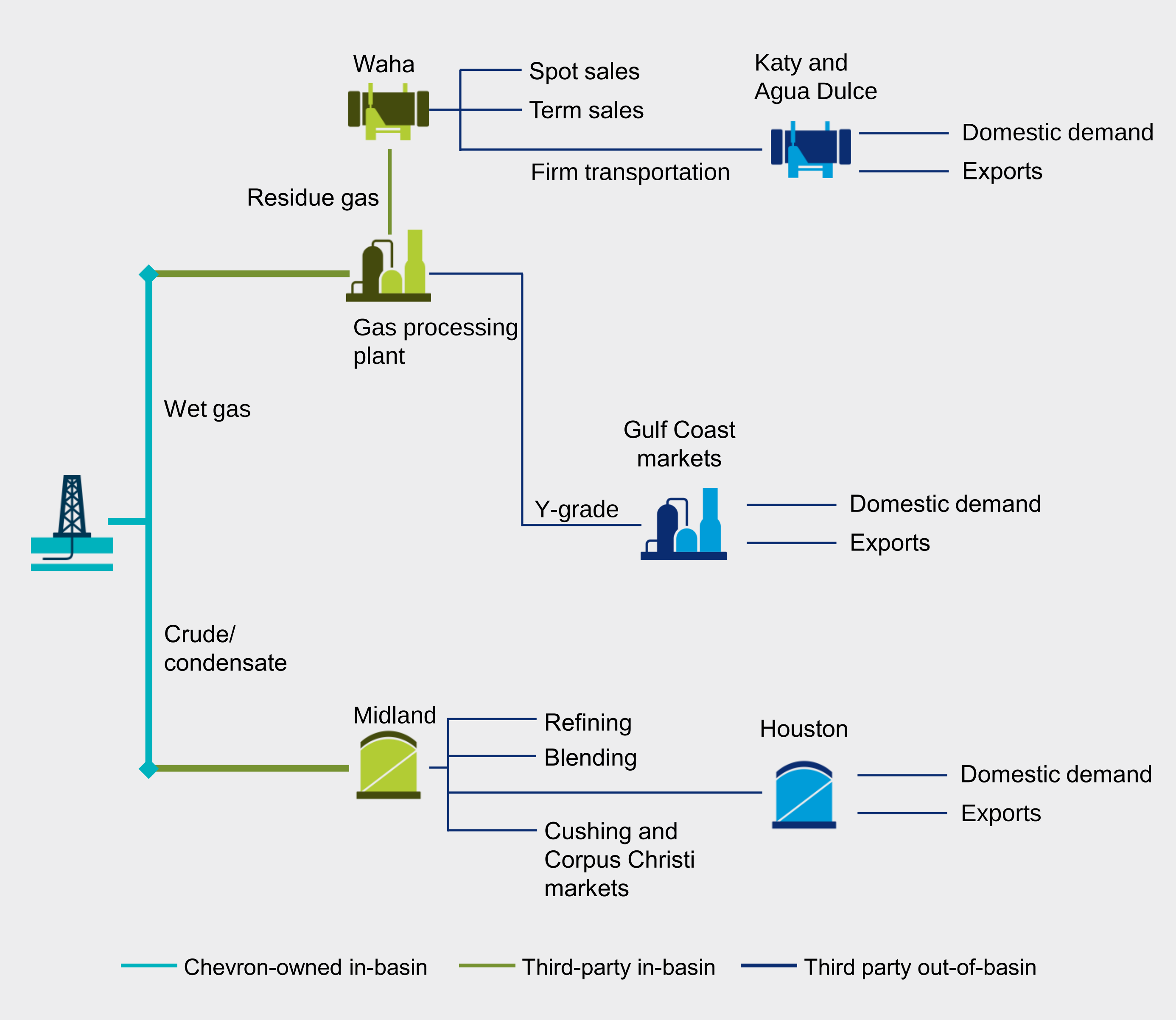
Permian value chain strategy

Maximize earnings for the enterprise

Advantaged commercial agreements with midstream service providers

Flow assurance for crude, gas, and NGLs to nearest liquid market

Global presence enables margin capture across geographies and commodities



Permian takeaway capacity

Crude oil strategy

Sufficient transport capacity
of operated + non-operated take-in-kind production through 2019

New industry capacity expected
to eliminate Midland to U.S. Gulf Coast bottlenecks by late 2019

Firm dock capacity in Houston Ship Channel increases in 2019
to support growing production

