



2018 has been a good year for Upstream, where we increased confidence in 2021 delivery and underpinned our ability to continue growth well into the next decade.



Bernard Looney
Chief executive, Upstream



63,000km²

new exploration access

(2017 28,000km²)

95.7%

BP-operated upstream plant reliability★

(2017 94.7%)

7

successful completion of turnarounds

(2017 6)

9

final investment decisions

(2017 3)

6

major project★ start-ups

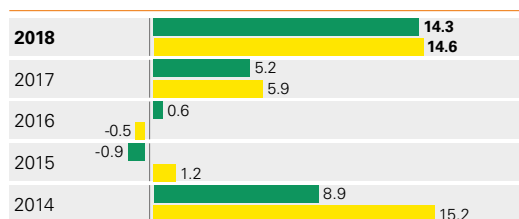
(2017 7)

2.5

million barrels of oil equivalent per day – hydrocarbon production

(2017 2.5mmb/d)

Upstream profitability (\$ billion)



● Replacement cost (RC) profit (loss) before interest and tax★
● Underlying RC profit (loss) before interest and tax★

Business model

The Upstream segment is responsible for our activities in oil and natural gas exploration, field development and production. We do this through five global technical and operating functions.

Exploration



The **exploration function** is responsible for renewing our resource base through access, exploration and appraisal, while the **reservoir development** function is responsible for the stewardship of our resource portfolio over the life of each field.

Wells and projects



The **global wells organization** and the **global projects organization** are responsible for the safe, reliable and compliant execution of wells (drilling and completions) and major projects.

Global operations organization



The **global operations organization** is responsible for safe, reliable and compliant operations, including upstream production assets and midstream transportation and processing activities.

Strategy

Our strategy has three parts and is enabled by:

Quality execution

We want to be the best at what we do – everywhere we work. This starts with executing our activity safely. In every basin, we will benchmark against the competition and aim to be the best – whether it be operating facilities reliably and cost effectively, with a focus on emissions, drilling wells, managing our reservoirs, exploring, building projects, or deploying technology. Through the quality of our execution, scale and infrastructure, we aim to be competitive in every basin, and as a business, get more from a unit of capital than our peers.

Growing advantaged oil and gas

We will manage our portfolio through disciplined investment in many of the world's great oil and gas basins. We plan to grow both oil and gas production. Natural gas is a big lever for reducing greenhouse gas emissions. This means taking a leadership role in tackling the challenge of methane. Our gas portfolio will be complemented by advantaged oil assets – oil we can produce at a lower cost or higher margin, creating a portfolio that is flexible for different price environments.

Returns-led growth

We want to grow – but not at any cost. We always look to grow returns and value. We believe this growth will come from many sources – production growth, expanding and managing our margins, operational efficiency, unit cost reduction, and capital efficiency with disciplined levels of capital reinvestment.

Underpinning our business model and strategy is our transformation agenda. We have around 1,000 projects across the Upstream aimed at sustainably improving both performance and how it feels to work in the Upstream. We believe in the potential of this agenda to transform the efficiency of our business, and we are delivering real value today to the bottom line.

In addition to our core Upstream exploration, development and production activities, the segment is responsible for midstream transportation, storage and processing. We also market and trade natural gas, including liquefied natural gas (LNG), power and natural gas liquids (NGL). In 2018 our activities took place in 33 countries.

The US Lower 48 business continues to operate as a separate, asset-focused, onshore business, and changed its name to BPX Energy in October.

With the exception of BPX Energy, we deliver our exploration, development and production activities through five global technical and operating functions.

We optimize and integrate the delivery of our activities across 12 regions, with support provided by global functions in specialist areas of expertise: technology, finance, procurement and supply chain, human resources, information technology and legal.

In 2016 we identified a future growth target of 900,000 barrels of oil equivalent per day of production from new major projects by 2021 and we remain on track to deliver that. We expect this production to deliver 35% higher operating cash margins★ on average than our 2015 upstream assets, which supports our value over volume strategy.

