A high-quality portfolio optimised for value

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President – Petroleum and Potash
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Disclaimer

Forward-looking statements

This release contains forward-looking statements, including statements regarding: 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.

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Other factors that may 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 U.S. 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.

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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 measures including Underlying attributable profit, Underlying basic earnings per share, Underlying EBITDA interest coverage, Adjusted effective tax rate, Underlying EBIT margin, Underlying EBITDA margin, Underlying return on capital, Free cash flow, Net debt and Net operating assets. 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 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.

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Disclaimer (continued)

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.

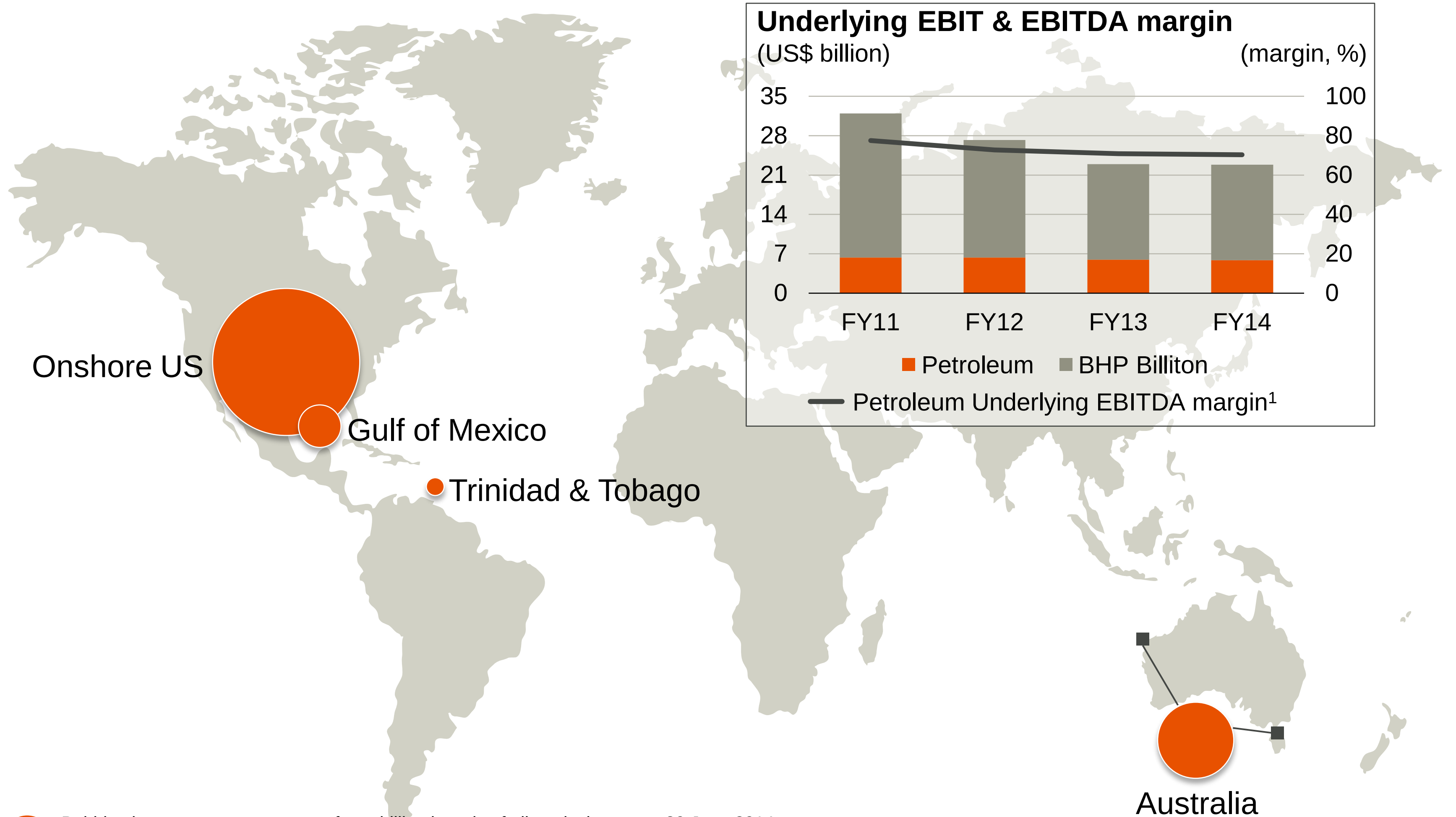
Aggregates of reserves and contingent resources estimates contained in this presentation have been calculated by arithmetic summation of field/project estimates by category. Due to portfolio effects, aggregates of proved reserves may be conservative. Reserves and contingent resources estimates have been estimated using deterministic methodology with the exception of the North West Shelf gas operation in Australia. For this project probabilistic methodology has been utilised to estimate and aggregate the proved reserves dedicated to the gas project only and represents an increment of 30 MMboe above the deterministic estimate. 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 in footnotes proximate to each resource graphic. 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 at 30 June 2014. 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 20F report with the SEC. All unproved volumes are estimated using SPE-PRMS guidelines which 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. We have provided a list of resource terms along with their definitions in this presentation. Non-proved estimates are inherently more uncertain than proved.

Key themes

- We have a clear strategy focused on value over volume
- Our Petroleum portfolio is underpinned by large, high-quality, upstream assets
- High-return brownfield investments will maintain stable Conventional volumes
- Liquids opportunities with Tier-1 potential are the focus of our exploration program
- Our Shale business is primed to generate strong growth in free cash flow
- We will continue to simplify the portfolio for value

A large, high-quality, upstream petroleum portfolio



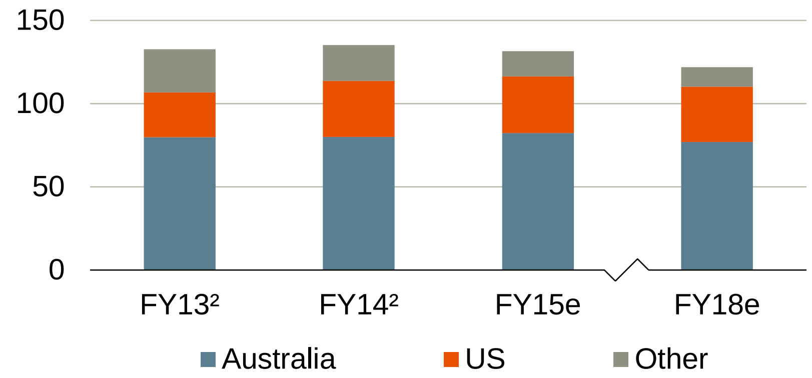
Bubble size represents resource of one billion barrels of oil equivalent as at 30 June 2014.
Portion of 1P, 2P reserves in bubbles: Onshore US=15%, 56%, GOM=37%, 59%, Trinidad & Tobago=48%, 62%, Australia=36%, 44%.
Fuel consumed in operations included: Onshore US=145 MMboe, GOM=16 MMboe, Trinidad & Tobago=2 MMboe, Australia=214 MMboe.