Permian takeaway capacity

NGL strategy

Sufficient transportation and fractionation coverage
for forecasted NGL equity production through 2019

Maximize physical connectivity and contractual flexibility
to enable deliveries to multiple markets

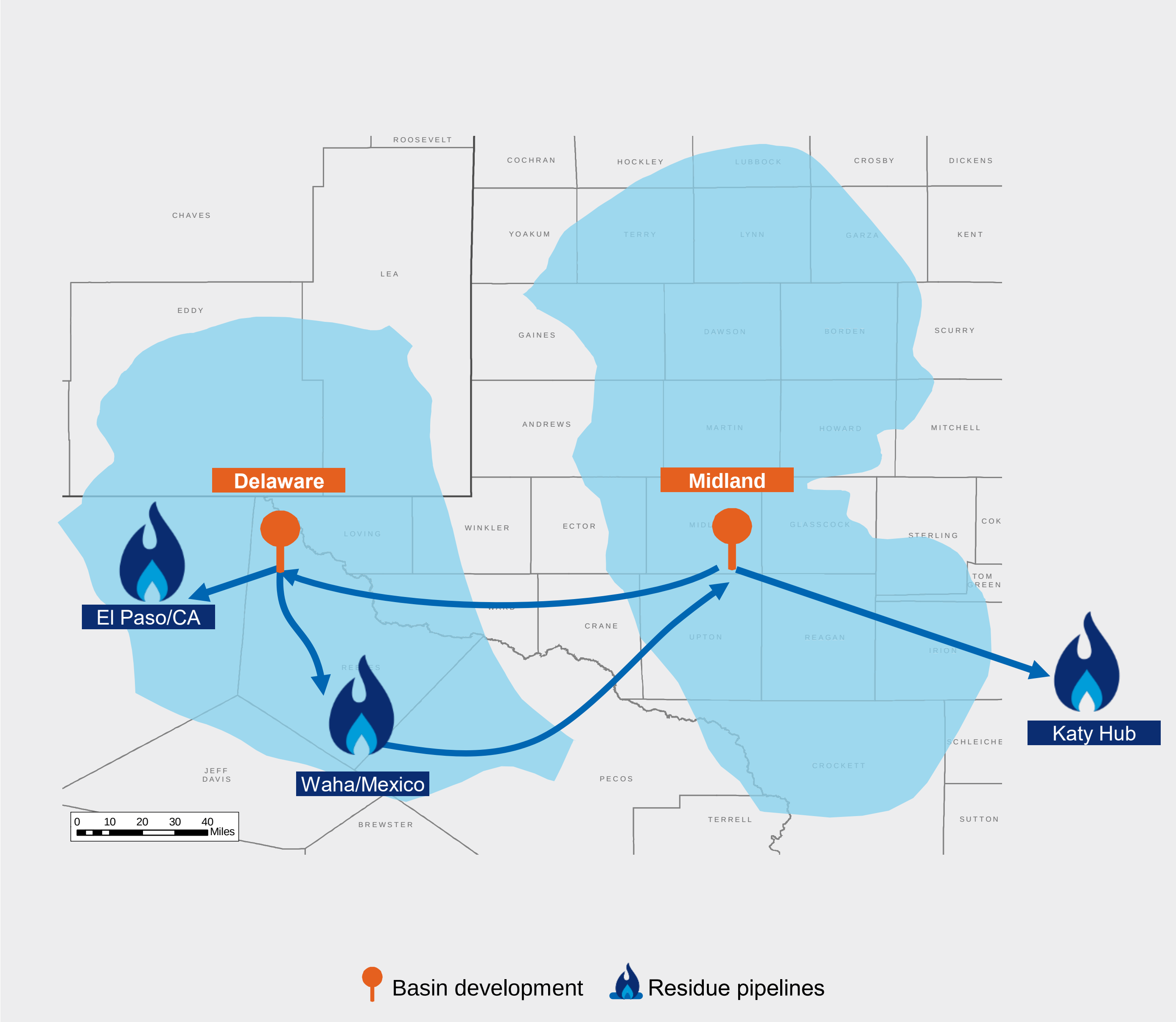
Secure access to exports

Permian takeaway capacity

Natural gas strategy

100% firm plant processing & takeaway
capacity to Waha

Sufficient takeaway capacity
for out-of-basin
(Houston Ship Channel, Mexico, LNG)