We see our scale and long history in many of the great basins in the world as a differentiator for BP and believe in the strength of our incumbent positions. We believe we are balanced and flexible – in terms of geography, hydrocarbon type and geology – and rather than being restricted by a traditional way of working, we have and will continue to use creative business models to generate value.

Financial performance

	\$ million		
	2018	2017	2016
Sales and other operating revenues ^a	56,399	45,440	33,188
RC profit before interest and tax	14,328	5,221	574
Net (favourable) adverse impact of non-operating items★ and fair value accounting effects★	222	644	(1,116)
Underlying RC profit (loss) before interest and tax	14,550	5,865	(542)
Organic capital expenditure★ ^b	12,027	13,763	14,344
BP average realizations^c	\$ per barrel		
Crude oil ^d	67.81	51.71	39.99
Natural gas liquids	29.42	26.00	17.31
Liquids★	64.98	49.92	38.27
	\$ per thousand cubic feet		
Natural gas	3.92	3.19	2.84
US natural gas	2.43	2.36	1.90
	\$ per barrel of oil equivalent		
Total hydrocarbons★ ^d	43.47	35.38	28.24
Average oil marker prices^e	\$ per barrel		
Brent★	71.31	54.19	43.73
West Texas Intermediate★	65.20	50.79	43.34
Average natural gas marker prices	\$ per million British thermal units		
Average Henry Hub★ gas price ^f	3.09	3.11	2.46
	pence per therm		
Average UK National Balancing Point gas price★ ^e	60.38	44.95	34.63

^a Includes sales to other segments.

^b A reconciliation to GAAP information at the group level is provided on page 275.

^c Realizations are based on sales by consolidated subsidiaries only, which excludes equity-accounted entities.

^d Includes condensate and bitumen.

^e All traded days average.

^f Henry Hub First of Month Index.





Growing advantaged oil and gas in the upstream



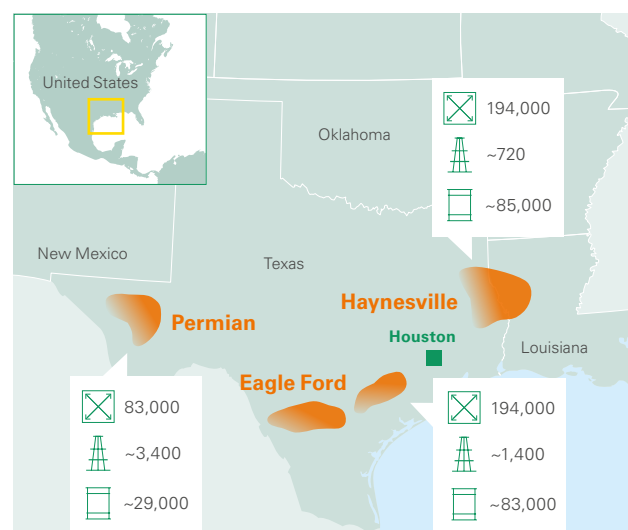
470,000
acres of access

Transforming US onshore

BP is transforming its US onshore oil and gas business with our purchase of world-class unconventional assets from BHP. This acquisition gives us access to some of the best basins in the onshore US and positions BP as a top producer in the region.

The transaction includes 470,000 acres of licences across a new position in the liquids-rich Permian-Delaware basin, and two premium positions in the Eagle Ford and Haynesville basins. Together these assets will significantly increase the liquid hydrocarbon proportion of our production and resources – helping to upgrade and reposition BPX Energy, which was previously known as the US Lower 48 business.

BPX Energy has operated as a separate business since 2015. Its innovative approach to using new technology such as big-data analytics, augmented reality, drones and advanced drilling techniques, have helped the business achieve significant improvements in operational and financial performance. We plan to apply this approach to operations at our newly acquired basins.



