Oil & Gas Authority

Wells Insight Report 2018

Key Insights

The need to keep on drilling

Story so far

7,800 wells drilled to date

Delivering **44 billion barrels**

Significant resource potential remaining

But, drilling activity is in decline:

2017 low well activity

19	**56**	**2128**
E&A Wells	Development Wells	wells in operation

Only 18% of future E&A wells (2018 to 2020) have financial approval

Declining trend in average discovery size

Development drilling has fallen 50% from 2015 to 2017

And while well costs are lower…

…this is largely driven by service rate reductions, not performance improvements…

…with non-productive time (NPT) making up >15% of cost

So in order to see a turnaround and deliver MER UK:

Increase
new well drilling & improve costs

Improve
base management

Improve
well abandonment planning

Huge value

In 2017

Safeguarded 21 million boe production through interventions

Added 22.5 million boe production (by improving underperforming wells and/or reactivating shut in wells)

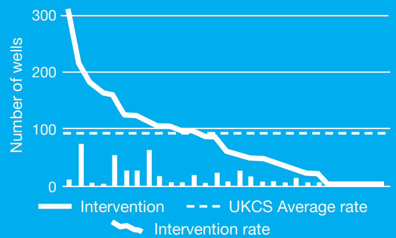
But…

33 million boe were not achieved as a result of well losses

Around 600 wells shut in with significant remaining reserves: **30% of existing active well stock**

from existing wells

Well integrity and water production issues account for **62%** of shut-ins



Intervention rates are too low:

8% surveillance rate

14% intervention rate

OGA will

- Develop a new Wells Strategy to support industry
- Establish a new Asset Stewardship Expectation focused on well management
- Publish a report detailing Wells lessons learned

Well abandonment

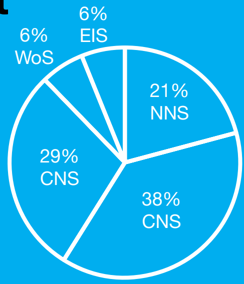
240 open water suspended E&A wells

Average age of 27 years, raising the issue of mechanical integrity

All require to be permanently abandoned

12 operators hold 70% of the wells

Further 28 operators hold the remaining 30%



Suspended E&A wells by area

Well abandonment activity has increased four-fold since 2016

Over 150 wells per year expected to be P&A'd

More wells being plugged and abandoned than drilled

P&A costs account for ca. 45% of the total decommissioning cost: Cost reduction is happening

2016: £402 million was spent on 76 abandonments

2017: £446 million spent on 163 abandonments

OGA work with industry to promote

- Information sharing on scope and abandonment plans
- Sharing P&A execution experience/ lessons learned
- Campaigns to achieve economies of scale, through higher rig and crew utilisations, fast learning curves and continuity of crews
- Visibility of future rig and service demand profiles to help supply chain to plan
- Novel and efficient contracting models

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Unless otherwise stated all analysis has been produced using OGA held data, including data collected via the UK Stewardship Survey and the Wells Notification system (WONS).

1. Executive summary

The OGA has spent the past two years collating and verifying well data to produce this report which, for the first time, provides a real insight into UKCS well stock and activity.

To date over 7,800 wells have been drilled in the UK Continental Shelf (UKCS), delivering over 44 billion barrels of oil equivalent (boe).

There is still significant remaining resource potential, however drilling activity has recently been in decline with exploration and appraisal (E&A) well activity declining steadily since 2008. Development infill well activity has halved since 2015 following the oil price drop.

The cost of drilling wells has reduced significantly in recent years but this has primarily been driven by rig and service rate reductions, rather than improved performance. Non-Productive Time (NPT) is still greater than 15% and represents a real opportunity for sustainable cost reduction through improved performance.

In addition over 600 wells, 30% of existing active well stock, are currently shut-in and well surveillance and intervention rates are low at 8% and 14% respectively. By improving base management and increasing intervention rates, industry can reduce the number of shut-in wells and maximise production.

Well abandonment activity has increased four-fold since 2016, with a similar forward trend predicted, with over 150 wells per annum being plugged and abandoned (P&A). There are also 240 currently suspended E&A wells, which require permanent abandonment, with 12 operators holding 70% of the well stock.

Industry now needs to make a concerted effort to increase cost effective drilling activity, improve the management of existing well stock and reduce well abandonment costs to maximise reserves, sustain production and minimise decommissioning costs.

This can be achieved by leveraging lessons learned, exploiting technology and working collaboratively with the supply chain to achieve transformational gains in performance.

The OGA is supporting this goal by working with industry to develop a wells strategy, sharing lessons learnt, and focusing on improved well stewardship.

2. Background

2.1 UKCS resource progression and wells

Resource progression is vital to sustain production operations in the UKCS. The OGA estimated that, in addition to the 5.4 bnboe of reserves still to be produced, there are 7.5 bnboe contingent resources which could be developed, plus a substantial yet to find (YTF).

To find and deliver the significant potential resources, a significant increase in drilling activity is required, both in exploration and development. This increase in activity must also be met with an improvement in cost efficiency and value if MER UK is to be achieved.

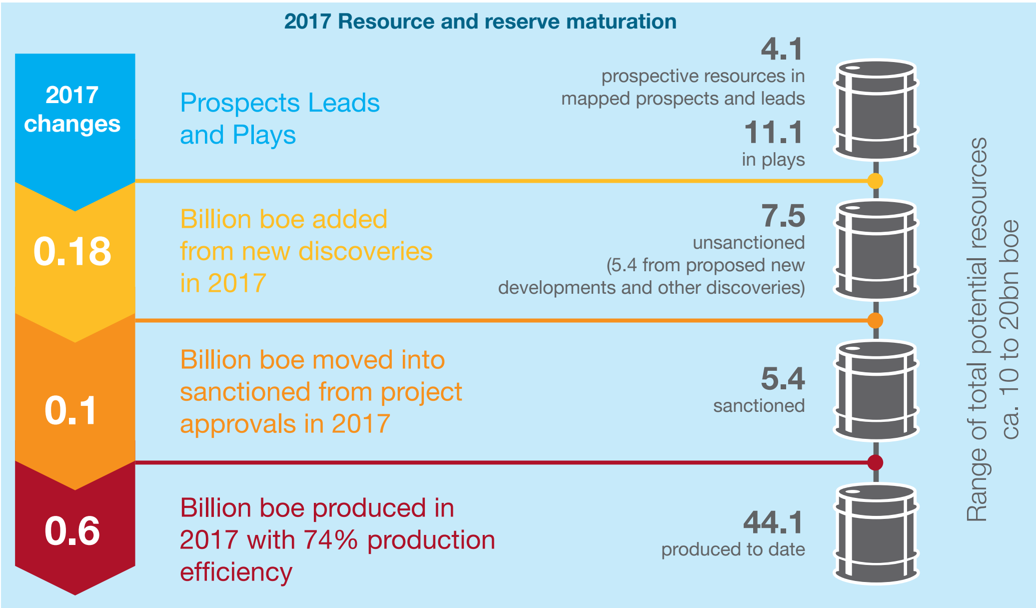


Figure 1

2017 well activity and inventory

19 E&A wells completed

56 development wells completed

2,148 wells in operations

It has taken 7800+ wells to find & produce 44 bnboe

Figure 2

Production levels

Production decline has been arrested since 2014 with sustained consistent production levels over the past 5 five years.

Drilling activity and well interventions have played a significant role in this arrest and it remains crucial to maintain the focus on management of the active well stock.

Despite the progress made on improving the overall production efficiency in recent years, well production losses remain high at 33 million mmboe per year and the large number of shut-in wells (circa 30% of total active wells) present opportunities for economic reactivation.

Production losses due to wells

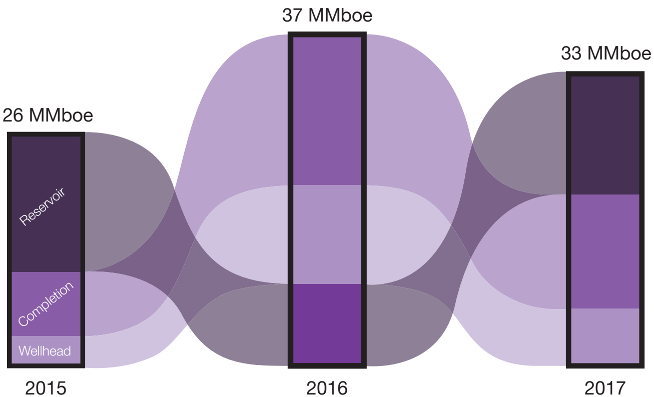


Figure 3

Production levels UKCS

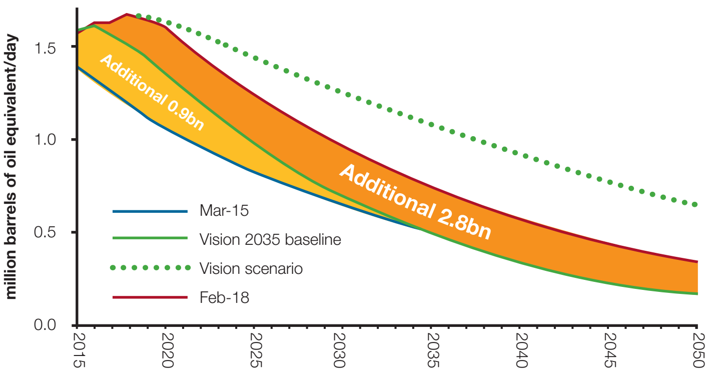


Figure 4

2.2 UKCS well stock (end of 2017)

Over 50 years of exploration and development activity on the UKCS have seen the delivery of a total of over 7,800 wells to the end of 2017 (requiring drilling of over 11,900 wellbores, including sidetracks).