1. Excludes third party products.

High-return brownfield Conventional investments will offset natural field decline

- Australia and the Gulf of Mexico are our core regions with valuable infrastructure in place
- Capital expenditure of ~US$1.5 billion per annum is expected to maintain stable conventional volumes for three to five years
  - benchmark operational uptime and a water injection program at Shenzi
  - infill drilling at Atlantis and Mad Dog will offset natural decline in the medium term
  - a multi-well extension program at Pyrenees is underway
  - start up of Greater Western Flank-A at North West Shelf is on schedule for CY16
- Returns exceeding 50%[1] are achievable from these low-risk investments

Stable conventional volumes
(MMboe)



FY15 Conventional infill drilling returns

Project	Capex (BHP Billiton share)	IRR[1]
Shenzi infill well	US$98 million	>70%
Atlantis infill wells[3]	US$592 million	50% to 100%
North West Shelf[4]	US$187 million	>50%

1. After tax, based on June 2014 futures prices.
2. Excludes Liverpool Bay asset, divested in FY14.
3. Comprised of four infill wells and two workover wells.
4. Persephone two well development.

Our focused exploration program

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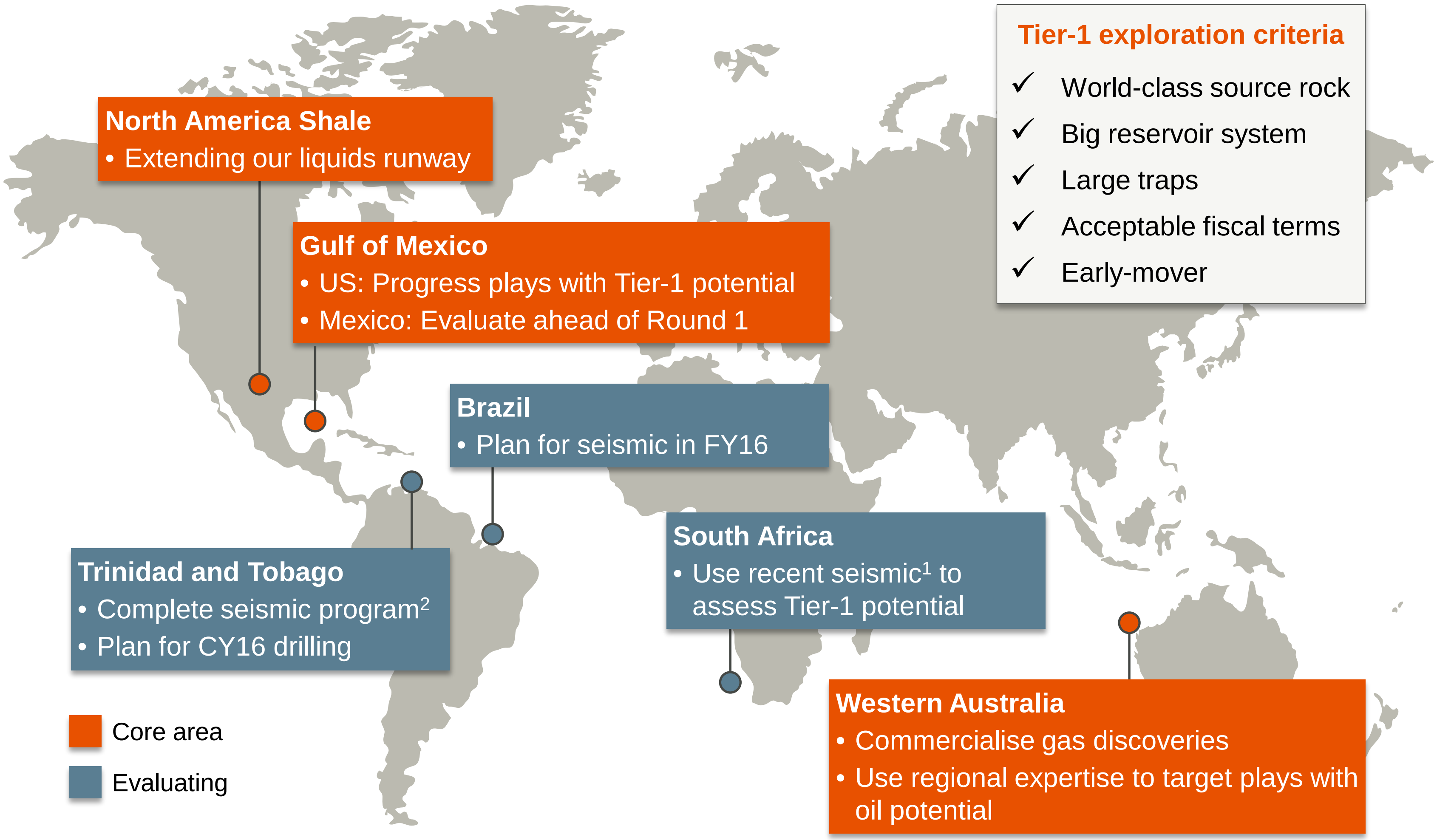


