NEWS RELEASE

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RICH SET OF OPPORTUNITIES TO DRIVE VALUABLE GROWTH

BHP Billiton today outlined the broad range of opportunities within its Petroleum business to grow value, returns and cash flow as markets improve.

Speaking at an investor briefing in London, BHP Billiton President Operations Petroleum, Steve Pastor said “Having both minerals and petroleum in our portfolio allows us to maximise the value of our petroleum assets at the right point in the cycle.”

“While currently well supplied, underlying fundamentals suggest both oil and gas markets are improving more quickly than our minerals commodities.”

“Over the next decade, demand growth, natural field decline and the effects of industry wide investment deferrals are expected to create a significant opportunity to invest and maximize value in oil. By 2025 the world is expected to consume more than 100,000 barrels of liquids per day – a third of which would come from new sources.

“We are well placed to capitalise on this opportunity. We have a large, high quality resource base. Our focus on productivity has significantly reduced both operating and capital costs, supporting a range of shale and conventional investment opportunities that would generate compelling returns at today’s prices. As a result, Petroleum is well placed to maintain its position as BHP Billiton’s highest margin business and to grow its free cash flow contribution.”

BHP Billiton runs its Onshore US assets to maximise value rather than volumes and will continue to adjust its investment plans to reflect market conditions.

“Our Onshore US business gives us valuable flexibility. Our shale assets generate cash at current prices, with significant upside should oil and gas prices recover as we expect,” Mr Pastor said.

“We operate in the heart of some of the best shale plays and by further reducing costs and improving capital efficiency to levels among the best in the industry, we have increased our investible well inventory. As a result, we now have up to 1,200 undrilled net oil wells, contingent upon trials in the Eagle Ford, and 220 undrilled net gas wells that generate a minimum 15 per cent internal rate of return (IRR) at US$50 per barrel of oil and US$3 per MMbtu.

“In the Permian, we have access to over one billion barrels of oil equivalent (boe) meaning this field has the potential to become the largest production and free cash contributor in our Petroleum portfolio within five years.”

In Conventional, BHP Billiton is expecting unit operating costs to remain at approximately US$10 per boe over the 2017 and 2018 financial years as it pursues a number of options to extend high margin production from its existing facilities.

“We have a rich portfolio of brownfield project options, with total capital expenditure of US$2.5 billion and an average IRR of 45 per cent that will help offset field decline. With significant improvements in capital efficiency, major capital projects like Mad Dog 2 are now economically attractive, even below US$50 per barrel of oil,” Mr Pastor said.

BHP Billiton today also announced positive drilling results at the Caicos exploration well in the Gulf of Mexico. Located in Green Canyon 564, this well is approximately 100 miles south of the Louisiana coast in the deep water Gulf of Mexico. Caicos was drilled to a total depth of 30,803 feet and encountered oil in multiple horizons.

“We are encouraged by the Caicos results and are moving to further appraise the area. The next step will be drilling the Wildling well in November. With success at Caicos and Shenzi North, we continue to be optimistic around the opportunity for a commercial development in the area.”

Further information on BHP Billiton can be found at: **bhpbilliton.com**

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BHP Billiton Petroleum

An exciting outlook for our Petroleum business

Steve Pastor President Operations, Petroleum

Disclaimer

Forward-looking statements

This presentation contains forward-looking statements, including statements regarding: reserves and resources and the production, revenues and costs relating thereto, trends in commodity prices and currency exchange rates; demand for commodities; plans, strategies and objectives of management; closure or divestment of certain operations or facilities (including associated costs); anticipated production or construction commencement dates; capital costs and scheduling; operating costs and shortages of materials and skilled employees; anticipated productive lives of projects, mines and facilities; provisions and contingent liabilities; tax and regulatory developments.

Forward-looking statements can be identified by the use of terminology such as ‘intend’, ‘aim’, ‘project’, ‘anticipate’, ‘estimate’, ‘plan’, ‘believe’, ‘expect’, ‘may’, ‘should’, ‘will’, ‘continue’, ‘annualised’ or similar words. These statements discuss future expectations concerning the results of operations or financial condition, or provide other forward-looking statements.

These forward-looking statements are not guarantees or predictions of future performance, and involve known and unknown risks, uncertainties and other factors, many of which are beyond our control, and which may cause actual results to differ materially from those expressed in the statements contained in this presentation. Readers are cautioned not to put undue reliance on forward-looking statements.

For example, future revenues from our operations, other results, projects or mines described in this presentation will be based, in part, upon the market price of the minerals, metals or petroleum produced, which may vary significantly from current levels. These variations, if materially adverse, may affect the timing or the feasibility of the development of a particular project, the expansion of certain facilities or mines, the continuation of existing operations.

Other factors that may cause actual results to differ from those expressed in the forward-looking statements include uncertainties in estimating reserves, difficulties in converting resources into reserves and reserves into quantities of oil and gas,

operating risks, changes in operating costs, factors that affect the actual construction or production commencement dates, costs or production output and anticipated lives of operations, mines or facilities include our ability to profitably produce and transport the minerals, petroleum and/or metals extracted to applicable markets; the impact of foreign currency exchange rates on the market prices of the minerals, petroleum or metals we produce; activities of government authorities in some of the countries where we are exploring or developing these projects, facilities or mines, including increases in taxes, changes in environmental and other regulations and political uncertainty; labour unrest; and other factors identified in the risk factors discussed in BHP Billiton’s filings with the US Securities and Exchange Commission (the “SEC”) (including in Annual Reports on Form 20-F) which are available on the SEC’s website at www.sec.gov.

Except as required by applicable regulations or by law, the Group does not undertake any obligation to publicly update or review any forward-looking statements, whether as a result of new information or future events.

Past performance cannot be relied on as a guide to future performance.

Non-IFRS financial information

BHP Billiton results are reported under International Financial Reporting Standards (IFRS) including Underlying EBIT and Underlying EBITDA which are used to measure segment performance. This release may also include certain non-IFRS and other financial measures including Adjusted effective tax rate, Free cash flow, Gearing ratio, Net debt, Net operating assets, Underlying attributable profit, Underlying basic (loss)/earnings per share, Underlying EBIT margin and Underlying EBITDA margin. These measures are used internally by management to assess the performance of our business, make decisions on the allocation of our resources and assess operational management. Non-IFRS and other financial measures have not been subject to audit or review and should not be considered as an indication of or alternative to an IFRS measure of profitability, financial performance or liquidity.

Presentation of data

Unless specified otherwise: all data is presented on a continuing operations basis to exclude the contribution from assets that were demerged with South32; references to Underlying EBITDA margin exclude third party trading activities; data from subsidiaries is shown on a 100 per cent basis and data from equity accounted investments and other operations is shown on a proportionate consolidation basis. Numbers presented may not add up precisely to the totals provided due to rounding. Onshore US scenarios are based on price estimates from Bank of America Merrill Lynch, Citi, Credit Suisse, Deutsche Bank, JP Morgan, Macquarie, Morgan Stanley and UBS as at 8 August 2016 and do not necessarily correspond to BHP Billiton’s view of prices.

No offer of securities

Nothing in this presentation should be construed as either an offer to sell or a solicitation of an offer to buy or sell BHP Billiton securities in any jurisdiction, or be treated or relied upon as a recommendation or advice by BHP Billiton.

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The views expressed in this presentation contain information that has been derived from publicly available sources that have not been independently verified. No representation or warranty is made as to the accuracy, completeness or reliability of the information. This presentation should not be relied upon as a recommendation or forecast by BHP Billiton.

Statement of Petroleum Resources

Petroleum Resources

The estimates of Petroleum Reserves and Contingent Resources contained in this presentation are based on, and fairly represent, information and supporting documentation prepared under the supervision of Mr. A. G. Gadgil, who is employed by BHP Billiton. Mr. Gadgil is a member of the Society of Petroleum Engineers and has the required qualifications and experience to act as a qualified Petroleum Reserves and Resources evaluator under the ASX Listing Rules. This presentation is issued with the prior written consent of Mr. Gadgil who agrees with the form and context in which the Petroleum Reserves and Contingent Resources are presented.

Reserves and Contingent Resources are net of royalties owned by others and have been estimated using deterministic methodology. Aggregates of Reserves and Contingent Resources estimates contained in this presentation have been calculated by arithmetic summation of field/project estimates by category with the exception of the North West Shelf (NWS) Gas Project in Australia. Probabilistic methodology has been utilised to aggregate the NWS Reserves and Contingent Resources for the reservoirs dedicated to the gas project only and represents an incremental 39 MMboe of Proved Reserves. The barrel of oil equivalent conversion is based on 6000 scf of natural gas equals 1 boe. The Reserves and Contingent Resources contained in this presentation are inclusive of fuel required for operations. The respective amounts of fuel for each category are provided by footnote for the resource graphics. The custody transfer point(s)/point(s) of sale applicable for each field or project are the reference point for Reserves and Contingent Resources. Reserves and Contingent Resources estimates have not been adjusted for risk. Unless noted otherwise, Reserves and Contingent Resources are as of 30 June 2016. Where used in this presentation, the term Resources represents the sum of 2P reserves and 2C Contingent Resources.

BHP Billiton estimates Proved Reserve volumes according to SEC disclosure regulations and files these in our annual 20-F report with the SEC. All Unproved volumes are estimated using SPE-PRMS guidelines, which among other things, allow escalations to prices and costs, and as such, would be on a different basis than that prescribed by the SEC, and are therefore excluded from our SEC filings. All Resources and other Unproved volumes may differ from and may not be comparable to the same or similarly-named measures used by other companies. Non-proved estimates are inherently more uncertain than proved.

Table 1 Net BHP Billiton Petroleum Reserves and Contingent Resources as of 30 June 2016

	Onshore US			Offshore US	Australia			Rest of World				
Net MMboe	**Eagle Ford & Permian**	**Haynesville & Fayetteville**	**Subtotal**	**Gulf of Mexico**	**Offshore Western Australia[1, 2]**	**Bass Strait & Offshore Victoria**	**Subtotal**	**Trinidad & Tobago**	**Algeria**	**United Kingdom & Other**	**Subtotal**	**Total BHP Billiton**
Proved	**124**	**173**	**298**	**210**	**414**	**303**	**717**	**56**	**22**	**-**	**78**	**1,303**
Probable	**1,433**	**1,273**	**2,707**	**127**	**59**	**94**	**153**	**17**	**10**	**-**	**27**	**3,013**
2P	**1,558**	**1,447**	**3,004**	**337**	**473**	**397**	**869**	**73**	**32**	**-**	**105**	**4,316**
2C	**1,547**	**1,782**	**3,329**	**392**	**1,099**	**153**	**1,252**	**52**	**18**	**20**	**89**	**5,061**
2P+2C	**3,105**	**3,228**	**6,333**	**729**	**1,571**	**550**	**2,121**	**124**	**50**	**20**	**194**	**9,377**
Fuel included above												
Proved	2.0	5.0	7.0	5.8	36.5	16.9	53.4	1.4	1.3	-	2.8	69.0
Probable	33.2	22.2	55.4	3.2	3.6	4.7	8.3	-	-	-	-	66.8
2P	35.2	27.2	62.4	8.9	40.0	21.7	61.7	1.4	1.3	-	2.8	135.8
2C	27.3	41.4	68.7	5.8	113.4	6.8	120.2	-	-	-	-	194.7
2P+2C	62.5	68.6	131.1	14.8	153.4	28.5	181.9	1.4	1.3	-	2.8	330.6

1) Includes NWS Gas Project probabilistic increment noted in disclaimer above.

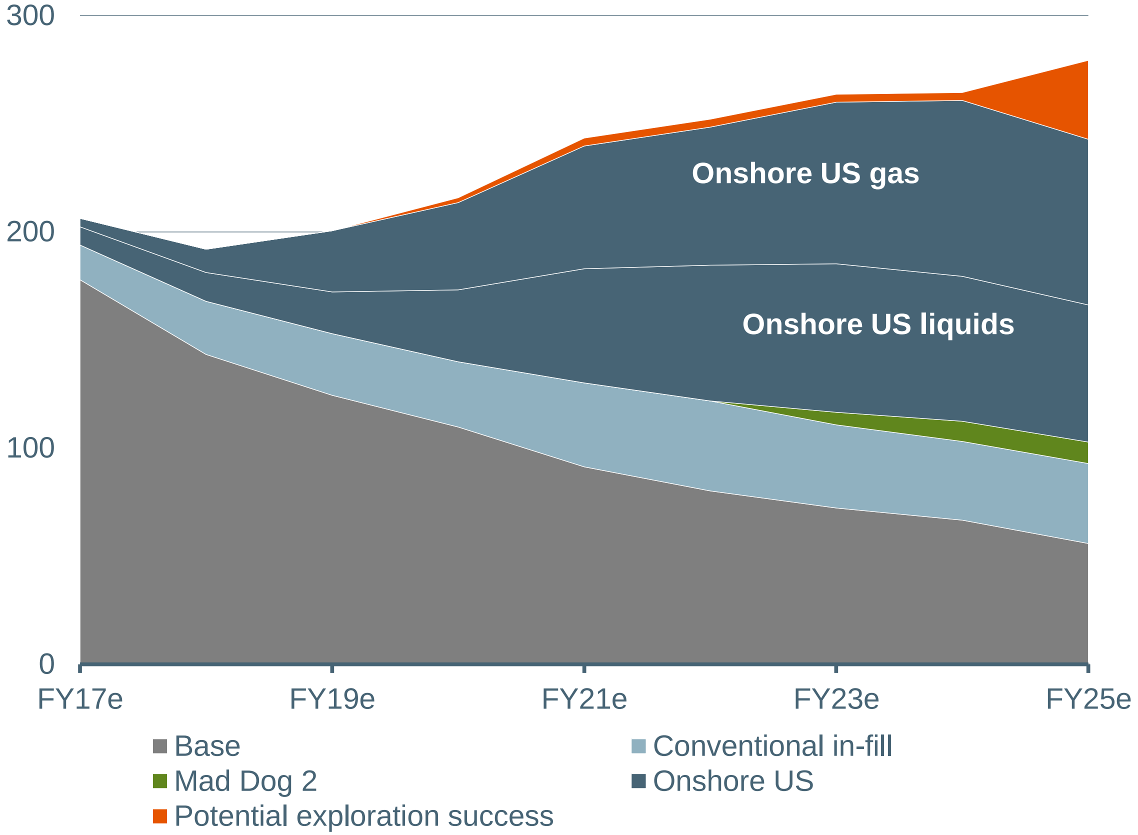
2) Australian resources prior to the announced agreement by Woodside to acquire 50% of BHP Billiton Scarborough area assets.

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only Proved, Probable and Possible Reserves, and only when such Reserves have been determined in accordance with SEC guidelines. We use certain terms in this presentation such as “Resources,” “Contingent Resources,” “2C Contingent Resources” and similar terms as well as Probable Reserves not determined in accordance with the SEC’s guidelines, all of which measures we are strictly prohibited from including in filings with the SEC. These measures include Reserves and Resources with substantially less certainty than Proved Reserves. U.S. investors are urged to consider closely the disclosure in our Form 20-F for the fiscal year ended June 30, 2016, File No. 001-09526 and in our other filings with the SEC, available from us at http://www.bhpbilliton.com/. These forms can also be obtained from the SEC as described above.

An exciting outlook for our Petroleum business

- **Petroleum is core to BHP Billiton**
  - strong financial and operating performance
  - oil and US gas markets expected to rebalance first
- **Petroleum strategy focused on value over volume**
- **Concentrated resource base and proven operating capability**
  - Onshore US – capturing full resource value while driving returns and free cash flow
  - Conventional – high margins with inventory of in-fill projects to offset field decline
- **Rich set of opportunities to drive valuable growth**
  - Mad Dog 2 investment decision expected in next six months
  - Haynesville acceleration supported by hedging
  - Permian progressing towards full pad development in FY19
  - exploration program yielding encouraging results
  - would consider value accretive acquisitions

Value accretive production potential over the next decade[1]
(BHP Billiton production, MMboe)



1. Production estimates for FY18 onwards represents a scenario. Scenarios do not constitute guidance; actual production will be determined according to market conditions prevailing at the relevant time.

Experienced leadership driving value and returns

- **Deep experience across leadership team**
  - average industry and functional experience of over 25 years
  - operating experience across six continents
- **Operating model supports improved returns**
  - operations enabled to focus on safety, volume and cost
  - globally integrated functions co-located with operations
  - accelerated sharing of best practice between minerals and petroleum
- **Dynamic approach focused on value**
  - monthly signpost reviews support hedging decisions
  - quarterly capital allocation reviews

President Operations Petroleum
Steve Pastor
27 years

Asset President Shale
Alex Archila
33 years

Asset President Conventional
Geraldine Slattery
26 years

VP Exploration
Niall McCormack
21 years

VP HSE
David Crawford
17 years

Head of Planning
John Simmons
24 years

VP Engineering
David Purvis
33 years

VP Drilling
Derek Cardno
33 years

VP Geoscience
Paul McIntosh
31 years

VP Marketing
Michiel Hovers
21 years

VP Finance
Michelle Turner
21 years

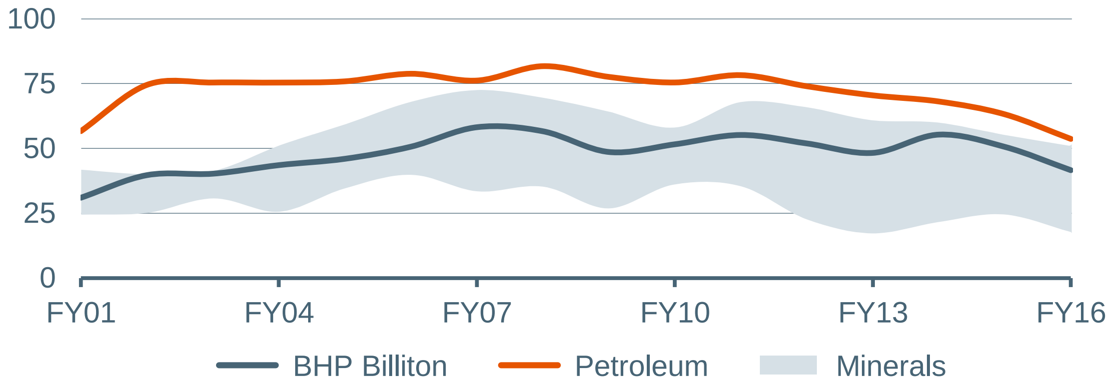
Global Functions ➡ Supply | Risk and Legal | Marketing | HR | Technology | Finance | Corporate Affairs

Global Centres of Excellence

Petroleum is core to BHP Billiton

- **Significant contributor over the last five years**
  - over 20% of Group production[1]
  - over 30% of Group Underlying EBITDA
  - average Underlying EBITDA margin of 66%
- **Differentiated diversification**
  - technical, operational and functional economies of scale
  - talent, ideas and best practice flow across the Group
  - diversification of customer markets and political jurisdictions
  - supports cash flow stability and strong balance sheet
  - enables greater capital mobility across commodity cycles
  - encourages increased competition for capital
- **Oil and US gas markets expected to rebalance first**

Strong and stable margins
(Underlying EBITDA margin[2], %)



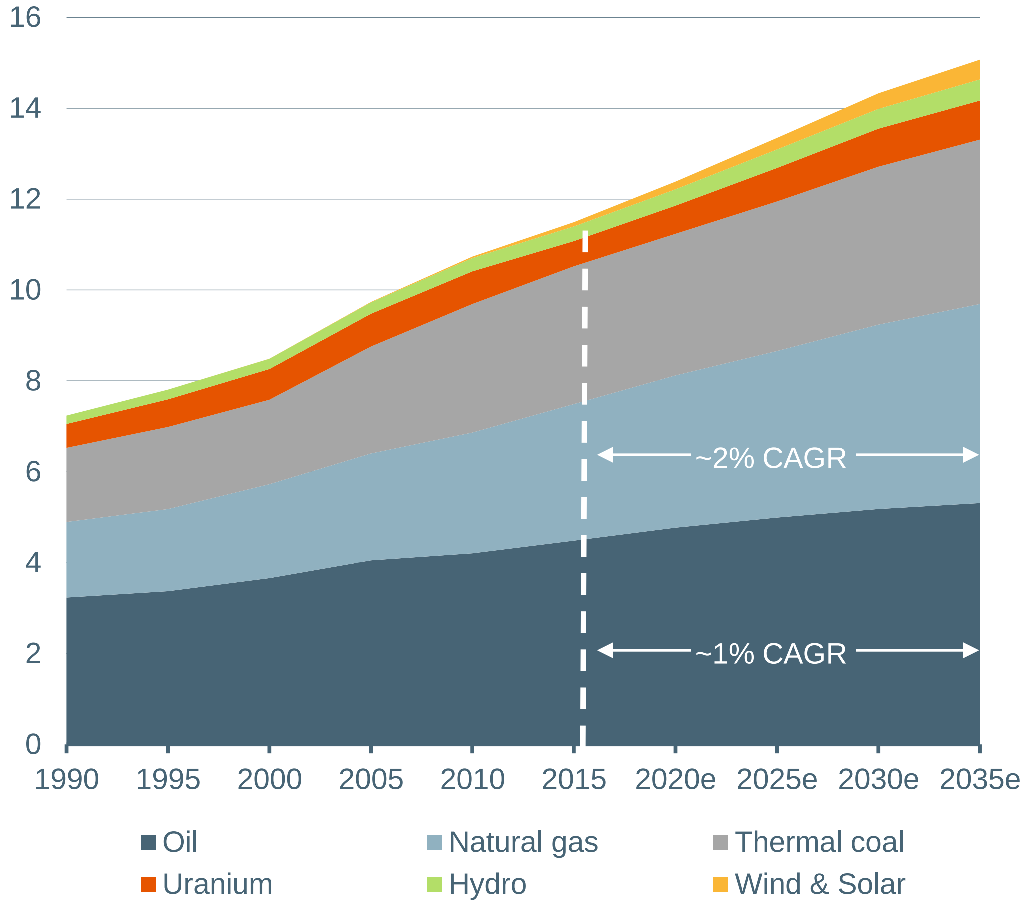
Commodity market outlook to 2025

1. Copper equivalent production based on continuing operations and FY16 realised prices.
2. BHP Billiton data for FY01 to FY13 presented on a total operations basis; FY14 to FY16 excludes Nickel West as reported in Group and unallocated items.
3. Versus 2015.

Global energy needs are rising

- **Emerging economies will drive energy demand**
  - global population to increase by 1.5 billion and GDP to double by 2035
  - world must pursue the twin objectives of providing access to affordable and reliable energy while limiting climate change
- **Fossil fuels will remain an important part of the energy mix**
  - fossil fuels represent four-fifths of the world's energy needs through to 2035
  - oil demand to grow as rising fleet size and industrial use more than offset efficiency gains and technological disruption
  - environmental, operational and economic advantages of natural gas enable it to be the fastest growing fossil fuel
  - despite strong growth in solar and wind, overall contribution to energy mix remains relatively small over the next two decades

Primary energy demand by commodity[1,2,3]
(Btoe[4])

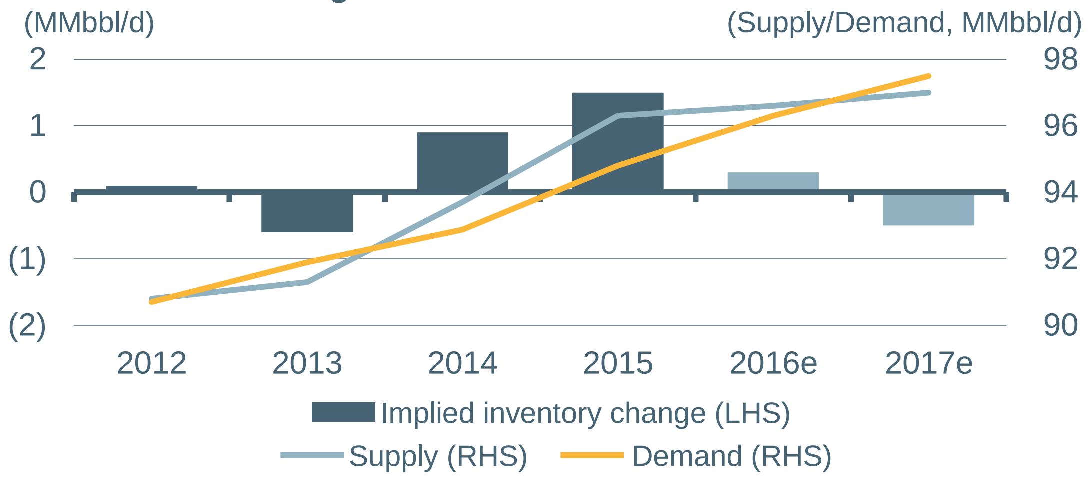


Source: International Energy Agency (IEA), BHP Billiton analysis.
1. Excludes metallurgical coal and biomass used in power and heating.
2. Oil includes biofuels.
3. Natural gas based on Standard cubic meter.
4. Billion tonnes of oil equivalent.

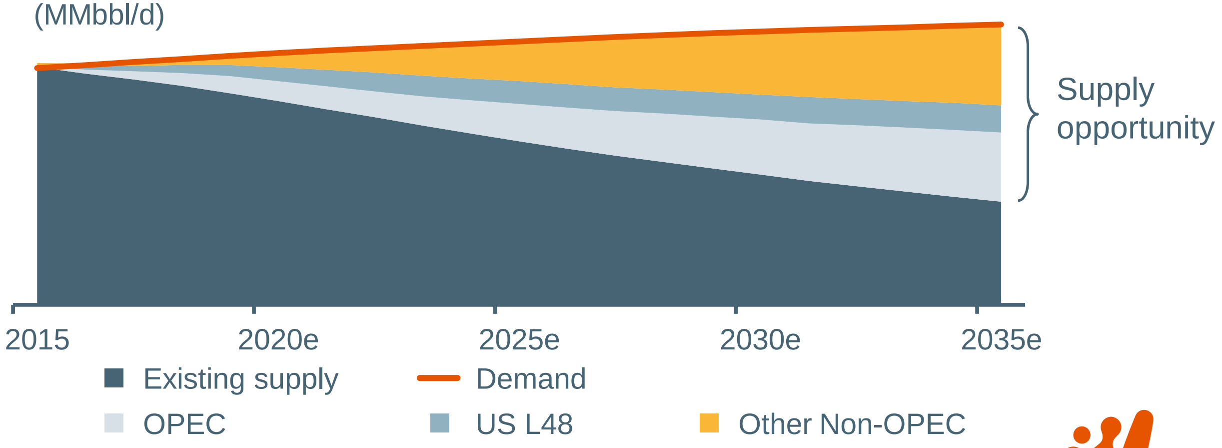
Attractive crude oil fundamentals

- **Oil market is rebalancing**
  - robust demand growth underpinned by developing countries
  - supply growth slowing as capital investment is deferred
- **Continue to see positive longer-term fundamentals**
  - demand growing ~1% per annum
  - natural field decline will continue at 3-4 MMbbl/d per annum
  - as lower cost supply declines, all major producing regions will need to grow to meet anticipated demand
  - higher prices required to induce new supply

Oil mass balance: global



Supply opportunity

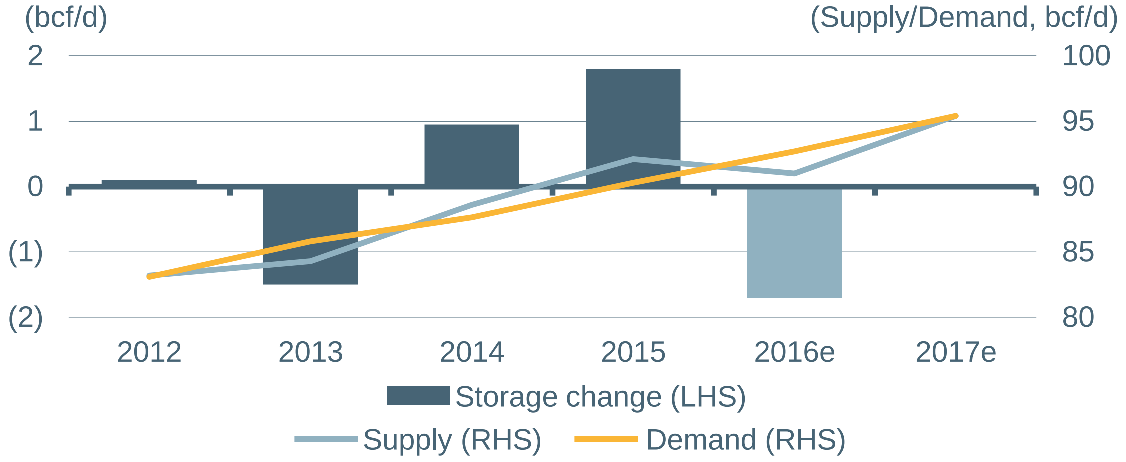


Source: International Energy Agency (IEA), BHP Billiton analysis.