It is evident that approximately half of all wells drilled are still active. AB1 and AB2 wells are plugged prior to abandonment and a significant portion of those wells are in open water. These wells will require to be permanently abandoned at some point in the future.

UKCS well stock and their status. (1964-2017)

	Well Type					
Well Status	**Exploration**	**Appraisal**	**Dev Platform**	**Dev Subsea**	**Combined Development**	**Totals**
Completed (Operating)			1506	622	2128	2128
(Completed Shut In)			386	310	696	696*
Plugged			224	43	267	267
AB1 & AB2	239				409	648
AB3 (Permanently Abandoned)	2345	1145			645	4135
Totals	2486	1373			4015	7874

Figure 5

*Approximately 100 of the 696 completed (shut in) wells are on fields that are due for cessation of production (COP) and are therefore not counted as part of the active well stock.

Of these well status categories the Completed (Operating) and Completed (Shut In) wells together on fields where there are still reserves represent the UKCS active well stock. Plugged, AB1 and AB2 wells are not included in the active well stock but are theoretically still accessible for future use as they are not permanently abandoned. The permanently abandoned wells are considered no longer accessible.

2.3 Industry landscape

The bulk of the historical drilling activity has been undertaken by oil and gas majors. By contrast, today a much more varied group of operators are undertaking exploration and development drilling activity.

This change in activity mix combined with recent asset transactions has resulted in a diverse distribution of well operatorship. The UKCS today has 12 companies operating 77% of the development well stock (each holding between 100 and 350 wells) and 60 further companies holding the remaining 750 wells.

Some 3000 development wells drilled to date are still active, either operating or still accessible through intervention work. This is a significant capital asset for the UKCS which operators must manage optimally. This is discussed further in section 4.5, Well Management.

UKCS development well stock ownership (operating, shut in, plugged, Ab1 and Ab2)

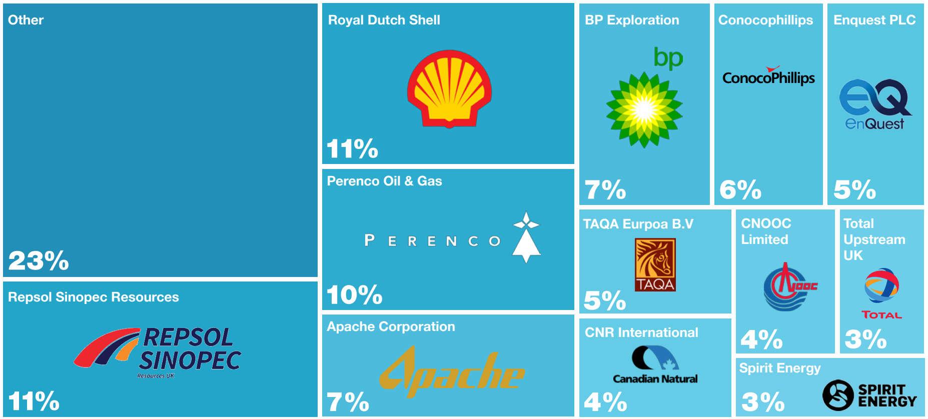


Figure 6

2.4 Role of OGA

Current well activity must increase to deliver MER UK. The OGA supports to improve well performance through benchmarking of performance data, sharing of lessons learned and targeted stewardship to drive increased well activity.

OGA supporting performance improvements

OGA focusing on regulatory excellence

OGA Wells Strategy (1Q 2019)

OGA Wells Stewardship Expectations (1Q 2019)

Driving increased well activity

Project contents

Well Interventions E&A drilling

Senior industry leadership and action

The OGA supports performance improvements by gathering and sharing comprehensive industry data across the well life-cycle. The annual Wells Insights report and other ad hoc reports such as the Wells Lessoned Learned report will be published to further the industry's knowledge.

The OGA's stewardship focus in this area will be defined by a wells strategy and a new wells stewardship expectation. The strategy will set out regulatory compliance, performance improvement and investment decision process requirements. The wells stewardship expectations will identify expected performance and benchmarks and form the basis for operator reviews.

The OGA is also driving increased well activity through project consents, well interventions, E&A drilling and engagement with senior industry leaders.

3.1 E&A drilling activity and discoveries

Exploration and appraisal drilling has been declining in the UKCS since the mid 2000s, having reached all time lows in 2016 and 2017. In addition, appraisal drilling has declined even more markedly than exploration, changing from a 50-60% share of total E&A activity in the 2000s to 36% and 39% in 2016 and 2017 respectively.

There has been a marginal increase in activity in 2017. The OGA is continuing to support E&A drilling through licensing rounds, including making significant quantities of high quality seismic and other exploration data openly available in support of these rounds.

E&A activity combined has declined in all UKCS areas, with the most marked decline in the Central North Sea (CNS). Exploration decline in the Southern North Sea (SNS), East Irish Sea (EIS) and West of Shetland (WoS) has resulted in an extremely low E&A activity of two to three well spuds (drilling commencement) per area per year. Activity in the Northern North Sea (NNS) shows the smallest decline when comparing 2016 and 2017 with the 2000s (around a 45% drop). The recent 2017 increase is entirely attributable to increased activity in the CNS.

E&A well spud count

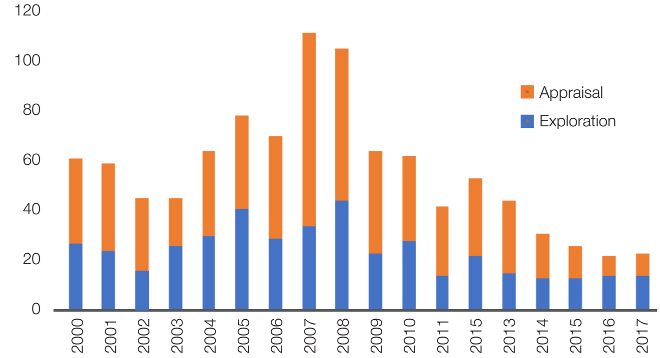


Figure 7

E&A well spud count by area

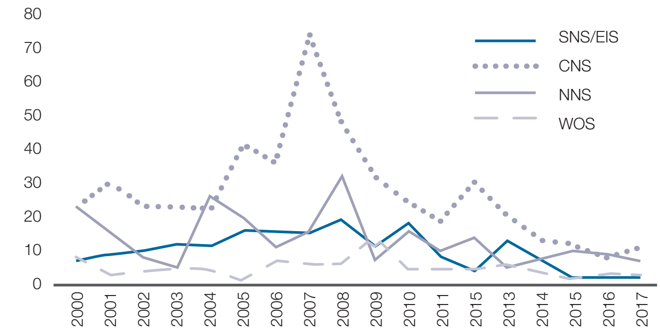


Figure 8

Exploration success rate

Exploration success rate has been largely consistent over the last two decades with around a 50% success rate.

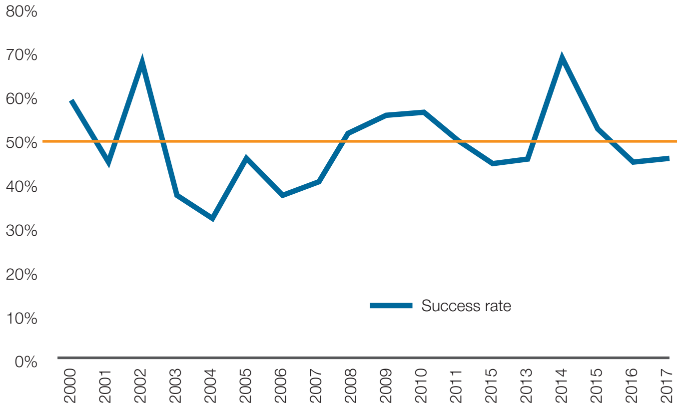


Figure 9

Total volumes discovered and average discovery size (mmboe)

There has been a declining trend in discovered volumes and average discovery size can be observed in the same period.

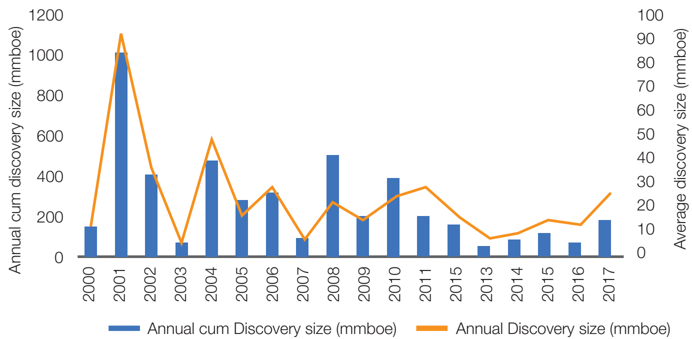


Figure 10

3.2 Exploration and appraisal well costs

A significant portion of UKCS capital spend is related to E&A well activity. Approximately £700 million over the last two years was spent on exploration and appraisal, representing some 20% of the total well capex.