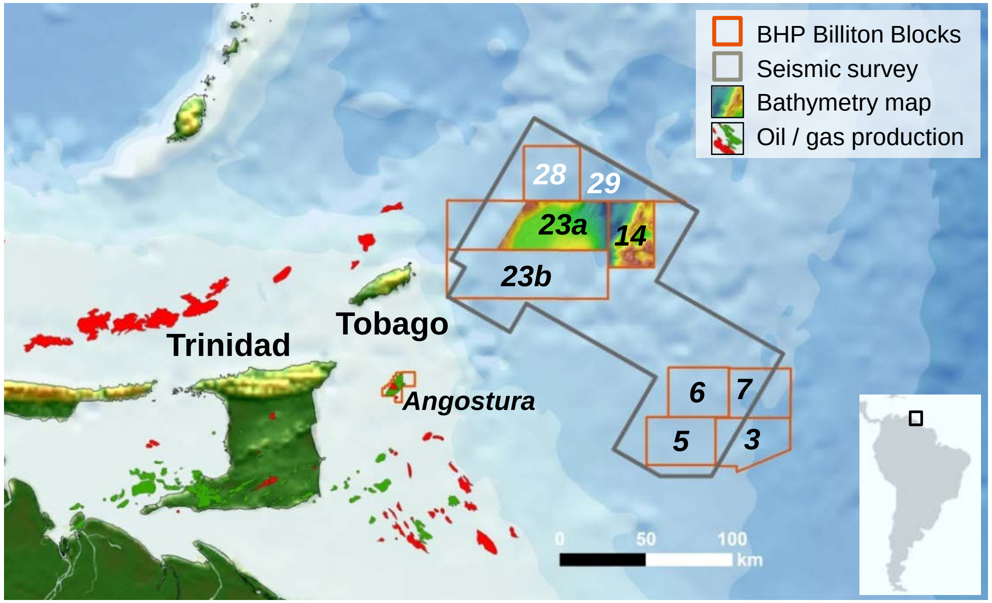
Tier-1 exploration criteria

- ✓ World-class source rock
- ✓ Big reservoir system
- ✓ Large traps
- ✓ Acceptable fiscal terms
- ✓ Early-mover

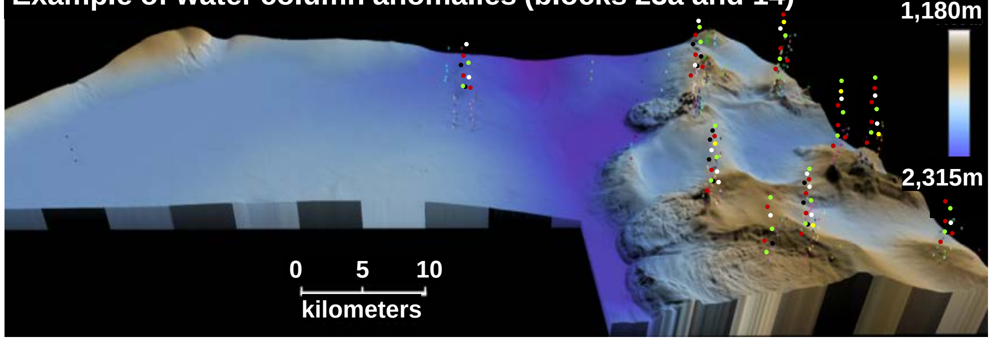
1. In FY13, BHP Billiton acquired 10,075 sq km 3D seismic in Block 3B/4B.
2. BHP Billiton is currently acquiring a 17,719 sq km survey in Blocks 5, 6, 14, 23a, 23b, 28 and 29.

Tier-1 oil potential in Trinidad and Tobago

- We have an established operational presence in Trinidad and Tobago with our shallow water Angostura asset
- The deepwater is largely untested and has Tier-1 oil potential
- We have a material 'early-mover' deepwater position with an average working interest of >70%
- We accessed four additional exploration blocks in CY14[1]
  - ~17,700 square kilometre seismic acquisition program[2] is progressing on schedule
  - positive seabed indications
- Anticipate initial exploration wells in CY16



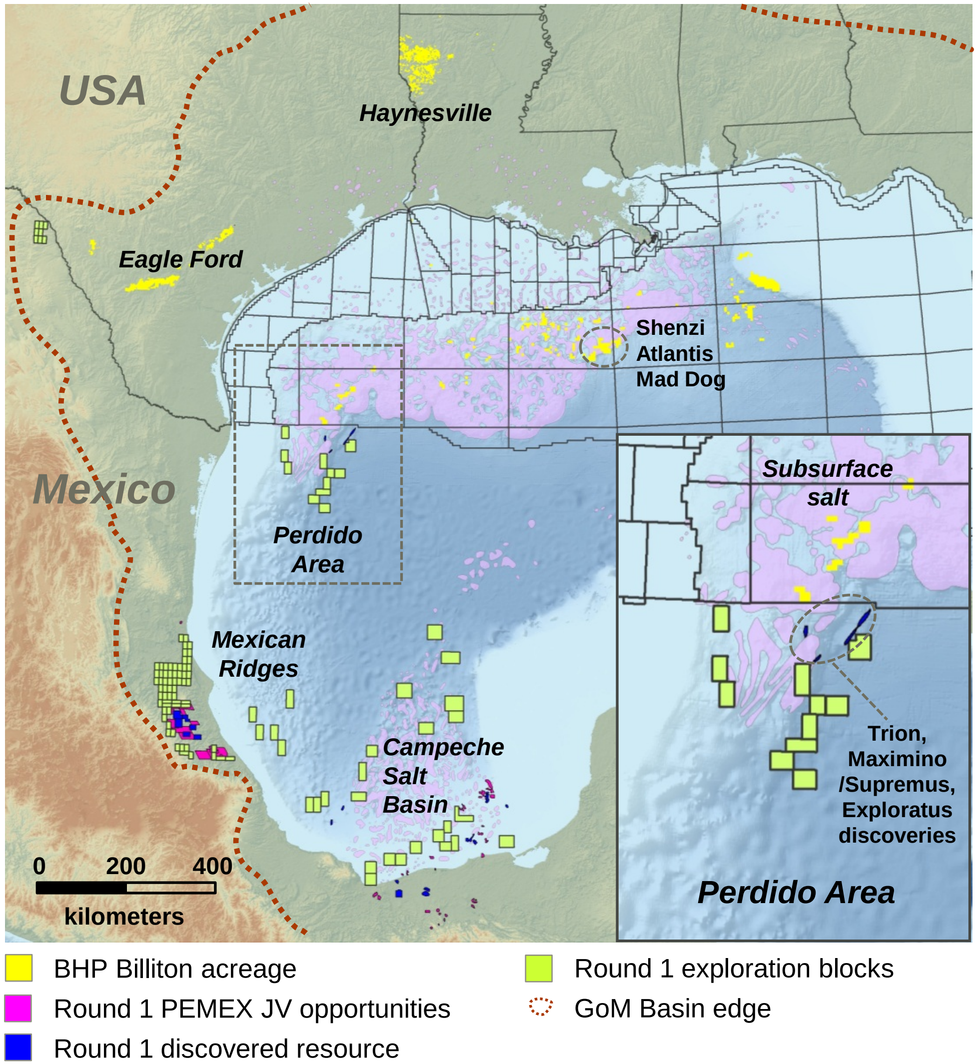
Example of water column anomalies (blocks 23a and 14)



1. Blocks 3 and 7 awarded to BHP Billiton in July 2014 with production sharing contracts currently being finalised. Blocks 14 and 23a accessed in February 2014 via a farm-in agreement with BP.
2. BHP Billiton is currently acquiring a 17,719 sq km survey in Blocks 5, 6, 14, 23a, 23b, 28 and 29.