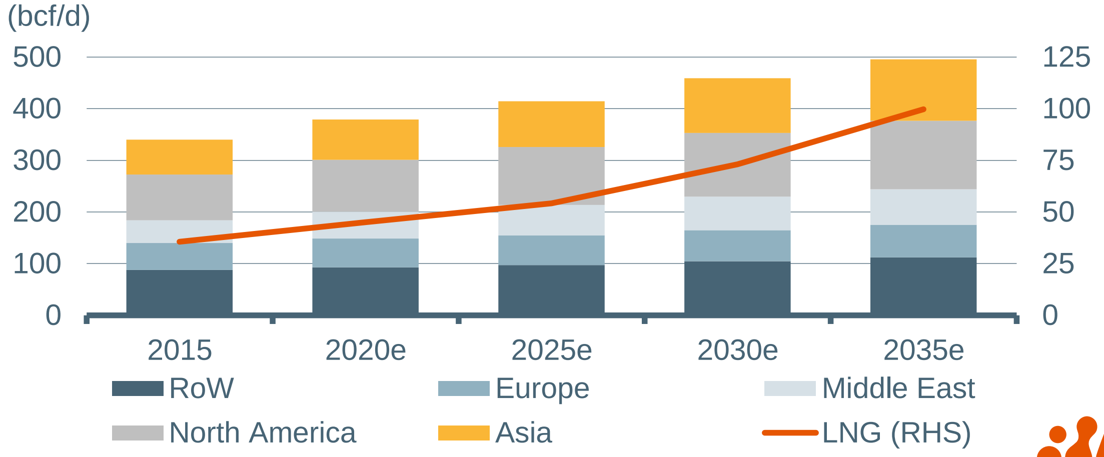
Robust gas demand growth

- **US market expected to rebalance at the end of this year**
  - mild winter, industry-wide productivity gains and resilient supply resulted in record inventory levels earlier this year
  - strong demand from the power sector and increasing exports
- **Long run demand growth driven by multiple regions**
  - global natural gas demand forecast to grow at ~2% per annum over the next 20 years
  - accelerating convergence of the global gas markets over the next decade as export capacity increases

Gas mass balance: North America



Global gas and LNG demand



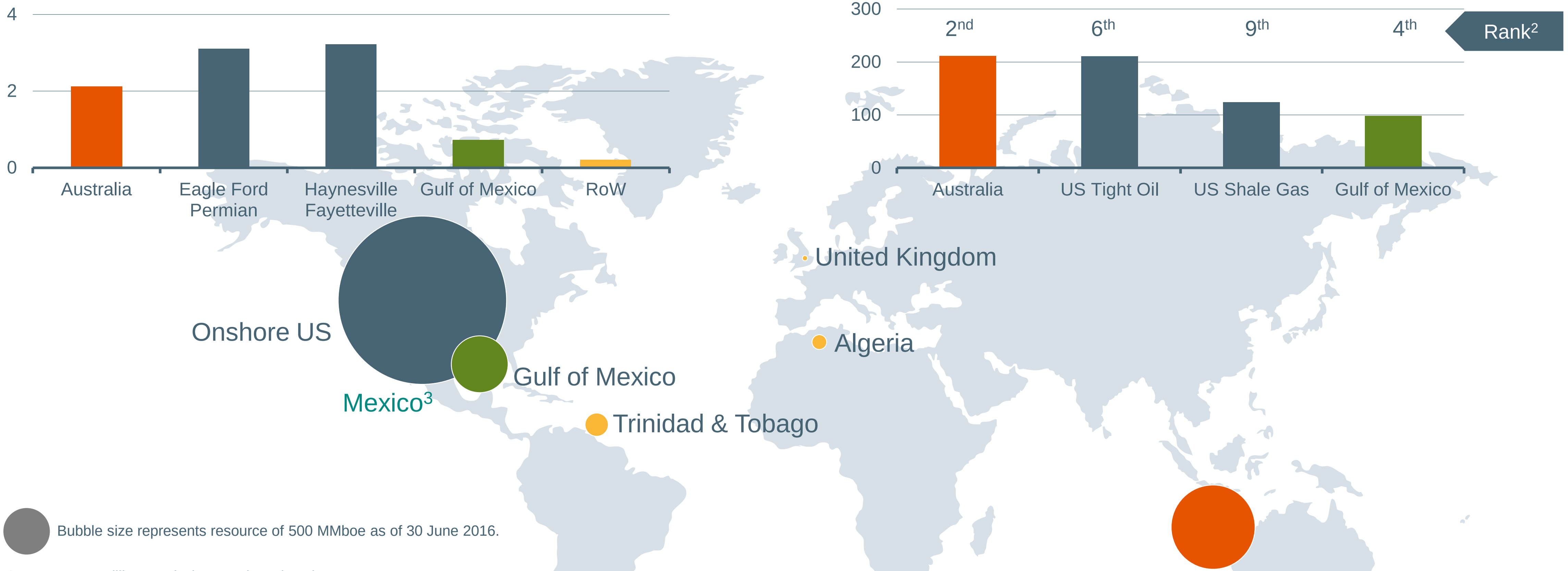
Source: US Energy information Administration (EIA), BHP Billiton analysis.

bhpbilliton

Australia and the US are our core regions

Our high-quality resource base…
(BHP Billiton resource, FY16, Bboe)[1]

…underpins our major producer position in core regions
(BHP Billiton production, Mboe/d, CY15, net)

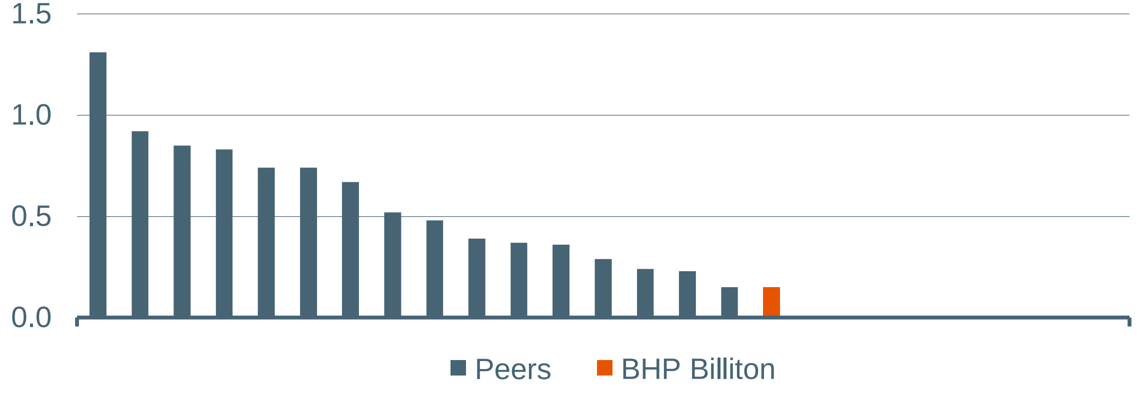


Source: BHP Billiton analysis, Wood Mackenzie.
1. Table 1 provides the Proved and Probable Reserves and 2C Contingent Resources and fuel amounts for the areas noted.
2. Peers: Woodside, Shell, ExxonMobil, Chevron, BP, Santos, ConocoPhillips, Apache, Sinopec, Anadarko, Hess, Freeport-MMR, ENI, Petrobras, Southwestern, Chesapeake, Devon, Range Resources, EOG, Marathon, Continental.
3. Represents potential exploration region.

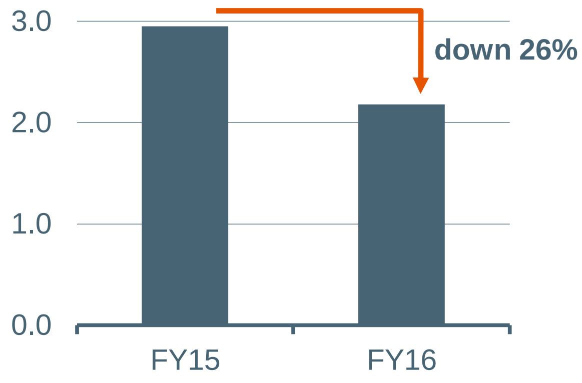
Operating safely and sustainably is our priority

- **The health and safety of our people is paramount**
  - record and reputation as one of the safest companies in the petroleum industry
  - number of recordable injuries reduced by 60% during period of significant market change
- **Meaningful contribution to the communities we operate in**
  - US$3.5 billion in payments to local suppliers and royalties to landowners in FY16
  - US$8.1 million in direct investment to support local community needs in FY16
- **Focused on environmental sustainability**
  - reduced greenhouse gas emissions by 7% in FY16
  - partnering to accelerate development of Carbon Capture and Storage technologies

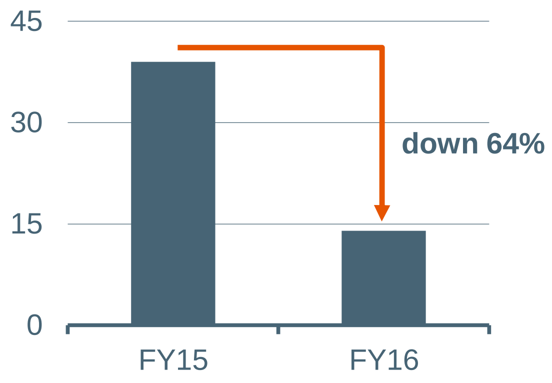
Lost-Time Injury Frequency (LTIF)
(number of recordable injuries per million hours worked[1])



Total Recordable Injury Frequency
(per million hours worked)



Significant events
(count)

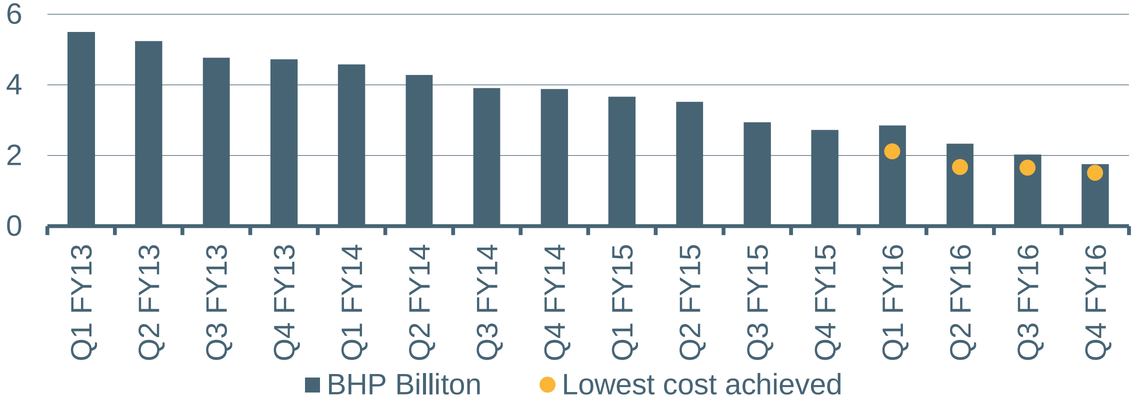


1. Source: IOGP Safety Performance Indicators – 2015 Data; excludes contractors.

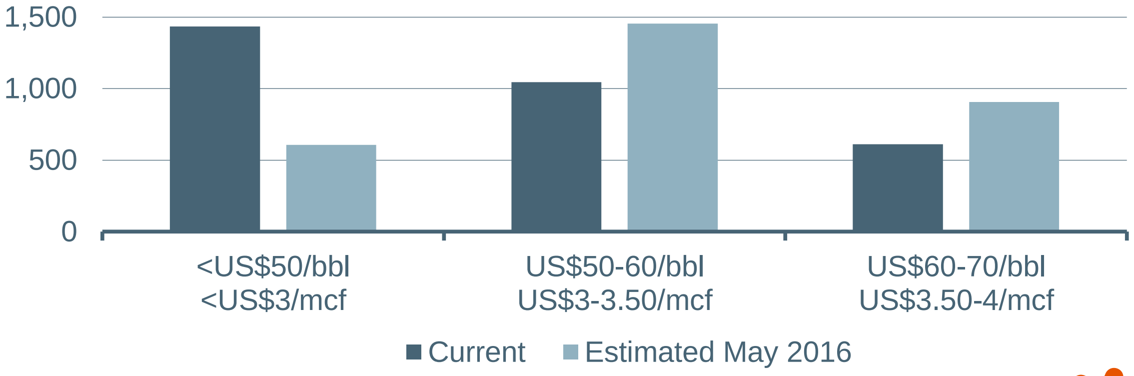
Onshore US well placed as prices recover

- **Operating in the heart of some of the best shale plays**
  - large resource base in Eagle Ford
  - significant potential in Permian
- **Continuing to reduce costs with technical excellence**
- **Improving economic inventory**
- **Monetising multi-decade gas resource through forward curve**
- **Focused on value and near-term free cash flow**
  - continue to exercise development flexibility to maximise value
  - potential to remain cash flow positive under the three price scenarios outlined

Black Hawk drilling cost performance
(US$ million/well, 100% basis)



Onshore US investable inventory[1,2,3]
(net working interest wells competitive for development)

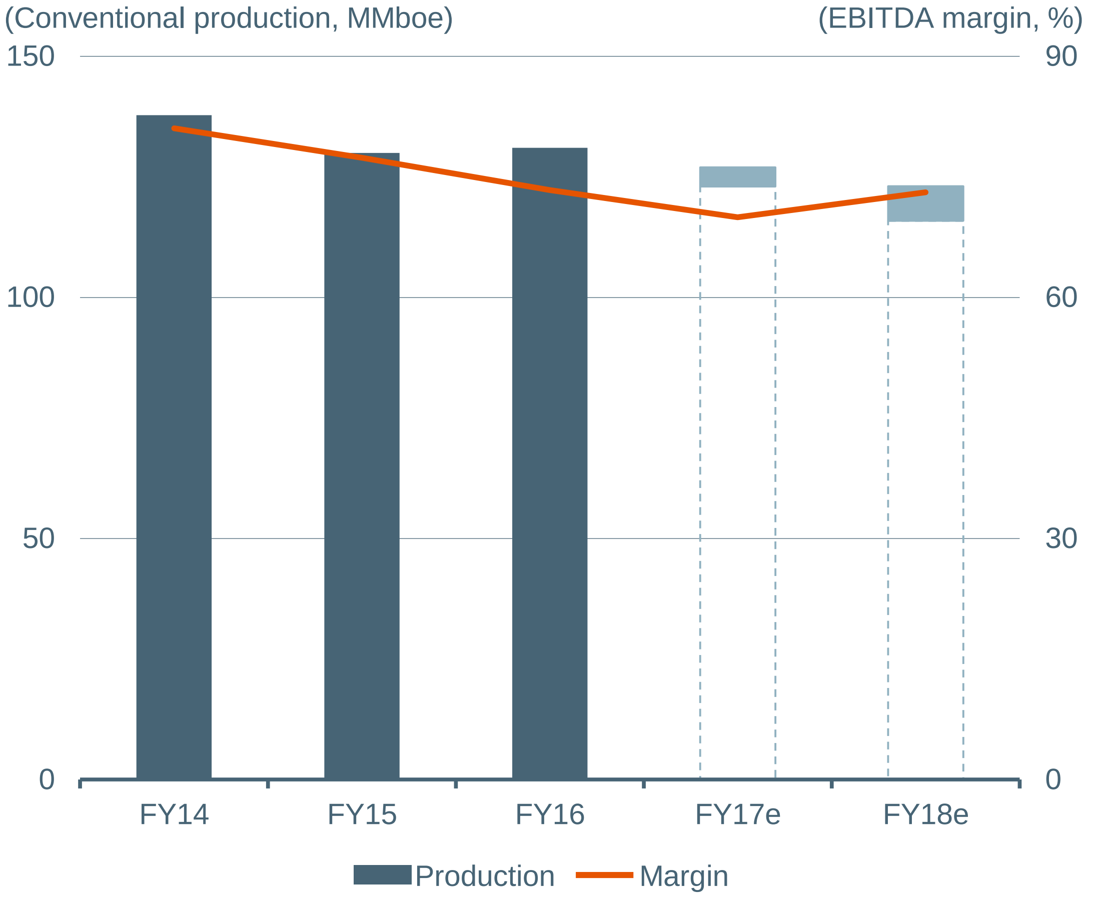


1. 15% rate of return under constant WTI oil and Henry Hub gas prices; liquids analysis assumes US$3.00/MMbtu Henry Hub gas price and NGL prices as a percentage of WTI. Incremental G&A not included for economic inventory; organisation is scalable for growth.
2. Where applicable, economics do not include Freight, Selling & Distribution (FS&D) costs.
3. Contingent upon ongoing and upcoming trials in Eagle Ford.

Stable volumes and high margins in Conventional

- **Our Conventional business is low cost and high-margin**
  - unit cash costs expected to be ~US$10/boe over the next two years[1,2]
- **Comprehensive portfolio of options to arrest field decline**
  - >40 brownfield projects with total capex of ~US$2.5 billion and an average IRR of ~45%
  - average ~140 MMboe of brownfield production expected in the next five years[2]
- **Mad Dog 2 investment decision expected in next six months**

High margins in Conventional[2]

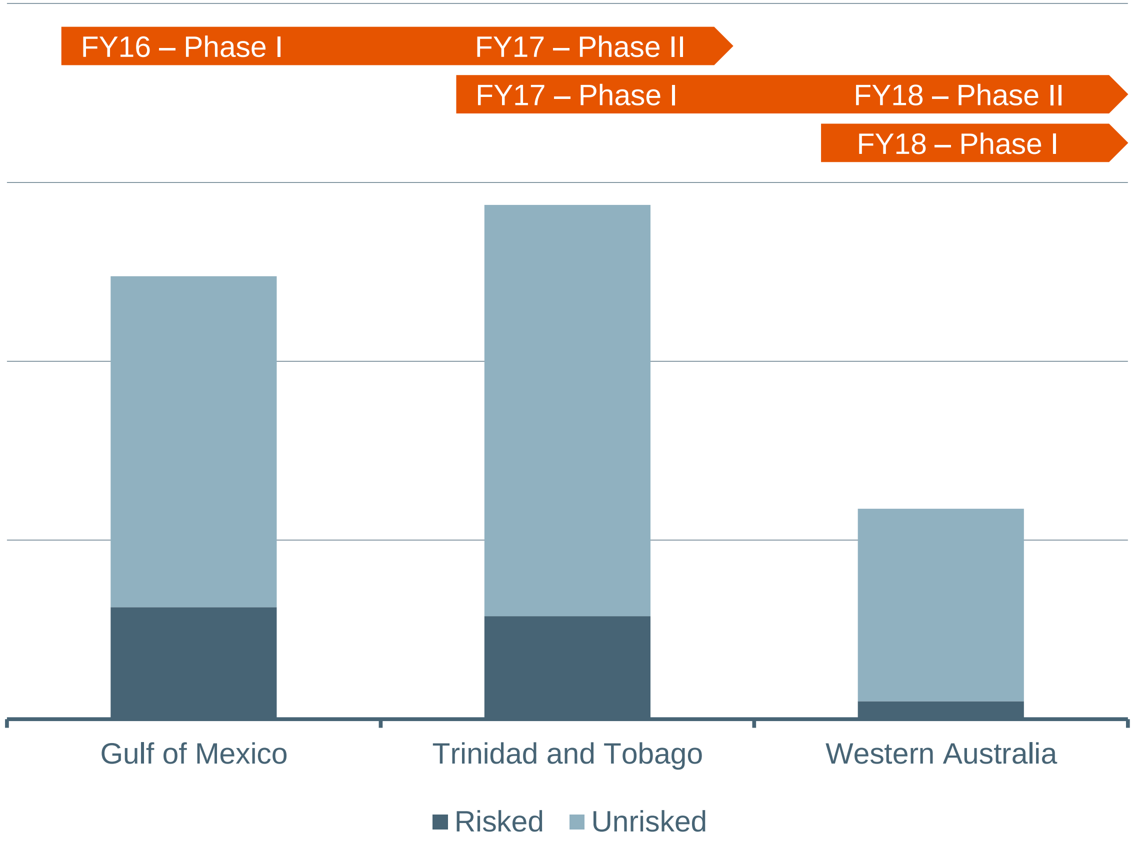


1. Unit cash costs exclude freight, distribution and selling, third party costs and exploration expenditure.
2. EBITDA margin estimates for FY17 onwards, and production and unit cash cost estimates for FY18 represent a scenario. Scenarios do not constitute guidance; actual EBITDA margin, production and unit cash costs will be determined according to market conditions prevailing at the relevant time.

Targeting Tier 1 liquids growth opportunities

- **Organic growth is the priority**
  - targeting frontier basins with Tier 1 potential
  - program aimed at conventional deepwater oil plays that complement our operating expertise and core portfolio
  - investing through the cycle and extending reach with countercyclical investment
- **Will selectively pursue inorganic opportunities that are aligned with our strategy**
  - must be value accretive
  - leverage our view of global endowment
  - focused primarily on deepwater conventional oil
  - rigorous screening applied against Capital Allocation Framework

Significant potential in oil exploration over the next three years
(value[1], BHP Billiton share)



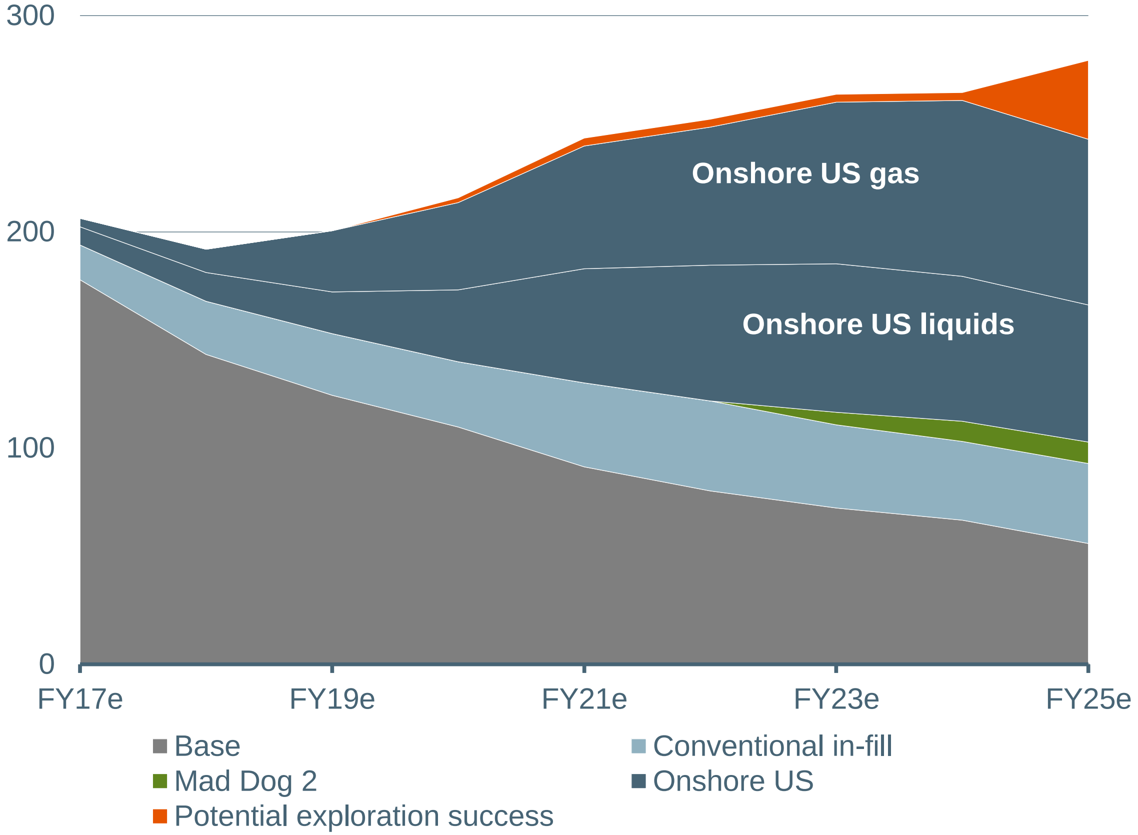
1. Under our long-term price forecasts; BHP Billiton share.

An exciting outlook for our Petroleum business

- **Petroleum is core to BHP Billiton**
  - strong financial and operating performance
  - oil and US gas markets expected to rebalance first
- **Petroleum strategy focused on value over volume**
- **Concentrated resource base and proven operating capability**
  - Onshore US – capturing full resource value while driving returns and free cash flow
  - Conventional – high margins with inventory of in-fill projects to offset field decline
- **Rich set of opportunities to drive valuable growth**
  - Mad Dog 2 investment decision expected in next six months
  - Haynesville acceleration supported by hedging
  - Permian progressing towards full pad development in FY19
  - exploration program yielding encouraging results
  - would consider value accretive acquisitions

Value accretive production potential over the next decade[1]

(BHP Billiton production, MMboe)



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Petroleum Marketing

Rebalancing markets, positive long-term fundamentals

Michiel Hovers Vice President Marketing, Petroleum

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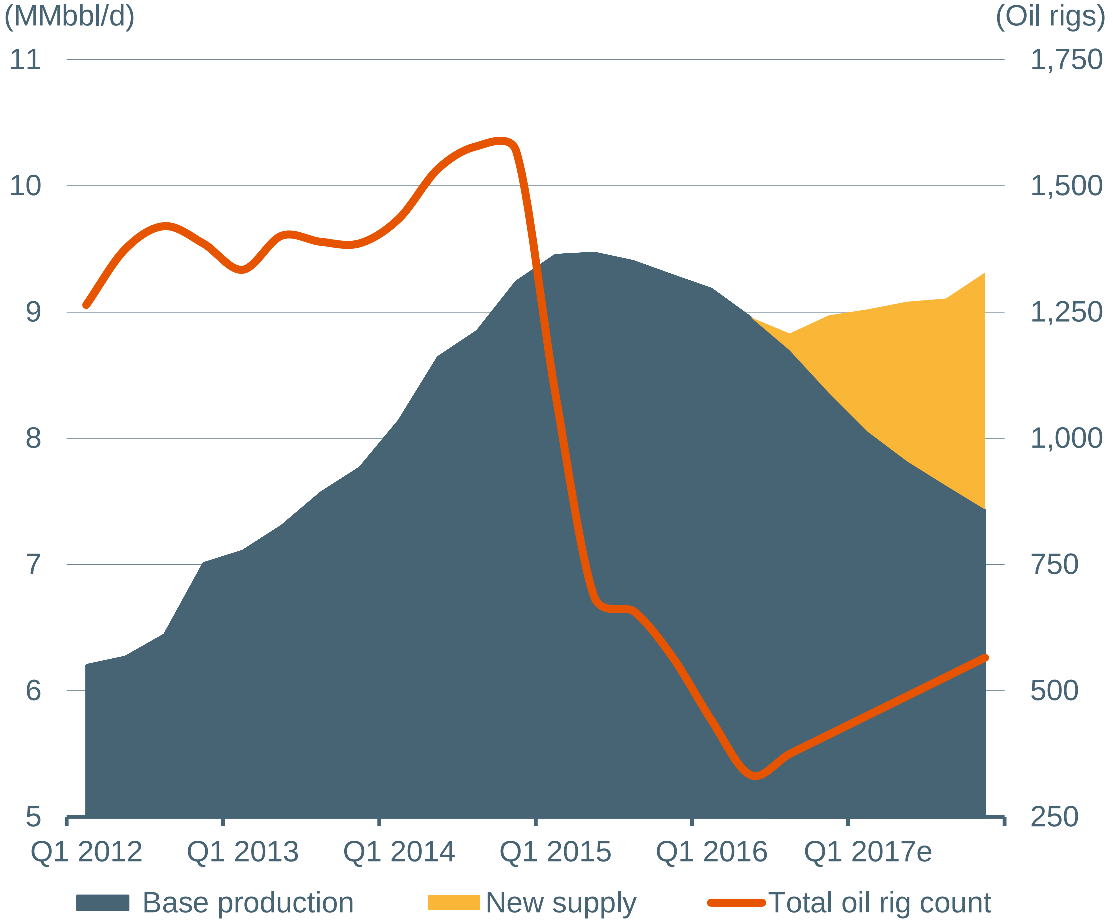
Rebalancing markets, positive long-term fundamentals

- **Oil market is rebalancing**
  - near-term demand growth of more than 1 MMbbl/d per annum
  - inventory drawdown as supply growth slows considerably
- **Long-term positive outlook for oil underpinned by strong fundamentals**
  - rising energy demand driven by non-OECD countries
  - natural field decline supports significant supply opportunity
- **North American gas long-term outlook – diversified demand growth**
  - multiple sectors contribute to total demand growth of 3% per annum
  - abundant supply options
- **Unique shale gas market characteristics support hedging**
  - hedging of gas price and input costs secures attractive returns at low risk
  - accelerates development of the Haynesville core

Global oil market is rebalancing

- **Global demand expected to surpass global supply in 2017, inventories to decline**
  - demand growth in 2017 expected to be 1.2 MMbbl/d
  - non-US production to remain relatively flat
  - estimated 2-3 days of demand cover in excess commercial inventory
- **New US supply needed to balance market**
  - US faces steep decline rates; output is down 1 MMbbl/d versus April 2015 peak
  - production needs to return to around 9 MMbbl/d by end of 2017 to balance market
  - actual ramp-up profile dependent on price, infrastructure and capital constraints

Total US crude oil production and rig profile

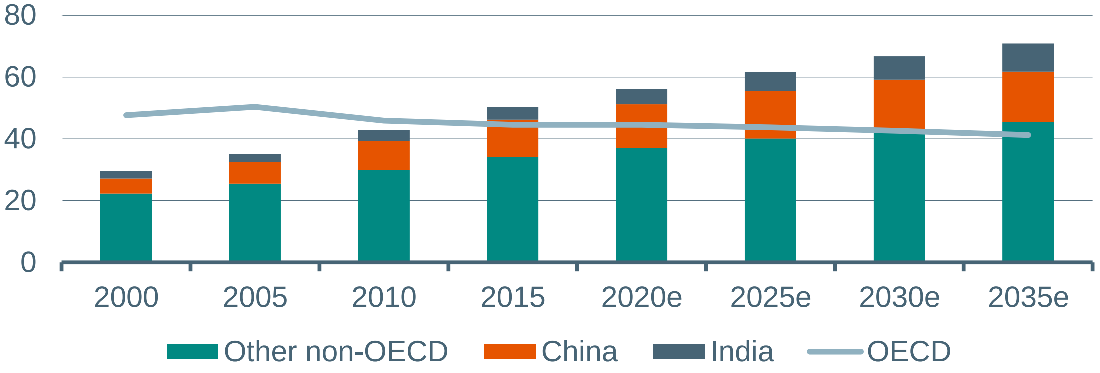


Source: US Energy Information Administration (EIA), BHP Billiton analysis.

Positive long-term oil demand fundamentals

- **Robust demand growth underpinned by developing countries**
  – China and India expected to account for half of global demand growth over the next decade
  – OECD demand has peaked and is expected to decline
- **Demand will rise, despite gains in energy efficiency and electric vehicles (EV)**
  – rising fuel efficiency of conventional and hybrid vehicles will be the major source of oil displacement over the next two decades
  – EV sales are expected to grow by ~25% per annum for 20 years, leading to a ~140 million EV fleet by 2035
  – EVs expected to displace more than 2 MMbbl/d of oil consumption in 2035, versus around 12.5 MMbbl/d from fuel efficiency improvements

Long-term liquids demand forecast
(MMbbl/d)



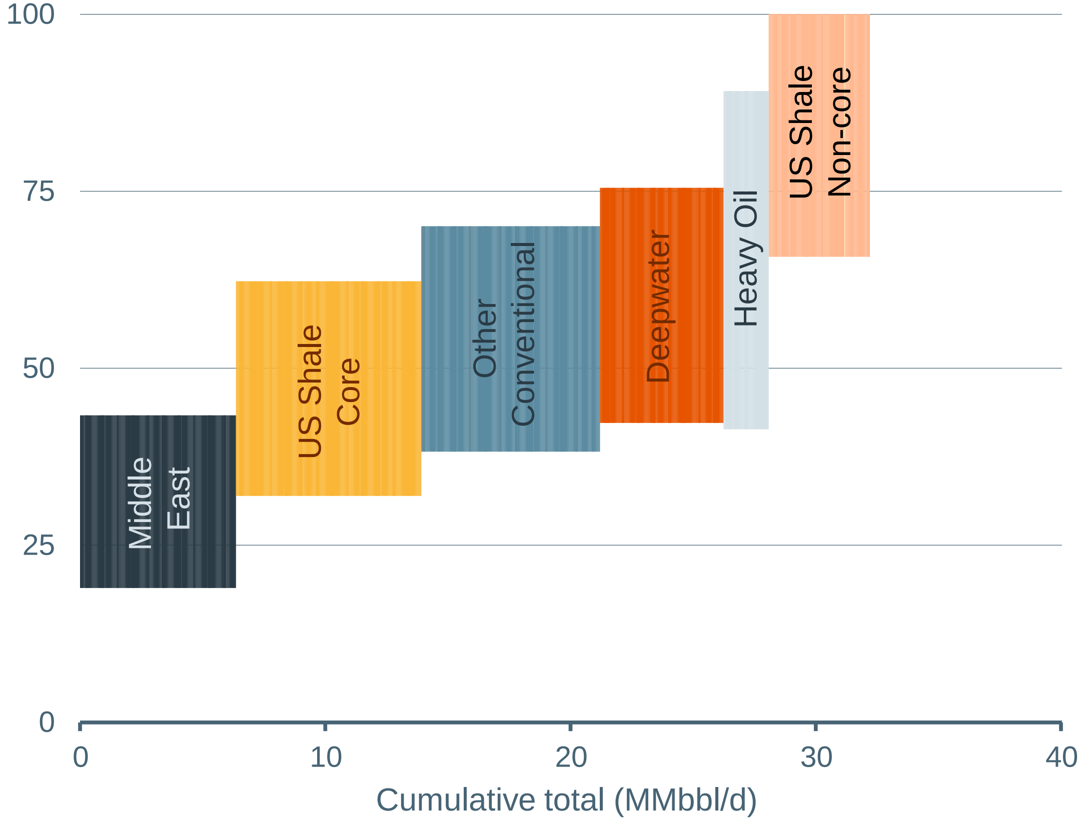
Prospects: a view from ground up
http://www.bhpbilliton.com/investors/prospects/electric-vehicles-why-all-the-noise

Source: International Energy Agency (IEA), BHP Billiton analysis.