	Exploration spend	Appraisal Spend	Total	No. wells
2016	£159 million	£159 million	£318MM	11
2017	£292 million (84% up on 2016)	£103million (35% down on 2016)	£395MM	19

Figure 11

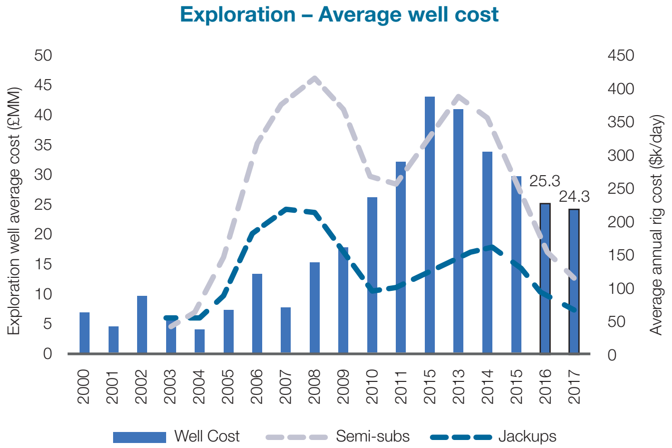


Figure 12 Source for graph: Wood Mackenzie, Stewardship Survey 2016 & 17 North Sea Reporter (Average rig cost)

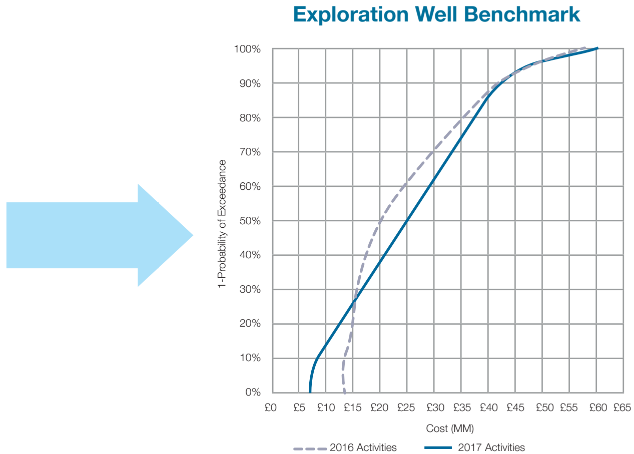


Figure 13

Between 2005 and 2009 there was a significant escalation in rig rates, while exploration well costs remained lower. In the period 2010 to 2015 rig rates again escalated with a resulting increase in well cost. As rig rates again have reduced in recent years, there remains an opportunity to learn from past cyclic events and ensure exploration well costs are efficiently managed.

Appraisal drilling follows similar trends to that of exploration with the escalation in prices during the 2000's and the drop in recent years. However, appraisal well costs are less predictable due to the specific information gathering requirements (samples and extended well tests).

Appraisal – average well cost

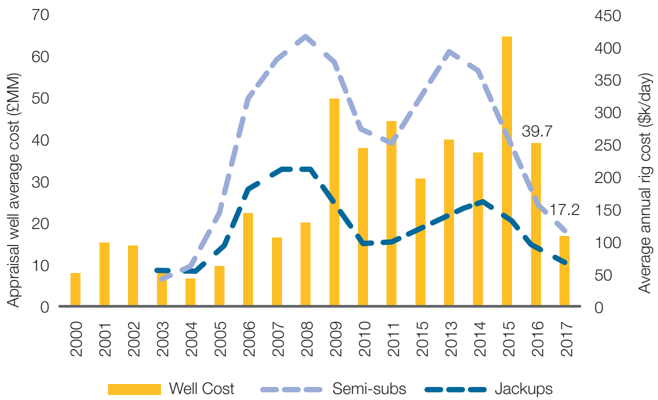


Figure 14

Appraisal Well Benchmark

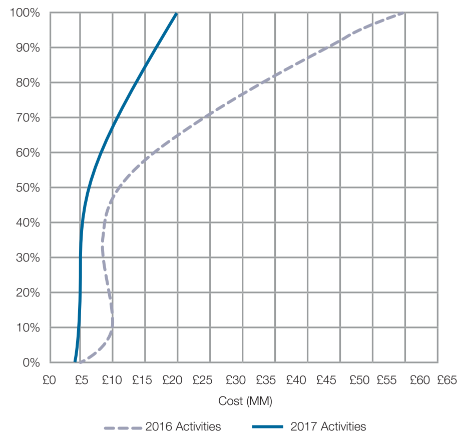


Figure 15

Source for graph: Wood Mackenzie, Stewardship Survey 2016 & 17
North Sea Reporter (Average rig cost)

Exploration wells – unit finding cost (£/boe)

The unit finding costs in UKCS for exploration wells has remained relatively stable at historical £2-4/boe average with a unit finding cost peak in 2013 (high activity levels and low success rate).

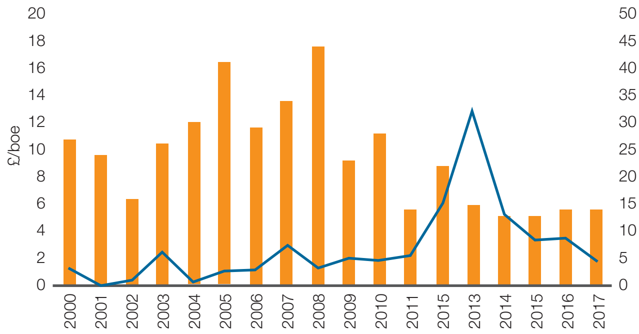
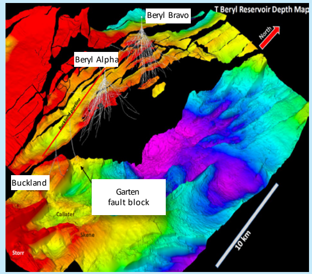


Figure 16

There is an opportunity for industry to maintain a sustainable, low unit finding cost while increasing exploration and appraisal activity. The UKCS exploration opportunity consists of varied exploration opportunities and the Garten case study shows an example of how infrastructure-led exploration can drive value.

CASE STUDY: Apache's Garten discovery



In March 2018, Apache made an oil discovery on Block 9/18a Area-W in the UK North Sea. The Garten discovery well lies 6 km south of the Beryl Alpha platform.

The well was spudded in February 2018 and targeted a downthrown structural closure. More than 700 ft of net oil pay in stacked, high-quality Jurassic-aged sandstone reservoirs was encountered. Recoverable resources are expected as 11 million bbl. of oil and 49 bcf of gas.

First hydrocarbons expected in Q4 2018, the turnaround time from exploration to development is short, a matter of months from spud to first production.

- High-quality 3D seismic data to uncover near-field prospectivity around Beryl Field.
- Modern data and the application of new technologies.
- Utilisation of existing vendors to allow timely engineering and design
- Use of existing stock and placement of long lead orders early
- Adopted industry first completion design to exploit full production potential
- Combine vessel campaigns to allow subsea tie-in early as possible post drill rig-off location

3.3 E&A activity outlook

Data from the OGA's UKCS Stewardship Survey indicates that exploration and appraisal activity is forecasted to increase over the next three years and approximately 120 well prospects have been identified as drillable opportunities. The forecast also indicates the level of probability of the wells being drilled. The highest probability of wells to be drilled are found in 2018, with diminishing probabilities in 2019 and 2020. However, delivery of exploration and appraisal wells in 2018 has been poor, with activity frequently deferred into 2019/2020.

E&A drilling outlook and probability

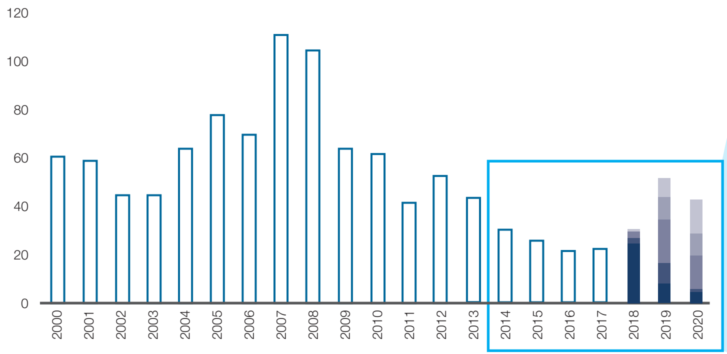


Figure 17

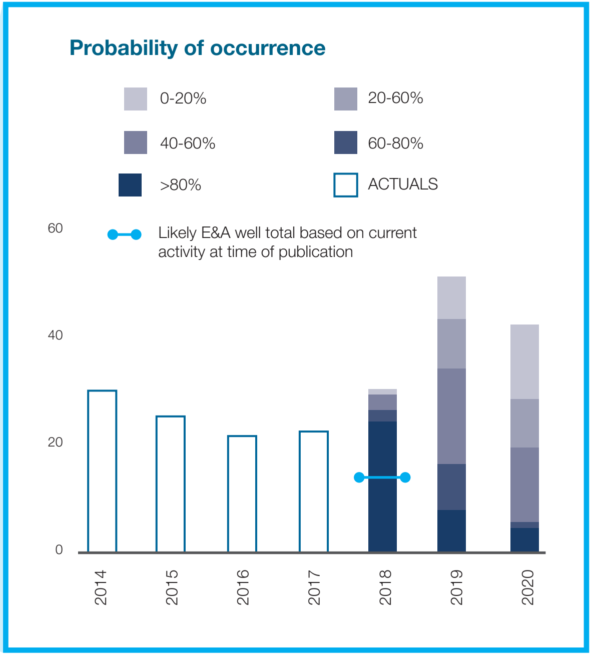


Figure 18

There is a forecast rebound in activity, but there remains a large uncertainty in plans with only 18% of future wells for the period 2018 to 2020 having secured financial approval. Planned activity is evenly split between exploration and appraisal wells for those with approval but overall number of appraisal wells being drilled is low.