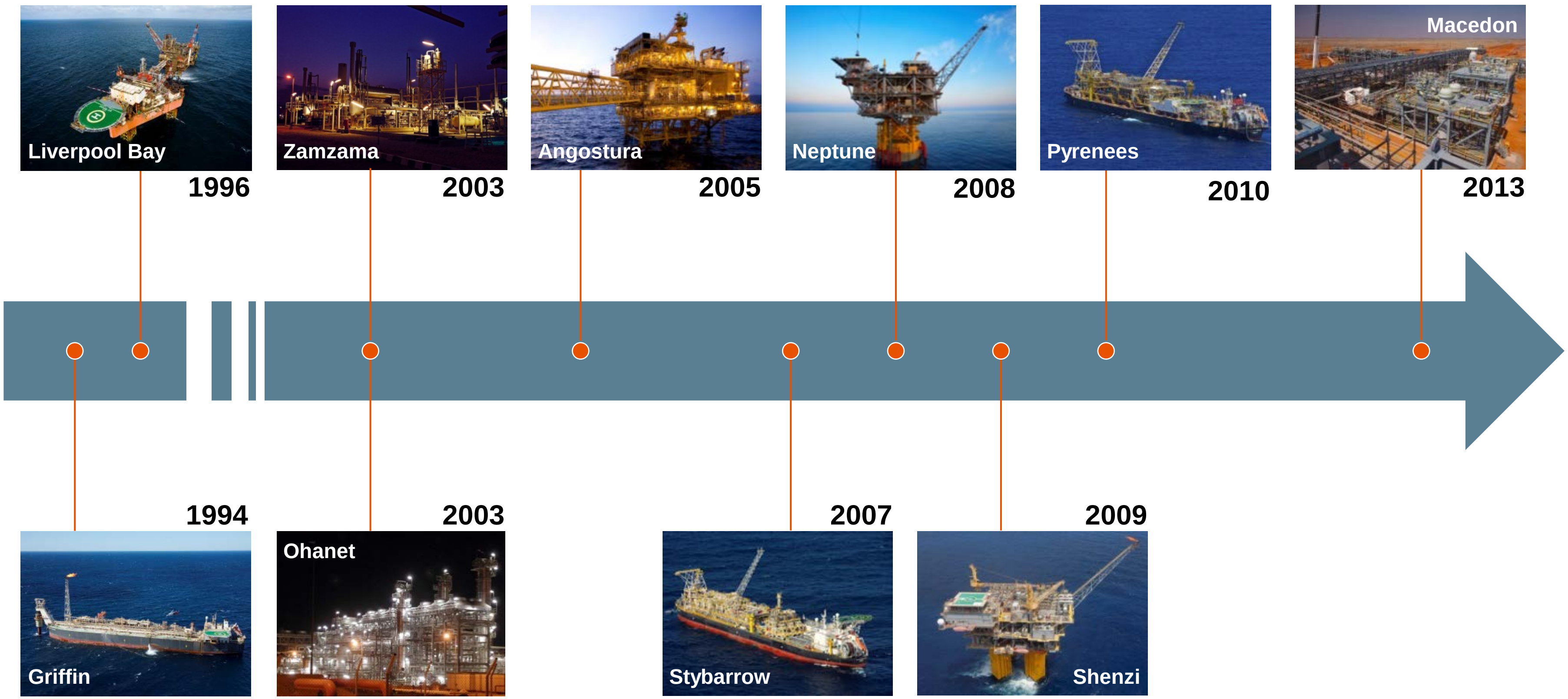
Leveraging our Gulf of Mexico expertise

- Recently executed Memorandum of Understanding with Pemex[1] to exchange technical knowledge and expertise
- The Gulf of Mexico (GoM) basin is the third highest oil producing basin in the world[2]
- We produce >350 net kboe/d and invest >80% of our Petroleum capital expenditure budget in this prolific geological basin
- BHP Billiton is well positioned to create value for shareholders and JV partners
  - the Perdido play is part of the GoM basin geology where we have deep expertise and multiple acreage positions
  - we have proven drilling, development and operating capabilities in deepwater GoM and onshore shale
- Industry awaits fiscal terms and data access



1. Petroleos Mexicanos.
2. Source: IHS; EIA.

We have proven project development capability



● BHP Billiton operated assets

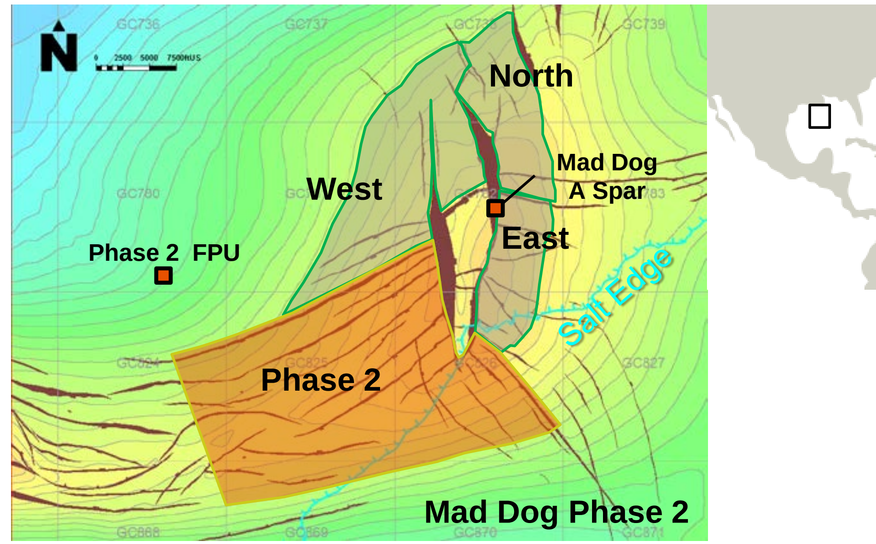
Development options competing for capital