~30 MMbbl/d of new supply required by 2025

- **Compelling supply opportunity**
  - natural field decline and demand growth drive need for new supply
  - new supply required equates to approximately one third of current demand by 2025
  - upstream spending is down significantly over the last two years
- **Higher prices required to induce investment**
  - many supply sources have a core that is profitable below US$60/bbl
  - development of non-core supply needs higher inducement prices; shale is no exception
  - productivity improvements likely to continue, but at a more moderate pace

Potential new oil supply[1] by 2025
(US$/bbl, real Jan 2016)

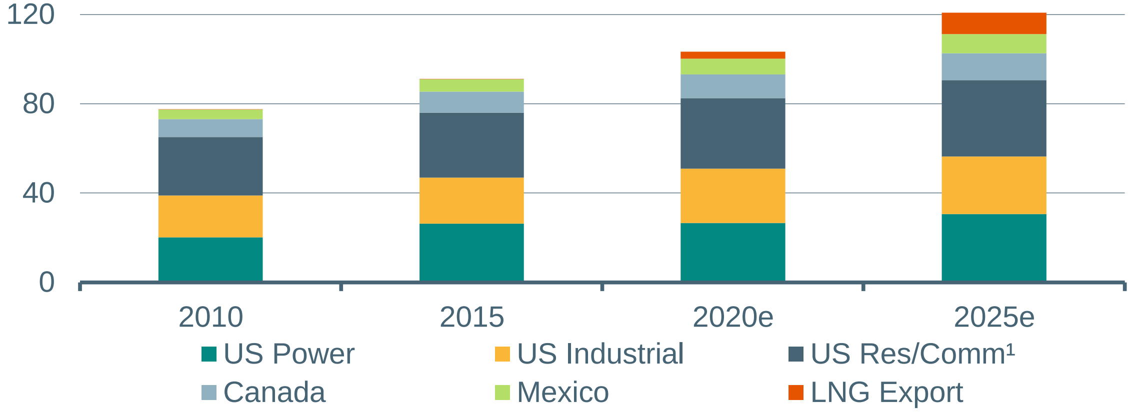


Source: BHP Billiton analysis.
1. Box width represents 2025 production by category; ordered by weighted average cost of production (lowest to highest). Excludes on-line supply and supply under development. Top/Bottom on box represents cost of production for 10/90 percentile for the respective category.

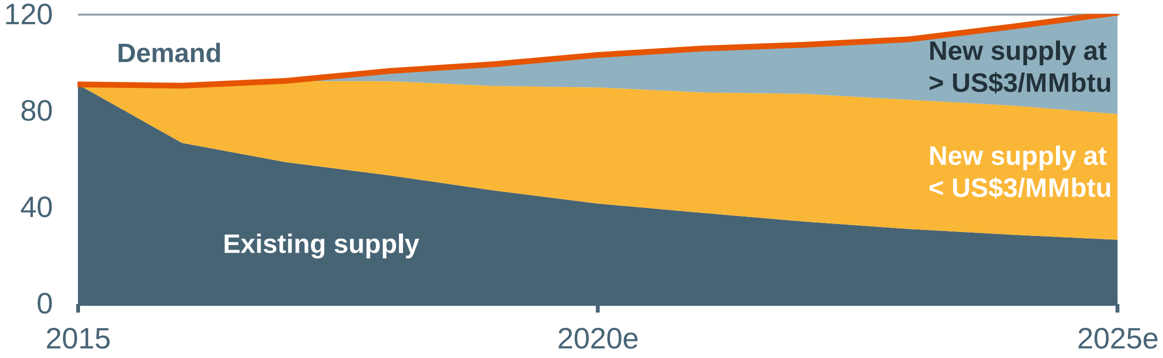
North American gas: strong demand, abundant supply

- **Strong demand growth underpinned by multiple sectors**
  - total North American demand CAGR of ~3% to 2025
  - gas is a reliable, economic and a low emission fuel for power generation
  - gas displaces coal and provides flexible generation to support the rising penetration of intermittent wind and solar in the power sector
  - US is becoming one of the top three LNG exporters globally
- **Availability of lower cost supply will limit price appreciation**
  - abundant supply options
  - as core areas are depleted, new production additions are incrementally higher cost

North America gas demand
(bcf/d)



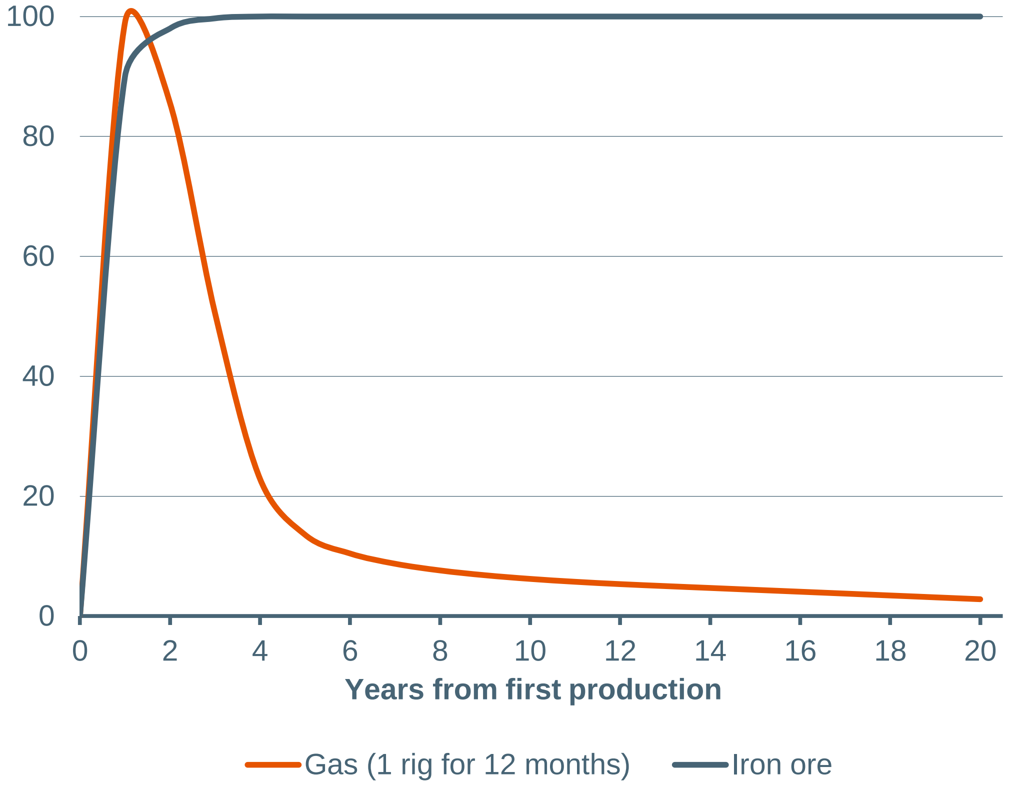
North America gas supply
(bcf/d)



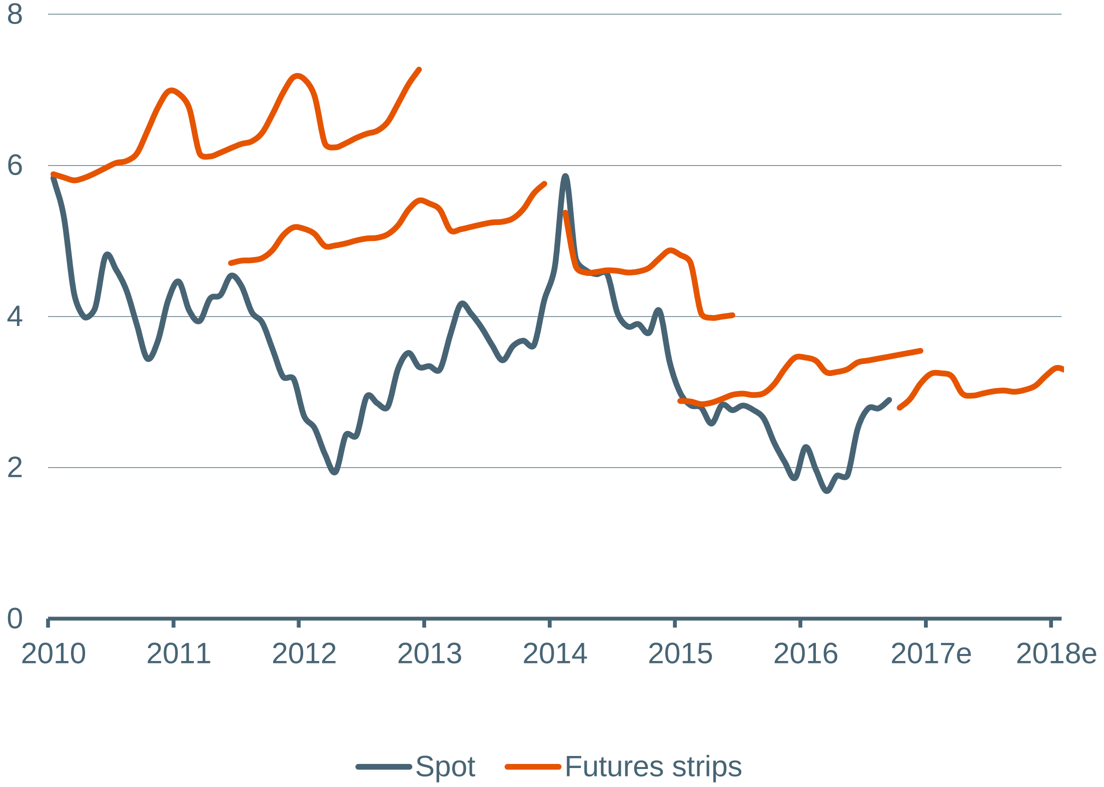
Source: BHP Billiton analysis.
1. Includes pipeline losses and other.

Hedging price and input costs accelerates Haynesville gas volumes

Gas and iron ore production profiles[1] comparison
(Production as % of peak rate)



Henry Hub monthly futures and spot pricing
(US$/MMbtu, nominal)



Source: BHP Billiton analysis.
1. Indicative production profiles.

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Petroleum Financial Performance

Driving productivity and capital discipline

Michelle Turner Vice President Finance, Petroleum

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Driving productivity and capital discipline

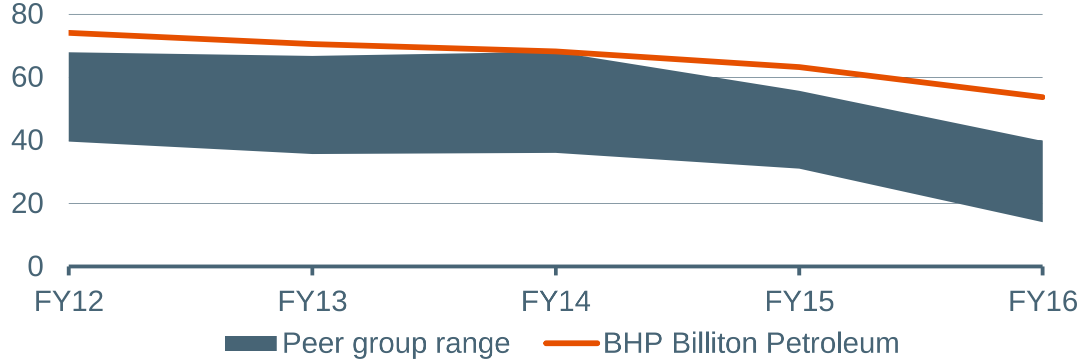
- **Petroleum supports cash flow stability**
  - average Underlying EBITDA margin of 66% over the last five years
  - Conventional provides stable volumes and cash flow
  - Onshore US provides flexibility to capture price cycles
- **Focus on productivity in all price environments**
  - targeting Petroleum unit cash costs of ~US$11/boe over the next two years[1]
  - increased capital efficiency across Conventional and Onshore US
- **Capital Allocation Framework provides discipline and transparency**
  - Petroleum projects compete well for capital
  - our global finance function plays a critical role in determining how our Company creates value

1. Unit cash cost estimates for FY18 represents a scenario. Scenarios do not constitute guidance; actual unit cash costs will be determined according to market conditions prevailing at the relevant time. Unit cash costs exclude freight, distribution and selling, third party costs and exploration expenditure.

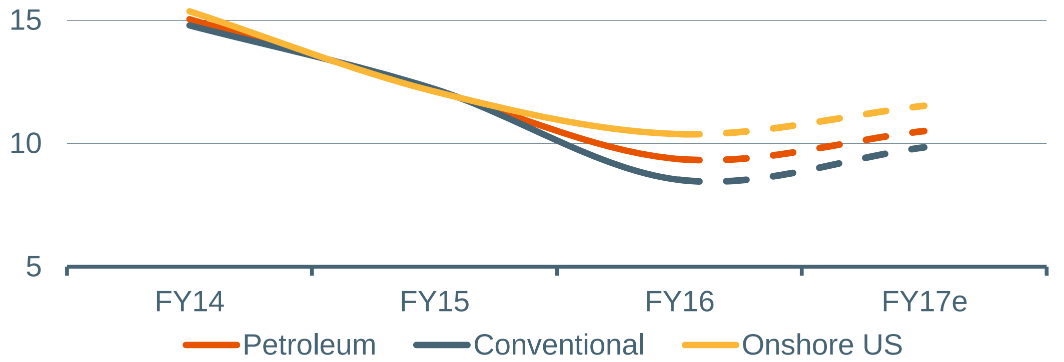
Leading EBITDA margins

- **Consistently strong margins over the last five years**
  - contributed ~US$40 billion Underlying EBITDA
  - peer leading Underlying EBITDA margin of 66%
- **Productivity supported FY16 financial performance**
  - ~US$3/boe reduction in cash costs
  - US$3.6 billion Underlying EBITDA in lower price environment
- **Productivity protecting margins**
  - ~US$11/boe Petroleum unit cash costs expected in FY17[2]
  - medium-term unit cash costs expected to remain below FY14 baseline

Peer leading EBITDA margins[1]
(Underlying EBITDA margin, %)



Unit cash costs to remain below FY14 baseline[2]
(US$/boe)



1. Source: FactSet. Peers include: Anadarko, ConocoPhillips, Freeport-McMoRan, Hess, Marathon Oil, Noble Energy, Occidental Petroleum, Devon Energy.
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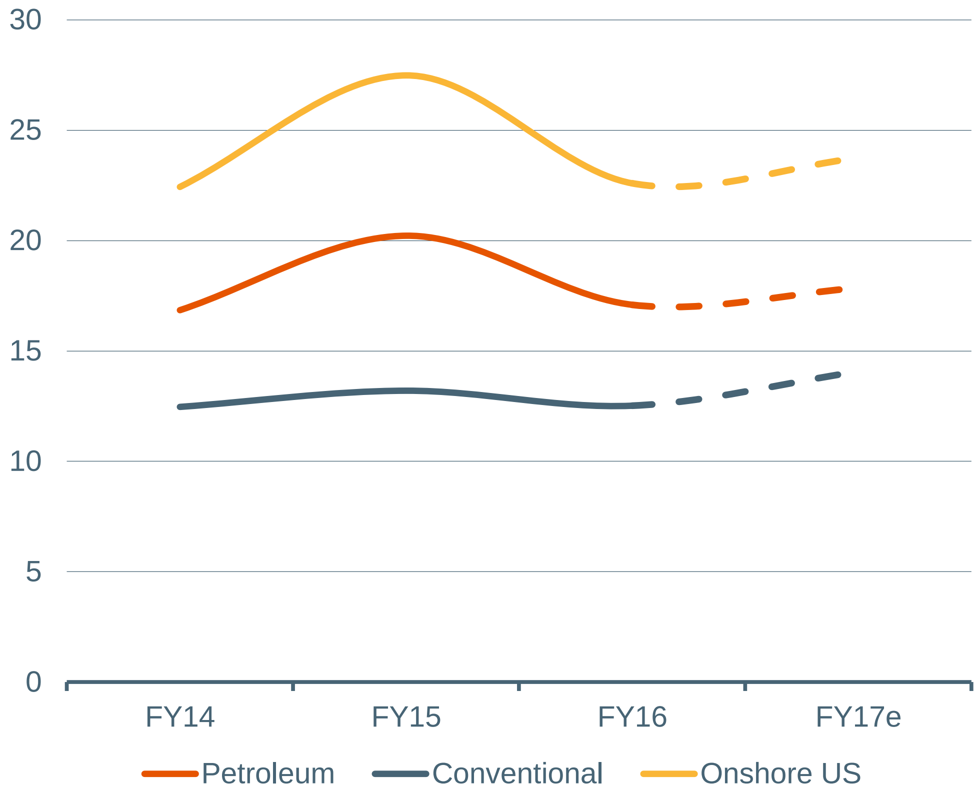
Depreciation ~US$18/boe in FY17

- **Conventional unit depreciation increases ~US$1/boe in FY17 reflecting project completions and timing of resource additions**
- **Onshore US depreciation increases ~US$1/boe in FY17**
  – the unit rate decline following the FY16 impairment is expected to be partially offset by price impacts
  – significant reductions in drilling times and well costs achieved in Onshore US reduces the depreciation rate

Petroleum depreciation rates[1]
(US$/boe)

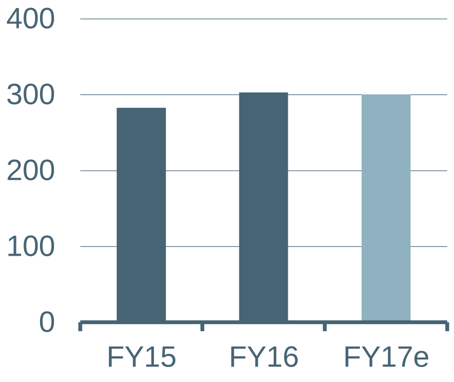


1. Excludes exploration.

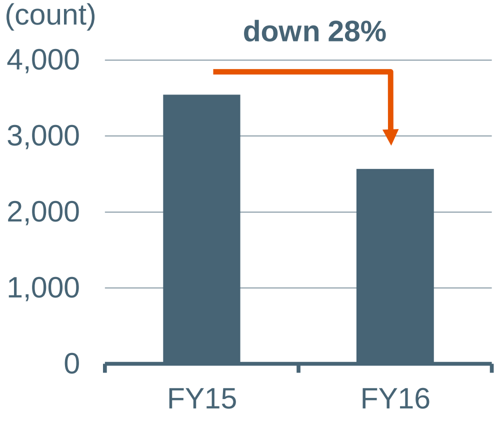
Driving capital and operating productivity

- **Productivity underpinned efficiency in FY16**
  - controllable cash costs fell US$677 million
  - working capital management decreased inventory by 25%
- **Right sizing our organisation**
  - overhead costs decreased by 22% during FY16
  - offshoring work to Trinidad and Malaysia
- **Capital efficiency supporting project returns**
  - ~40% reduction in Onshore US well costs[1,2]
  - US$586 million of supply savings[2]
- **Culture of continuous improvement**
  - employees engaged through "transformation" campaign
  - functional business partnering accelerates value creation

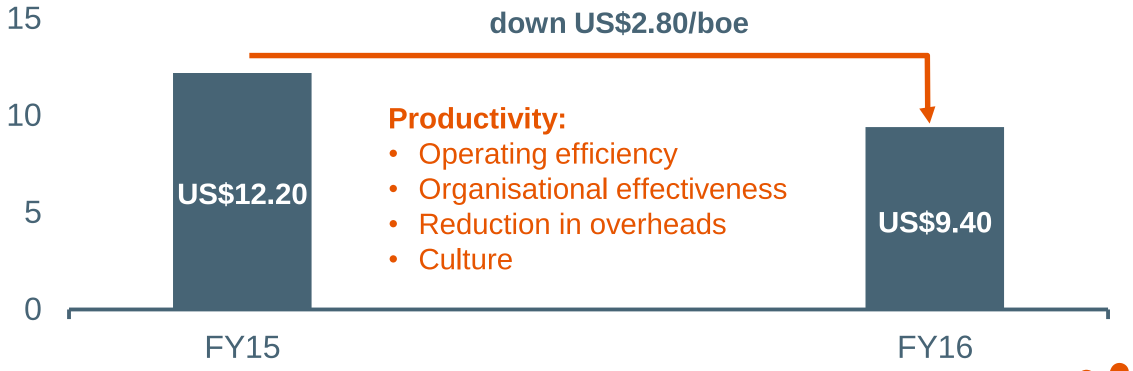
Annual supply savings
(US$ million)



Petroleum headcount
(count)



Total unit cash cost
(US$/boe, average)

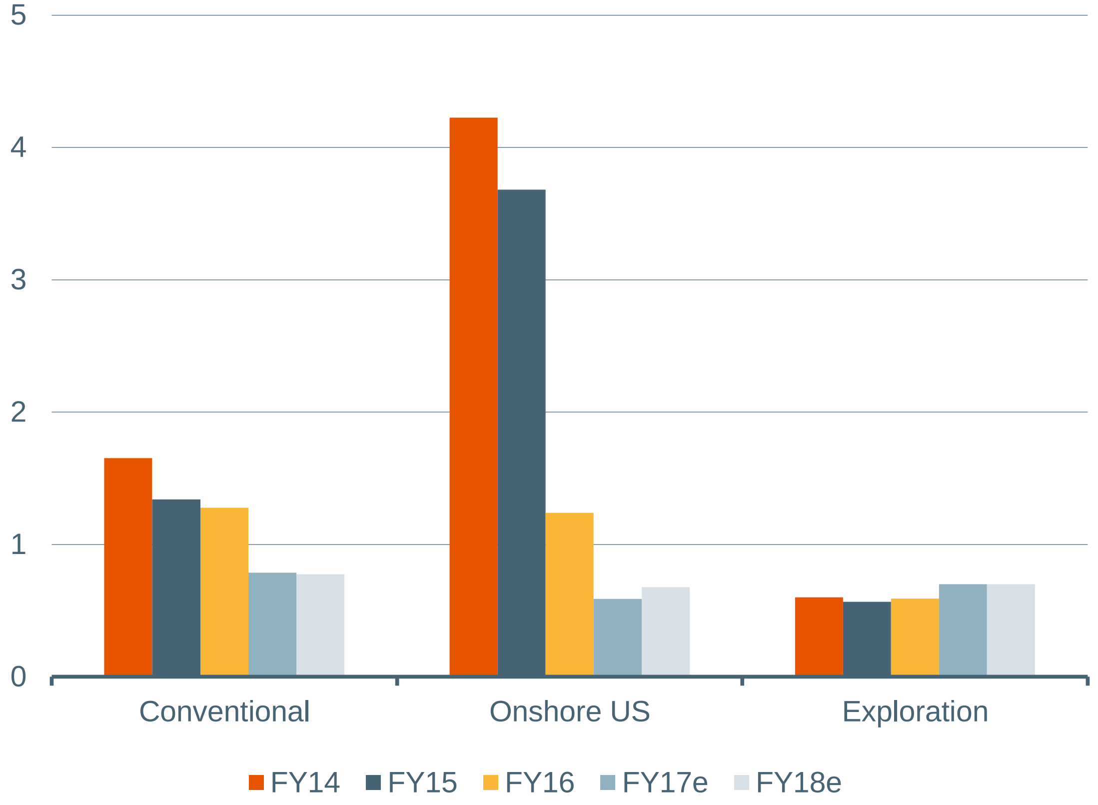


1. Drilling and completion costs are not normalised for lateral length. Black Hawk drilling cost calculated for 2-string wells only. Permian drilling and completion costs calculated using North Reeves activities. Completion costs exclude trials.
2. Savings in FY15 and FY16.

Capital allocation provides discipline and transparency

- **Globalised finance function oversees capital allocation**
  - co-located finance teams support operations
  - competition for capital focused on value over volume
- **Flexibility to adjust Onshore US development**
  - cost efficiencies continue to increase investable well inventory
  - dynamic capital allocation for Onshore US
- **Petroleum's high-return projects competitive for capital**
  - high-return conventional brownfield projects
  - high-return incremental wells in Onshore US
  - Tier 1 exploration opportunities

Capital and exploration expenditure[1]
(US$ billion)



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Onshore US

Capturing full resource value

Alex Archila Asset President, Shale

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Petroleum Resources

The estimates of Petroleum Reserves and Contingent Resources contained in this presentation are based on, and fairly represent, information and supporting documentation prepared under the supervision of Mr. A. G. Gadgil, who is employed by BHP Billiton. Mr. Gadgil is a member of the Society of Petroleum Engineers and has the required qualifications and experience to act as a qualified Petroleum Reserves and Resources evaluator under the ASX Listing Rules. This presentation is issued with the prior written consent of Mr. Gadgil who agrees with the form and context in which the Petroleum Reserves and Contingent Resources are presented.

Reserves and Contingent Resources are net of royalties owned by others and have been estimated using deterministic methodology. Aggregates of Reserves and Contingent Resources estimates contained in this presentation have been calculated by arithmetic summation of field/project estimates by category with the exception of the North West Shelf (NWS) Gas Project in Australia. Probabilistic methodology has been utilised to aggregate the NWS Reserves and Contingent Resources for the reservoirs dedicated to the gas project only and represents an incremental 39 MMboe of Proved Reserves. The barrel of oil equivalent conversion is based on 6000 scf of natural gas equals 1 boe. The Reserves and Contingent Resources contained in this presentation are inclusive of fuel required for operations. The respective amounts of fuel for each category are provided by footnote for the resource graphics. The custody transfer point(s)/point(s) of sale applicable for each field or project are the reference point for Reserves and Contingent Resources. Reserves and Contingent Resources estimates have not been adjusted for risk. Unless noted otherwise, Reserves and Contingent Resources are as of 30 June 2016. Where used in this presentation, the term Resources represents the sum of 2P reserves and 2C Contingent Resources.

BHP Billiton estimates Proved Reserve volumes according to SEC disclosure regulations and files these in our annual 20-F report with the SEC. All Unproved volumes are estimated using SPE-PRMS guidelines, which among other things, allow escalations to prices and costs, and as such, would be on a different basis than that prescribed by the SEC, and are therefore excluded from our SEC filings. All Resources and other Unproved volumes may differ from and may not be comparable to the same or similarly-named measures used by other companies. Non-proved estimates are inherently more uncertain than proved.

Table 1 Net BHP Billiton Petroleum Reserves and Contingent Resources as of 30 June 2016

	Onshore US			Offshore US	Australia			Rest of World				
Net MMboe	**Eagle Ford & Permian**	**Haynesville & Fayetteville**	**Subtotal**	**Gulf of Mexico**	**Offshore Western Australia[1, 2]**	**Bass Strait & Offshore Victoria**	**Subtotal**	**Trinidad & Tobago**	**Algeria**	**United Kingdom & Other**	**Subtotal**	**Total BHP Billiton**
Proved	**124**	**173**	**298**	**210**	**414**	**303**	**717**	**56**	**22**	**-**	**78**	**1,303**
Probable	**1,433**	**1,273**	**2,707**	**127**	**59**	**94**	**153**	**17**	**10**	**-**	**27**	**3,013**
2P	**1,558**	**1,447**	**3,004**	**337**	**473**	**397**	**869**	**73**	**32**	**-**	**105**	**4,316**
2C	**1,547**	**1,782**	**3,329**	**392**	**1,099**	**153**	**1,252**	**52**	**18**	**20**	**89**	**5,061**
2P+2C	**3,105**	**3,228**	**6,333**	**729**	**1,571**	**550**	**2,121**	**124**	**50**	**20**	**194**	**9,377**
Fuel included above												
Proved	2.0	5.0	7.0	5.8	36.5	16.9	53.4	1.4	1.3	-	2.8	69.0
Probable	33.2	22.2	55.4	3.2	3.6	4.7	8.3	-	-	-	-	66.8
2P	35.2	27.2	62.4	8.9	40.0	21.7	61.7	1.4	1.3	-	2.8	135.8
2C	27.3	41.4	68.7	5.8	113.4	6.8	120.2	-	-	-	-	194.7
2P+2C	62.5	68.6	131.1	14.8	153.4	28.5	181.9	1.4	1.3	-	2.8	330.6

1) Includes NWS Gas Project probabilistic increment noted in disclaimer above.

2) Australian resources prior to the announced agreement by Woodside to acquire 50% of BHP Billiton Scarborough area assets.

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only Proved, Probable and Possible Reserves, and only when such Reserves have been determined in accordance with SEC guidelines. We use certain terms in this presentation such as "Resources," "Contingent Resources," "2C Contingent Resources" and similar terms as well as Probable Reserves not determined in accordance with the SEC's guidelines, all of which measures we are strictly prohibited from including in filings with the SEC. These measures include Reserves and Resources with substantially less certainty than Proved Reserves. U.S. investors are urged to consider closely the disclosure in our Form 20-F for the fiscal year ended June 30, 2016, File No. 001-09526 and in our other filings with the SEC, available from us at http://www.bhpbilliton.com/. These forms can also be obtained from the SEC as described above.