E&A well intent

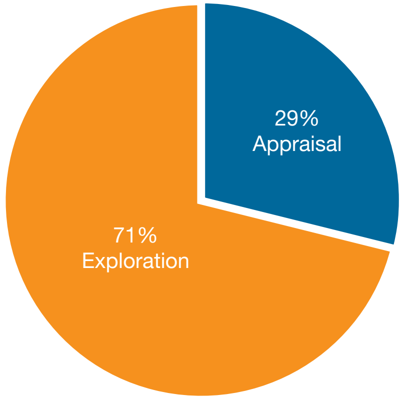


Figure 19

2018-20 E&A wells vs financial approval

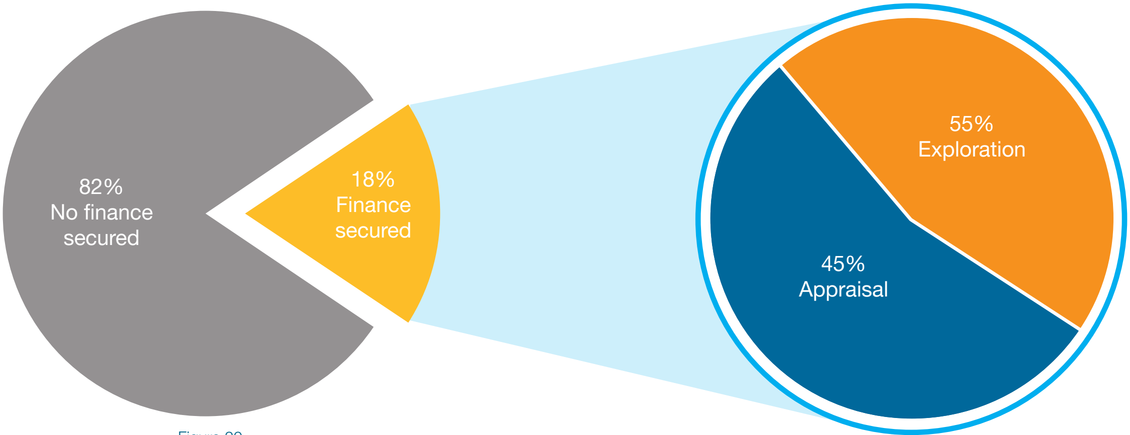


Figure 20

Figure 21

4. Development wells

4.1 Development drilling activity (historical)

There is a lag observed between the 2014 oil price drop and the reduction in spud count. This may be due to prior rig commitments and the lag in budget cycles or consented projects.

In the UKCS over 2016 and 2017, 106 development wells were drilled at a cost of £3.4 billion (24% of UK capex).

The effect of the recent oil price downturn on development drilling in the UKCS has been marked. The level of activity recorded in 2017 now sits at 50% of 2015 levels.

This represents a substantial decline in activity, both in infill and new well activity.

There has been a narrowing of the gap between spuds and associated completed wells. This is partly due to the advancement of technology. There is an opportunity to reduce this gap further by eliminating the causes of mechanical and certain geological sidetracks.

The greatest effect of the recent drop in drilling activity can be attributed to the decline of drilling in the CNS. The SNS and NNS areas have steadied more recently but it can be clearly seen that activity in all areas except for WoS has been on long term decline.

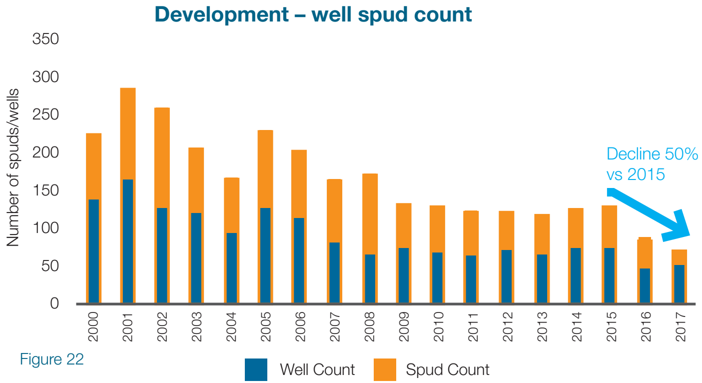


Figure 22

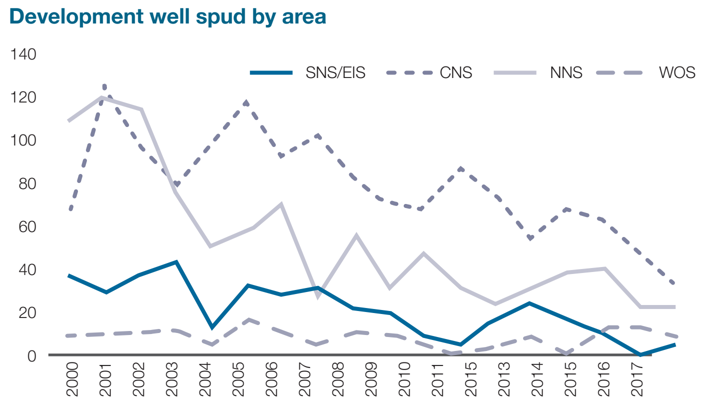
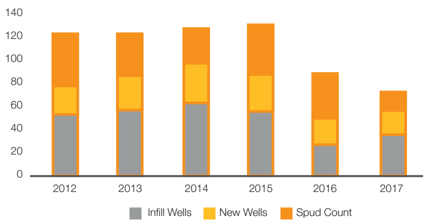


Figure 23

4.2 Development well delivery (2016/17)

There has been a significant drop in the numbers of new and infill wells being completed since 2015. Of particular concern is the drop in infill well drilling. The outlook is improving but it is vital that development drilling activity significantly improves to deliver MER requirements.

Development – infill v new wells



Development – well analysis by area and rig type

Rig analysis indicates that platform and semi-submersible drilling increased year on year while jackup activity decreased. The majority of platform wells are side-tracks from existing wells which are less costly to drill thus reduce the average cost in 2017.

Number of development wells by rig type

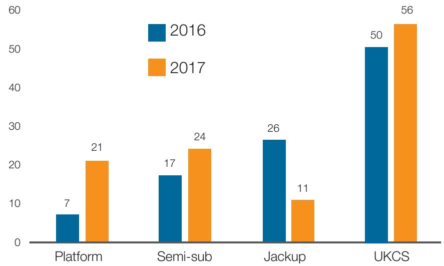


Figure 24

2016-2017 Number of development wells by rig type

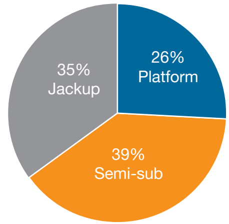


Figure 26

Number of development wells by area

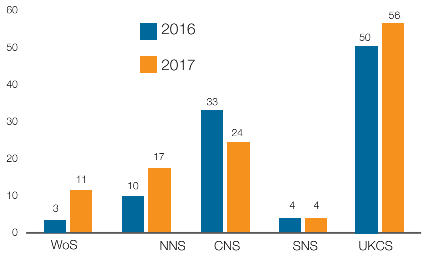


Figure 25

2016-2017 Number of development wells by area

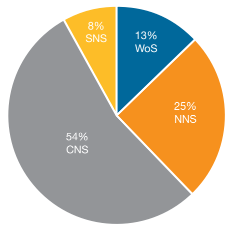


Figure 27

The analysis also indicates that the majority of wells delivered in 2016 and 2017 are in the CNS. There was significant increase in activity year on year in WoS and NNS, with SNS activity remaining static.

4.2 Development well delivery (2016/17) (Continued)

What projects are driving development well activity?

Historically, the majority of wells in the UKCS have been drilled as part of large campaigns (Brent, Forties, Brae etc). More recently there has been more focus on brownfield drilling and developing smaller accumulations, either as standalone assets or nearfield tie-backs to existing infrastructure. However, recent projects such as Catcher (including Varadero and Burgman), Kraken, Mariner and Scheihallion (as well as the ongoing Forties and Beryl infill drilling) have seen the return of more material drilling campaigns (see 'large project' wedge).

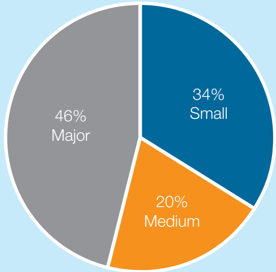


Figure 28

Development well count by project size
Cum. 2016-2017

Project Size Definition	
Small	1 – 4 wells
Medium	5 – 10 wells
Major	11 or more

Figure 29

Who is drilling wells?

Historically, the majority of wells in the UKCS have been drilled by major operators (as part of large campaigns such as those mentioned above). More recently, and due to the changing operator landscape, almost two thirds of the wells delivered in 2016-17 were by small and medium size operators.

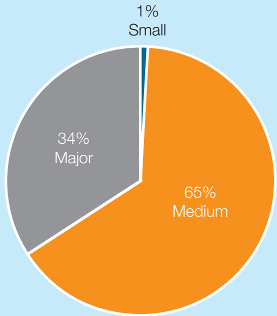


Figure 30

By operator size 2016-17

Operator Size Definition	
Small	Minor position within UKCS
Medium	Significant UKCS position
Major	Significant global footprint

Figure 31

Leveraging experience

Typically, the benefits of lessons learned, repeatability and economies of scale are fully appreciated on large drilling campaigns. However, approximately half of expected future drilling activity is within small to medium size projects. To decrease cost and increase the value of any well drilled (excluding rig/service rate reduction), the benefits from large campaigns must be realised on small and medium sized projects.

Therefore industry must use the lessons learned in order for all wells to benefit from the combined UKCS experience and achieve collective performance gains.

This performance improvement would de-risk future projects, improve value and ultimately result in additional well investment.

The OGA is continuing to support the communication of lessons learned, including exploiting technology and better partnering with the supply chain.

Participation in industry forums such as the Oil & Gas UK Wells Forum, OTM's European Drilling Engineering Association or Engineering Institutes is helping support the communication of lessons and knowledge throughout the industry.

A collaborative mindset has already been proven to allow small and medium sized operators to become agile, efficient and experts within their field.