Midstream plans for other unconventional plays

Argentina

Loma Campana

Infrastructure and market development still in early stages

Monitor development and assess risks of takeaway bottlenecks

Canada

Duvernay

Long-term agreements for gas processing, liquid transportation, and NGL fractionation

Access to multiple markets

Appalachia

Marcellus / Utica

100% transportation coverage for 2019 production

Focus on ensuring flow and maximizing netbacks while limiting high-cost and long-term transportation commitments

LNG value chain strategy

Focus on cost competitive opportunities

Reliable operations for enhanced cash generation

Leverage strong customer base in Asia Pacific marketplace

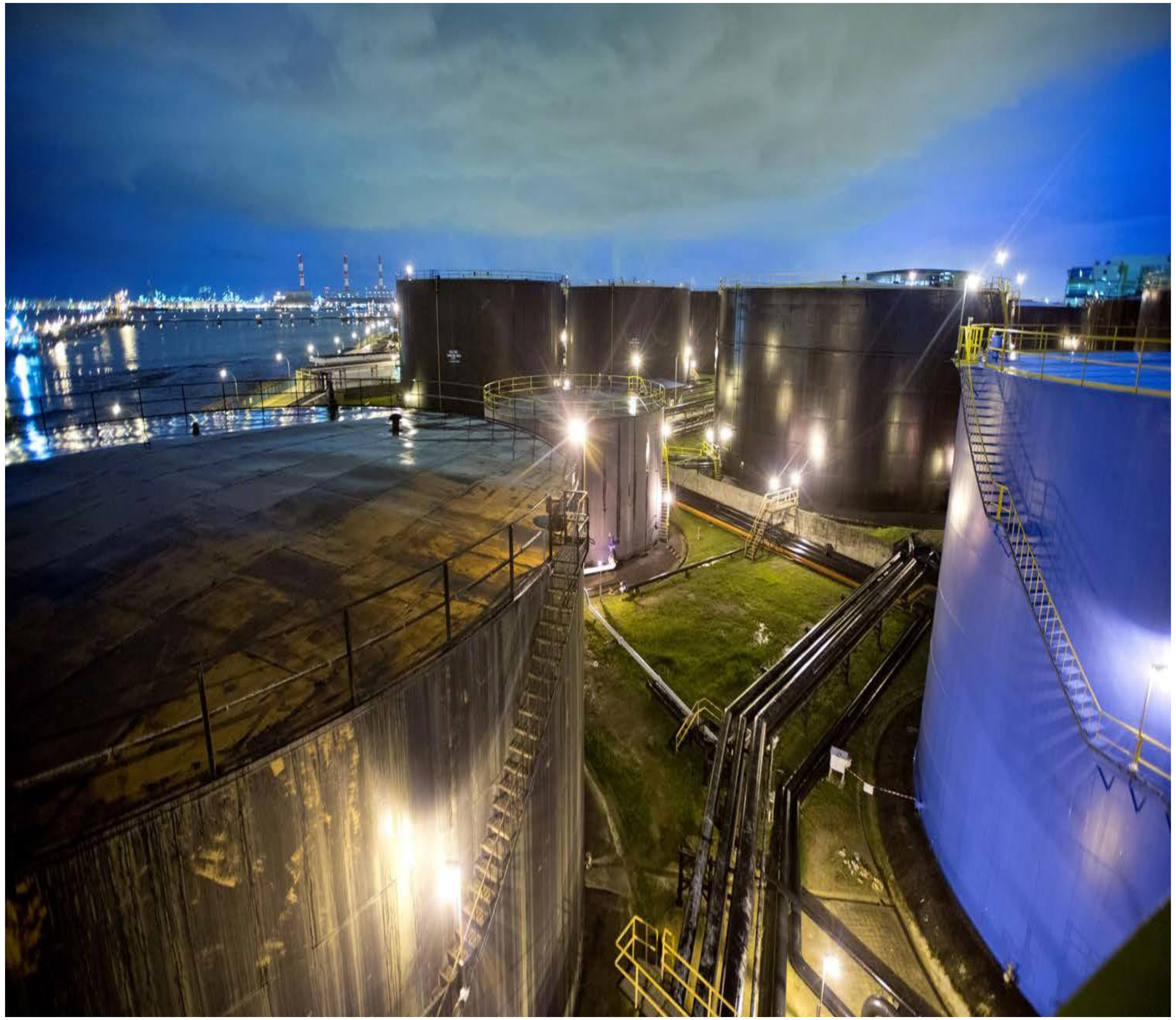
Optimized Shipping and Trading strategy

Supply & Trading strategy

Flow – Optimize – Trade

Focus on flow assurance and physical optimization

Leverage expertise to add value across the value chain



Upstream Major Capital Projects [1]