Capturing full resource value

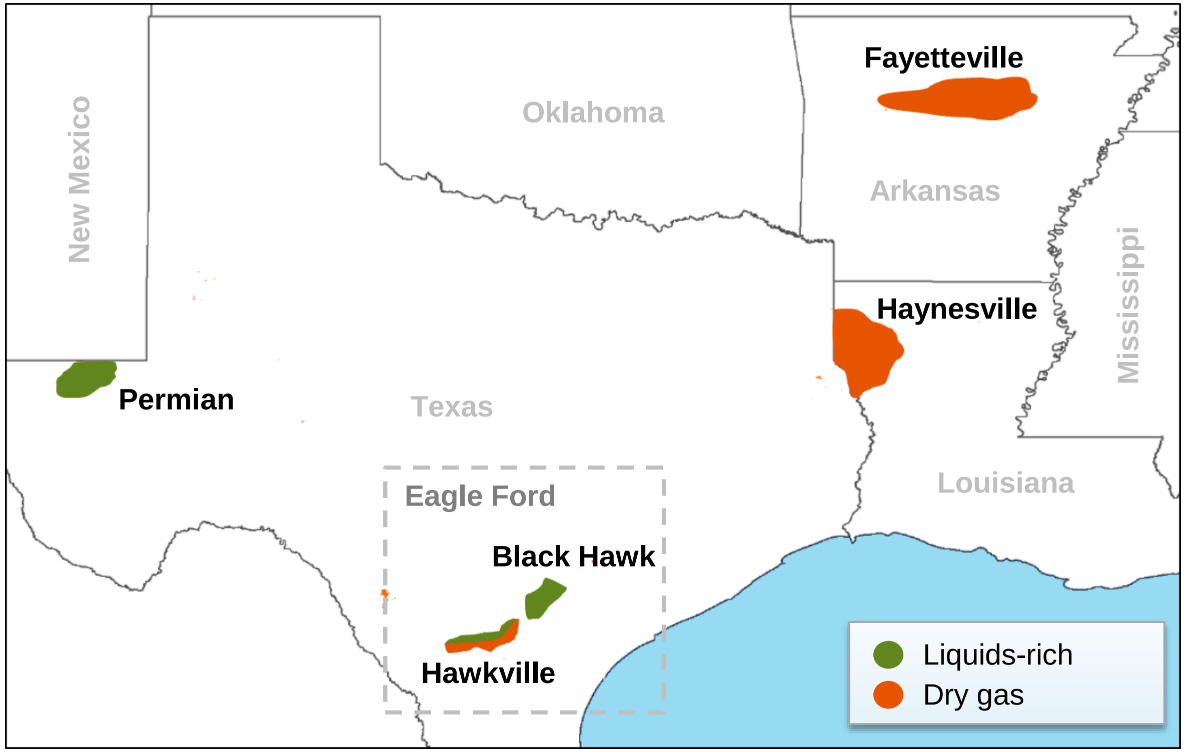
- **Large, quality resource supports returns and optionality**
  - 3 Bboe 2P[1] reserves including ~500 MMbbls of oil
  - up to 1,200 net liquids-rich wells deliver at least 15% IRR at US$50/bbl, contingent upon trials in Eagle Ford
  - up to 220 net dry gas wells deliver at least 15% IRR at US$3/MMbtu
  - pursuing additional resource potential across all fields
- **Productivity is increasing recoveries and lowering breakevens**
  - well costs and field operating costs down ~30% in FY16
  - superior well performance in Black Hawk and Permian
  - return to drilling in Haynesville supported by hedging program
- **Capturing full resource value while driving returns and free cash flow**
  - potential to remain cash flow positive at a range of consensus prices through investment flexibility
  - significant net cash flow could be generated at average analyst prices, with low cost of carry at low prices and upside at higher prices
  - will consider monetisation of long-dated dry gas options for value

1. Total Proved reserves: 0.3 Bboe, Probable reserves: 2.7 Bboe, includes fuel consumed in operations: Proved: 7 MMboe, Probable: 55 MMboe.

Approximately 850k net acres across four large fields

- **Eagle Ford**
  - largest component of current production
  - liquids-rich acreage in Black Hawk
  - mix of condensate and dry gas acreage in Hawkville
- **Permian**
  - liquids-rich with multiple productive horizons
  - clear line of sight to full pad development within 2-3 years
- **Haynesville**
  - high-pressure / high-recovery dry gas wells
  - accelerating high-return development through productivity
- **Fayetteville**
  - low technical risk, long-term dry gas option

Outline of BHP Billiton Onshore US acreage by play

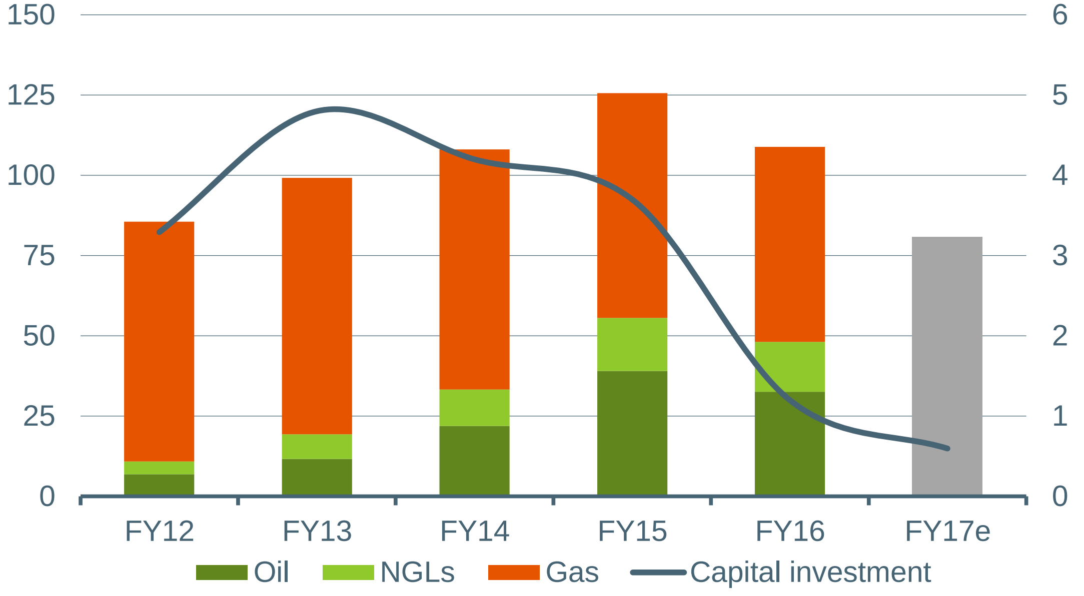


Responding to market while improving capital efficiency

- Production growth over FY12 to FY15 (14% CAGR) demonstrates rapid growth potential with new investment
- Reduction in capital investment since FY15 highlights flexibility to dynamically respond to changing market conditions
- Productivity has further improved capital efficiency and partially offset production impact of lower investment
  - ~85% capital reduction in FY15-17e
  - ~35% production decline in FY15-17e

Onshore US production[1]
(MMboe, BHP Billiton share)

Onshore US capital[1]
(US$ billion, BHP Billiton share)



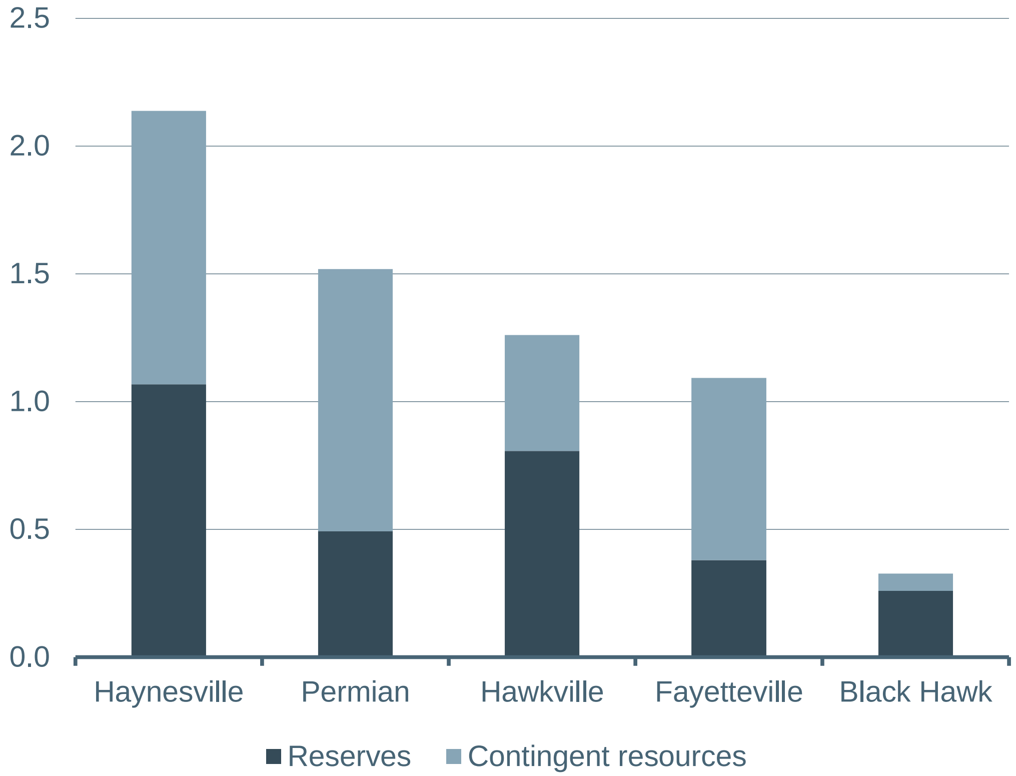
Average WTI oil prices[2]
(US$ per barrel)

FY12	FY13	FY14	FY15	FY16
95	92	101	69	42

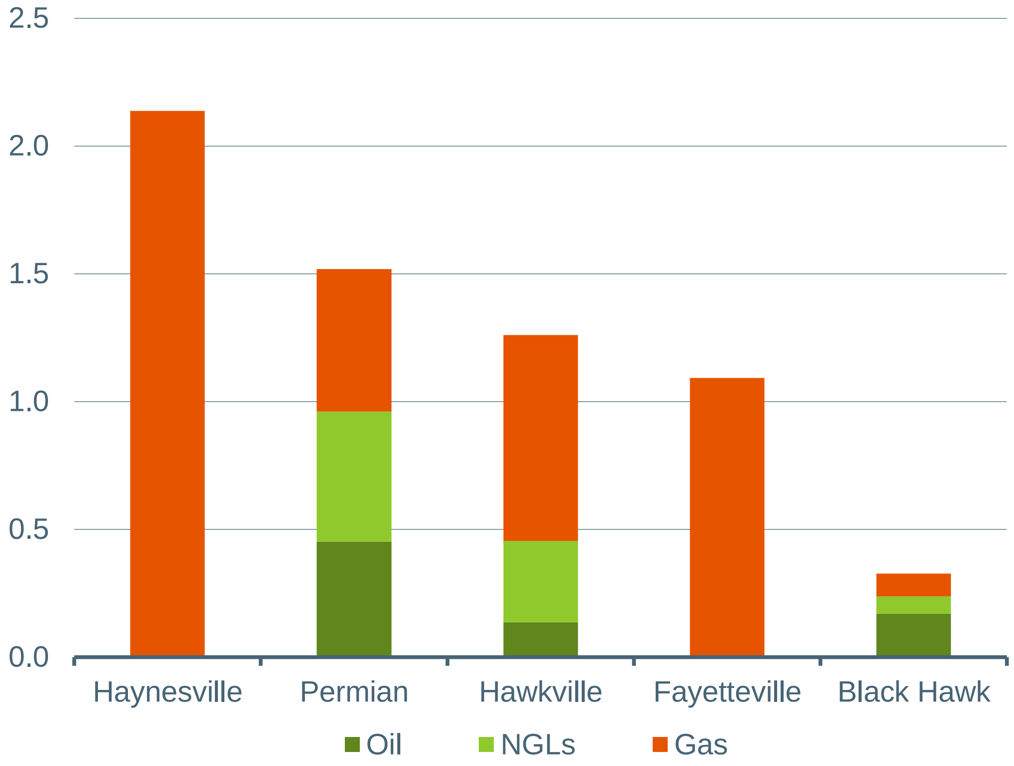
1. Source: BHP Billiton analysis.
2. Source: Energy Information Administration (EIA).

3 Bboe 2P reserves including ~500 MMbbls of oil

Onshore US reserves and resources[1, 2, 3]
(as at 30 June 2016, Bboe, BHP Billiton share)



Onshore US resources by product[1, 2, 3]
(as at 30 June 2016, Bboe, BHP Billiton share)

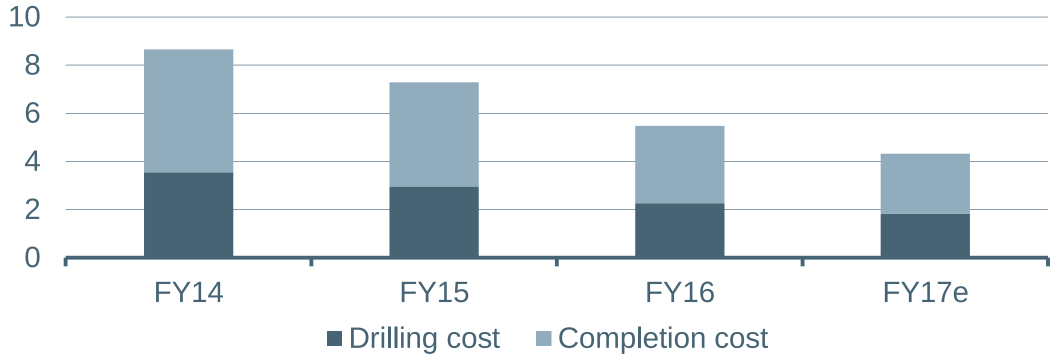


1. Total Proved reserves: 0.3 Bboe, Probable reserves: 2.7 Bboe, Contingent resources: 3.3 Bboe.
2. 2016 year-end 2P+2C resources totaled 6.3 Bboe or a net reduction of 1.2 Bboe from FY15. The overall resource reduction was a result of production of 0.1 Bboe, new additions of 2C resources of 0.3 Bboe, divestments and lease expiries of 1.3 Bboe and other revisions of -0.1 Bboe.
3. Includes fuel consumed in operations: Proved: 7 MMboe, Probable: 55 MMboe, Contingent: 69 MMboe.

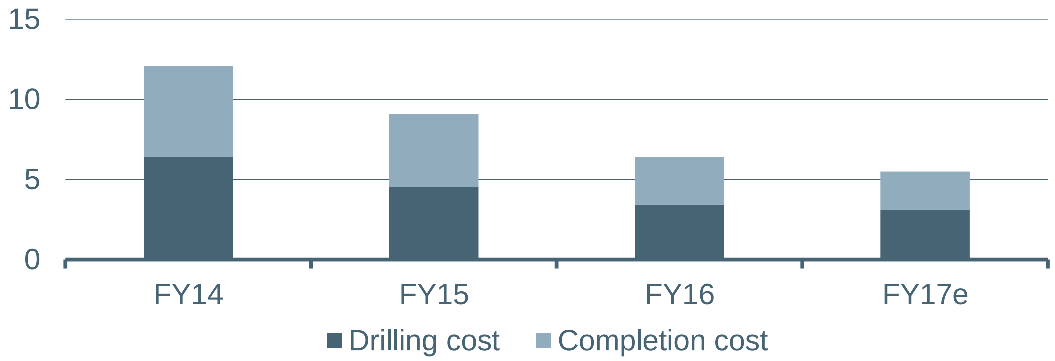
Continuing to deliver material well cost savings

- Well costs down ~40% over the past two years with further reductions in FY17
- Large portion of drilling cost reductions will be maintained independent of price environment
  - drilling rate increased up to 50%
  - rig move time reduced by ~50%
- Similar cost reductions achieved in well-site facilities

Reduction in Black Hawk well costs[1]
(US$ million, 100% basis)



Reduction in Permian well costs[1]
(US$ million, 100% basis)

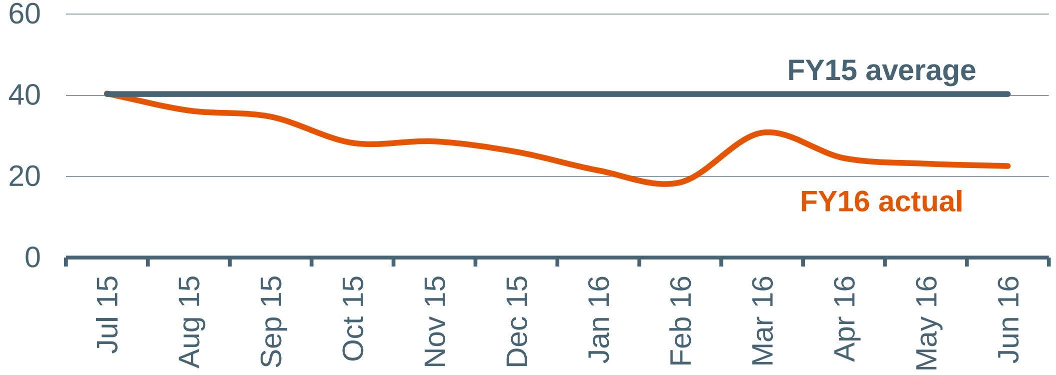


1. Drilling and completion costs are not normalised for lateral length. Black Hawk drilling cost calculated for 2-string wells only. Permian drilling and completion costs calculated using North Reeves activities. Completion costs exclude trials.

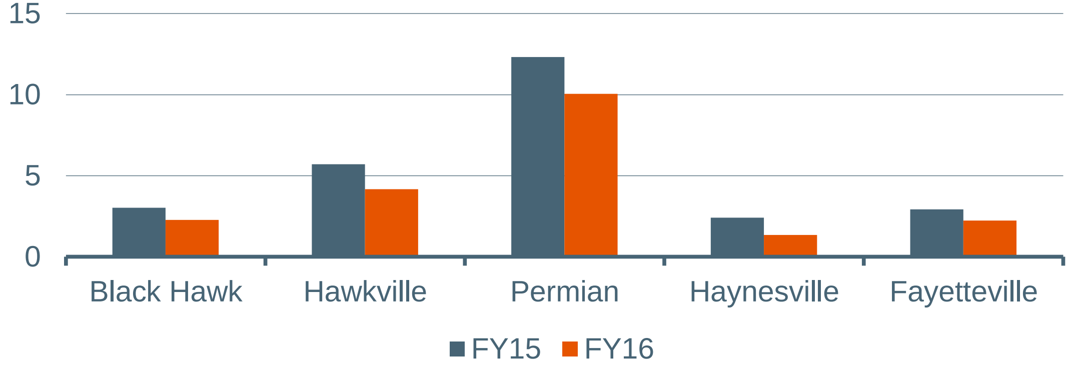
Operating productivity delivering significant savings

- ~30% reduction in field operating costs relative to FY15
  - embedded tools and practices originally developed by Minerals business
  - rapid progress enabled by reduction in activity levels
- Absolute cost reductions continue in FY17
- ~20% reduction in G&A[1] costs relative to FY15

Reduction in upstream field operating costs
(US$ million, BHP Billiton share)



Upstream field operating costs improvement by field[2]
(US$/boe)

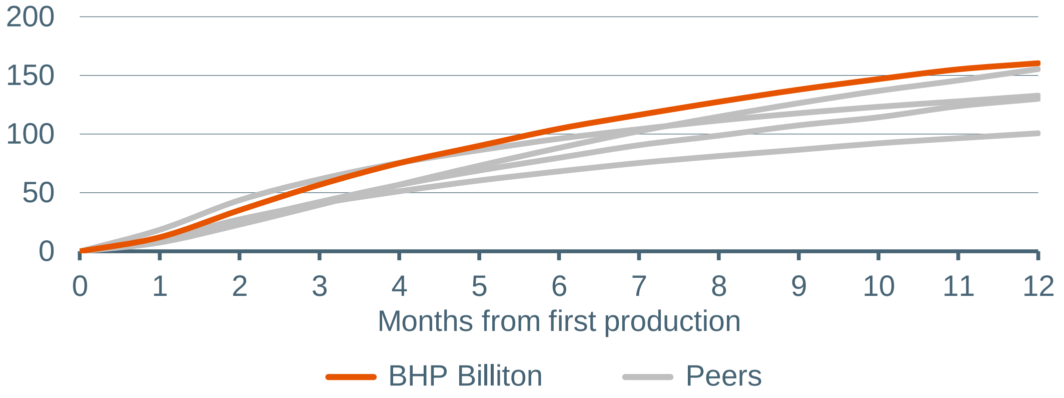


1. General & Administrative costs.
2. Upstream field operating costs include lifting, workovers and other field costs; does not include midstream, secondary taxes or Freight, Selling & Distribution (FS&D) costs.

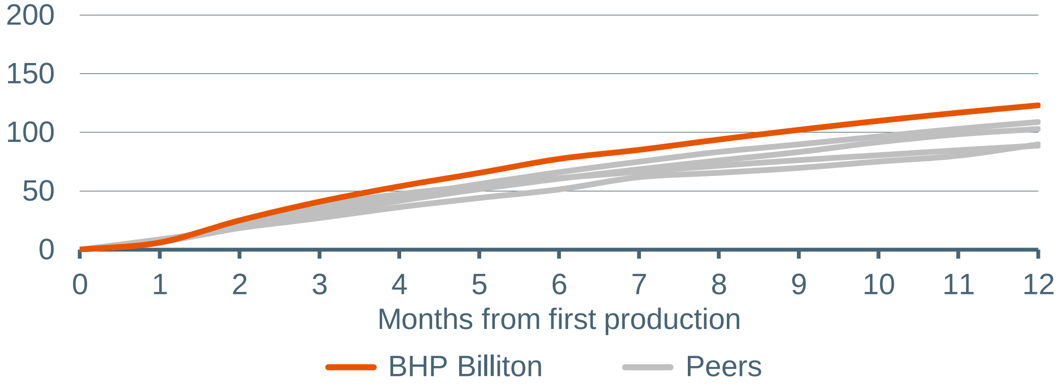
Superior well performance in core liquids-rich fields

- Condensate production in the first 12 months outperforms peers in both Black Hawk and Permian
- First-mover position and reservoir/fluid quality in both basins provide an advantage over the competition
- Continuous incremental completion optimisations further reduce costs and improve recoveries

Black Hawk well performance relative to peers[1, 2, 3]
(cumulative production, gross condensate Mbbls)



Permian Upper Wolfcamp well performance relative to peers[1, 2, 4]
(cumulative production, gross condensate Mbbls)

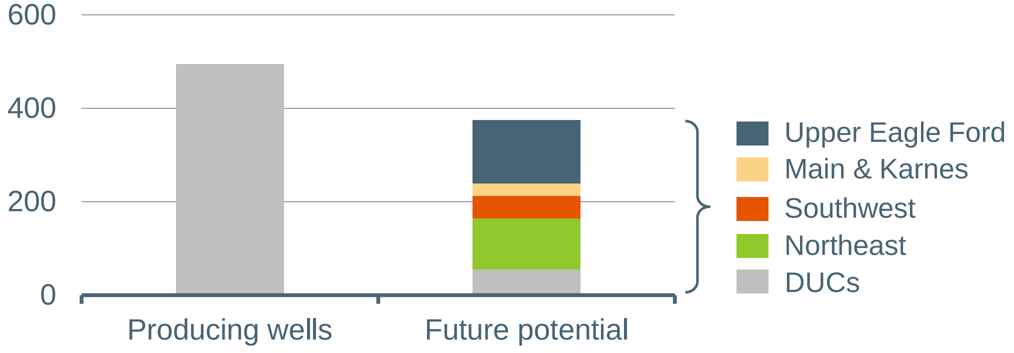


Source: IHS, BHP Billiton analysis.
1. Cumulative production on single well basis calculated from total monthly production divided by well count for each operator. Peer selection based on well count, rig activity and offset acreage. Analysis excludes peers with less than five comparable wells.
2. Data normalised for 5,000 ft lateral length.
3. Peers are Conoco, EOG, Marathon and Pioneer.
4. Peers are Anadarko, Cimarex, EOG and RKI/WPX.

Black Hawk: expanding inventory

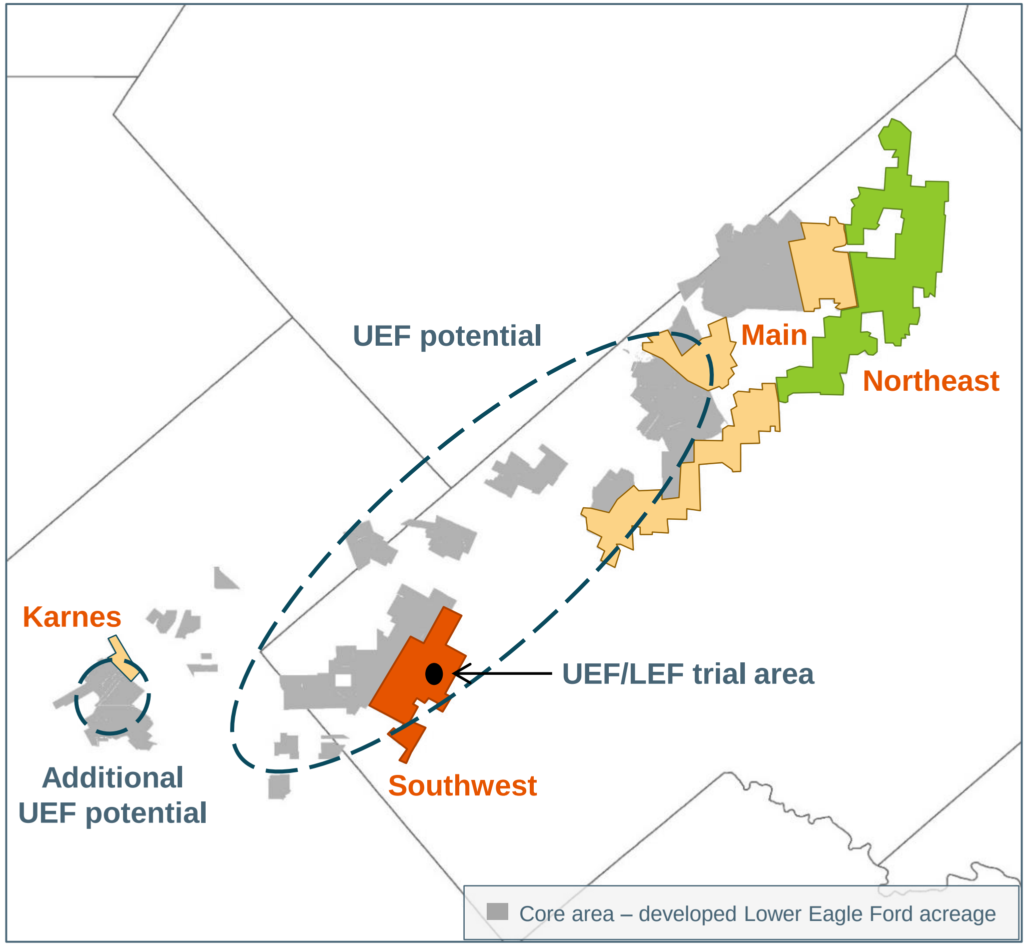
- Current production of ~55 Mboe/d (net)
- De-risking future development areas through ongoing trials
  - ongoing Lower Eagle Ford (LEF) trials in Southwest and upcoming trials in Northeast
  - ongoing Upper Eagle Ford (UEF) trial with encouraging results from nearby operators
- Majority of DUCs[1] inventory (~45 of ~55 net wells)[2] expected to come online in FY17

Existing and potential Black Hawk well inventory[2]
(net wells)



1. Drilled but Uncompleted wells.
2. As at 30 June 2016.

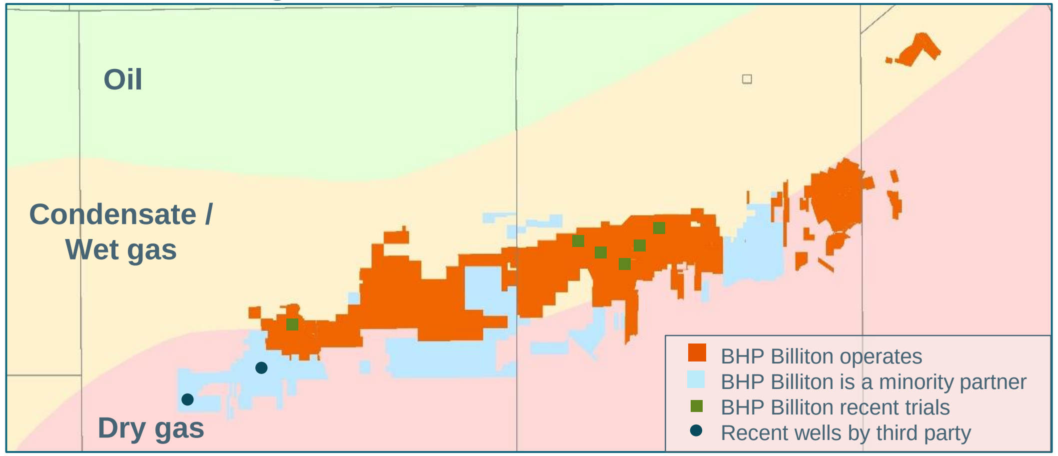
Black Hawk field acreage



Hawkville: encouraging results from recent trials

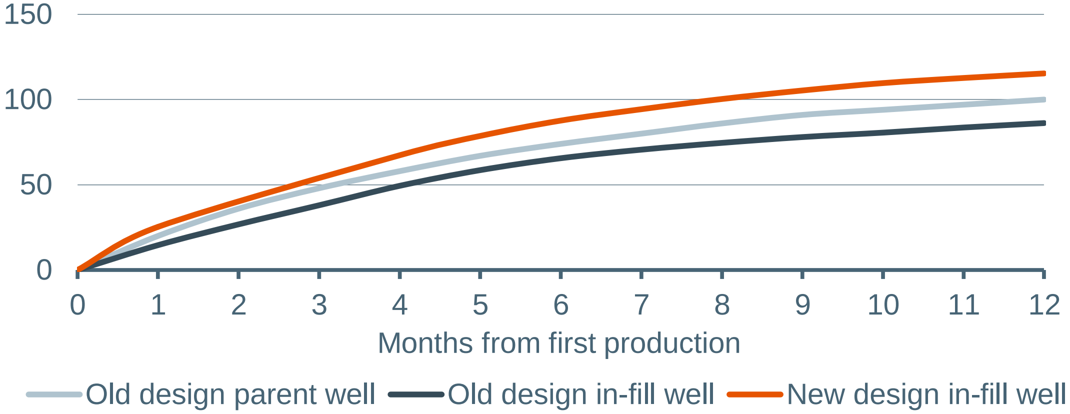
- Current production of ~30 Mboe/d (net)
- Evaluating encouraging results from new completions designs trialled by both BHP Billiton and other operators
- ~230 net wells delivering at least 15% IRR at $50/bbl
- Majority of drilling obligations successfully deferred to FY18
- Evaluating divestment of less competitive dry-gas areas for value