4.2 Development well delivery (2016/17) (Continued)

UK Wells Stakeholder Landscape

Role	Drilling & Construction	Operations & Interventions	Plug & Abandon
Regulatory & Advisory	Health and Safety Executive (HSE) and Department for Business, Energy & Industrial Strategy (BEIS) (Offshore Safety Directive Regulator)		
	Oil and Gas Authority (OGA) (Regulate, Promote & Influence)		
	Oil & Gas UK guidelines, Institute of Petroleum (IP) guidelines, American Petroleum Institute (API)/International Organisation for Standardisation (ISO)/British Standards (BS) standards, Well Examiners		
Technologies	**Technology Leadership Board (TLB)**	**Asset Stewardship Task Force (ASTF)**	**Decommissioning Task Force (DTF)**
	Technology Organisations (OGTC, Academia)		
Design and Operations	**Oil & Gas UK Wells Forum**	**Oil & Gas UK Reservoir & Wells Optimisation Group**	**Oil & Gas UK Well Abandonment Group**
	East of England Energy Group (EEEGR)		
	Operators **Drilling Contractors, International Association of Drilling Contractors (IADC)** **Service Companies**		
	Professional Bodies Institute of Materials, Minerals and Mining (IOM3), Society of Petroleum Engineers (SPE), Intervention Coiled Tubing Association (ICOTA), Energy Institute (EI)		

Figure 32

4.3 Development well costs

Although development drilling activity has reached a historical low, there was an increase in the well count delivered year on year with a resulting reduction in cost of £534 million (28%). The reduction in cost is attributed to a reduction in high cost well activity and the termination of high rate, long term rig contracts during this period.

	Number of development wells completed	Development well spend
2016	50	£1,933MM
2017	56	£1,456MM
Total	106	£3,389MM

Figure 33

Cost methodology

In order to present a consistent cost insight in average well cost and non-productive time (NPT), the 2016/17 dataset has been truncated such that outliers in the data do not dominate the findings.

While some data points have been discounted from this analysis, the OGA is further analysing these wells separately in order to extract and share lessons learned and understand how future performance may be improved.

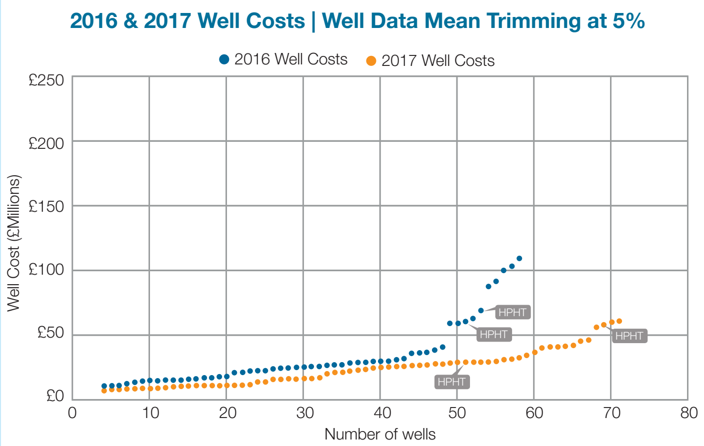


Figure 34

A "trimmed mean" approach has been used so that outliers, both at the top and bottom of the dataset, have been removed from the analysis. This graph shows which data points have been used for the average cost and NPT calculations.

Development well cost analysis (2016/17)

There was a drop of 33% (£33 million to £22 million) in the average UKCS well costs over the period. This is consistent with the findings in figure 34, demonstrating that overall well costs were reduced in 2017, however there remains a large range of cost outcomes with a range of cost around three times that of the average.
The reduction in cost range in 2017 indicates a positive trend.

Further analysis indicates that this cost improvement is driven by rig and service rate reductions and the number of relatively low cost sidetracked wells.

Average well costs split by area and by rig type are shown, with an indication of range to demonstrate the spread of individual well costs.

It is apparent from figure 35 (right) and figure 36 (adjacent below) above that there is a wide spread of well costs. Understanding this range and determining the reasons would potentially lead to better predictability and significant cost savings across UKCS.

The O&G UK Wells Forum are continuing to look at methods to reduce well cost, including improving the use of networks, sharing equipment on a formalised basis, reducing NPT and optimising scope.

2016-17 Average Development Cost by Area

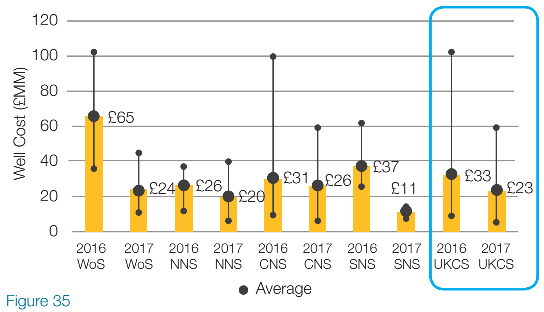


Figure 35

2016-17 Average Development Cost by Rig Type

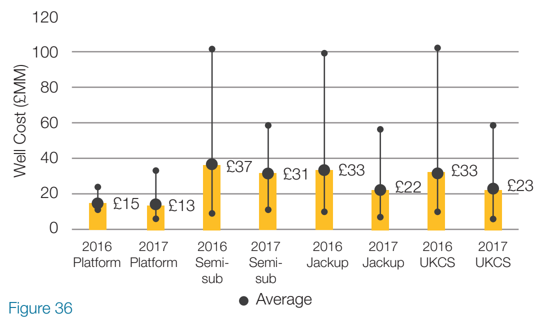


Figure 36

Development well cost analysis: rig type

The set of benchmarks below compare 2016 and 2017 well cost data. Platform, semi-sub and jackup costs have been split out so that appropriate comparisons can be made.

Platform

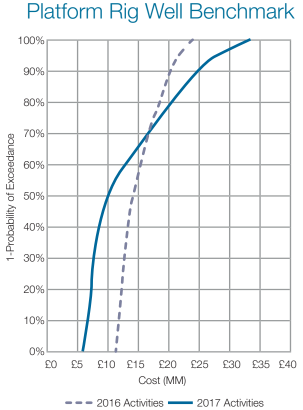


Figure 37

Limited dataset but platform 2017 performance shows improvement over 2016.

Semi-sub

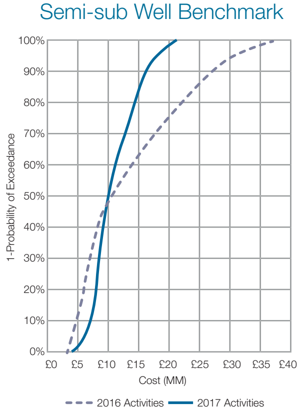


Figure 38

Semi-sub P50's are similar. 2017 performance shows a reduction in high cost wells contributing to the drop in average cost but performance gains at the lower end were not achieved.

Jackup

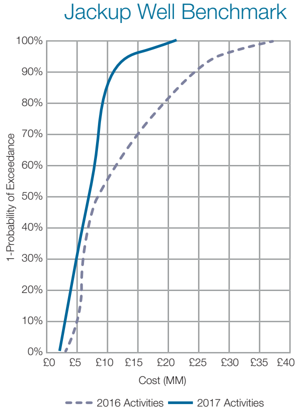


Figure 39

Jackup 2016 and 2017 curves display similar trends to that of semi-subs. There is a slight improvement in performance of lower cost wells since 2016.

MODU drilling costs have reduced in 2017 compared to 2016. This has been brought about by the narrowing of the range of well costs. However, actual performance has not increased significantly. Platform drilling has seen in an increase in the range of costs into 2017 yet performance has noticeably improved with more lower cost sidetracks being drilled.

4.3 Development well costs (Continued)

The largest cost components in well delivery are attributed to the rig rate and service and equipment rentals, typically costing between 50-75% of the total well cost. These components are both time-dependent and a function of prevailing service market demand.

2017 Semi-sub & jackup development well cost breakdown

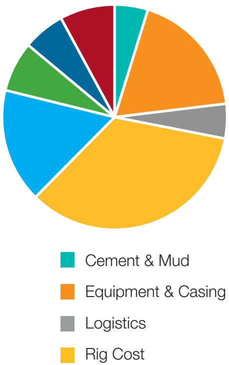


Figure 40

2017 Platform development well cost breakdown

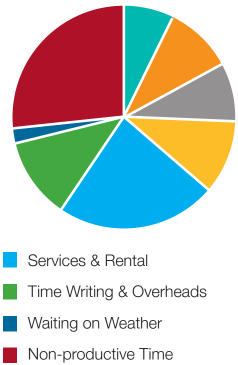


Figure 41

Central North Sea Wells Total Time

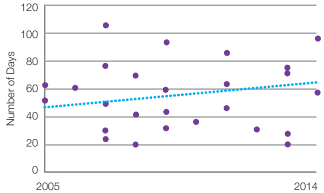


Figure 42

Central North Sea Non-productive Time

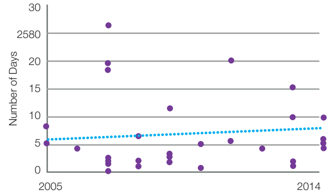


Figure 43

Source: Exeed

In the figures above the rig rate difference between platform wells and semi-sub/jackup wells are expected, however there is significantly higher proportional NPT in platform wells.

In order to understand NPT as a function of overall well efficiency, a sample of 100 comparable CNS wells stretching over 10 years (2005-14) was analysed. In that time period there was no obvious trend in total time to drill wells, nor in NPT.

Therefore, it can be deduced that the recent cost declines highlighted earlier, not attributable to a reduced number of high cost wells, were mainly due to changes in market rates, rather than time efficiencies.

It is evident that average NPT has reduced from 2016 to 2017 in both platform drilling and mobile offshore drilling units (MODU), reflecting the overall reduction in well cost. Platform drilling NPT is twice that of MODUs and there appears to be an overall performance improvement 2016 to 2017.

Platform wells on average have slightly reduced NPT. However, there are significant outliers in the platform data where up to 70% of the wells cost was attributed to NPT. This could be credited to a number of reasons such as aging equipment or competing priorities on platforms.

The average NPT of MODU wells has also slightly reduced in line with that of platform NPT. However, the range of well cost NPT has significantly reduced.

Some operators are achieving repeatable, low NPT figures while others have varying results from low to very high. What is clear that very low NPT figures are achievable and that should be the goal for all operators.