Project	Location	Operator	WI %	Facility Design Capacity [2] Liquids MBPD	Facility Design Capacity [2] Gas MMCFPD	Current Phase	Startup [3]
Clair Ridge	UK	Other	19.4	120	100	Production	2018
Big Foot	United States	Chevron	60.0	75	25	Production	2018
Stampede	United States	Other	25.0	80	40	Production	2018
Tahiti Vertical Expansion	United States	Chevron	58.0	Maintain Capacity		Production	2018
Mad Dog 2	United States	Other	15.6	140	-	Construction	2021
Gorgon Stage 2	Australia	Chevron	47.3	Maintain Capacity		Design	2022
TCO Future Growth Project	Kazakhstan	Affiliate	50.0	260 [4]	–	Construction	2022
TCO Wellhead Pressure Management Project	Kazakhstan	Affiliate	50.0	Maintain Capacity		Construction	2022
Kitimat LNG	Canada	Chevron	50.0	–	1,600	Design	2023+
Indonesia Deepwater Development - Gendalo – Gehem	Indonesia	Chevron	62.0	30	920	Design	2023+
Captain EOR Stage 2	UK	Chevron	85.0	Maintain Capacity		Design	2023+
Anchor	United States	Chevron	61.3 / 55.0 [5]	75	28	Design	2023+

(1) The projects in the table are considered the most significant in the development portfolio and have commenced production or are in the design or construction phase. Each project has an estimated project cost of more than $500 million, Chevron share.
(2) Facility Design Capacity are 100% gross estimates.
(3) Start-up timing for non-operated projects per operator's estimate.
(4) Represents expected total daily production.
(5) Represents 61.3% interest in the northern unit blocks and 55% interest in the southern unit blocks.

Appendix: reconciliation of Chevron's adjusted earnings

	TOTAL DOWNSTREAM				
	2014	2015	2016	2017	2018
Reported Earnings ($MM)	**$4,336**	**$7,601**	**$3,435**	**$5,214**	**$3,798**
Adjustment Items:					
Asset Dispositions	(960)	(1,710)	(490)	(675)	(350)
Other Special Items[1]	160	--	110	(1,160)	--
Total Adjustment Items	(800)	(1,710)	(380)	(1,835)	(350)
Adjusted Earnings ($MM)[2]	**$3,536**	**$5,891**	**$3,055**	**$3,379**	**$3,448**
Average Capital Employed ($MM)	$23,167	$23,734	$23,430	$23,928	$25,028
Adjusted ROCE[1,2,3]	15.3%	24.8%	13.0%	14.1%	13.8%

[1] Includes asset impairments & revaluations, certain non-recurring tax adjustments & environmental remediation provisions, severance accruals, and any other special items.
[2] Adjusted Earnings = Reported earnings less adjustments for asset dispositions and other special items, except foreign exchange.
[3] Adjusted Return on Capital Employed (ROCE) = Adjusted Earnings divided by Average Capital Employed.

Appendix: reconciliation of Chevron's adjusted earnings

TOTAL DOWNSTREAM, EXCLUDING PETROCHEMICALS	2014	2015	2016	2017	2018
Earnings ($MM)	**$3,176**	**$6,586**	**$2,823**	**$4,671**	**$2,932**
Adjustment Items:					
Asset Dispositions	(960)	(1,710)	(490)	(675)	(350)
Other Special Items[1]	160	--	110	(1,160)	--
Total Adjustment Items	(800)	(1,710)	(380)	(1,835)	(350)
Adjusted Earnings ($MM)[2]	**$2,376**	**$4,876**	**$2,443**	**$2,836**	**$2,582**
Volumes (MBD)	2,711	2,735	2,675	2,690	2,655
Earnings per Barrel	$3.21	$6.60	$2.88	$4.76	$3.03
Adjusted Earnings per Barrel	$2.40	$4.88	$2.50	$2.89	$2.66

[1] Includes asset impairments & revaluations, certain non-recurring tax adjustments & environmental remediation provisions, severance accruals, and any other special items.
[2] Adjusted Earnings = Reported earnings less adjustments for asset dispositions and other special items, except foreign exchange.