Hawkville acreage



Hawkville trial results

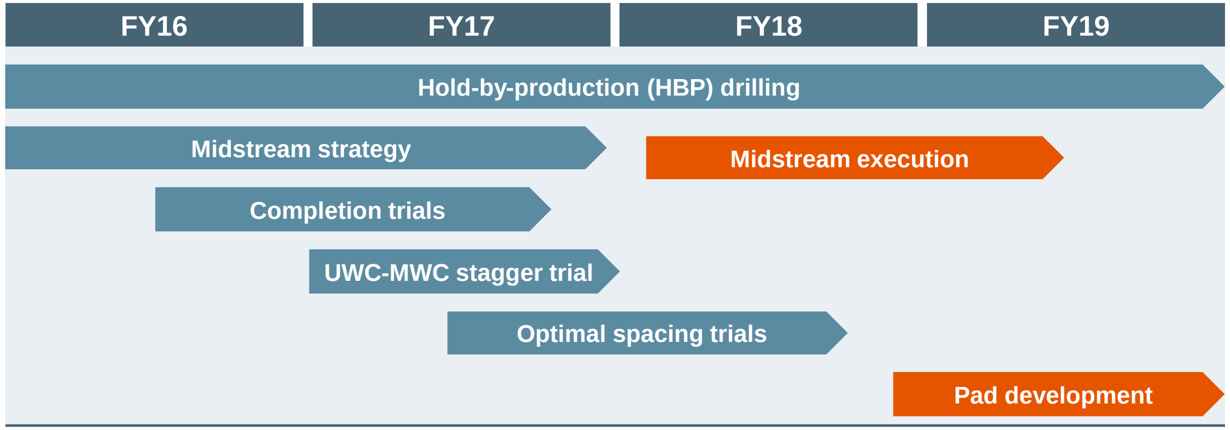
(cumulative production, gross condensate Mbbls)



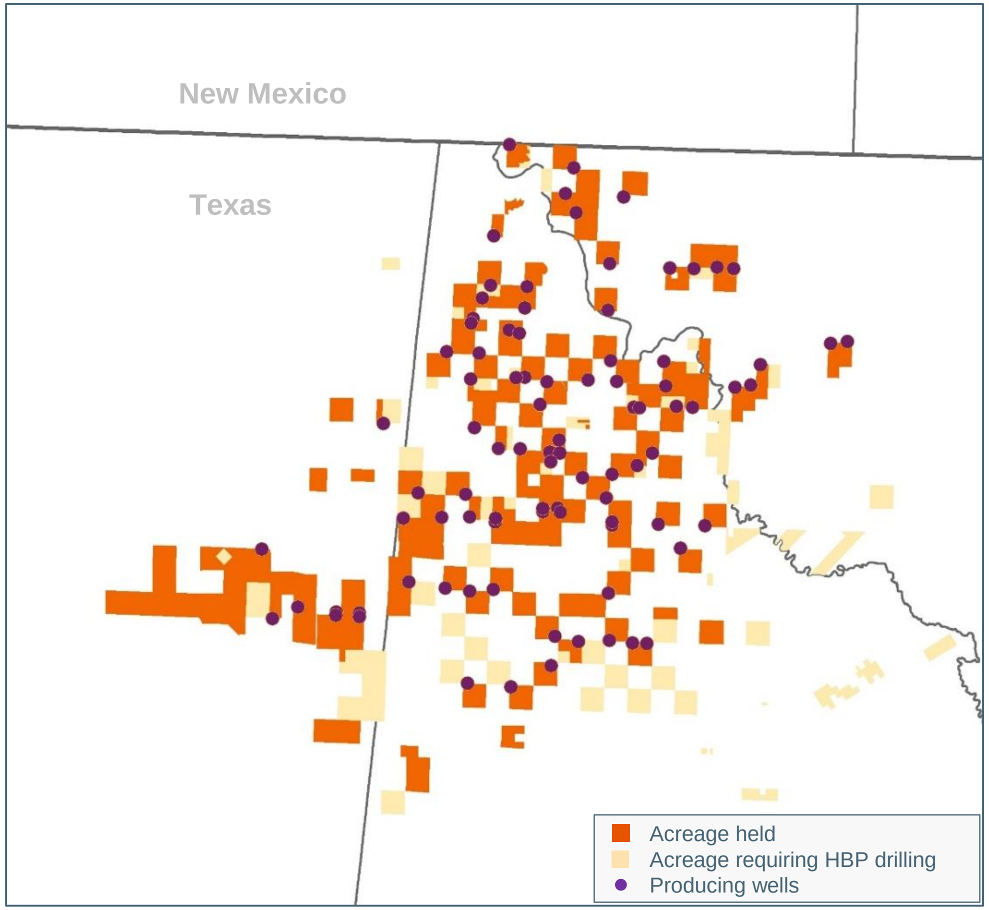
Permian: clear line of sight to development

- Current production of ~30 Mboe/d (net)
  - one rig focused on ~100 remaining obligation wells (gross)
  - recent acreage swaps to enable longer laterals
- Progressing toward full pad development in FY19 with six rigs
  - potential ~150 Mboe/d (net) within four years of development start
  - targeting multi-horizon Wolfcamp development

Possible Permian path to full development



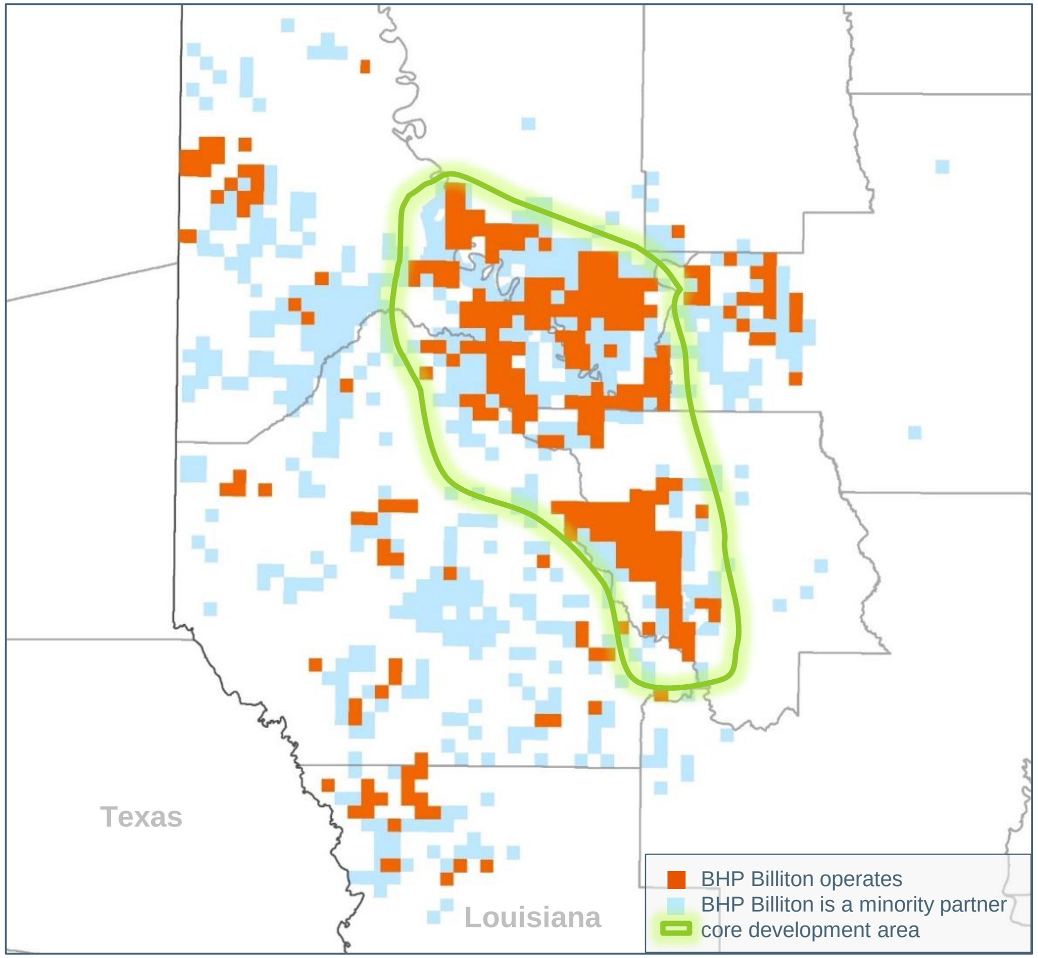
Permian core acreage and producing wells



Haynesville: recommenced high-return drilling program

- Current production of ~50 Mboe/d (net)
- Commenced drilling 16 well (gross) program in October with >30% returns[1]
  - production hedged at ~US$3/MMbtu
  - supply contracts locked for key services
  - executing long laterals and optimised completion design
- Working towards drilling ~100 additional wells (gross) beginning as early as FY18
- Evaluating divestment of less competitive acreage for value

Haynesville acreage and core development area

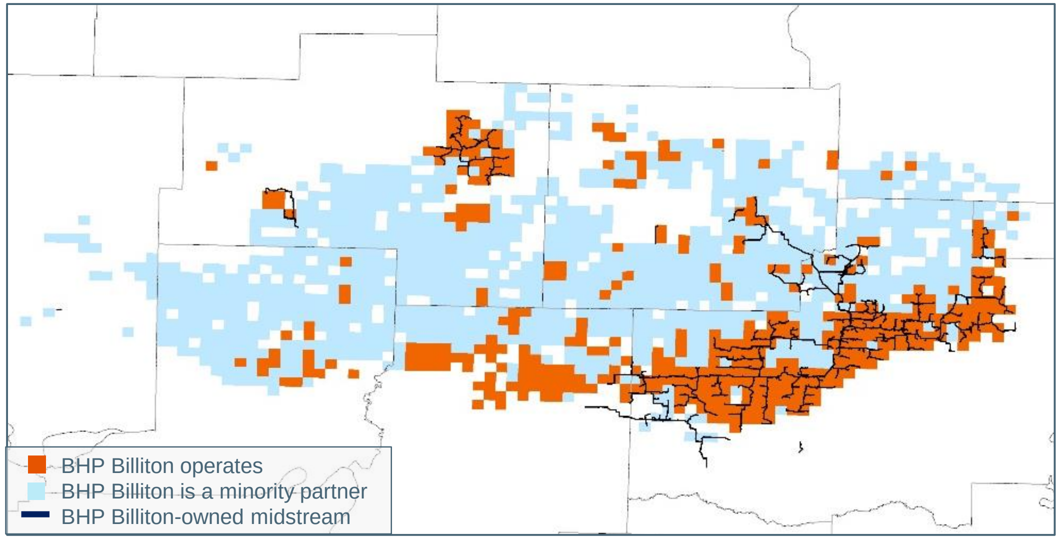


1. Incremental economics exclude otherwise unutilised transportation cost.

Fayetteville: low technical risk, long-term option

- Current production of ~45 Mboe/d (net)
- Extensively drilled with low geological risk
- Investment limited to minimal OBO[1] elections
- Working with partners to assess new potential Moorefield horizon

Fayetteville acreage

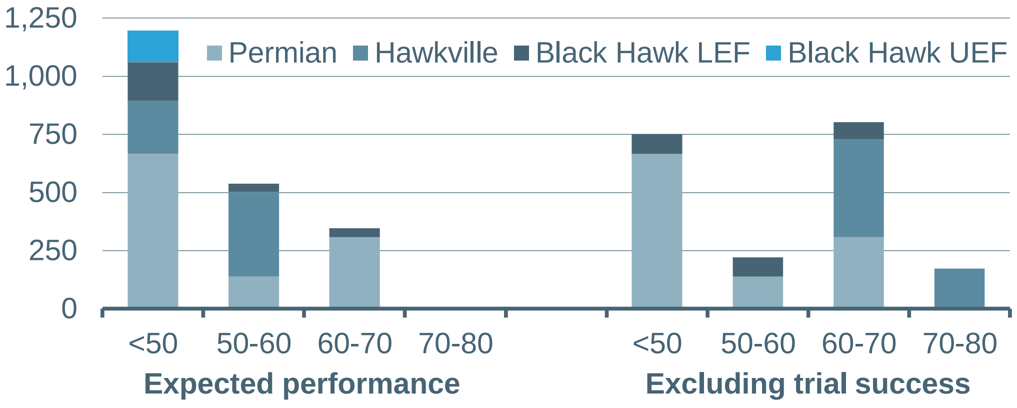


1. Operated by others.

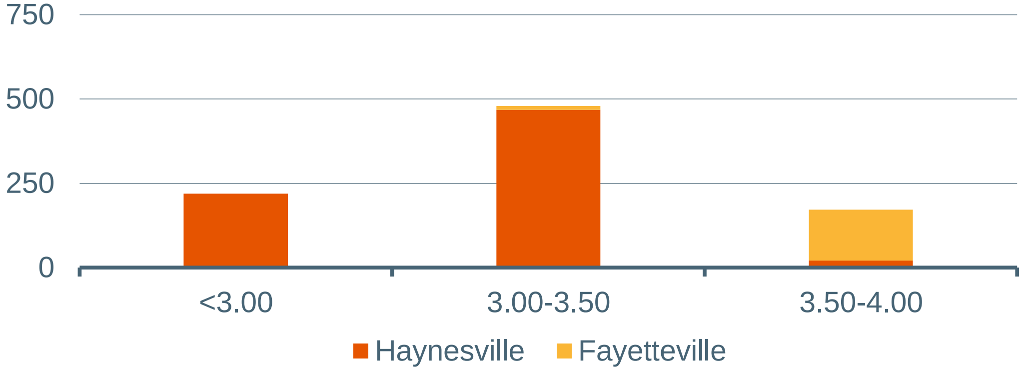
Large and improving investable inventory

- Attractive investment options at relatively low prices
  - ~1,200 net liquids-rich wells deliver at least 15% IRR at US$50/bbl
  - ~220 net dry gas wells deliver at least 15% IRR at US$3/MMbtu
- Ongoing trials to confirm improved productivity at Lower Eagle Ford (LEF) and the extent of Upper Eagle Ford (UEF) potential
- Capital allocation will time investment to maximise value and optimise free cash flow

Liquids-rich portfolio delivering 15% returns at flat price bands[1, 2, 3]
(net working interest wells, US$/bbl)



Dry gas portfolio delivering 15% returns at flat price bands[1, 2, 3]
(net working interest wells, US$/MMbtu)

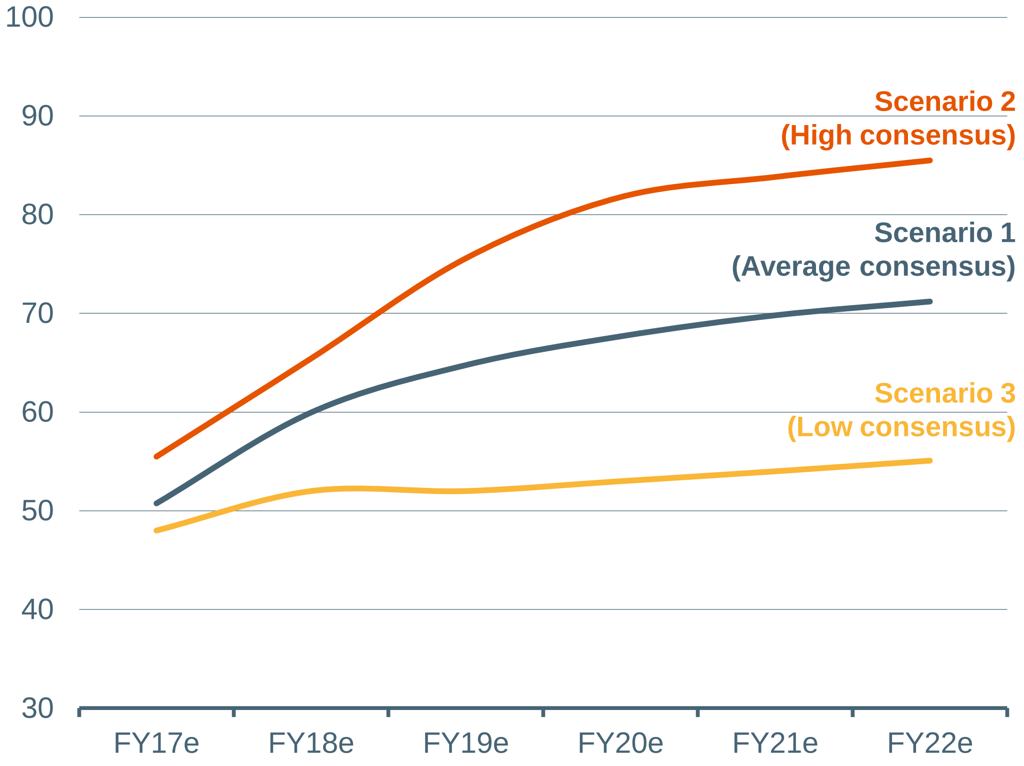


1. 15% rate of return under constant WTI oil and Henry Hub gas prices; liquids analysis assumes US$3.00/MMbtu Henry Hub gas price and NGL prices as a percentage of WTI. Incremental G&A not included for economic inventory; organisation is scalable for growth.
2. Where applicable, economics do not include Freight, Selling & Distribution (FS&D) costs.
3. Inventory includes only BHP Billiton-operated investments; information relating to non-operated inventory is included in the Appendix.

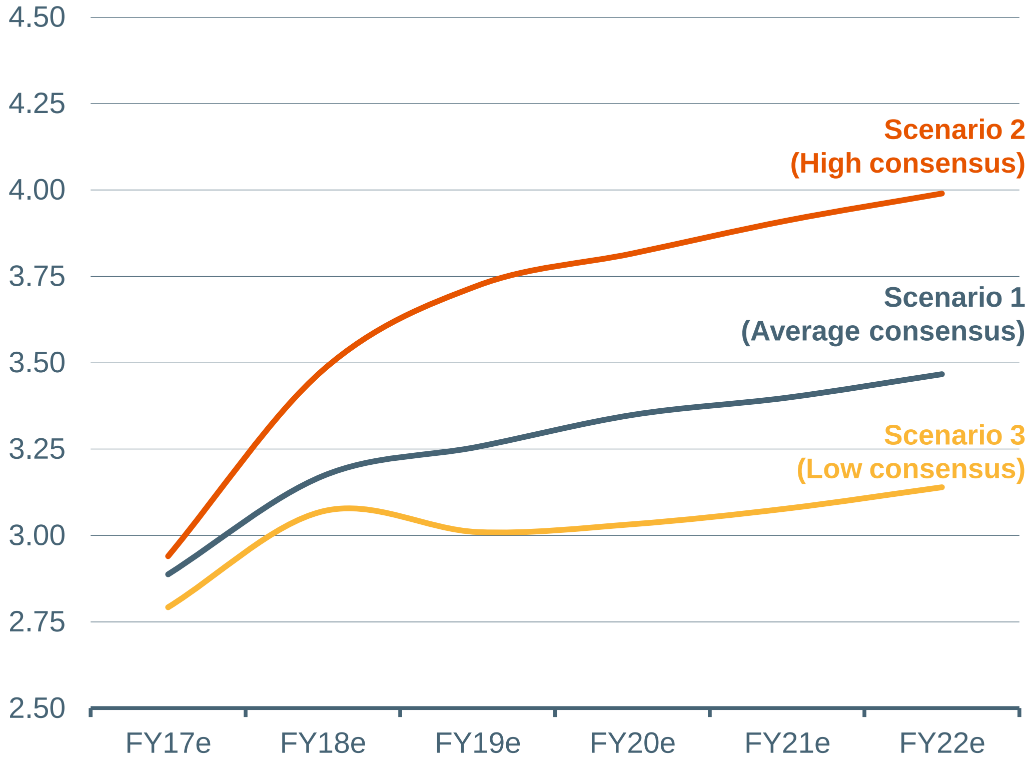
Price scenarios

A range of possible price scenarios derived from analysts' forecasts.

West Texas Intermediate crude oil consensus prices
(US$/bbl, nominal)



Henry Hub natural gas consensus prices
(US$/MMbtu, nominal)

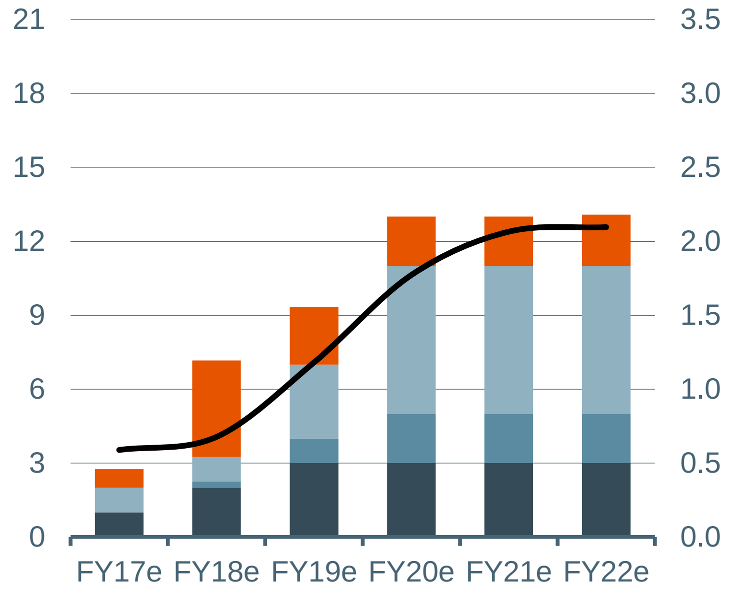


Note: Range of possible price scenarios is presented for illustrative purposes; this range does not necessarily correspond to BHP Billiton's view of prices going forward.

Operational capability to respond to market conditions

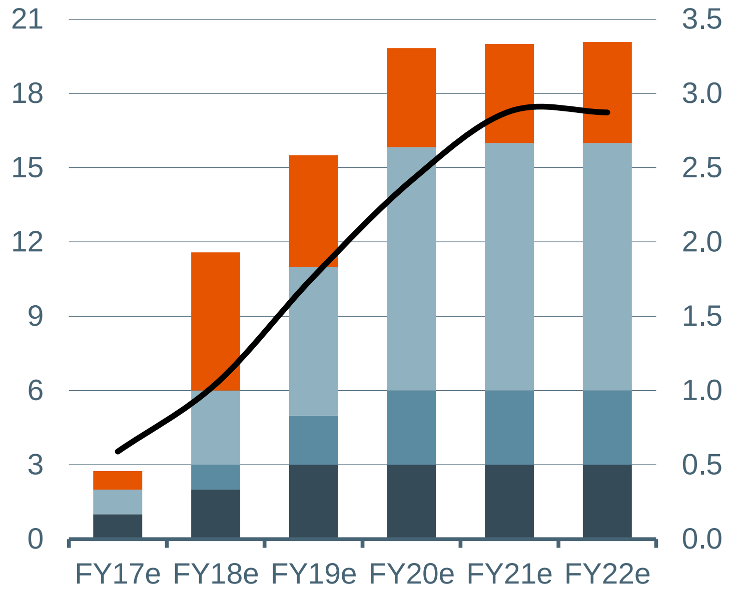
Scenario 1[1, 2, 3]
Mid activity based on consensus average prices

Gross operated rigs (annual average) — **Capital investment** (US$ billion, net, nominal)



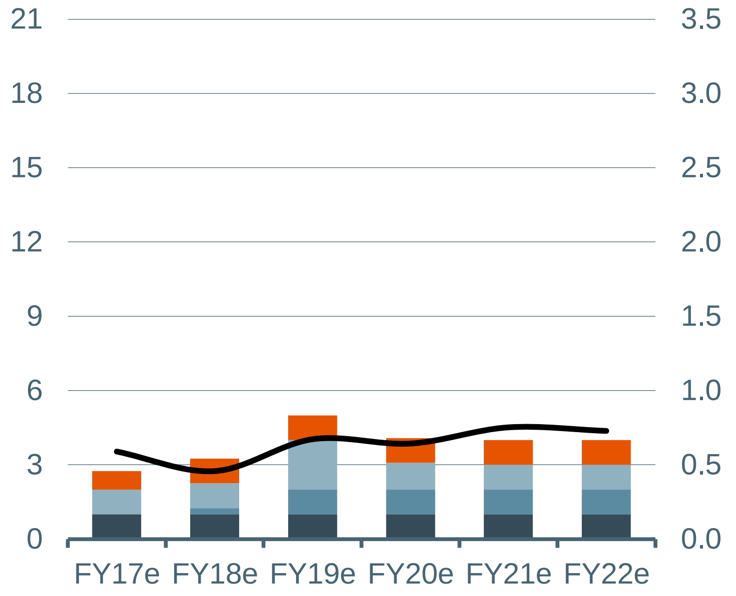
Scenario 2[1, 2, 3]
High activity based on consensus high prices

Gross operated rigs (annual average) — **Capital investment** (US$ billion, net, nominal)



Scenario 3[1, 2, 3]
Low activity based on consensus low prices

Gross operated rigs (annual average) — **Capital investment** (US$ billion, net, nominal)



Black Hawk | Hawkville | Permian | Haynesville | Capital investment

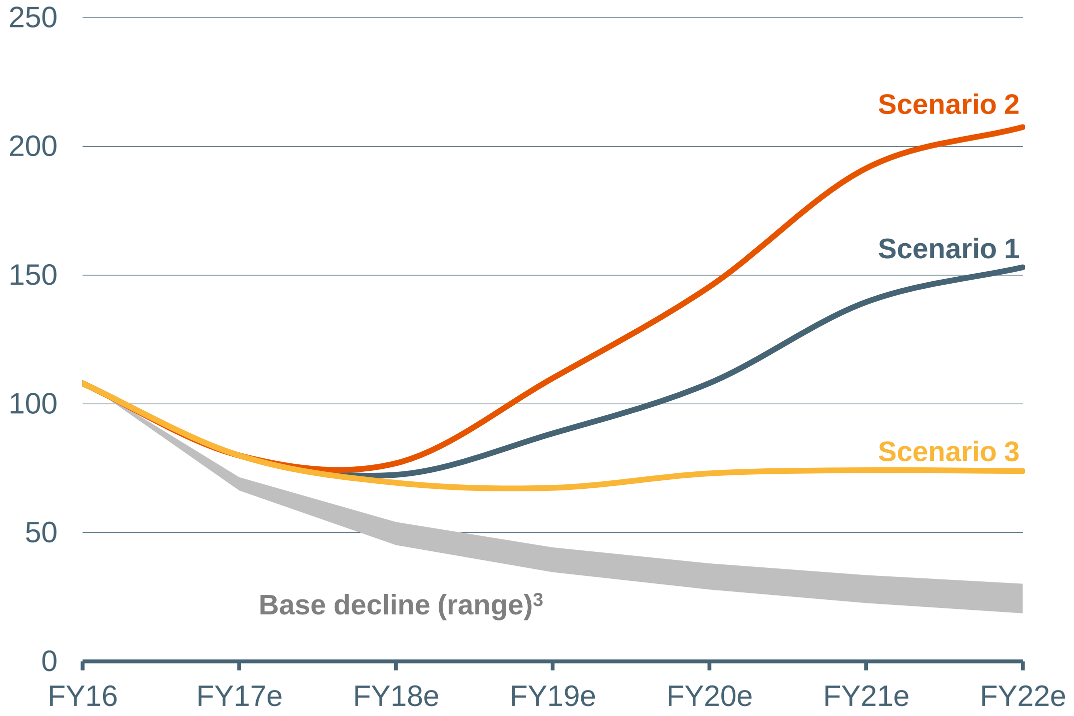
Note: Gross operated rig count and capital investment estimates for FY18 onwards represent possible responses to price scenarios. Scenarios do not constitute guidance; actual response will be determined according to market conditions prevailing at the relevant time.

1. Source: BHP Billiton analysis.
2. FY17 includes non-rig driven capital associated with Black Hawk DUC inventory.
3. Includes non-operated capital associated with investments in new wells operated by others (see Appendix for OBO information), and non-well specific capital investments (e.g. Permian water infrastructure, artificial lift, etc.).

Ability to quickly adjust production response

- Potential response in a range of price scenarios
  - annual average base decline of ~15% in FY18-22
  - volumes broadly flat in low price scenario from FY18 with key acreage retained
  - volumes could more than double within five years in high price scenario with rig count capped at 20 to preserve productivity
- Increased investment flexibility
  - majority of long-term rig contracts expired or terminated
  - organisation right-sized but scalable for growth

Onshore US potential production response[1, 2]
(MMboe, BHP Billiton share)



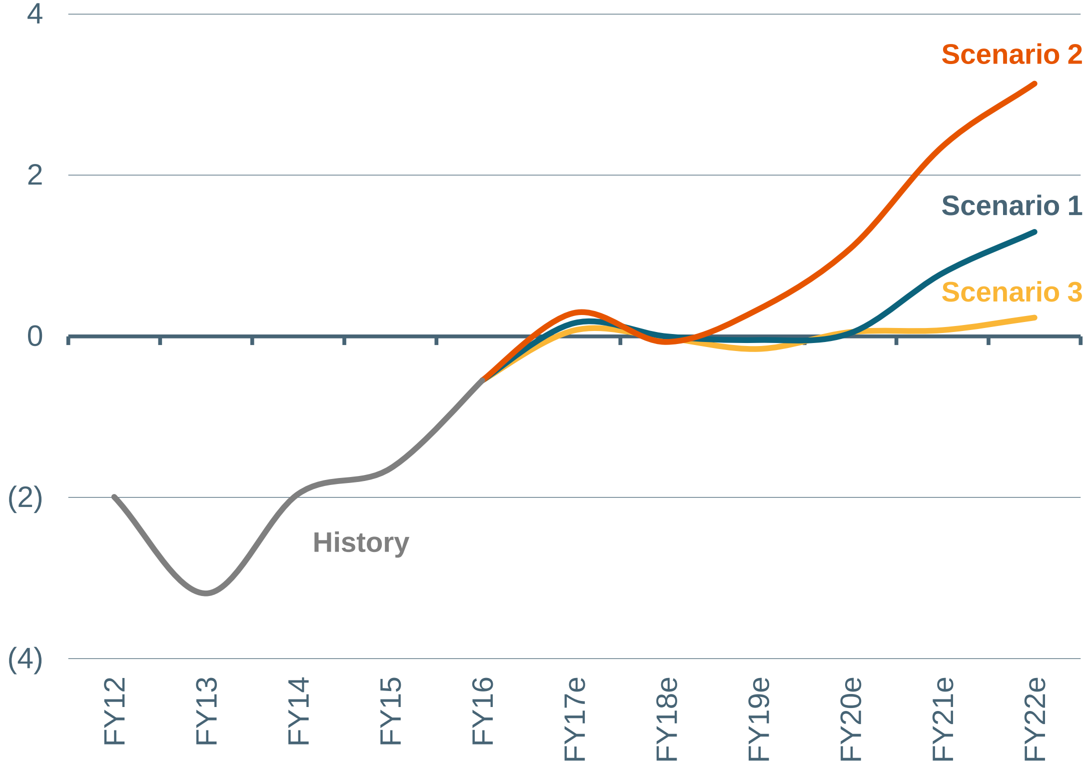
Note: Production estimates for FY18 onwards represent potential outcomes from possible responses to price scenarios. Scenarios do not constitute guidance; actual production will be determined according to market conditions prevailing at the relevant time.

1. Source: BHP Billiton analysis.
2. Base production and scenarios include BHP Billiton's share of production from wells operated by others.
3. Over the period FY17-22, portion of crude/condensate comprising base production is expected to decline from 25% to 20%, portion of NGLs is expected to decline from 14% to 13%, and portion of dry gas is expected to increase from 61% to 67%.