The 2016 and 2017 NPT represents between 15 to 17% of the total well cost or some £400 million over the two past years.

This presents a significant opportunity to improve well efficiency and overall project value.

A large proportion of very large NPT cases are caused by borehole stability and other associated issues. By understanding this cause, industry can potentially eliminate what is a large contributor to NPT. Industry also needs to better understand and mitigate NPT on platform-based operations where NPT is more severe.

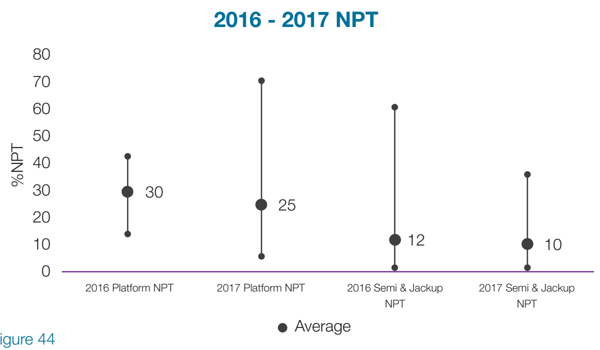


Figure 44

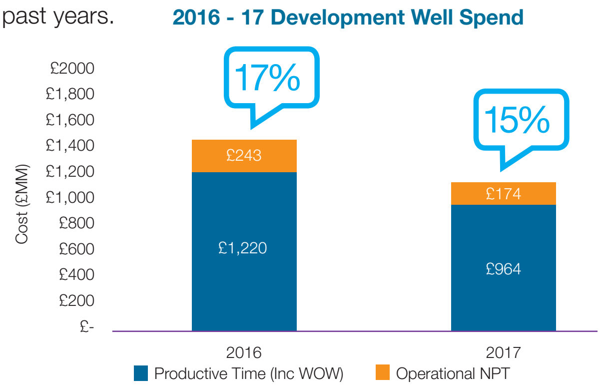


Figure 45

4.3 Development well costs (Continued)

Well cost improvements

The well cost data for 2016/17 suggests that there are significant opportunities to improve well cost through improved performance. While NPT is a significant factor, it remains that the overall well cost reductions in 2017 have been primarily driven by rig and service rate reductions and not performance improvements.

The challenge is to build on existing improvements and good practices to achieve a sustainable well cost predictability and overall cost reduction. The OGA is actively engaging with industry on how this can be achieved.

Contracting

Leverage knowledge and experience of the Supply Chain

Multi-operator drilling campaigns, sharing risk and cost

Design & Execution

Optimised well designs for cost and value, e.g.

- High angle infill
- Multi-laterals

Focus on NPT reduction

Minimum technical scope

Supporting Technologies

Adopt the most appropriate technologies, for e.g:

- Directional drilling
- Stimulation
- Rig operations

Develop and pilot new technologies – also collaboratively

The following are three case studies displaying what industry bodies and operators are already doing to manage and optimise well costs.

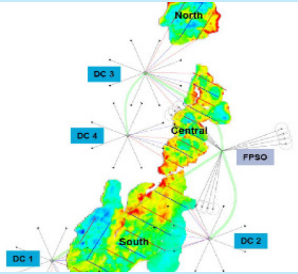
CASE STUDY: Oil & Gas UK competitive well delivery focus areas

Focus Area	Aim	Example of Initiative
Lean Well Design Principles	Delivering competitive,affordable and credible well designs	Right Scoping Guideline
Optimising Procurement	Improve procurement processes to encourage sustainable rates and contract Terms & Conditions (in line with the Efficiency Task Force)	Supply Chain Code of Practice, Efficiency Taskforce Tender Efficiency Framework
Operational Efficiency	Improve the time, cost and quality through the wells operational process	Non-Productive Time Analysis
New Technology	Unlocking technology and techniques to advance projects that may otherwise have been left on the shelf	Extended Reach Drilling Workshop
Sharing Knowledge & Inventory	Facilitate collaborative opportunities for existing equipment to unlock cost efficiencies	Subsea tooling and equipment sharing database

Figure 46

4.3 Development well costs (Continued)

CASE STUDY: EnQuest's Kraken field



- 25 well subsea development tied back to high-capacity FPSO
- Developed from four drill centres
- Technology helped to exceed drilling plan expectations on both productivity and costs, including:
- Reservoir imaging well placement (up to 100ft 'vision')
- Reduce well placement uncertainty
- High confidence for sidetracks
- Riserless mud recovery
- Reduction in well lengths & trajectory complexity: Allowed shallow build in weak, unconsolidated sands
- Offshore thermal cuttings processing
- Smaller environmental footprint and reduced exposure to weather
- 'Designer mud' for injector reservoirs
- Breaker converts oil phase to water phase and dissolves calcium carbonate
- Removes onerous requirement to flow back wells
- PPRT
- Monitor open hole conditions etc when non-drilling operations
- Increase ROP based on constant monitoring

CASE STUDY: Ithaca's Harrier field

- Medium-size condensate field, to start producing in 2018
- Subsea tieback (7.5km) to Stella
- Use of innovative concepts and supply chain experience drove 50% capex efficiencies
- Dual-lateral well with multi-stage, acid stimulation (a UKCS first)
- To support economic value, the company has drilled the dual lateral well into the two reservoirs formations
- To maximise recovery an acid stimulation using optimised acid diversion technology will be applied in each of the laterals
- Harrier is the world's first fracture stimulated multi-lateral offshore well

4.4 Development drilling outlook

Based on data from the 2017 UKCS Stewardship Survey, the expected well count for 2018 to 2020 is some 261 wells. This represents a significant increase compared to recent historic activity. However there remains some uncertainty in committed plans.

The 2018-20 forecast has secured approval for 31% of the activity, predominantly in 2018. The 2019 and 2020 forecasts are somewhat less certain.

Development well spud outlook

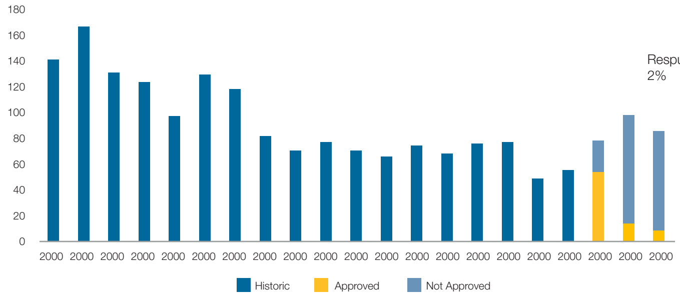
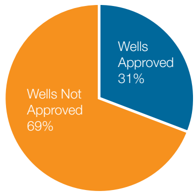


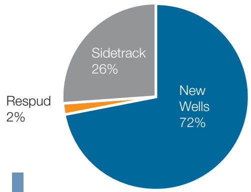
Figure 47

The size of the UKCS project pipeline, as illustrated by the number of Field Development Plans (FDP) and addenda currently under discussion, would support the above outlook. This information can help industry plan for the future and alleviate the possibility of an overheated market.

New well approved



New well types



New well types

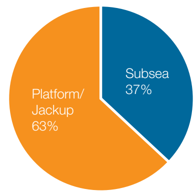


Figure 48

#Operators planning to drill in 2018-20

(Total 30/75 operators, 40%)

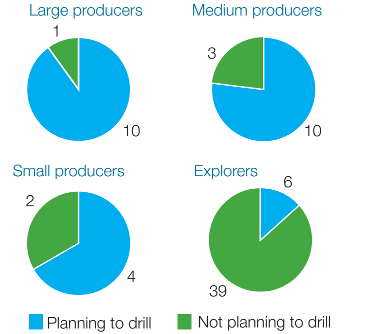


Figure 49

Number of FDP and FDPA approvals

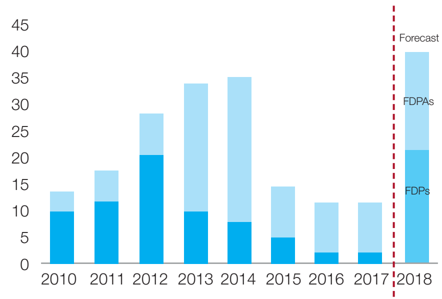


Figure 50

4.5 Well management

In total, around 7,500 development wellbores have been drilled on the UKCS from just over 4,000 surface locations. Of these, approximately 2,700 wells represent the UKCS active well stock with over 2,000 wells currently reported on-line and around 600 wells shut in. The remaining development wells have one of the following status: plugged, AB1, AB2 or AB3 and are no longer considered to be an active well.

In 2017, around 600 million boe was produced through the 2,128 operating wells, however, 33 million boe of production losses were attributed to wells (16% of the total UKCS production losses for 2017).

This existing well stock represents a significant capital asset for the UKCS which the industry must manage. The OGA expects this to be carried out through effective surveillance, intervention and workover operations to maximise value to UKCS.

In 2017:

- 21 million boe of production was safeguarded through intervention operations (mainly pumping)
- An additional 22.5 million boe of production was added (by improving underperforming wells and/or reactivating shut in wells)
- 33 million boe were not achieved, as a result of well losses

Approximately 41% of the well stock is in the CNS with 26% and 24% in the SNS and 24% in the NNS, with the remaining 9% split between WoS and EIS areas.

The asset type of the UKCS well stock is 68% platform based, whether manned or un-manned, and the remaining 32% are subsea wells.