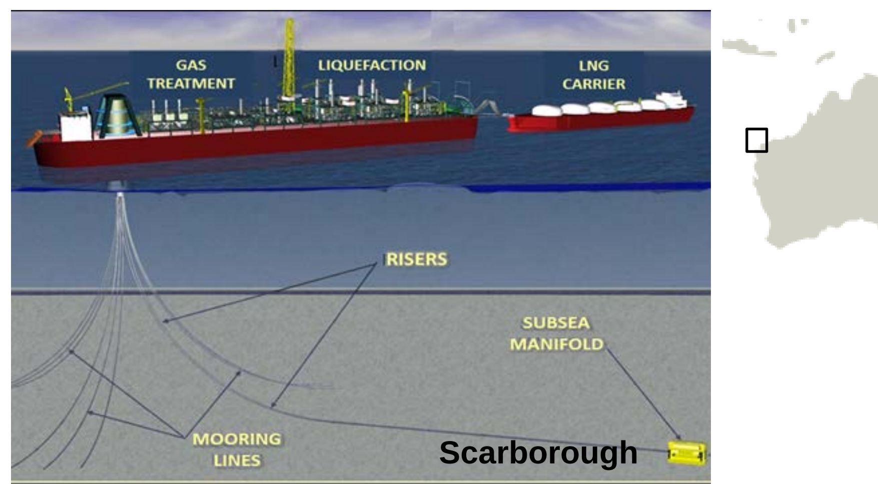
Mad Dog Phase 2

- One of the largest discovered, undeveloped oil reservoirs in the Gulf of Mexico
- Partnership is aligned on a semi-submersible floating production unit (FPU) concept
- BHP Billiton working interest 23.9%, operated by BP

Scarborough

- Early stages of project development with significant progress made
  - environmental approval received
- Floating LNG considered the lead development option
- BHP Billiton working interest 52%, operated by ExxonMobil





Onshore US is primed to generate strong growth in free cash flow

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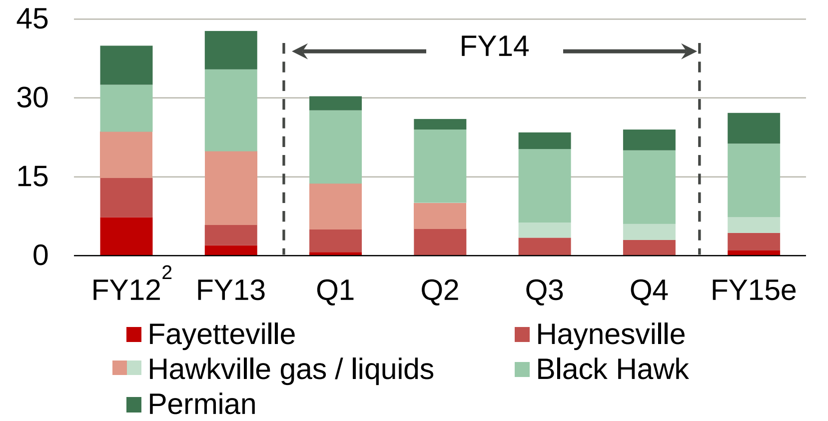
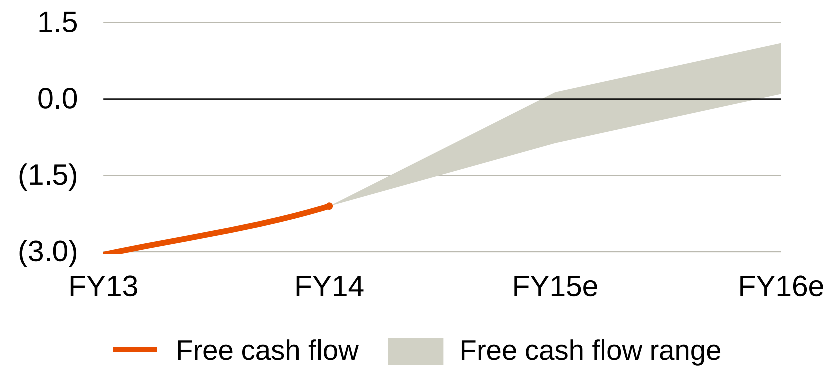
- We have a premier acreage position over multiple shale plays
- Strong financial performance will be supported by continued growth in liquids production
  - 50% increase in liquids production in FY15[1]
  - forecast ~200 kboe/d of liquids production from the Eagle Ford and Permian by FY17[1]
  - expecting ~14 gross operated rigs in the Permian by FY18
  - expected to be free cash flow positive by FY16 and approach US$3 billion per annum by the end of the decade
  - infrastructure spend remains ~10% of total Shale capital expenditure

Focused on developing our liquids-rich areas
(gross operated rigs)



Onshore US free cash flow scenario[3]
(US$ billion, net, nominal)

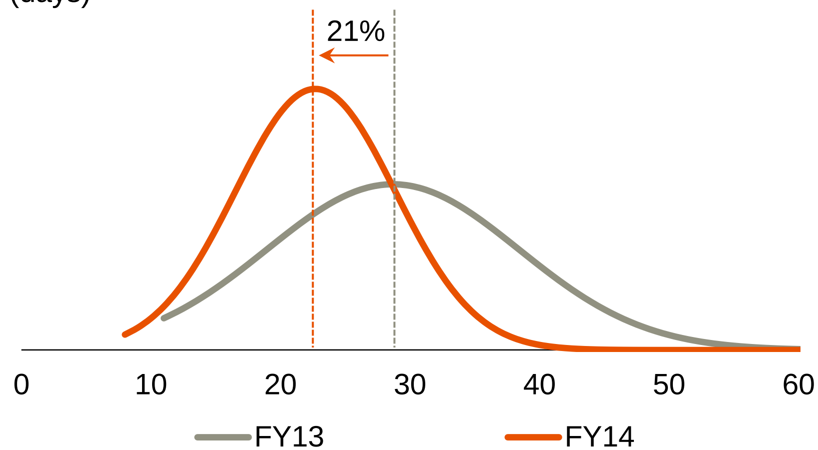


1. Production rates represent net BHP Billiton portion.
2. FY12 represents partial year of drilling (Q3 and Q4 only).
3. Forward projections are based on current development plans and September 2014 future prices.