Maximising value and cash flow

- Potential to remain cash flow positive under the three price scenarios outlined
- Flexibility remains to pivot toward higher or lower activity levels in any given year in response to market conditions
- Progressing development with a commercial mindset
  - disciplined capital allocation
  - executed gas hedge with more under evaluation
  - pursuing monetisation of long-dated options (~US$100 million proceeds for non-core acreage closed or nearing close in FY17)

Onshore US potential pre-tax free cash flow[1, 2]
(US$ billion, BHP Billiton share, nominal)



Note: Free cash flow estimates for FY17 onwards represent potential outcomes from possible responses to price scenarios. Scenarios do not constitute guidance; actual response will be determined according to market conditions prevailing at the relevant time.

1. Pre-tax free cash flow: EBITDA less capital expenditure. Excludes working capital in FY17e-22e.
2. Source: BHP Billiton analysis.

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  - will consider monetisation of long-dated dry gas options for value

1. Total Proved reserves: 0.3 Bboe, Probable reserves: 2.7 Bboe, includes fuel consumed in operations: Proved: 7 MMboe, Probable: 55 MMboe.

Appendices

Key well parameters: Black Hawk

	<$50/bbl[1]	$50-60/bbl wells[1]	$60-70/bbl wells[1]
Total acreage (thousand acres)	97		
Rig line efficiency	30 wells / year[2]		
Future well locations (gross)	489[3]	70	67
Average WI/NRI	54% / 41%	50% / 37%	57% / 43%
Gross well capex (real US$ million)	5.2[2]	5.6[2]	5.3[2]
Total production over life (million boe)	0.6	0.7	0.8
30-day IP (boe/day)	1,400	1,300	900
3-year cumulative production (million boe)	0.4	0.4	0.5
Gross cash costs (real US$)[4]	3,000/well/month + 6.00/boe	3,000/well/month + 6.00/boe	3,000/well/month + 6.25/boe
Product mix, crude / residue gas / NGLs	60% / 23% / 17%	36% / 35% / 29%	23% / 44% / 33%

1. Required flat WTI price to deliver 15% rate of return. Analysis assumes US$3.00/MMbtu Henry Hub gas price and NGL prices as a percentage of WTI.
2. Cost and rig efficiency as of FY17 start. Figures do not include further productivity improvements and capex savings that are included in the scenarios provided.
3. Excludes 97 gross (~55 net working interest) DUCs.
4. Excludes G&A and severance tax; these costs are included in the scenarios provided.

Key well parameters: Hawkville

	<$50/bbl wells[1]	$50-60/bbl wells[1]	$60-70/bbl wells[1]
Total acreage (thousand acres)	248		
Rig line efficiency	30 wells / year[2]		
Future well locations (gross)[3]	233	376	0
Average WI/NRI	98% / 73%	97% / 73%	n/a
Gross well capex (real US$ million)	5.4[2]	5.5[2]	n/a
Total production over life (million boe)	0.9	1.1	n/a
30-day IP (boe/day)	1,000	1,200	n/a
3-year cumulative production (million boe)	0.4	0.5	n/a
Gross cash costs (real US$)[4]	6,000/well/month + 6.50/boe	6,000/well/month + 6.50/boe	n/a
Product mix, crude / residue gas / NGLs	36% / 35% / 29%	15% / 52% / 33%	n/a

1. Required flat WTI price to deliver 15% rate of return. Analysis assumes US$3.00/MMbtu Henry Hub gas price and NGL prices as a percentage of WTI.
2. Cost and rig efficiency as of FY17 start. Figures do not include further productivity improvements and capex savings that are included in the scenarios provided.
3. Well count excludes ~60 OBO wells (BHP Billiton working interest).
4. Excludes G&A and severance tax; these costs are included in the scenarios provided.

Key well parameters: Permian

	<$50/bbl wells[1]	$50-60/bbl wells[1]	$60-70/bbl wells[1]
Total acreage (thousand acres)	123		
Rig line efficiency	15 wells / year[2]		
Future well locations (gross)	790	152[3]	371[3]
Average WI/NRI	84% / 63%	90% / 68%	83% / 63%
Gross well capex (real US$ million)	6.5[2]	7.1[2, 3]	6.1[2, 4]
Total production over life (million boe)	0.8	0.8	0.5
30-day IP (boe/day)	1,400	1,300	900
3-year cumulative production (million boe)	0.5	0.5	0.3
Gross cash costs (real US$)[4]	12,500/well/month + 8.50/boe	12,500/well/month + 9.00/boe	12,500/well/month + 9.50/boe
Product mix, crude / residue gas / NGLs	46% / 27% / 27%	41% / 31% / 28%	43% / 30% / 27%

1. Required flat WTI price to deliver 15% rate of return. Analysis assumes US$3.00/MMbtu Henry Hub gas price and NGL prices as a percentage of WTI.
2. Cost and rig efficiency as of FY17 start. Figures do not include further productivity improvements and capex savings that are included in the scenarios provided.
3. Scenarios provided assume sequential development of Middle Wolfcamp (488 gross wells) leading to wellsite facilities capex savings of US$0.75 million per well (not reflected in capex above).
4. Excludes G&A and severance tax; these costs are included in the scenarios provided.

Key well parameters: Haynesville

	<$3/MMbtu wells[1]	$3-3.50/MMbtu wells[1]	$3.50-4/MMbtu wells[1]
Total acreage (thousand acres)	275		
Rig line efficiency	12 wells / year[2]		
Future well locations (gross)[3]	305	615	25
Average WI/NRI	72% / 55%	76% / 59%	86% / 71%
Gross well capex (real US$ million)	7.5[2]	7.1[2]	7.3[2]
Total production over life (million boe)	2	1.2	1.2
30-day IP (boe/day)	2,100	1,500	1,200
3-year cumulative production (million boe)	1.3	0.8	0.6
Gross cash costs (real US$)[4]	5,000/well/month + 3.75/boe	5,000/well/month + 4.50/boe	5,000/well/month + 4.75/boe
Product mix, crude / residue gas / NGLs	0% / 100% / 0%	0% / 100% / 0%	0% / 100% / 0%

1. Required flat Henry Hub price to deliver 15% rate of return.
2. Cost and rig efficiency as of FY17 start. Figures do not include further productivity improvements and capex savings that are included in the scenarios provided.
3. Well count excludes ~110 OBO wells (BHP Billiton working interest).
4. Excludes G&A and severance tax; these costs are included in the scenarios provided.

Key well parameters: Fayetteville

	<$3/MMbtu wells[1]	$3-3.50/MMbtu wells[1]	$3.50-4/MMbtu wells[1]
Total acreage (thousand acres)	625		
Rig line efficiency	31 well / year[2]		
Future well locations (gross)[3]	0	21	275
Average WI/NRI	n/a	52% / 43%	55% / 46%
Gross well capex (real US$ million)	n/a	2.9[2]	2.8[2]
Total production over life (million boe)	n/a	0.7	0.5
30-day IP (boe/day)	n/a	500	400
3-year cumulative production (million boe)	n/a	0.3	0.2
Gross cash costs (real US$)[4]	n/a	3,500/well/month + 2.25/boe	3,500/well/month + 3.50/boe
Product mix, crude / residue gas / NGLs	n/a	0% / 100% / 0%	0% / 100% / 0%

1. Required flat Henry Hub price to deliver 15% rate of return.
2. Cost and rig efficiency as of FY17 start. Figures do not include further productivity improvements and capex savings that are included in the scenarios provided.
3. Well count excludes ~200 OBO wells (BHP Billiton working interest).
4. Excludes G&A and severance tax; these costs are included in the scenarios provided.

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Conventional Petroleum

Extending the production runway

Geraldine Slattery Asset President, Conventional

Disclaimer

Forward-looking statements

This presentation contains forward-looking statements, including statements regarding: reserves and resources and the production, revenues and costs relating thereto, trends in commodity prices and currency exchange rates; demand for commodities; plans, strategies and objectives of management; closure or divestment of certain operations or facilities (including associated costs); anticipated production or construction commencement dates; capital costs and scheduling; operating costs and shortages of materials and skilled employees; anticipated productive lives of projects, mines and facilities; provisions and contingent liabilities; tax and regulatory developments.

Forward-looking statements can be identified by the use of terminology such as 'intend', 'aim', 'project', 'anticipate', 'estimate', 'plan', 'believe', 'expect', 'may', 'should', 'will', 'continue', 'annualised' or similar words. These statements discuss future expectations concerning the results of operations or financial condition, or provide other forward-looking statements.

These forward-looking statements are not guarantees or predictions of future performance, and involve known and unknown risks, uncertainties and other factors, many of which are beyond our control, and which may cause actual results to differ materially from those expressed in the statements contained in this presentation. Readers are cautioned not to put undue reliance on forward-looking statements.

For example, future revenues from our operations, other results, projects or mines described in this presentation will be based, in part, upon the market price of the minerals, metals or petroleum produced, which may vary significantly from current levels. These variations, if materially adverse, may affect the timing or the feasibility of the development of a particular project, the expansion of certain facilities or mines, the continuation of existing operations.

Other factors that may cause actual results to differ from those expressed in the forward-looking statements include uncertainties in estimating reserves, difficulties in converting resources into reserves and reserves into quantities of oil and gas,

operating risks, changes in operating costs, factors that affect the actual construction or production commencement dates, costs or production output and anticipated lives of operations, mines or facilities include our ability to profitably produce and transport the minerals, petroleum and/or metals extracted to applicable markets; the impact of foreign currency exchange rates on the market prices of the minerals, petroleum or metals we produce; activities of government authorities in some of the countries where we are exploring or developing these projects, facilities or mines, including increases in taxes, changes in environmental and other regulations and political uncertainty; labour unrest; and other factors identified in the risk factors discussed in BHP Billiton's filings with the US Securities and Exchange Commission (the "SEC") (including in Annual Reports on Form 20-F) which are available on the SEC's website at www.sec.gov.

Except as required by applicable regulations or by law, the Group does not undertake any obligation to publicly update or review any forward-looking statements, whether as a result of new information or future events.

Past performance cannot be relied on as a guide to future performance.

Non-IFRS financial information

BHP Billiton results are reported under International Financial Reporting Standards (IFRS) including Underlying EBIT and Underlying EBITDA which are used to measure segment performance. This release may also include certain non-IFRS and other financial measures including Adjusted effective tax rate, Free cash flow, Gearing ratio, Net debt, Net operating assets, Underlying attributable profit, Underlying basic (loss)/earnings per share, Underlying EBIT margin and Underlying EBITDA margin. These measures are used internally by management to assess the performance of our business, make decisions on the allocation of our resources and assess operational management. Non-IFRS and other financial measures have not been subject to audit or review and should not be considered as an indication of or alternative to an IFRS measure of profitability, financial performance or liquidity.

Presentation of data

Unless specified otherwise: all data is presented on a continuing operations basis to exclude the contribution from assets that were demerged with South32; references to Underlying EBITDA margin exclude third party trading activities; data from subsidiaries is shown on a 100 per cent basis and data from equity accounted investments and other operations is shown on a proportionate consolidation basis. Numbers presented may not add up precisely to the totals provided due to rounding. Onshore US scenarios are based on price estimates from Bank of America Merrill Lynch, Citi, Credit Suisse, Deutsche Bank, JP Morgan, Macquarie, Morgan Stanley and UBS as at 8 August 2016 and do not necessarily correspond to BHP Billiton's view of prices.

No offer of securities

Nothing in this presentation should be construed as either an offer to sell or a solicitation of an offer to buy or sell BHP Billiton securities in any jurisdiction, or be treated or relied upon as a recommendation or advice by BHP Billiton.

Reliance on third party information

The views expressed in this presentation contain information that has been derived from publicly available sources that have not been independently verified. No representation or warranty is made as to the accuracy, completeness or reliability of the information. This presentation should not be relied upon as a recommendation or forecast by BHP Billiton.

Statement of Petroleum Resources

Petroleum Resources

The estimates of Petroleum Reserves and Contingent Resources contained in this presentation are based on, and fairly represent, information and supporting documentation prepared under the supervision of Mr. A. G. Gadgil, who is employed by BHP Billiton. Mr. Gadgil is a member of the Society of Petroleum Engineers and has the required qualifications and experience to act as a qualified Petroleum Reserves and Resources evaluator under the ASX Listing Rules. This presentation is issued with the prior written consent of Mr. Gadgil who agrees with the form and context in which the Petroleum Reserves and Contingent Resources are presented.

Reserves and Contingent Resources are net of royalties owned by others and have been estimated using deterministic methodology. Aggregates of Reserves and Contingent Resources estimates contained in this presentation have been calculated by arithmetic summation of field/project estimates by category with the exception of the North West Shelf (NWS) Gas Project in Australia. Probabilistic methodology has been utilised to aggregate the NWS Reserves and Contingent Resources for the reservoirs dedicated to the gas project only and represents an incremental 39 MMboe of Proved Reserves. The barrel of oil equivalent conversion is based on 6000 scf of natural gas equals 1 boe. The Reserves and Contingent Resources contained in this presentation are inclusive of fuel required for operations. The respective amounts of fuel for each category are provided by footnote for the resource graphics. The custody transfer point(s)/point(s) of sale applicable for each field or project are the reference point for Reserves and Contingent Resources. Reserves and Contingent Resources estimates have not been adjusted for risk. Unless noted otherwise, Reserves and Contingent Resources are as of 30 June 2016. Where used in this presentation, the term Resources represents the sum of 2P reserves and 2C Contingent Resources.

BHP Billiton estimates Proved Reserve volumes according to SEC disclosure regulations and files these in our annual 20-F report with the SEC. All Unproved volumes are estimated using SPE-PRMS guidelines, which among other things, allow escalations to prices and costs, and as such, would be on a different basis than that prescribed by the SEC, and are therefore excluded from our SEC filings. All Resources and other Unproved volumes may differ from and may not be comparable to the same or similarly-named measures used by other companies. Non-proved estimates are inherently more uncertain than proved.

Table 1 Net BHP Billiton Petroleum Reserves and Contingent Resources as of 30 June 2016

	Onshore US			Offshore US	Australia			Rest of World				
Net MMboe	**Eagle Ford & Permian**	**Haynesville & Fayetteville**	**Subtotal**	**Gulf of Mexico**	**Offshore Western Australia[1, 2]**	**Bass Strait & Offshore Victoria**	**Subtotal**	**Trinidad & Tobago**	**Algeria**	**United Kingdom & Other**	**Subtotal**	**Total BHP Billiton**
Proved	**124**	**173**	**298**	**210**	**414**	**303**	**717**	**56**	**22**	**-**	**78**	**1,303**
Probable	**1,433**	**1,273**	**2,707**	**127**	**59**	**94**	**153**	**17**	**10**	**-**	**27**	**3,013**
2P	**1,558**	**1,447**	**3,004**	**337**	**473**	**397**	**869**	**73**	**32**	**-**	**105**	**4,316**
2C	**1,547**	**1,782**	**3,329**	**392**	**1,099**	**153**	**1,252**	**52**	**18**	**20**	**89**	**5,061**
2P+2C	**3,105**	**3,228**	**6,333**	**729**	**1,571**	**550**	**2,121**	**124**	**50**	**20**	**194**	**9,377**
Fuel included above												
Proved	2.0	5.0	7.0	5.8	36.5	16.9	53.4	1.4	1.3	-	2.8	69.0
Probable	33.2	22.2	55.4	3.2	3.6	4.7	8.3	-	-	-	-	66.8
2P	35.2	27.2	62.4	8.9	40.0	21.7	61.7	1.4	1.3	-	2.8	135.8
2C	27.3	41.4	68.7	5.8	113.4	6.8	120.2	-	-	-	-	194.7
2P+2C	62.5	68.6	131.1	14.8	153.4	28.5	181.9	1.4	1.3	-	2.8	330.6

1) Includes NWS Gas Project probabilistic increment noted in disclaimer above.

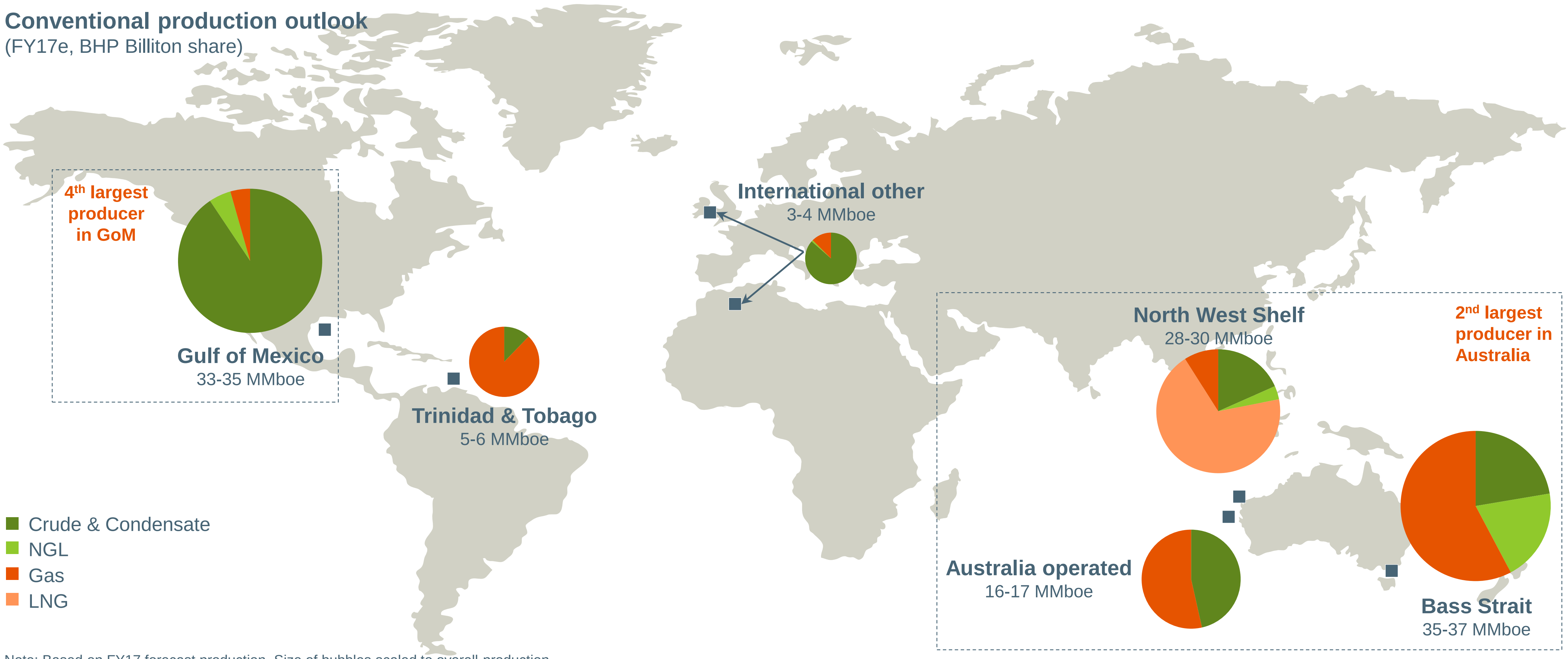
2) Australian resources prior to the announced agreement by Woodside to acquire 50% of BHP Billiton Scarborough area assets.

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only Proved, Probable and Possible Reserves, and only when such Reserves have been determined in accordance with SEC guidelines. We use certain terms in this presentation such as “Resources,” “Contingent Resources,” “2C Contingent Resources” and similar terms as well as Probable Reserves not determined in accordance with the SEC’s guidelines, all of which measures we are strictly prohibited from including in filings with the SEC. These measures include Reserves and Resources with substantially less certainty than Proved Reserves. U.S. investors are urged to consider closely the disclosure in our Form 20-F for the fiscal year ended June 30, 2016, File No. 001-09526 and in our other filings with the SEC, available from us at http://www.bhpbilliton.com/. These forms can also be obtained from the SEC as described above.

Extending the production runway

- **Quality assets provide strong foundations**
  - low cost assets in stable political environments
  - material player in chosen production heartlands
  - strong free cash flow and returns through the price cycle
- **Operating and development excellence provides competitive advantage**
  - focus on safety and productivity continues to improve performance and protect margins
  - low unit costs and deepwater drilling performance reflect leading operating and development capability
  - operating and development competencies support acceleration of schedule from discovery to first oil
- **Multiple options to replenish oil reserves and extend production**
  - suite of high-return brownfield projects to offset near-term decline
  - Mad Dog 2 investment decision expected in next six months with production from CY22 if approved
  - currently exploring in deepwater basins of choice

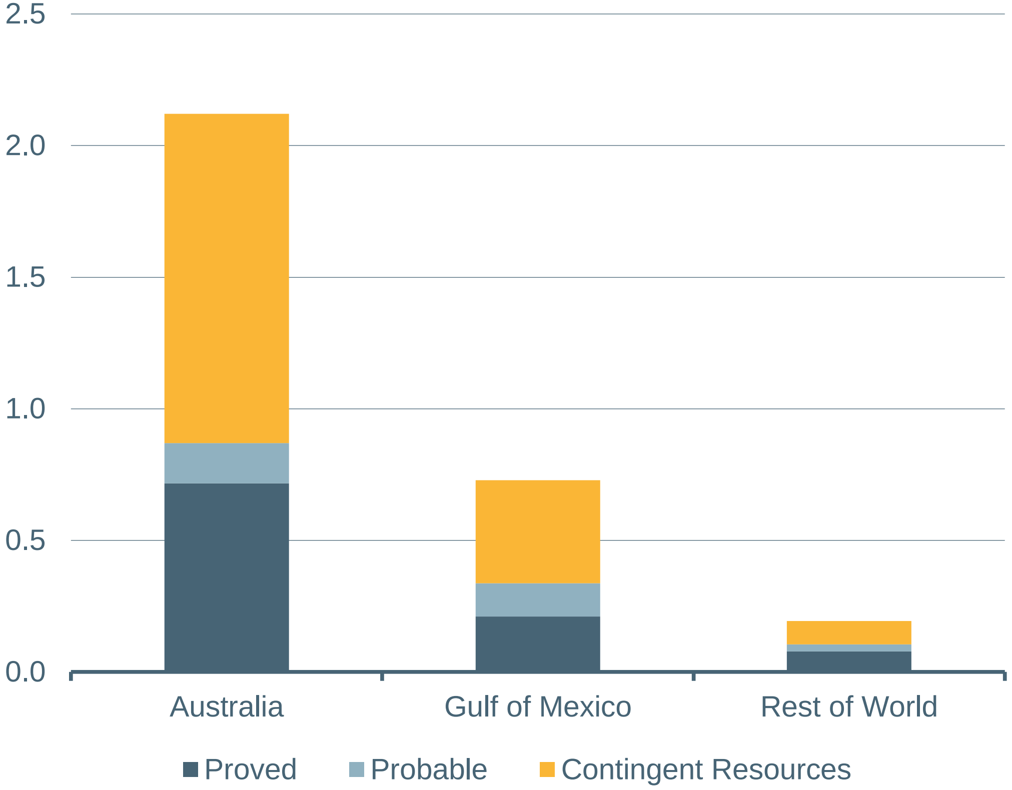
Quality assets concentrated in Australia and GoM



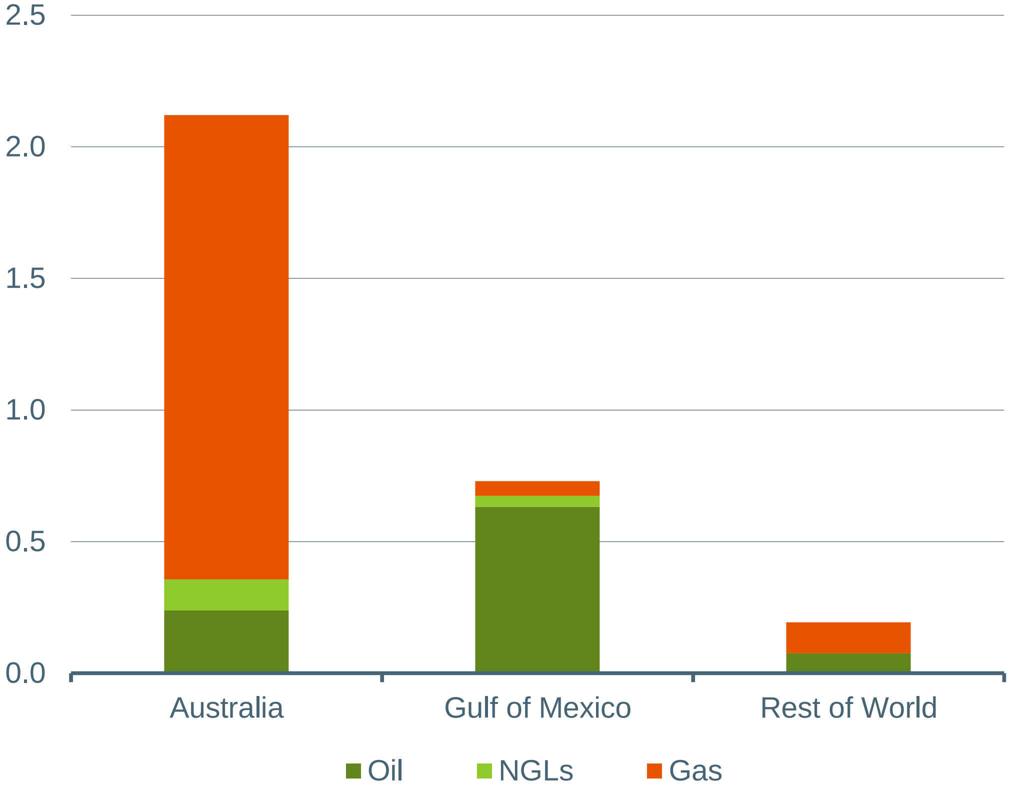
Note: Based on FY17 forecast production. Size of bubbles scaled to overall production.

1.3 Bboe 2P reserves including ~500 MMbbls of oil

Conventional reserves and resources[1]
(as at 30 June 2016, Bboe, BHP Billiton share)



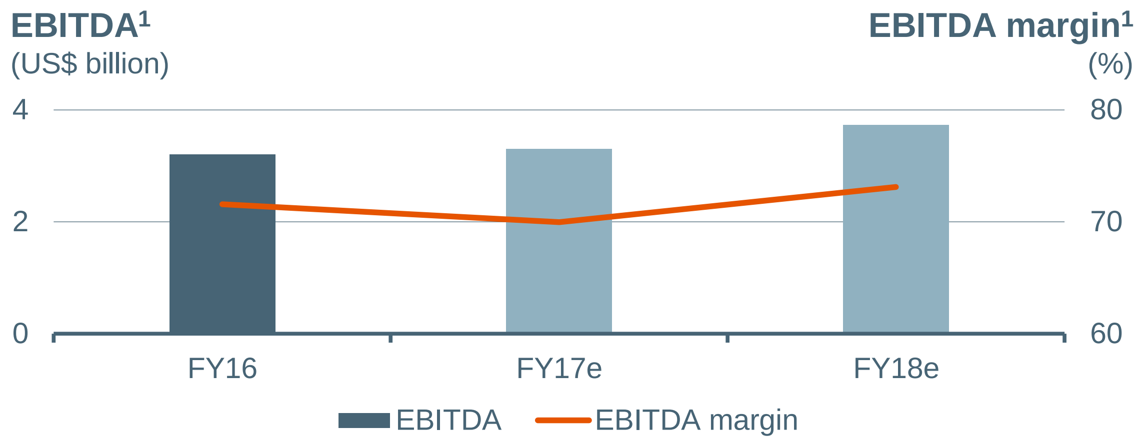
Conventional reserves and resources by product[1]
(as at 30 June 2016, Bboe, BHP Billiton share)

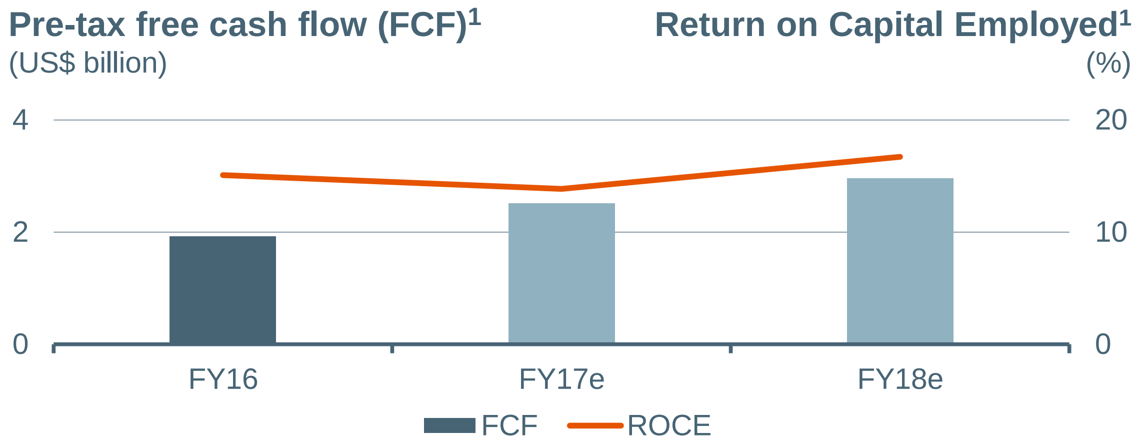


1. Total Proved reserves: 1,005 MMboe, Probable reserves: 307 MMboe, 2C Contingent resources: 1,732 MMboe. Includes fuel consumed in operations: Proved: 62 MMboe, Probable: 11 MMboe, 2C Contingent Resources: 126 MMboe.

Strong cash flow through the price cycle

- Attractive business at consensus prices over the next two years[1]:
  - EBITDA margin of >70%
  - EBITDA of ~US$3.5 billion per annum
  - pre-tax free cash flow of ~US$2.7 billion per annum
  - Return on Capital Employed of ~15%
- Low unit cost legacy assets
- High-margin low-risk life extension projects continue to yield strong cash flow and earnings
- Future investment underpinned by operating cash flows



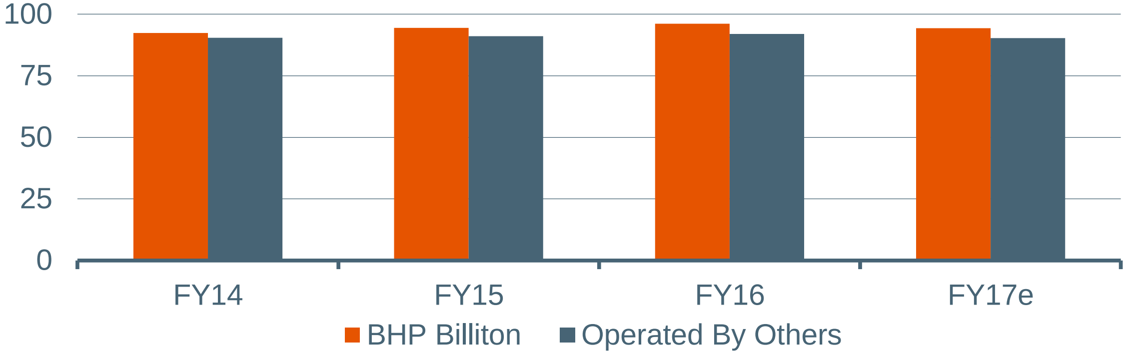


1. Pre-tax free cash flow, EBITDA, EBITDA margin and Return on Capital Employed estimates for FY17 onwards represents a scenario. Scenarios do not constitute guidance; actual response will be determined according to market conditions prevailing at the relevant time. Pre-tax free cash flow: EBITDA less capital and exploration expenditure. Excludes working capital.