The well stock can also be split into fluid type showing 50% of UKCS development wells are liquids (oil or condensate) producers, and 35% are gas producers, with the remaining 15% being injectors

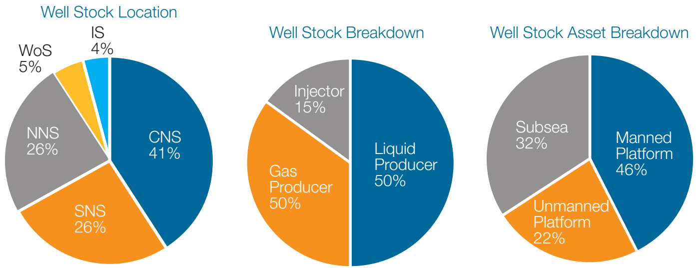


Figure 51

Production losses

Production losses attributable to the well stock in 2017 was 33 million boe, down from the 37 million boe reported in 2016. However, the 2017 figure is still 27% higher than the 2015 figure of 26 million boe so there is no discernible downward trend. Although industry has significantly improved overall production efficiency, there is still a challenge in reducing losses attributed to wells.

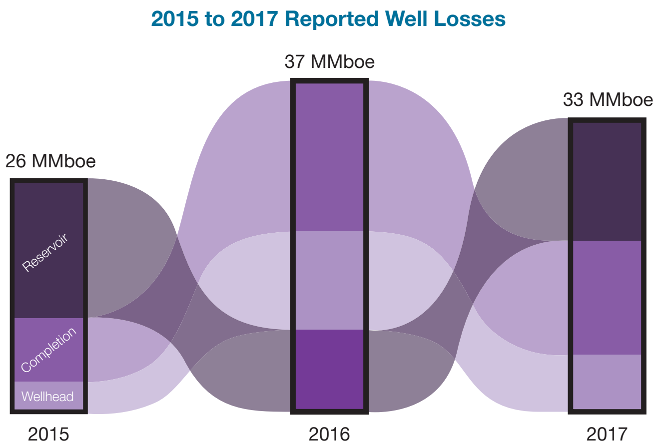


Figure 51

The main issues reported in the 2017 survey effecting well production losses were:

- Integrity
- Scaling
- water production
- Artificial lift
- Sand production

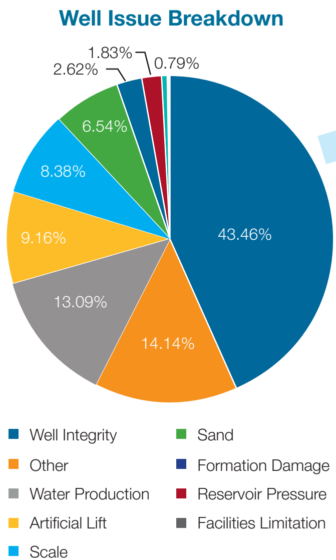


Figure 52

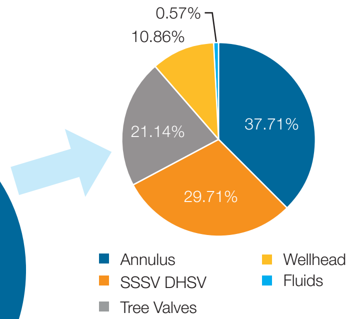


Figure 53

This data indicates where the industry and the OGA must focus attention in order to reduce well issues, in turn reducing overall well losses and increasing UKCS production efficiency. The next steps will be detailed in the Wells Strategy.

Shut-in wells

There are currently around 600 of the active wells stock shut-in. While it is unknown how much production potential relate to these wells, it remains evident that there is a large stock of active wells shut-in in fields that have large remaining resources to be produced.

There may be opportunity to realise additional upside through rejuvenation of these wells and improve the recovery factor on the field where the shut in wells reside.

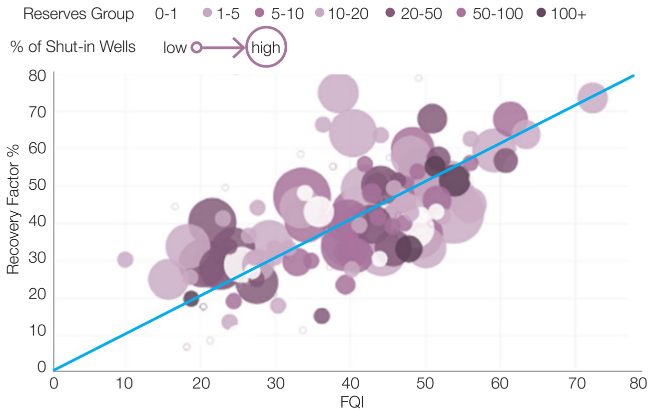


Fig 54

Figure 54 shows the percentage of shut-in wells on fields on a plot showing the Field Quality Index (used by the OGA for benchmarking) and recovery factor. The large bubbles and dark colour indicate remaining resources in fields with a high number of shut-in wells. The OGA use data such as these to help inform stewardship conversations.

Analysis of the shut-in wells stock indicate a high incidence of:

- Subsea wells that are shut-in (representing 40% of 32% of the total well stock)
- Injector wells that are shut-in (representing 20% of 15% of the total well stock)

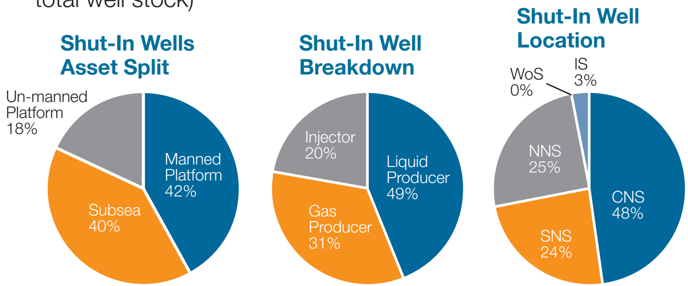


Fig 55

Of the reported shut-in wells the two dominant issues, which account for 62% of the issues associated with shut-in wells, are well integrity and water production.

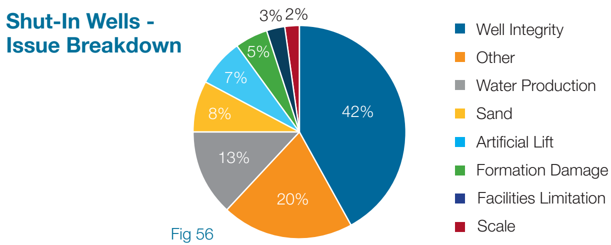


Fig 56

4.6 Well intervention

In 2017, UKCS operators spent £685 million on well intervention. The intervention activities are reported in five categories, listed below:

- **Well surveillance – Activities to measure the condition of a well**
- **Safeguarding – Activities to maintain production**
- **Optimisation – Activities that generate additional production**
- **Restoration – Activities to return a well to production**
- **Well plug and Abandon – Activities associated with the final P&A of a well**

Safeguarding was the most common type of intervention activity, followed by plug and abandon activities.

Surveillance rates are very low (around 8%) and this is a concern as to whether this is sufficient to understand and optimise production.

Activity breakdown

The vast majority of the reported intervention and surveillance activities occurred on manned platforms. Subsea and unmanned platforms saw far fewer intervention and surveillance activities as a proportion of their share of UKCS well stock. The well intervention cost in subsea remains a potential issue with 14% of all subsea wells having an intervention accounting for 54% of the cost.

Intervention by Objective

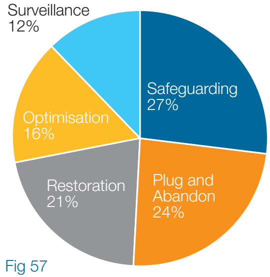


Fig 57

The vast majority of the reported intervention and surveillance activities occurred in the CNS on manned platforms, which also accounted for 69% of the total well intervention spend.

Intervention by Asset Type

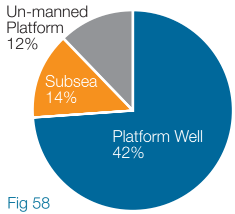
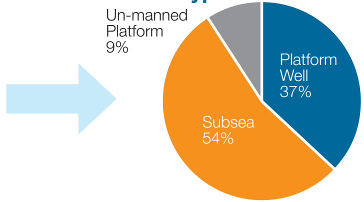


Fig 58

Well Intervention Cost by Asset Type



Intervention by Area

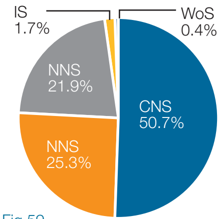
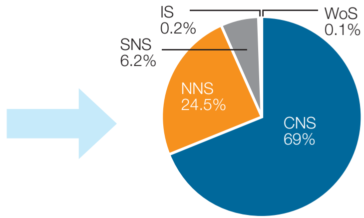


Fig 59

Well Intervention Cost by Area



Well Intervention rate

The average intervention rate on the UKCS well stock in 2017 was 14%. However, there were also large differences in the approach. Figure 60 indicates the well interventions carried out as a function of the active well stock held by each operator.

There is a wide range of activity levels, with some companies working on over 30% of their wells, and other operators not carrying out any surveillance or intervention activity.

Intervention vs Activity on Well Stock

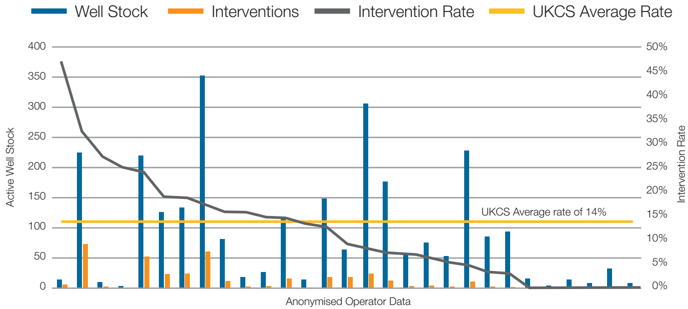


Fig 60

Well Issues addressed

Related to well intervention rate is the effectiveness of industry to respond to well issues that have been raised. It can be seen from figure 61 that the number of wells issues that resulted in work being carried out on the well/issue varies considerably.