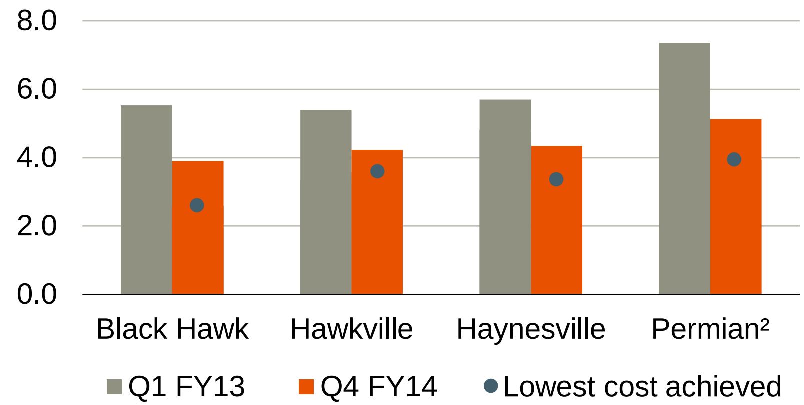
Driving improved capital efficiency through productivity

- Repetitive, manufacturing nature of shale is ideally suited to our productivity agenda
- Application of technology will ensure we achieve the best recoveries while being cost competitive
- We use internal and external benchmarking to drive 'best in class' performance
- Reduced drilling time and cost per well
  - 21% drilling time improvement in the Black Hawk in FY14
  - reduced variability in drilling performance
  - 29% decline in drilling costs in the Black Hawk from Q1 FY13 to Q4 FY14
- These efficiencies will unlock significant value over our five year, ~2,130 gross development well program

Black Hawk drilling time per well[1]
(days)



Shale drilling cost performance
(US$ million, average per well, gross)

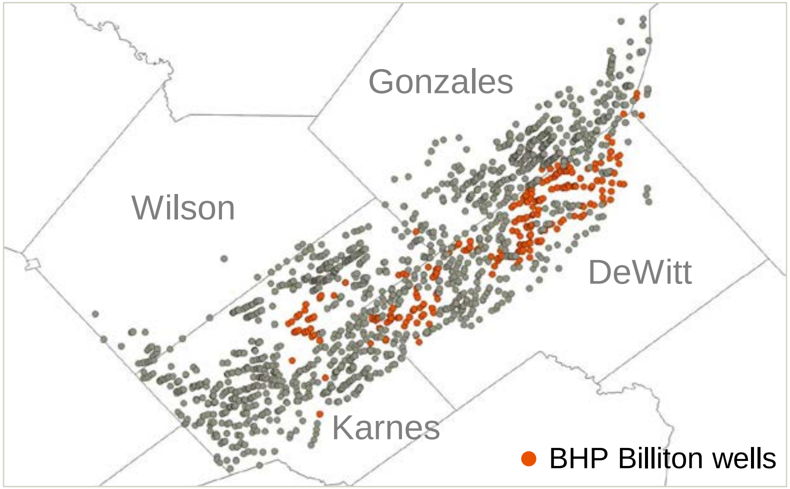


1. Drilling time from spud to rig release.
2. Based on Q2 FY13 instead of Q1 FY13 due to sample size.

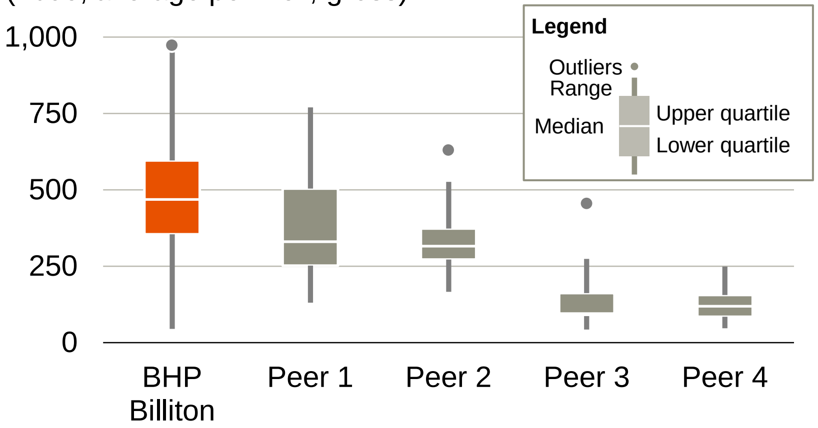
We are the top performer in Black Hawk recovered reserves

- Using low-cost initiatives to maximise recoveries and unlock substantial value
  - restricted flows
  - optimal stage spacing
  - efficient proppant placement
- We are best among peers in recovered reserves
  - initial production rates are competitive across the peer group
  - ~250 kboe ahead of peers on average three year cumulative production in the Black Hawk[1]
- Significant opportunity to replicate this success across our Onshore US business

Black Hawk producing wells[2]



Black Hawk 3 year cumulative production[1,3]
(kboe, average per well, gross)

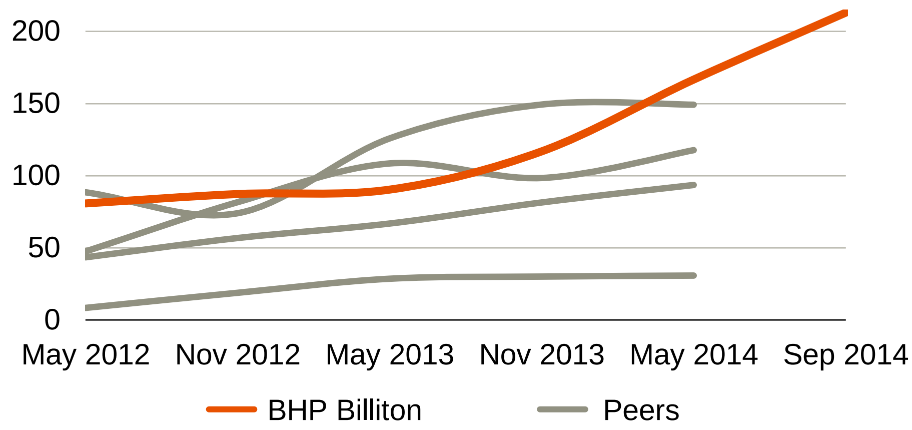


Source: IHS.
1. Based on production data from April 2009 to May 2014 (wells POL before June 2011).
2. Represents producing wells as at May 2014.
3. Represents wells with at least 3 years of production.