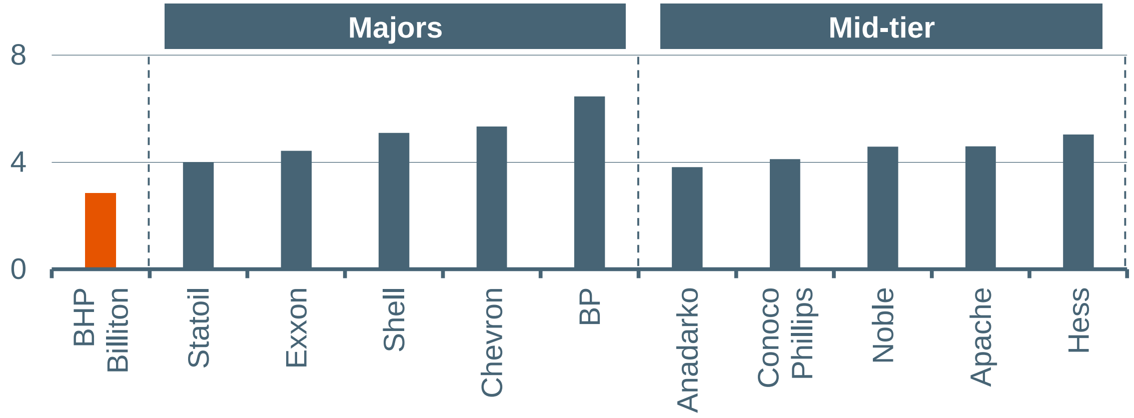
Industry leading operating and development capabilities

- Competitive with majors in deepwater drilling performance
- Industry leading operating uptime and unit costs
- Relentless focus on safety and productivity improvements
  - continuous improvement culture
  - latent capacity utilisation
  - supply chain, technology, work processes

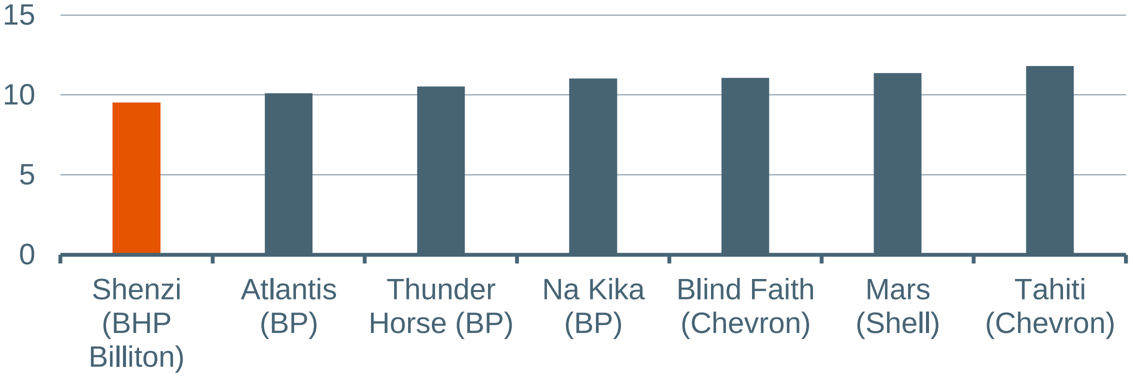
Operating uptime[3]
(%)



GOM average drill time[1,2]
(days per 1,000 ft)



Deepwater GOM total operating costs (2016)[4]
(US$/boe)



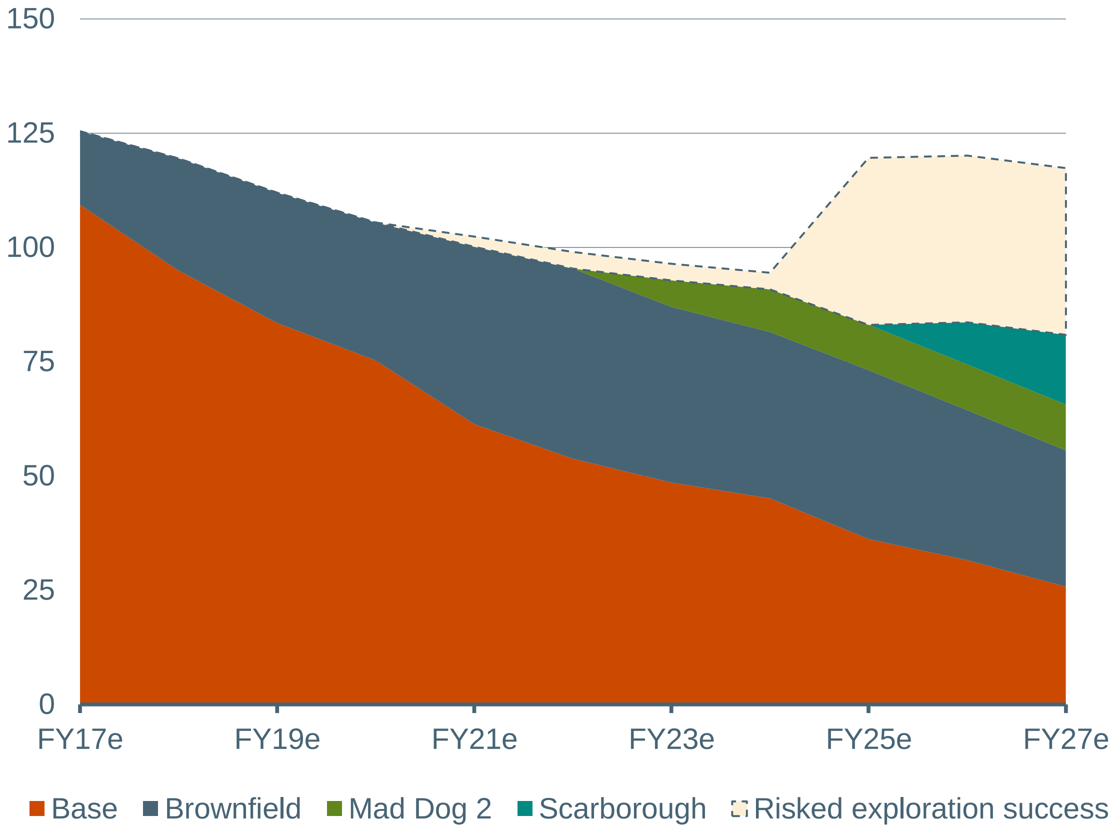
1. Deepwater Gulf of Mexico, sub-salt, 2013-2016.

Sources: 2. Rushmore, Offshore Oil Scouts Association (OOSA), BHP Billiton analysis. 3. BHP Billiton analysis. 4. Wood Mackenzie Oil Supply analysis.

Brownfield and greenfield options to mitigate base decline

- **Protecting margins from existing assets**
  - maintain industry leading operating and development performance
  - productivity and capital efficiency protect margins and cash flow
  - base and brownfield production robust across range of consensus prices
- **Suite of existing opportunities slow base decline**
  - brownfield opportunities leverage existing infrastructure
  - Mad Dog 2 Final Investment Decision expected in FY17
  - Scarborough offers significant gas position
- **Significant deepwater exploration potential**
  - targeting competitive economic developments in deepwater basins

Conventional brownfield extension and greenfield growth[1]
(MMboe, net)

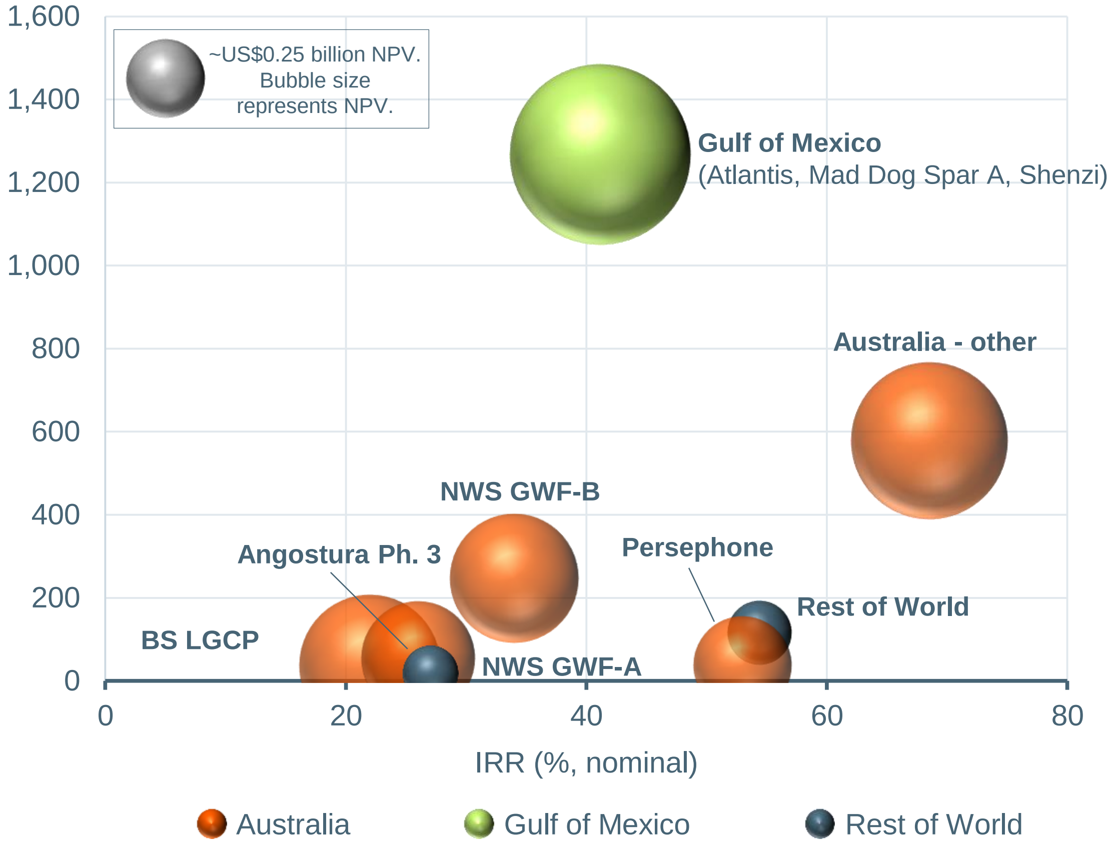


1. Production estimates for FY18 onwards represents a scenario. Scenarios do not constitute guidance; actual production will be determined according to market conditions prevailing at the relevant time. Assumes sell down of 50% of BHP Billiton's interest in Scarborough.

Rich portfolio of brownfield opportunities

- **High-return brownfield projects in execution**
  - North West Shelf (NWS) GWF-A first production achieved Q4 CY15 with all wells producing within FY17
  - Angostura Phase 3 first production achieved in September 2016
  - Bass Strait Longford Gas Conditioning Plant 99% complete with first production anticipated in Q4 CY16
  - Persephone tieback to NWS North Rankin platform with first production anticipated in CY17
  - NWS GWF-B anticipated to achieve first production in CY19 and all wells producing by CY20
- **Further near-term development projects**
  - Atlantis, Mad Dog Spar A Development and infill wells offer robust returns
  - multiple investment opportunities remain in Bass Strait: West Barracouta, Kipper, Snapper and Tuna areas
  - Exmouth sub-basin potential being evaluated to leverage existing Pyrenees and Macedon infrastructure

Brownfield growth capital[1]
(US$ million nominal, net, FY17-21 forecast)



1. Gulf of Mexico spend excludes Mad Dog 2.

Greenfield developments provide longer term optionality

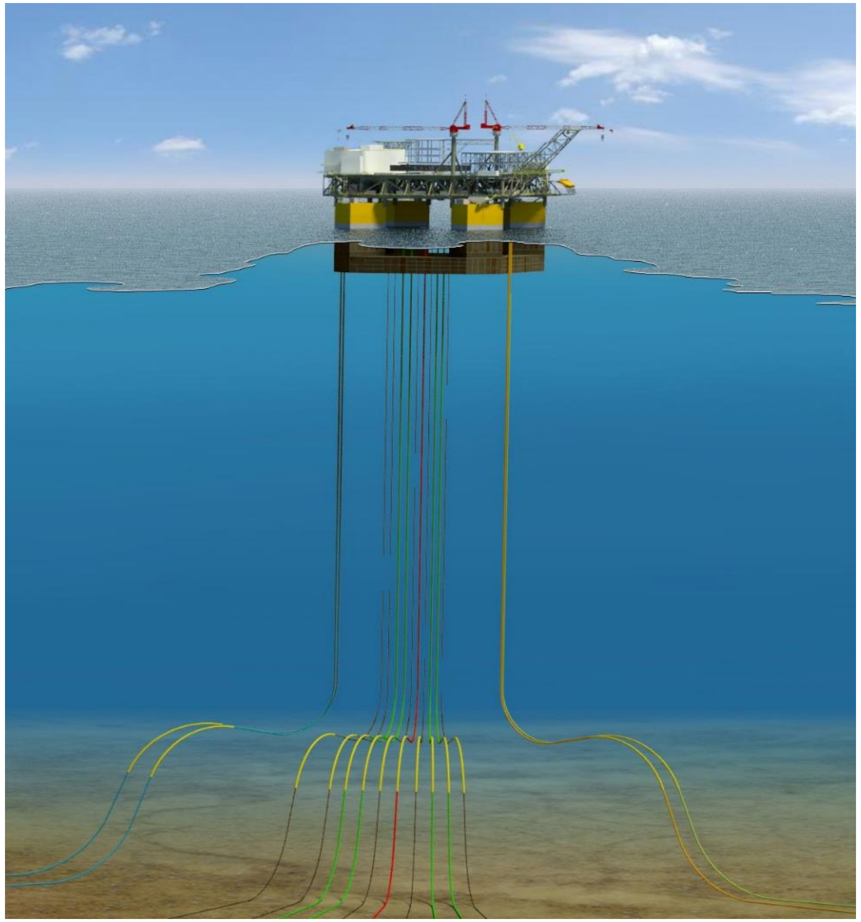
Mad Dog Phase 2

- Capital estimate halved since 2013
  - field development plan optimisation
  - standardisation
  - design simplification
  - capture market deflation
- Wet tree subsea development supported by a floating semi-submersible production and water injection facility
- Final Investment Decision expected in next six months with first production in CY22 if approved

Scarborough

- Large gas resource with development concept optionality
- Potential aggregator within geographic area

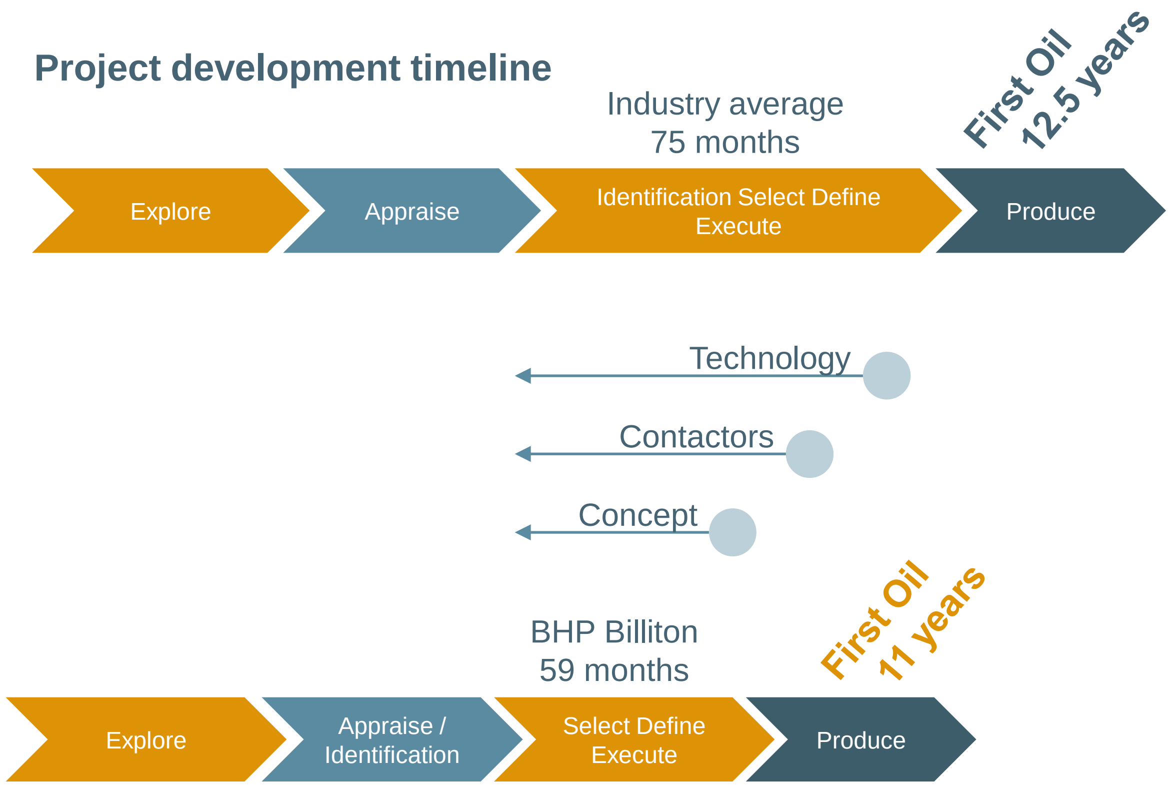
Mad Dog 2 concept



Accelerating development schedule post discovery

- **Leveraging deepwater development capabilities**
  - positioned to capitalise on industry leading geological, development and operating capabilities
- **Accelerating discovery to production cycle**
  - targeting ~20% reduction in development time
  - evaluating development concepts in parallel with appraisal
  - pre-screening vendors
  - applying standard industry solutions vs bespoke design

Project development timeline



Source: Wood Mackenzie and Performance Forum JIP Benchmark Data for comparable generic project description.

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Appendices

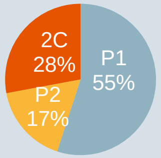
Australia non-operated focus areas

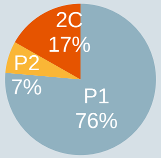
Bass Strait

- Delivery of Longford Gas Conditioning Plant project in Q4 CY16
- Progressing multiple investment opportunities
  - West Barracouta
  - Kipper
  - Snapper
  - Tuna
- Targeted divestment of mature Bass Strait oil assets

North West Shelf

- Executing brownfield projects
  - GWF A and B
  - Persephone
- Assessing ullage opportunities

Operator	• Esso	
BHP Billiton Ownership	• GBJV 50.0% • KUJV 32.5%	
First production	• 1969	Resources[2,3]
FY16 production[1]	• 35.3MMboe	
Resources[2]	• 548MMboe	

Operator	• Woodside	
BHP Billiton Ownership	• ~13% NRI over 9 separate JV agreements	
First production	• 1984	Resources[2,3]
FY16 production[1]	• 27.5MMboe	
Resources[2]	• 401MMboe	

1. MMboe, BHP Billiton share.
2. 2P+2C remaining resources as at 30 June 2016, BHP Billiton share.
3. Fuel included in P1, P2 and 2C respectively: Bass Strait: 16.9, 4.7, 6.8 MMboe; NWS: 33.5, 1.4, 7.5 MMboe.

Australia operated focus areas

Pyrenees

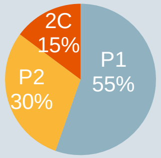
- Phase 3 infill program executed in FY16
- Phase 4 infill opportunities being assessed
- Supporting Exmouth basin seismic appraisal of the region

Macedon

- Optimising value through utilisation of plant capacity by capturing spot gas sales
- Assessing timing of wet gas compression development

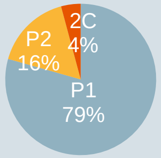
Operator	• BHP Billiton
BHP Billiton Ownership	• 71.43%
First production	• 2010
FY16 production[1]	• 8.6MMboe
Resources[2]	• 52MMboe

Resources[2,3]



Operator	• BHP Billiton
BHP Billiton Ownership	• 71.43%
First production	• 2013
FY16 production[1]	• 8.5MMboe
Resources[2]	• 99MMboe

Resources[2,3]



1. MMboe, BHP Billiton share.
2. 2P+2C remaining resources as at 30 June 2016, BHP Billiton share.
3. Fuel included in P1, P2 and 2C respectively: Pyrenees: 0.8, 1.5, 0 MMboe; Macedon: 2.2, 0.6, 0.1 MMboe.

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Gulf of Mexico focus areas

Atlantis

- Executing high-return multi-year infill program

Mad Dog

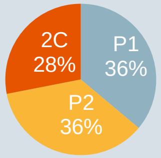
- Executing high-value multi-year Spar A infill program
- Progressing Mad Dog 2 for FID

Shenzi

- Maintaining industry leading production and water injection uptime

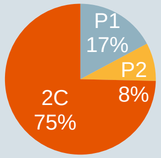
Operator	• BP
BHP Billiton Ownership	• 44.0%
First production	• 2007
FY16 production[1]	• 18.3MMboe
Resources[2]	• 225Mmboe

Resources[2,3]



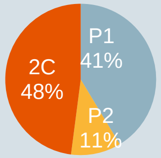
Operator	• BP
BHP Billiton Ownership	• 23.9%
First production	• 2005
FY16 production[1]	• 3.5MMboe
Resources[2]	• 329MMboe

Resources[2,3]



Operator	• BHP Billiton
BHP Billiton Ownership	• 44.0%
First production	• 2009
FY16 production[1]	• 13.7MMboe
Resources[2]	• 168MMboe

Resources[2,3]



1. MMboe, BHP Billiton share.
2. 2P+2C remaining resources as at 30 June 2016, BHP Billiton share.
3. Fuel included in P1, P2 and 2C respectively: Atlantis: 2.6, 2.6, 0 MMboe; Mad Dog: 1.0, 0.2, 5.7 MMboe; Shenzi: 1.9, 0.3, 0 MMboe.

Rest of World assets

Angostura

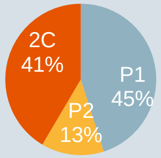
- Angostura Phase 3 completed
- Supporting exploration in the region

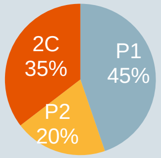
Algeria

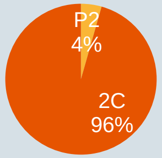
- Production Sharing Contract 10 year extension signed
- Progressing government approval of extension
- Executing infill program

North Sea

- End of field life planning

Operator	• BHP Billiton	
BHP Billiton Ownership	• 45.0% Block 2(c) • 25.5% Block 3(a)	
First production	• 2005	Resources[2,3] 
FY16 production[1]	• 5.9MMboe	
Resources[2]	• 124MMboe	

Operator	• Groupement Sonatrach Agip	
BHP Billiton Ownership	• 45.0%	
First production	• 2004	Resources[2,3] 
FY16 production[1]	• 3.7MMboe	
Resources[2]	• 50MMboe	

Operator	• BP	
BHP Billiton Ownership	• 16.0% Bruce • 31.83% Keith	
First production	• 1993 Bruce • 2000 Keith	Resources[2,3] 
FY16 production[1]	• 1.0MMboe	
Resources[2]	• 7MMboe	

1. MMboe, BHP Billiton share.
2. 2P+2C remaining resources as at 30 June 2016, BHP Billiton share.
3. Fuel included in P1, P2 and 2C respectively: Angostura: 1.5, 0, 0 MMboe; Algeria: 1.3, 0, 0 MMboe; North Sea: nil.

Petroleum Exploration

Finding the next wave of conventional growth

Niall McCormack Vice President Exploration, Petroleum

Deepwater Invictus

Disclaimer

Forward-looking statements

This presentation contains forward-looking statements, including statements regarding: reserves and resources and the production, revenues and costs relating thereto, trends in commodity prices and currency exchange rates; demand for commodities; plans, strategies and objectives of management; closure or divestment of certain operations or facilities (including associated costs); anticipated production or construction commencement dates; capital costs and scheduling; operating costs and shortages of materials and skilled employees; anticipated productive lives of projects, mines and facilities; provisions and contingent liabilities; tax and regulatory developments.

Forward-looking statements can be identified by the use of terminology such as 'intend', 'aim', 'project', 'anticipate', 'estimate', 'plan', 'believe', 'expect', 'may', 'should', 'will', 'continue', 'annualised' or similar words. These statements discuss future expectations concerning the results of operations or financial condition, or provide other forward-looking statements.

These forward-looking statements are not guarantees or predictions of future performance, and involve known and unknown risks, uncertainties and other factors, many of which are beyond our control, and which may cause actual results to differ materially from those expressed in the statements contained in this presentation. Readers are cautioned not to put undue reliance on forward-looking statements.

For example, future revenues from our operations, other results, projects or mines described in this presentation will be based, in part, upon the market price of the minerals, metals or petroleum produced, which may vary significantly from current levels. These variations, if materially adverse, may affect the timing or the feasibility of the development of a particular project, the expansion of certain facilities or mines, the continuation of existing operations.

Other factors that may cause actual results to differ from those expressed in the forward-looking statements include uncertainties in estimating reserves, difficulties in converting resources into reserves and reserves into quantities of oil and gas,

operating risks, changes in operating costs, factors that affect the actual construction or production commencement dates, costs or production output and anticipated lives of operations, mines or facilities include our ability to profitably produce and transport the minerals, petroleum and/or metals extracted to applicable markets; the impact of foreign currency exchange rates on the market prices of the minerals, petroleum or metals we produce; activities of government authorities in some of the countries where we are exploring or developing these projects, facilities or mines, including increases in taxes, changes in environmental and other regulations and political uncertainty; labour unrest; and other factors identified in the risk factors discussed in BHP Billiton's filings with the US Securities and Exchange Commission (the "SEC") (including in Annual Reports on Form 20-F) which are available on the SEC's website at www.sec.gov.

Except as required by applicable regulations or by law, the Group does not undertake any obligation to publicly update or review any forward-looking statements, whether as a result of new information or future events.

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Presentation of data

Unless specified otherwise: all data is presented on a continuing operations basis to exclude the contribution from assets that were demerged with South32; references to Underlying EBITDA margin exclude third party trading activities; data from subsidiaries is shown on a 100 per cent basis and data from equity accounted investments and other operations is shown on a proportionate consolidation basis. Numbers presented may not add up precisely to the totals provided due to rounding. Onshore US scenarios are based on price estimates from Bank of America Merrill Lynch, Citi, Credit Suisse, Deutsche Bank, JP Morgan, Macquarie, Morgan Stanley and UBS as at 8 August 2016 and do not necessarily correspond to BHP Billiton's view of prices.

No offer of securities

Nothing in this presentation should be construed as either an offer to sell or a solicitation of an offer to buy or sell BHP Billiton securities in any jurisdiction, or be treated or relied upon as a recommendation or advice by BHP Billiton.

Reliance on third party information

The views expressed in this presentation contain information that has been derived from publicly available sources that have not been independently verified. No representation or warranty is made as to the accuracy, completeness or reliability of the information. This presentation should not be relied upon as a recommendation or forecast by BHP Billiton.