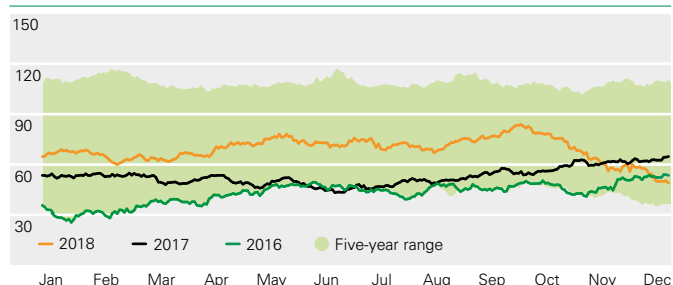
- | | Size (acres) | Number of drilling sites | Current production (boe/d) |
|--------------------|---|--------------------------|----------------------------|
| Permian | <ul style="list-style-type: none"> Delaware sub-basin of the Permian in West Texas. 83,000 acres with around 3,400 drilling sites. Current production – around 29,000boe/d (~70% liquids). | | |
| Eagle Ford | <ul style="list-style-type: none"> Karnes Trough and Eagle Ford in South Texas. 194,000 acres with 1,400 gross drilling locations. Current production – around 83,000boe/d (~70% liquids). | | |
| Haynesville | <ul style="list-style-type: none"> East Texas and Louisiana. 194,000 acres with 720 gross drilling locations. Current production – around 85,000boe/d, all gas. | | |

As at 31 December 2018.

Market prices

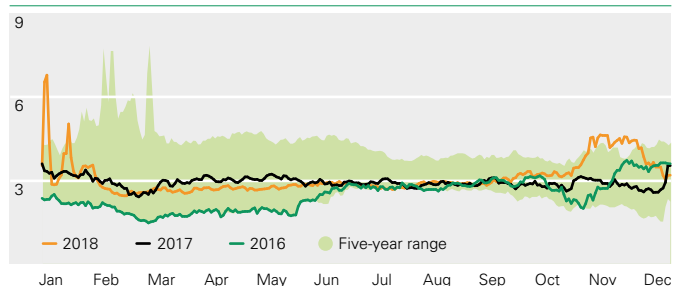
Brent remains an integral marker to the production portfolio, from which a significant proportion of production is priced directly or indirectly.

Brent (\$/bbl)



Dated Brent crude oil prices averaged \$71.31 per barrel in 2018 – a second consecutive annual increase but still well below the average of more than \$110 seen in 2011-13. Prices drifted higher over the first half of the year, then rose more rapidly to reach an annual peak near \$85 in October, before falling sharply and ending the year at an annual low point of about \$50. Oil demand recorded a fourth consecutive above-average increase, growing by 1.3mmb/d. Global production increased by an even more robust 2.6mmb/d, with all of the increase coming from non-OPEC countries (2.7mmb/d); the US recorded record production growth of 2.2mmb/d. OPEC production fell slightly (-0.1mmb/d) for a second consecutive year as the group engaged with co-operating non-OPEC countries in production restraint early in the year, although OPEC production began to recover in the second half of the year as production restraint was eased.

Henry Hub (\$/mmBtu)



Henry Hub prices decreased to \$3.09/mmBtu in 2018 from \$3.11/mmBtu in 2017. The UK National Balancing Point hub price was 60.38 pence per therm in 2018, 34% higher than in 2017 (44.95), on the back of increasing coal, oil and CO₂ prices. Asian spot prices rose to \$9.76/mmBtu in 2018, up from \$7.13/mmBtu supported by higher coal, and oil prices as well as a relatively tight LNG market – except in the later part of 2018, where ample LNG supplies combined with warm weather caused Asian spot prices to drop to below \$9/mmBtu.

For more information on global energy markets in 2018 see page 18.

Financial results

Sales and other operating revenues for 2018 increased compared with 2017, primarily reflecting higher liquids realizations, higher production and higher gas marketing and trading revenues. The increase in 2017 compared with 2016 primarily reflected higher liquids realizations, higher production and higher gas marketing and trading revenues.

Replacement cost profit before interest and tax for the segment included a net non-operating charge of \$183 million. This primarily relates to impairment charges associated with a number of assets,

following changes in reserves estimates, the decision to dispose of certain assets and the decision to relinquish a number of leases expiring in the near future, partially offset by reversals of prior year impairment charges. See Financial statements – Note 5 for further information. Fair value accounting effects had an adverse impact of \$39 million relative to management's view of performance.