Building momentum in the Black Hawk

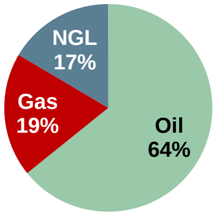
- We are a top producer in the Eagle Ford with investment prioritised on liquids-rich acreage
  - ~75% of our Onshore US drilling and development expenditure in FY14 was focused on the Eagle Ford
- Our Black Hawk acreage is in the heart of the condensate window
  - current wells generating IRRs of 65%[1] at today's prices
- The Black Hawk is expected to be the single largest producer in our Petroleum portfolio in FY15
  - 284 net producing wells at the end of FY14
  - on track to deliver 120 planned net wells in FY15

Black Hawk production rates[2]
(gross, kboe/d)



Our Black Hawk position	
FY14 initial 30-day average production rate[3]	1,140 boe/d
Median 3 year cumulative production[4]	468 kboe
Additional gross wells expected[5]	~ 840

Expected FY15 product mix

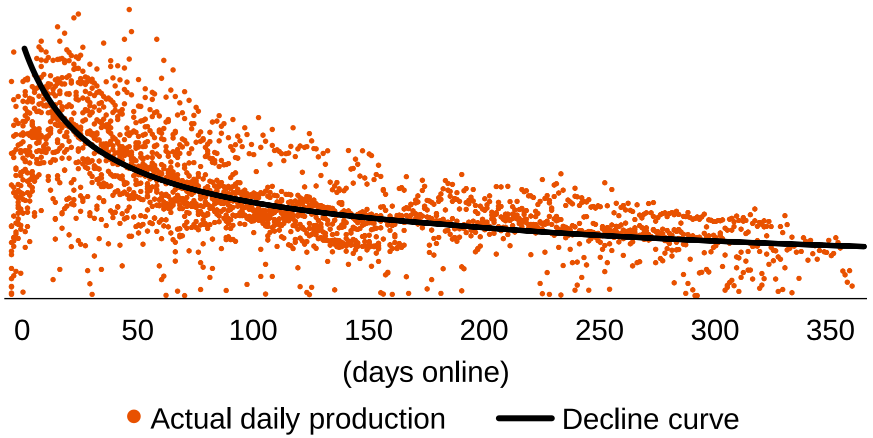


1. After tax, based on our FY15 program at September 2014 futures prices.
2. Source: IHS. Based on monthly average for the months shown; peer data not available beyond May 2014.
3. BHP Billiton data based on a 30-day average of all BHP Billiton wells.
4. Represents wells with at least 3 years of production (average per well, gross).
5. Operated wells to be added from FY15 onwards under current development plan with an average expected working interest of 52%.

Extending our liquids runway in the Permian

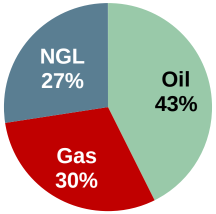
- We are leading the appraisal of the Wolfcamp with more than 75 wells drilled to date
  - extensive vertical and lateral appraisal of the resource
- We are running ahead of plan in FY15 and on track to build a 100 kboe/d business by the end of FY18[1]
  - we are delivering excellent, repeatable well results with IRRs >30%[2]
  - we are assessing options to optimise delivery of product to market including trucking, pipeline and rail
- Our Permian development plan has upside potential given multiple prospective horizons

Upper Wolfcamp well performance[3]
(gross production, boe/d)



Our Permian position	
FY14 initial 30-day average production rate[4]	1,400 boe/d
Additional gross wells expected[5]	~ 650

Expected FY15 product mix



1. Production rates represent net BHP Billiton portion.
2. After tax, based on our FY15 program at September 2014 futures prices.
3. Based on actual performance of 14 wells within a core development area.
4. Based on early performance of Upper Wolfcamp wells (gross total production, excluding downtime and ramp-up).
5. Operated wells to be added from FY15 onwards under current development plan with an average expected working interest of 84%.

Generating strong returns at current prices in the Haynesville

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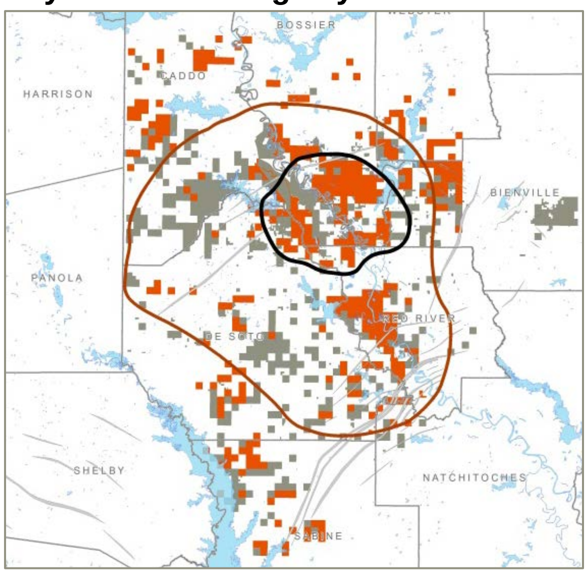
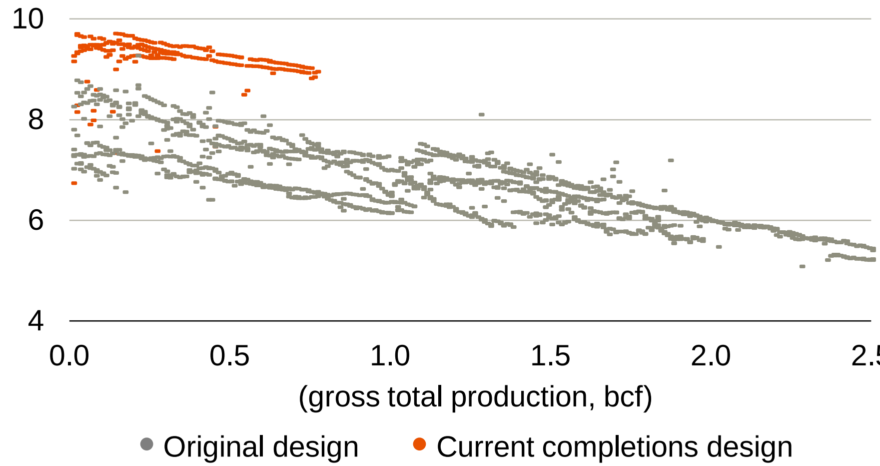
- We have the premier acreage position in one of the most productive US shale gas plays
  - 370 net shale producing wells as at 30 June 2014[1]
- Advances in completion optimisation show potential for a significant increase in EUR
- Delivering IRRs >25%[2] at current prices