Multi-billion barrel risked potential in current program

- **Refocused portfolio on Tier 1 opportunities**
  - from 12 countries to three focus areas
  - dominant acreage position in each basin and operatorship
  - prospective multi-billion barrel risked potential
- **100% success rate from three wells in 12 months**
  - multiple oil shows at Shenzi North and Caicos in the Gulf of Mexico
  - large potential gas resource at LeClerc with encouraging oil shows at depth
- **Testing six plays and three basins in three years**
  - accelerated drilling to take advantage of low-cost environment
  - potential discoveries commercial at less than US$50/bbl

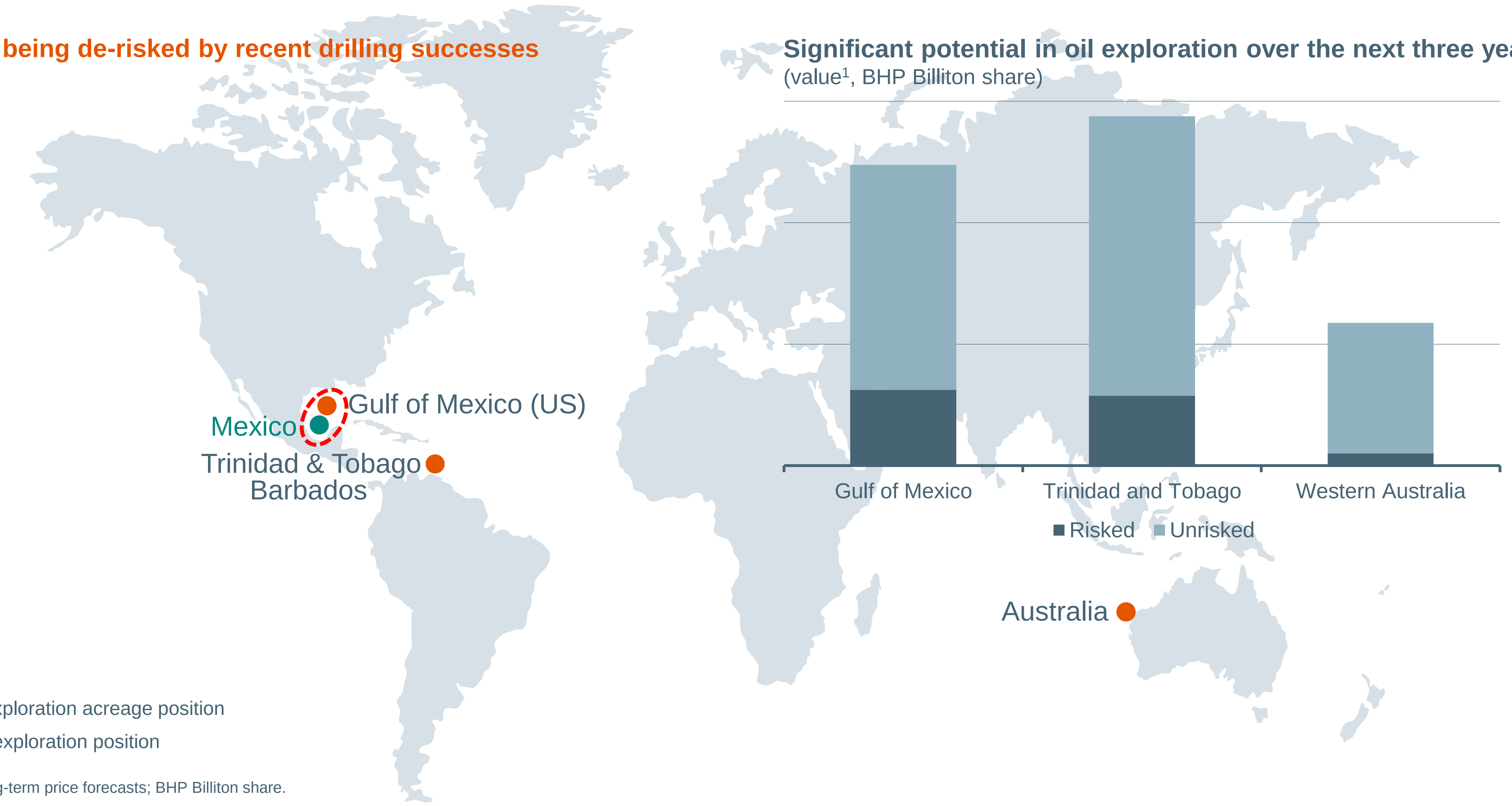
2012: 12 countries, 5 continents, over 100 prospects

2016: just 3 focus areas

- Current exploration acreage position
- Potential exploration position

Focused footprint offers large prospective upside

Upside is being de-risked by recent drilling successes



- Current exploration acreage position
- Potential exploration position

Significant potential in oil exploration over the next three years
(value[1], BHP Billiton share)

1. Under our long-term price forecasts; BHP Billiton share.

Testing three basins, six plays in three years

Exploration program timed to minimise cost while maximising value

	FY16		FY17		FY18+		
Explore — Reduced cycle time from access to drill through technology, right data, workflows	Shenzi North	LeClerc	Burrokeet	*Scimitar*	*T&T*	*T&T*	*T&T*
Appraise — Increased investment to appraise success	Caicos		Wildling		*Further Appraisal*		

GoM Miocene

Trinidad & Tobago Southern Neogene

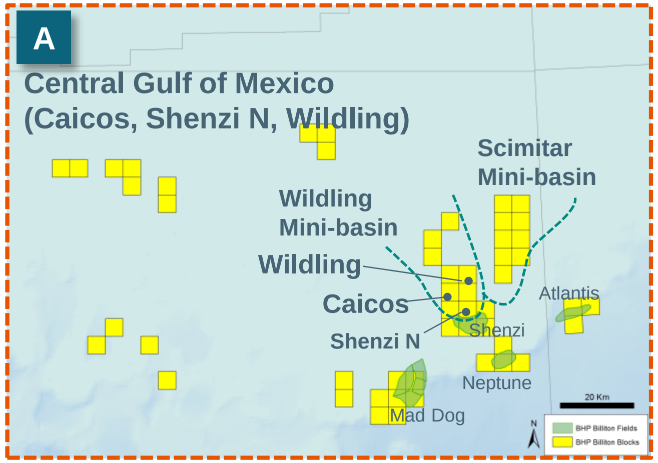
Trinidad & Tobago Northern Paleogene

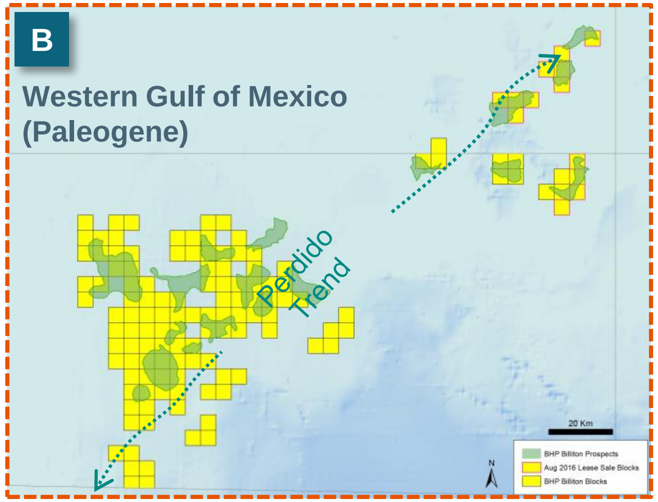
Future wells

Gulf of Mexico: Miocene success and Paleogene potential

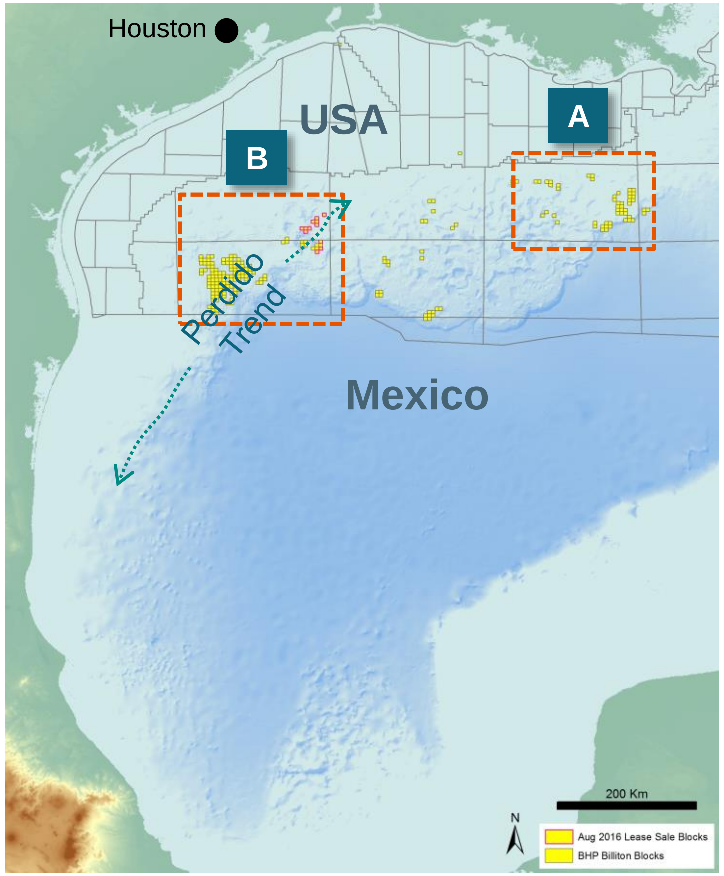
- **Oil discoveries in central GoM Miocene**
  - leverages our understanding from Shenzi, Mad Dog and Atlantis
  - oil discovered in multiple horizons at Shenzi North and Caicos
  - accelerating investment to follow-up on success – drilling Wildling in Q4 CY16
- **Established position in highly prospective US GoM subsalt Perdido Trend**
  - Western GoM Paleogene play
  - multi-billion barrel potential in large reservoir system
  - dominant acreage holder
  - 152 blocks containing 12 leads
  - large, high-equity, operated position
  - plan to drill first play test in CY18

Green Canyon and Perdido





US Gulf of Mexico



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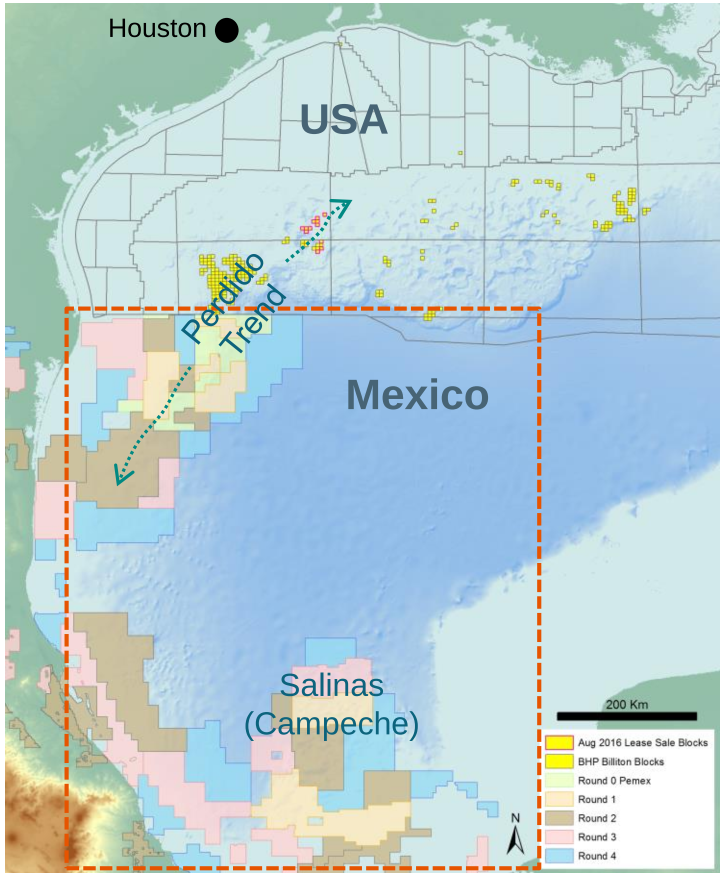
Mexico: a natural extension of our Perdido position

- **Early entrant opportunity for potential Tier 1**
  - positioned to bid if prospects and fiscal terms are attractive
  - significant potential (>10 Bbbl unrisked)
  - pre-qualified as deepwater exploration operator
- **Perdido Trend**
  - an extension of the US sub-salt Perdido play
  - high early success rates through limited drilling activity
- **Salinas Trend**
  - very limited activity in deepwater to date
  - world-class source rock and large traps
- **Discovered resource opportunity**
  - first Discovered Resource Round (Trion) planned for December 2016
  - one of six companies submitted as an operator

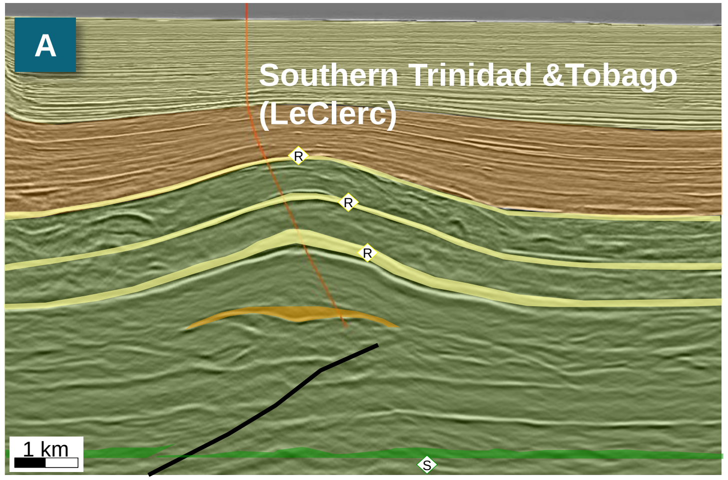
Mexican deep water bid round blocks

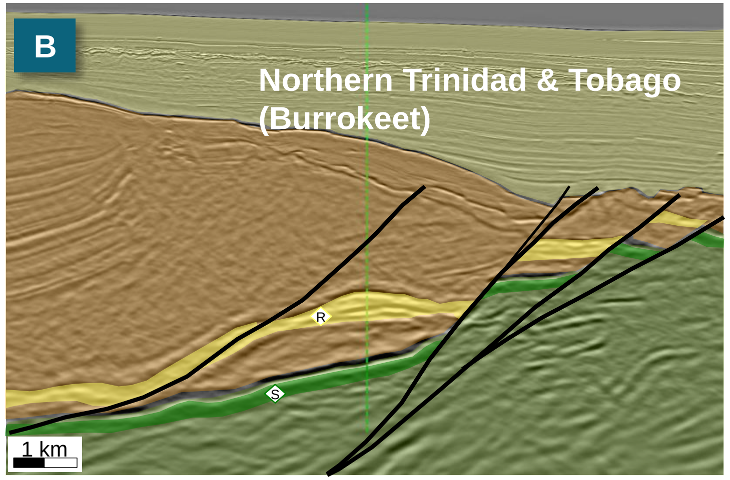


Encouraging early results in the Caribbean

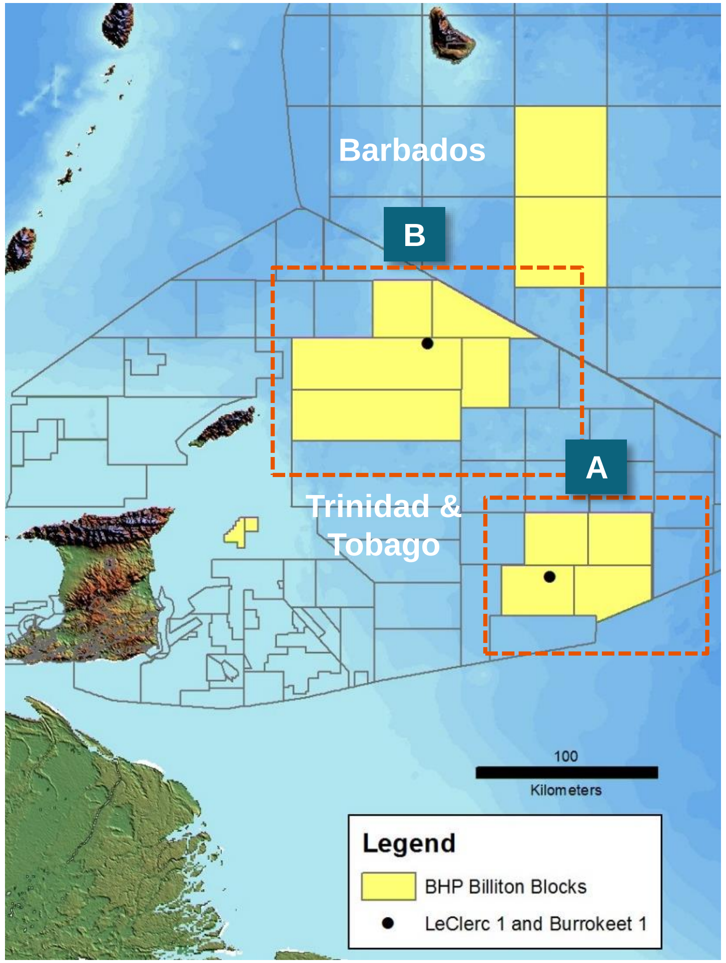
- **Tier 1 potential in Trinidad**
  - large structures, world-class source rock
  - at least 12 significant leads and prospects
- **Accelerated program**
  - from acreage access to first well in 3 years
  - 8 well campaign at industry leading pace
- **Miocene**[1]
  - LeClerc (65% operator, Shell 35%)
  - first Ultra-Deepwater Discovery in Caribbean at LeClerc
  - gas in multiple zones, oil shows at depth
  - encouraging results for play
- **Paleogene**[2]
  - Burrokeet (70% operator, BP 30%)
  - first play test in northern Paleogene

Geoseismic images of LeClerc and Burrokeet



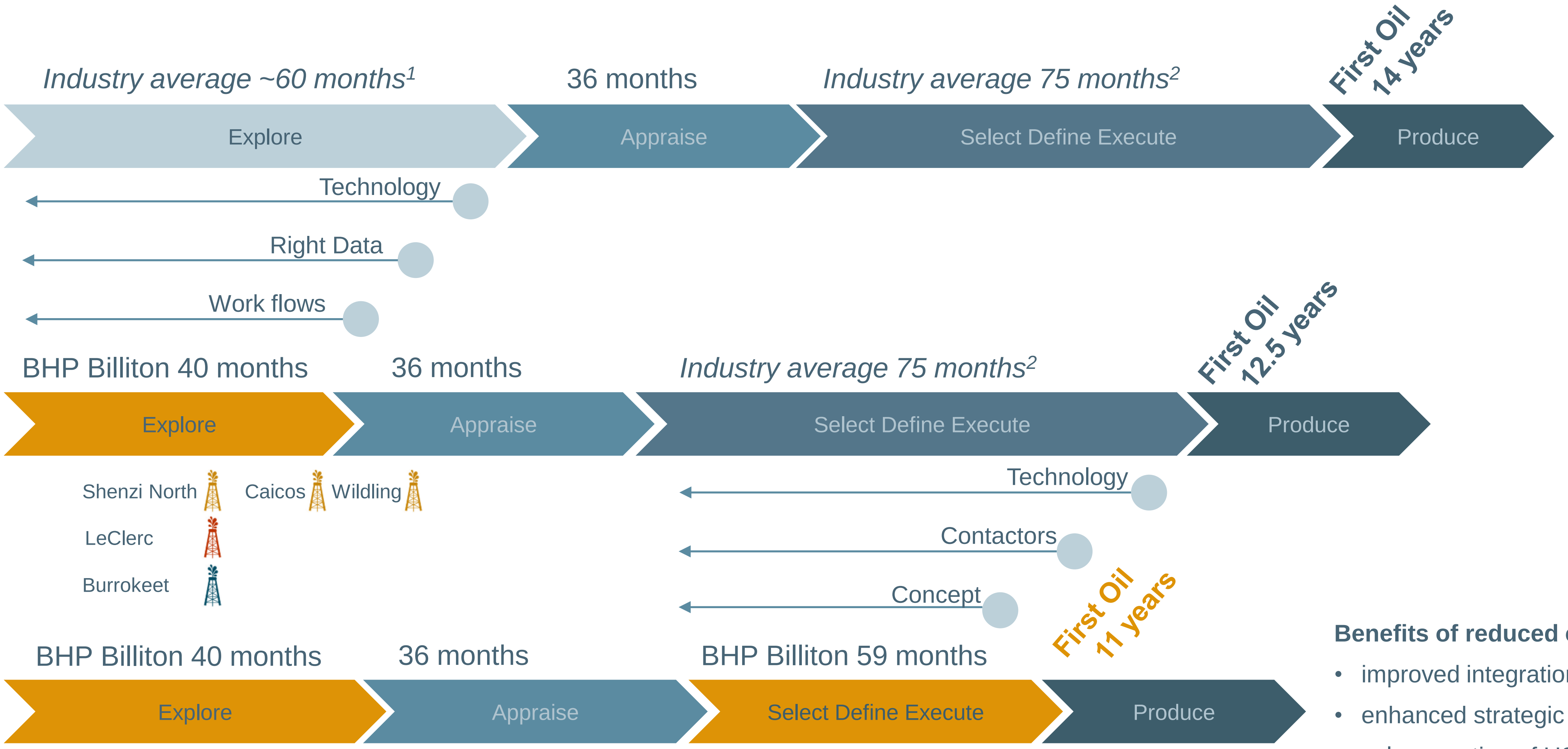


Material operated Caribbean position



1. BHP Billiton 65% operator, Shell 35% across all blocks.
2. Equity position and partners vary by block.

Maximising value through operational excellence



Benefits of reduced cycle time:

- improved integration of technical work
- enhanced strategic planning
- value creation of US$100 million per annum[3]

Source: Wood Mackenzie, Performance Forum JIP Benchmark data, BHP Billiton analysis.
1. BHP Billiton analysis of Wood Mackenzie's deepwater well dataset.
2. Performance Forum JIP Benchmark Data for comparable generic project description.
3. Assumes a success case for a 300 MMbbl oil field using BHP Billiton long-term price assumptions.

Multi-billion barrel risked potential in current program

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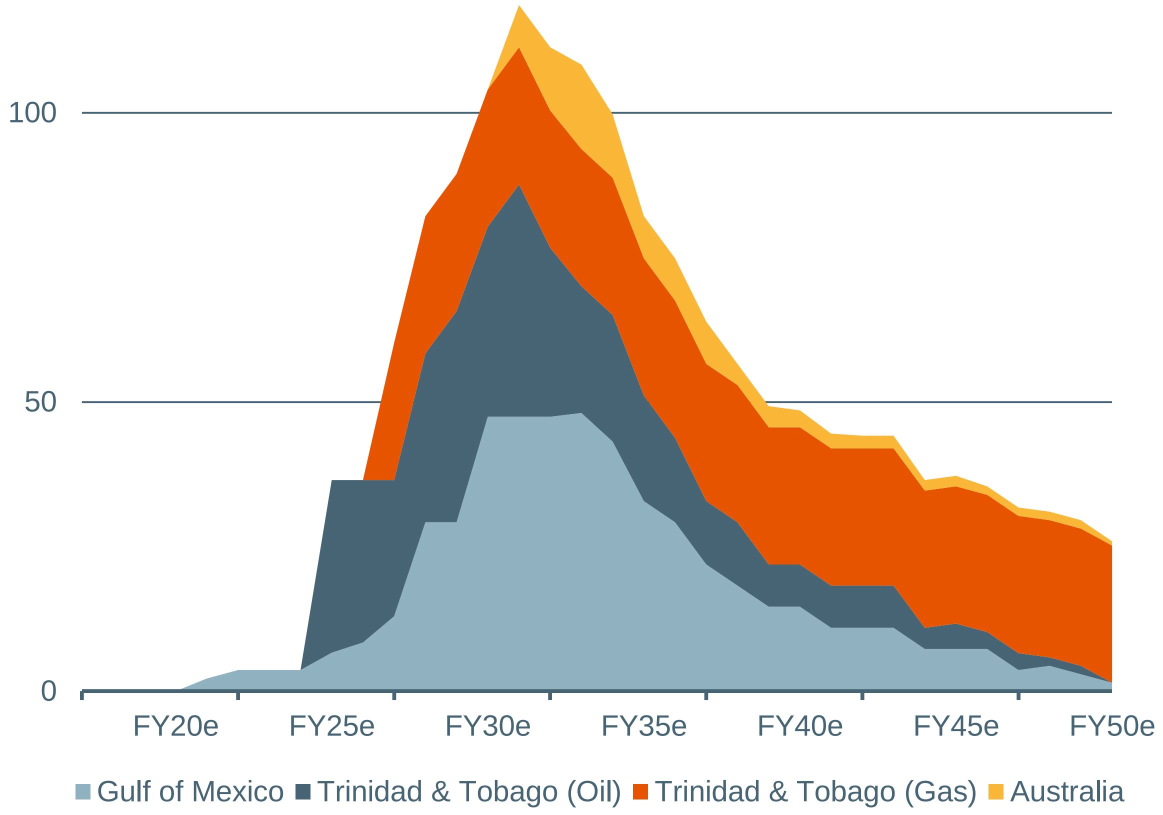
- **Testing six plays and three basins in three years**
  - accelerated drilling to take advantage of low-cost environment
  - potential discoveries commercial at less than US$50/bbl

Significant risked future production potential to be tested by current drilling program[1]
(risked potential future production, MMboe, BHP Billiton share)



1. Possible production profiles based on a simulation of risked success cases from the current exploration portfolio.

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BHP Billiton Petroleum

Closing remarks

Steve Pastor President Operations, Petroleum

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Statement of Petroleum Resources

Petroleum Resources

The estimates of Petroleum Reserves and Contingent Resources contained in this presentation are based on, and fairly represent, information and supporting documentation prepared under the supervision of Mr. A. G. Gadgil, who is employed by BHP Billiton. Mr. Gadgil is a member of the Society of Petroleum Engineers and has the required qualifications and experience to act as a qualified Petroleum Reserves and Resources evaluator under the ASX Listing Rules. This presentation is issued with the prior written consent of Mr. Gadgil who agrees with the form and context in which the Petroleum Reserves and Contingent Resources are presented.

Reserves and Contingent Resources are net of royalties owned by others and have been estimated using deterministic methodology. Aggregates of Reserves and Contingent Resources estimates contained in this presentation have been calculated by arithmetic summation of field/project estimates by category with the exception of the North West Shelf (NWS) Gas Project in Australia. Probabilistic methodology has been utilised to aggregate the NWS Reserves and Contingent Resources for the reservoirs dedicated to the gas project only and represents an incremental 39 MMboe of Proved Reserves. The barrel of oil equivalent conversion is based on 6000 scf of natural gas equals 1 boe. The Reserves and Contingent Resources contained in this presentation are inclusive of fuel required for operations. The respective amounts of fuel for each category are provided by footnote for the resource graphics. The custody transfer point(s)/point(s) of sale applicable for each field or project are the reference point for Reserves and Contingent Resources. Reserves and Contingent Resources estimates have not been adjusted for risk. Unless noted otherwise, Reserves and Contingent Resources are as of 30 June 2016. Where used in this presentation, the term Resources represents the sum of 2P reserves and 2C Contingent Resources.

BHP Billiton estimates Proved Reserve volumes according to SEC disclosure regulations and files these in our annual 20-F report with the SEC. All Unproved volumes are estimated using SPE-PRMS guidelines, which among other things, allow escalations to prices and costs, and as such, would be on a different basis than that prescribed by the SEC, and are therefore excluded from our SEC filings. All Resources and other Unproved volumes may differ from and may not be comparable to the same or similarly-named measures used by other companies. Non-proved estimates are inherently more uncertain than proved.

Table 1 Net BHP Billiton Petroleum Reserves and Contingent Resources as of 30 June 2016

	Onshore US			Offshore US	Australia			Rest of World				
Net MMboe	**Eagle Ford & Permian**	**Haynesville & Fayetteville**	**Subtotal**	**Gulf of Mexico**	**Offshore Western Australia[1, 2]**	**Bass Strait & Offshore Victoria**	**Subtotal**	**Trinidad & Tobago**	**Algeria**	**United Kingdom & Other**	**Subtotal**	**Total BHP Billiton**
Proved	**124**	**173**	**298**	**210**	**414**	**303**	**717**	**56**	**22**	**-**	**78**	**1,303**
Probable	**1,433**	**1,273**	**2,707**	**127**	**59**	**94**	**153**	**17**	**10**	**-**	**27**	**3,013**
2P	**1,558**	**1,447**	**3,004**	**337**	**473**	**397**	**869**	**73**	**32**	**-**	**105**	**4,316**
2C	**1,547**	**1,782**	**3,329**	**392**	**1,099**	**153**	**1,252**	**52**	**18**	**20**	**89**	**5,061**
2P+2C	**3,105**	**3,228**	**6,333**	**729**	**1,571**	**550**	**2,121**	**124**	**50**	**20**	**194**	**9,377**
Fuel included above												
Proved	2.0	5.0	7.0	5.8	36.5	16.9	53.4	1.4	1.3	-	2.8	69.0
Probable	33.2	22.2	55.4	3.2	3.6	4.7	8.3	-	-	-	-	66.8
2P	35.2	27.2	62.4	8.9	40.0	21.7	61.7	1.4	1.3	-	2.8	135.8
2C	27.3	41.4	68.7	5.8	113.4	6.8	120.2	-	-	-	-	194.7
2P+2C	62.5	68.6	131.1	14.8	153.4	28.5	181.9	1.4	1.3	-	2.8	330.6

1) Includes NWS Gas Project probabilistic increment noted in disclaimer above.

2) Australian resources prior to the announced agreement by Woodside to acquire 50% of BHP Billiton Scarborough area assets.

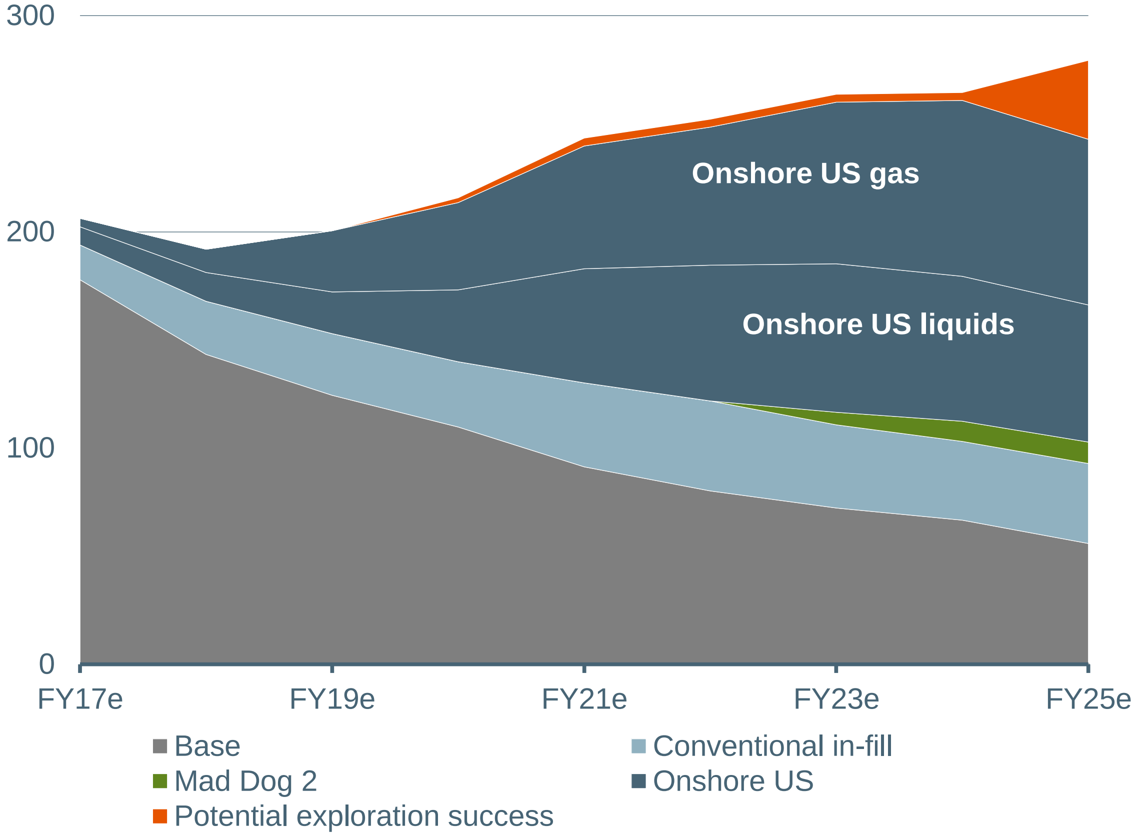
The SEC permits oil and gas companies, in their filings with the SEC, to disclose only Proved, Probable and Possible Reserves, and only when such Reserves have been determined in accordance with SEC guidelines. We use certain terms in this presentation such as “Resources,” “Contingent Resources,” “2C Contingent Resources” and similar terms as well as Probable Reserves not determined in accordance with the SEC’s guidelines, all of which measures we are strictly prohibited from including in filings with the SEC. These measures include Reserves and Resources with substantially less certainty than Proved Reserves. U.S. investors are urged to consider closely the disclosure in our Form 20-F for the fiscal year ended June 30, 2016, File No. 001-09526 and in our other filings with the SEC, available from us at http://www.bhpbilliton.com/. These forms can also be obtained from the SEC as described above.

An exciting outlook for our Petroleum business

- **Petroleum is core to BHP Billiton**
  - strong financial and operating performance
  - oil and US gas markets expected to rebalance first
- **Petroleum strategy focused on value over volume**
- **Concentrated resource base and proven operating capability**
  - Onshore US – capturing full resource value while driving returns and free cash flow
  - Conventional – high margins with inventory of in-fill projects to offset field decline
- **Rich set of opportunities to drive valuable growth**
  - Mad Dog 2 investment decision expected in next six months
  - Haynesville acceleration supported by hedging
  - Permian progressing towards full pad development in FY19
  - exploration program yielding encouraging results
  - would consider value accretive acquisitions

Value accretive production potential over the next decade[1]

(BHP Billiton production, MMboe)



1. Production estimates for FY18 onwards represents a scenario. Scenarios do not constitute guidance; actual production will be determined according to market conditions prevailing at the relevant time.

bhpbilliton