The 2017 result included a net non-operating charge of \$671 million, primarily related to impairment charges associated with a number of assets, following changes in reserves estimates, and the decision to dispose of certain assets. Fair value accounting effects had a favourable impact of \$27 million relative to management's view of performance. The 2016 result included a net non-operating gain of \$1,753 million, primarily related to the reversal of impairment charges associated with a number of assets, following a reduction in the discount rate applied and changes to future price assumptions. Fair value accounting effects had an adverse impact of \$637 million.

After adjusting for non-operating items and fair value accounting effects, the underlying replacement cost result before interest and tax was significantly higher in 2018 compared with 2017. This primarily reflected higher liquids and gas realizations, higher production and lower exploration write-offs.

Compared with 2016 the 2017 result reflected higher liquids realizations, and higher production including the impact of the Abu Dhabi onshore concession renewal and major projects start-ups, partly offset by higher depreciation, depletion and amortization, and higher exploration write-offs.

Organic capital expenditure was \$12.0 billion.

In total, disposal transactions generated \$2.1 billion in proceeds in 2018, with a corresponding reduction in net proved reserves of 229mmboe within our subsidiaries. The major disposal transactions during 2018 were the disposal of our interests in the Bruce, Keith and Rhum fields in the UK North Sea and our interest in the Greater Kuparuk Area in the US, the consideration for which was a 16.5% interest in the Clair field in North Sea. More information on disposals is provided in Upstream analysis by region on page 279 and Financial statements – Note 4.

Outlook for 2019

- Five new major projects expected to start up in 2019.
- We expect underlying production★ to be higher than 2018 due to major projects. The actual reported outcome will depend on the exact timing of project start-ups, acquisitions and divestments, OPEC quotas and entitlement impacts in our production-sharing agreements★.
- Upstream capital investment is expected to increase, largely as a result of our increased presence in the onshore US.
- We expect oil prices will continue to be volatile in the near term.

Exploration

The group explores for oil and natural gas under a wide range of licensing, joint arrangement and other contractual agreements. We may do this alone or, more frequently, with partners.

Our exploration and new access teams work to optimize our resource base and provide us with a greater number of options.

In the current environment, we are spending less on exploration and we will spend a material part of our exploration budget on lower-risk, shorter-cycle-time opportunities around our incumbent positions.

New access in 2018

We gained access to new acreage covering around 63,000km² in 10 countries – Australia, Azerbaijan, Brazil, Canada, Egypt, Madagascar, Mexico, São Tomé and Príncipe, the UK North Sea and the US Gulf of Mexico.

Exploration success

We participated in three potentially commercial discoveries in 2018 – Manuel and Nearly Headless Nick in the US Gulf of Mexico and Bongos in Trinidad.

Exploration and appraisal costs

Excluding lease acquisitions, the costs for exploration and appraisal were \$1,298 million (2017 \$1,655 million, 2016 \$1,402 million). These costs included exploration and appraisal activities, which were capitalized within intangible fixed assets, and geological and geophysical exploration costs, which were charged to income as incurred.

Approximately 5% of exploration and appraisal costs were directed towards appraisal activity. We participated in 29 gross (19 net) exploration and appraisal wells in eight countries.

Exploration expense

Total exploration expense of \$1,445 million (2017 \$2,080 million, 2016 \$1,721 million) included the write-off of expenses related to unsuccessful drilling activities, lease expiration or uncertainties around development in the Gulf of Mexico (\$450 million), Egypt (\$236 million), and others (\$759 million), as well as geological and geophysical exploration costs (see Financial statements – Note 8).

Reserves booking

Reserves bookings from new discoveries will depend on the results of ongoing technical and commercial evaluations, including appraisal drilling. The segment's total hydrocarbon reserves on an oil-equivalent basis, including the segment's equity-accounted entities at 31 December 2018, increased by 11% (an increase of 7% for subsidiaries and an increase of 47% for equity-accounted entities) compared with proved reserves at 31 December 2017.

Proved reserves replacement ratio★

The proved reserves replacement ratio for the segment in 2018 was 69% for subsidiaries and equity-accounted entities (2017 127%), 66% for subsidiaries alone (2017 133%) and 106% for equity-accounted entities alone (2017 78%). For more information on proved reserves replacement for the group see page 285.