Haynesville acreage by recoverable reserves



1. Excludes conventional producing wells (approx. 592).
2. After tax, based on our FY15 program at September 2014 futures prices.

Potential for higher EUR from optimised completions
(gross production, MMcf/d)



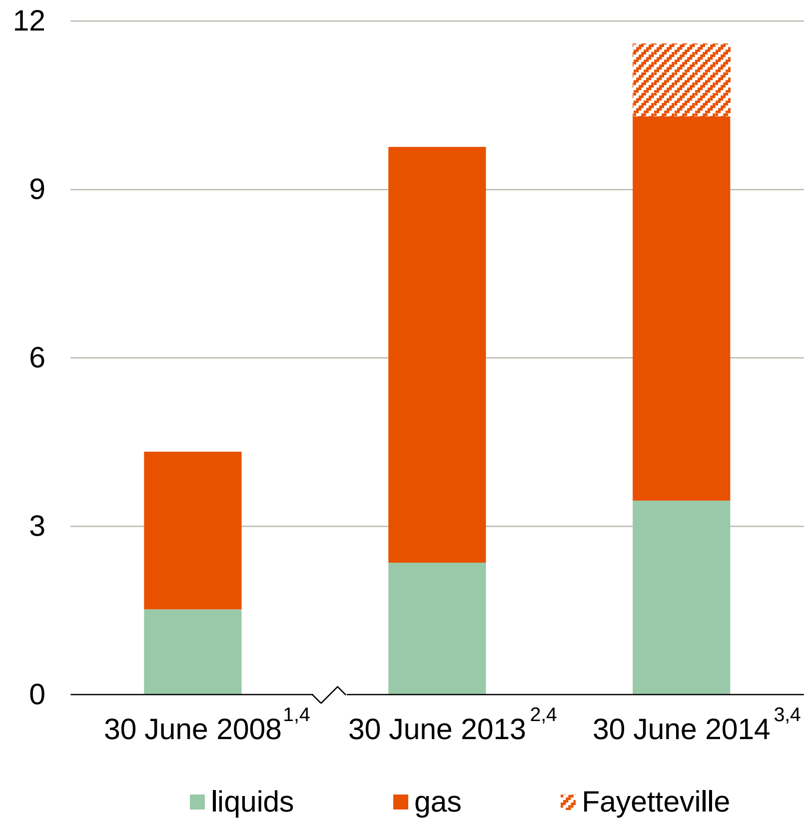
Our Haynesville position	
FY14 initial 30-day average production rate[3]	7,800 Mcf/d
Median 3 year cumulative production[4]	3.9 bcf
Additional gross wells expected[5]	~ 2,300

3. Based on early performance of 42 wells (gross total production, excluding downtime and ramp-up).
4. Represents wells with at least 3 years of production (average per well, gross).
5. Operated wells to be added from FY15 onwards under current development plan with an average expected working interest of 70%.

Simplifying the portfolio for value

- We manage the portfolio for value
  - extending our liquids runway in our Shale business through acreage optimisation
  - targeted exploration program pursuing Tier-1 Conventional oil opportunities
  - divesting smaller, more mature assets
- We are prioritising our significant, longer-term unconventional gas plays
  - planning for the full development of our high-return Haynesville resources
  - we have initiated the marketing of our Fayetteville asset
- We will only pursue divestments if full value can be realised for our owners

BHP Billiton petroleum resource
(billion boe)



1. Resource classification (2008) – Proved Reserves (1P) 1,375 MMboe, Proved and Probable Reserves (2P) 2,151 MMboe, Contingent Resources (2C) 2,180 MMboe.
2. Resource classification (2013) – Proved Reserves (1P) 2,563 MMboe, Proved and Probable Reserves (2P) 6,501 MMboe, Contingent Resources (2C) 3,259 MMboe.
3. Resource classification (2014) – Proved Reserves (1P) 2,443 MMboe, Proved and Probable Reserves (2P) 6,234 MMboe, Contingent Resources (2C) 5,365 MMboe.
4. 2008 resources exclude fuel consumed in operations, 2013 and 2014 resources include 280 MMboe and 214 MMboe fuel consumed in operations respectively.

Key themes

- We have a clear strategy focused on value over volume
- Our Petroleum portfolio is underpinned by large, high-quality, upstream assets
- High-return brownfield investments will maintain stable Conventional volumes
- Liquids opportunities with Tier-1 potential are the focus of our exploration program
- Our Shale business is primed to generate strong growth in free cash flow
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Glossary of selected terms

Reserves

Those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: They must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.

1P 1P is equivalent to proved reserves and is also commonly called P1. It denotes a low estimate scenario of petroleum reserves.

2P 2P is equivalent to the sum of proved reserves plus probable reserves. It denotes the best estimate scenario of petroleum reserves.

P2 P2 is equivalent to probable reserves.

EUR Estimated Ultimate Recovery (best estimate basis).

Contingent Resources

Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources.

1C Denotes the low estimate scenario of contingent resources.

2C Denotes the best estimate scenario of contingent resources.

Deterministic Methodology

A discrete value or array of values for each parameter is selected based on the estimator’s choice of the values that are most appropriate for the corresponding resource category. A single outcome of recoverable quantities is derived for each deterministic increment or scenario.

Probabilistic Methodology

A distribution representing the full range of possible values for each input parameter is developed and a range of outcomes are statistically derived for each scenario.

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