Appendix: reconciliation of Chevron's adjusted earnings

TOTAL UPSTREAM	2014	2015	2016	2017	2018
Earnings ($MM)	**$16,893**	**$(1,961)**	**$(2,537)**	**$8,150**	**$13,316**
Adjustment Items:					
Asset Dispositions	(1,780)	(310)	70	(760)	--
Other Special Items[1]	950	4,180	2,915	(2,750)	1,590
Total Adjustment Items	(830)	3,870	2,985	(3,510)	1,590
Adjusted Earnings ($MM)[2]	**$16,063**	**$1,909**	**$448**	**$4,640**	**$14,906**
Net Production Volume (MBOED)[3]	2,484	2,539	2,513	2,634	2,827
Earnings per Barrel	$18.63	$(2.12)	$(2.76)	$8.48	$12.90
Adjusted Earnings per Barrel	$17.72	$2.06	$0.49	$4.83	$14.45

[1] Includes asset impairments & revaluations, certain non-recurring tax adjustments & environmental remediation provisions, severance accruals, and any other special items.
[2] Adjusted Earnings = Reported earnings less adjustments for asset dispositions and other special items, except foreign exchange.
[3] Excludes own use fuel (natural gas consumed in operations).

Appendix: reconciliation of non-GAAP measures

Reported earnings to earnings excluding special items and FX

	3Q18	4Q18	1Q19	2Q19	3Q19
Reported earnings ($ millions)					
Upstream	3,379	3,290	3,123	3,483	2,704
Downstream	1,373	859	252	729	828
All Other	(705)	(419)	(726)	93	(952)
Total reported earnings	**4,047**	**3,730**	**2,649**	**4,305**	**2,580**
Diluted weighted avg. shares outstanding ('000)	1,917,473	1,906,823	1,900,748	1,902,977	1,893,928
Reported earnings per share	**$2.11**	**$1.95**	**$1.39**	**$2.27**	**$1.36**
Special items ($ millions)					
UPSTREAM					
Asset dispositions	--	--	--	--	--
Impairments and other*	(930)	(270)	--	180	--
Subtotal	(930)	(270)	--	180	--
DOWNSTREAM					
Asset dispositions	350	--	--	--	--
Impairments and other*	--	--	--	--	--
Subtotal	350	--	--	--	--
ALL OTHER					
Impairments and other*	--	--	--	740	(430)
Subtotal	--	--	--	740	(430)
Total special items	**(580)**	**(270)**	**--**	**920**	**(430)**
Foreign exchange ($ millions)					
Upstream	(42)	250	(168)	22	49
Downstream	(7)	23	31	(9)	27
All other	(2)	(5)	--	2	(2)
Total FX	**(51)**	**268**	**(137)**	**15**	**74**
Earnings excluding special items and FX ($ millions)					
Upstream	4,351	3,310	3,291	3,291	2,655
Downstream	1,030	836	221	738	801
All Other	(703)	(414)	(726)	(649)	(520)
Total earnings excluding special items and FX ($ millions)	**4,678**	**3,732**	**2,786**	**3,370**	**2,936**
Earnings per share excluding special items and FX	**$2.44**	**$1.95**	**$1.47**	**$1.77**	**$1.55**

* Includes asset impairments & revaluations, certain non-recurring tax adjustments & environmental remediation provisions, severance accruals and any other special items.

Appendix: reconciliation of non-GAAP measures

Cash flow from operations excluding working capital
Free cash flow excluding working capital

$ millions	FY 2016	FY 2016 Quarterly Avg.*	FY 2017	FY 2017 Quarterly Avg.*	FY 2018	FY 2018 Quarterly Avg.*	1Q19	2Q19	3Q19
Net Cash Provided by Operating Activities	12,690	3,173	20,338	5,085	30,618	7,655	5,057	8,783	7,817
Net Decrease (Increase) in Operating Working Capital	(327)	(82)	520	130	(718)	(180)	(1,210)	930	1,406
Cash Flow from Operations Excluding Working Capital	**13,017**	**3,254**	**19,818**	**4,955**	**31,336**	**7,834**	**6,267**	**7,853**	**6,411**
Net Cash Provided by Operating Activities	12,690	3,173	20,338	5,085	30,618	7,655	5,057	8,783	7,817
Less: Cash Capital Expenditures	18,109	4,527	13,404	3,351	13,792	3,448	2,953	3,584	3,369
Free Cash Flow	**(5,419)**	**(1,355)**	**6,934**	**1,734**	**16,826**	**4,207**	**2,104**	**5,199**	**4,448**

* Numbers may not sum due to rounding.