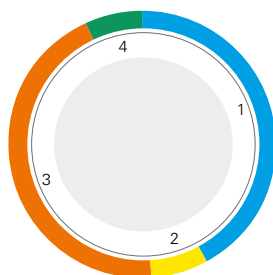
Upstream proved reserves (mmbobe)

Liquids

1. Subsidiaries	4,954
2. Equity-accounted entities	808
Total	5,762

Gas

3. Subsidiaries	5,234
4. Equity-accounted entities	786
Total	6,020



Estimated net proved reserves^a (net of royalties)

	2018	2017	2016
Liquids			
million barrels			
Crude oil ^b			
Subsidiaries★	4,378	4,129	3,778
Equity-accounted entities ^c	794	674	771
	5,172	4,803	4,549
Natural gas liquids			
Subsidiaries	576	318	373
Equity-accounted entities ^c	15	18	16
	590	336	389
Total liquids			
Subsidiaries ^d	4,954	4,447	4,151
Equity-accounted entities ^c	808	692	787
	5,762	5,139	4,938
Natural gas			
billion cubic feet			
Subsidiaries ^e	30,355	29,263	28,888
Equity-accounted entities ^c	4,559	2,274	2,580
	34,914	31,537	31,468
Total hydrocarbons			
million barrels of oil equivalent			
Subsidiaries	10,188	9,492	9,131
Equity-accounted entities ^c	1,594	1,085	1,232
	11,782	10,577	10,363

^a Because of rounding, some totals may not agree exactly with the sum of their component parts.

^b Includes condensate and bitumen.

^c BP's share of reserves of equity-accounted entities in the Upstream segment. During 2018 upstream operations in Argentina, Bolivia, Mexico, Russia and Norway as well as some of our operations in Angola were conducted through equity-accounted entities.

^d Includes 12 million barrels (14 million barrels at 31 December 2017 and 16 million barrels at 31 December 2016) in respect of the 30% non-controlling interest in BP Trinidad & Tobago LLC.

^e Includes 1,573 billion cubic feet of natural gas (1,860 billion cubic feet at 31 December 2017 and 2,026 billion cubic feet at 31 December 2016) in respect of the 30% non-controlling interest in BP Trinidad & Tobago LLC.

Developments

We achieved six major project start-ups in 2018 – in Azerbaijan, Australia, the Gulf of Mexico, Egypt, Russia and the UK North Sea. In addition to these, we made good progress on projects in Trinidad, Egypt and the UK North Sea.

- **Trinidad** – Work on the Angelin project progressed well after we started the drilling programme in late 2018, and we announced first gas production in February 2019.
- **Egypt** – Raven, the third phase of the West Nile Delta development project is on target to achieve first gas in second half of 2019 with well commissioning activities underway.
- **UK North Sea** – At Culzean, perforation of wells on the Total-operated project is about to get underway after completion of trees installation. Production is expected in the first half of 2019.

Subsidiaries' development expenditure incurred, excluding midstream activities, was \$9.9 billion (2017 \$10.7 billion, 2016 \$11.1 billion).

Our project pipeline

*BP operated

Project	Location	Type
2018 start-ups		
Shah Deniz Stage 2*	Azerbaijan	Gas
Western Flank B	Australia	Gas
Atoll Phase 1*	Egypt	Gas
Clair Ridge*	UK North Sea	Oil
Taas Expansion	Russia	Oil
Thunder Horse North West Expansion*	US Gulf of Mexico	Oil

Expected start-ups 2019-2021

Projects currently under construction

Angelin ^a	Trinidad	Gas
Cassia Compression*	Trinidad	Gas
Culzean	UK North Sea	Gas
KG D6 R-Series	India	Gas
KG D6 Satellites	India	Gas
Khazzan Phase 2*	Oman	Gas
Tanggah Expansion*	Indonesia	Gas
West Nile Delta Giza and Fayoum ^a	Egypt	Gas
West Nile Delta Raven*	Egypt	Gas
Alligin*	UK North Sea	Oil
Atlantis Phase 3	US Gulf of Mexico	Oil
Constellation ^a	US Gulf of Mexico	Oil
Mad Dog Phase 2*	US Gulf of Mexico	Oil
Manuel*	US Gulf of Mexico	Oil
Vorlich*	UK North Sea	Oil
Zinia 2	Angola	Oil

^a Production commenced in early 2019.

Beyond 2021

We have a deep hopper of projects that are currently under appraisal. Our focus here is to ensure we maximize value and select the optimum project concept before we move it forward into design. We do not expect to progress all of the projects – only the best. This includes:

- a mix of resource types: split across conventional oil, deepwater oil, conventional gas and unconventionals★.
- geographic spread: across six of the seven continents.
- a range of development types: from exploration to brownfield and near-field.

Production

Our offshore and onshore oil and natural gas production assets include wells, gathering centres, in-field flow lines, processing facilities, storage facilities, offshore platforms, export systems (e.g. transit lines), pipelines and LNG plant facilities. These include production from conventional and unconventional assets. Our principal areas of production are Angola, Argentina, Australia, Azerbaijan, Egypt, Oman, Trinidad, the UAE, the UK and the US. With BP-operated plant reliability increasing from around 86% in 2011 to 96% in 2018, efficient delivery of turnarounds and strong infill drilling performance, we have maintained base decline at less than 3% on average over the last five years. Our long-term expectation for managed base decline remains at the 3-5% per annum guidance we have previously given.

Production (net of royalties)^a

	2018	2017	2016
Liquids			
thousand barrels per day			
Crude oil ^b			
Subsidiaries	1,051	1,064	943
Equity-accounted entities ^c	121	199	179
	1,172	1,263	1,122
Natural gas liquids			
Subsidiaries	88	85	82
Equity-accounted entities ^c	8	8	4
	96	93	86
Total liquids			
Subsidiaries	1,139	1,149	1,025
Equity-accounted entities ^c	129	207	184
	1,268	1,356	1,208
Natural gas			
million cubic feet per day			
Subsidiaries	6,900	5,889	5,302
Equity-accounted entities ^c	474	547	494
	7,374	6,436	5,796
Total hydrocarbons			
thousand barrels of oil equivalent per day			
Subsidiaries	2,328	2,164	1,939
Equity-accounted entities ^c	211	302	269
	2,539	2,466	2,208

^a Because of rounding, some totals may not agree exactly with the sum of their component parts.

^b Includes condensate and bitumen.

^c Includes BP's share of production of equity-accounted entities in the Upstream segment.

Our total hydrocarbon production for the segment in 2018 was 3.0% higher compared with 2017. The increase comprised a 7.6% increase (0.9% decrease for liquids and 17.2% increase for gas) for subsidiaries and a 30.0% decrease (37.6% for liquids and 13.4% for gas) for equity-accounted entities compared with 2017. For more information on production see Oil and gas disclosures for the group on page 285.

In aggregate, underlying production increased versus 2017.

The group and its equity-accounted entities have numerous long-term sales commitments in their various business activities, all of which are expected to be sourced from supplies available to the group that are not subject to priorities, curtailments or other restrictions. No single contract or group of related contracts is material to the group.

Gas and power marketing and trading activities

Our integrated supply and trading function markets and trades our own and third-party natural gas (including LNG), biogas, power and NGLs. This provides us with routes into liquid markets for the gas we produce and generates margins and fees from selling physical products and derivatives to third parties, together with income from asset optimization and trading. This means we have a single interface with gas trading markets and one consistent set of trading compliance and risk management processes, systems and controls. We are expanding our LNG portfolio, which includes global partnerships with utility companies, gas distributors and national oil and gas companies.

The activity primarily takes place in North America, Europe and Asia, and supports group LNG activities, managing market price risk and creating incremental trading opportunities through the use of commodity derivative contracts. It also enhances margins and generates fee income from sources such as the management of price risk on behalf of third-party customers.

Our trading financial risk governance framework is described in Financial statements – Note 29 and the range of contracts used is described in Glossary – commodity trading contracts on page 315.