On average operators only carried out intervention or surveillance on 53% of wells where issues occurred in 2017. This gives room for a significant improvement which could reduce well losses and is an area of attention for the OGA.

Issues vs Activity on Well Stock

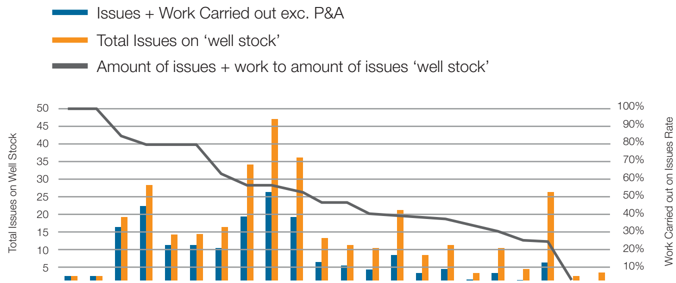


Fig 61

Results of well interventions

Intervention efforts that were undertaken in 2017 were very positive, with approximately 43.5 million boe safeguarded, restored or added to the UKCS production figures.

Of the total of £685 million that was spent on intervention and surveillance activities, £400 million was spent on P&A associated intervention activities meaning the 43.5 million boe maintained and added to the UKCS production figures was achieved for £285 million. This equates to an average unit cost of £6.48/boe in 2017.

The 43.5 million barrels attributed to intervention activities was made up of:

- 6.5 million boe from optimisation
- 16 million boe from restoring or improving underperforming wells
- 21 million boe from safeguarding

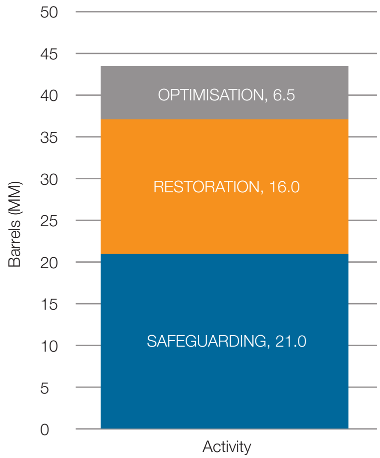


Fig 62

It should be noted that the barrels reported for an intervention were for a total of one years production. This may have a significant impact on the cost per barrel figures of certain intervention activities where the activity itself will have a positive effect on the well for years to come. An example of this will be the re-completion of a well that could extend the well life for many years.

Safeguarding

Activities regarding the safeguarding of wells were split into four operational categories:

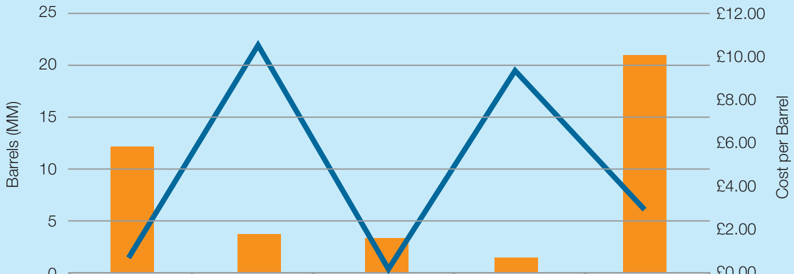
Scale Squeezes

Regular washes

Solvent treatments

Tubing clean outs

Safeguarding Breakdown



	Scale squeezes	Other	Reg water washes and other reg solvent treatments	Clean outs	Grand Total
Barrels	12.19	3.74	3.5	1.48	20.91
Cost per Barrel	£0.78	£10.45	£0.08	£9.26	£2.99

Restoration Type

Fig 63

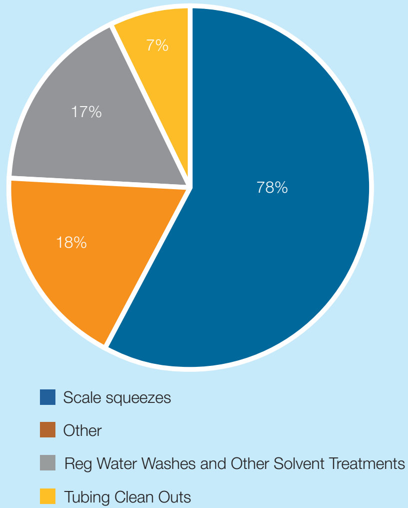


Fig 64

Restoration

Restoration activities accounted for approximately 16 million boe of production restored in 2017. The majority of the reported barrels were attributed to Tree/Wellhead repairs SCSSSV/DHSV repairs.

The average cost per barrel for restoration activities was £8.29/boe

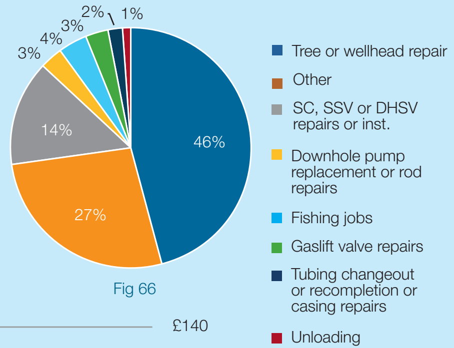
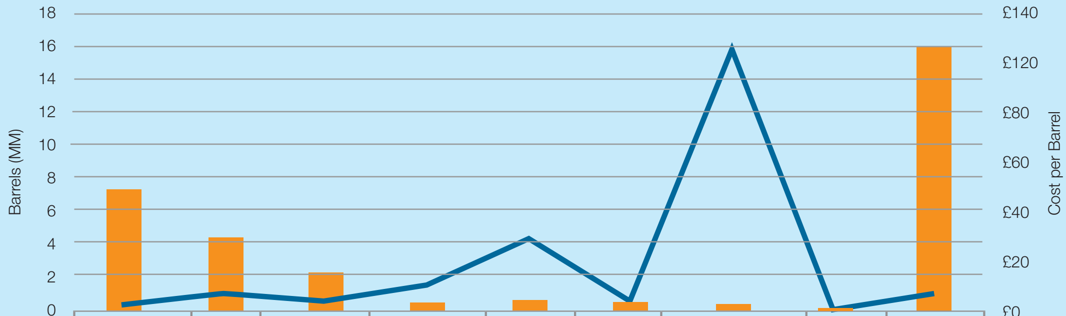


Fig 66

Restoration Breakdown



	Tree or wellhead repairs	Other	SC, SSV or DHSV repairs or inst.	Downhole pump replacement or rod repairs	Fishing jobs	Gaslift valve repairs	Tubing changeout or recompletion or casing repairs	Unloading	Grand Total
Barrels	7.31	4.34	2.31	0.51	0.61	0.48	0.37	0.14	16.07
Cost per Barrel	£2.27	£4.08	£4.03	£12.10	£34.36	£3.45	£124.25	£0.03	£8.29

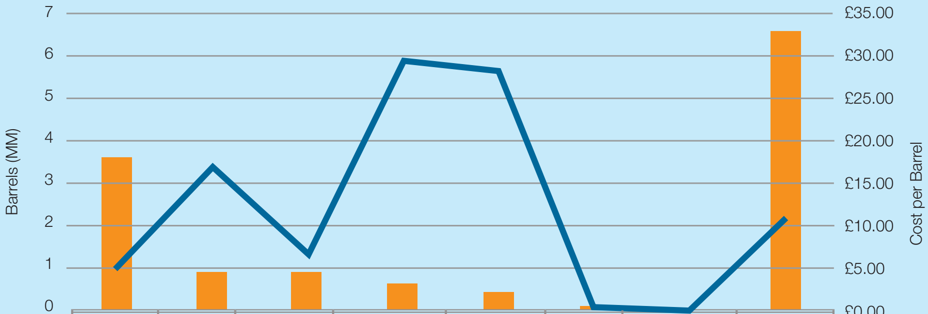
Restoration Type

Fig 65

Optimisation

Around 6.5 million boe of production was added in 2017 by optimisation activities. The majority of the reported barrels were attributed to re-perforating and adding perforations. The average cost per barrel for optimisation activities was £10.69/boe.

Optimisation Breakdown



	Re add perforations	Other	Acid stimulations	Water and Gas Shut Offs	Gaslift optimisation or retrofit	Foam lift installation	Downhole pump optimisation or retrofitting	Grand Total
Barrels	3.587925	0.93	0.9	0.65	0.43	0.1	0	6.597925
Cost per Barrel	£4.87	£16.88	£6.65	£29.39	£28.06	£0.24	£0.00	£10.69

Restoration Type

Fig 67

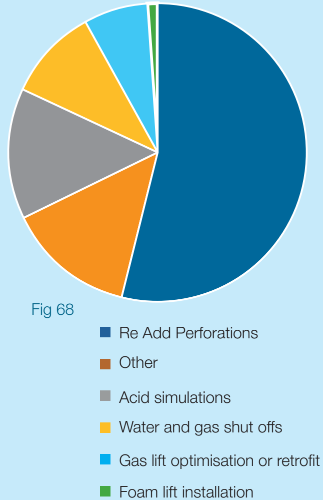


Fig 68

Opportunity from well management

The economic opportunity from effective management of the UKCS well stock is significant. In 2017 the industry effectively added 22.5 million boe to 2017 production figures and safeguarded 21 million boe. However, as discussed previously well losses still accounted for 33 million boe (16%) of the total 2017 production losses.

The data gleaned from the UKCS Stewardship Survey highlights the economic opportunity to continue and increase investment in the maintenance, restoration and improvement of the UKCS well stock. With the cost per barrel of well activities (note only one year of production is reported) clearly showing operators should examine existing well stock for cost efficiencies. Effective well management should be viewed alongside incremental brownfield gains.

Another potential economic opportunity is the 600 wells that are reported to be shut in. The OGA is working with industry through the stewardship process to evaluate and determine the economic value of these wells.

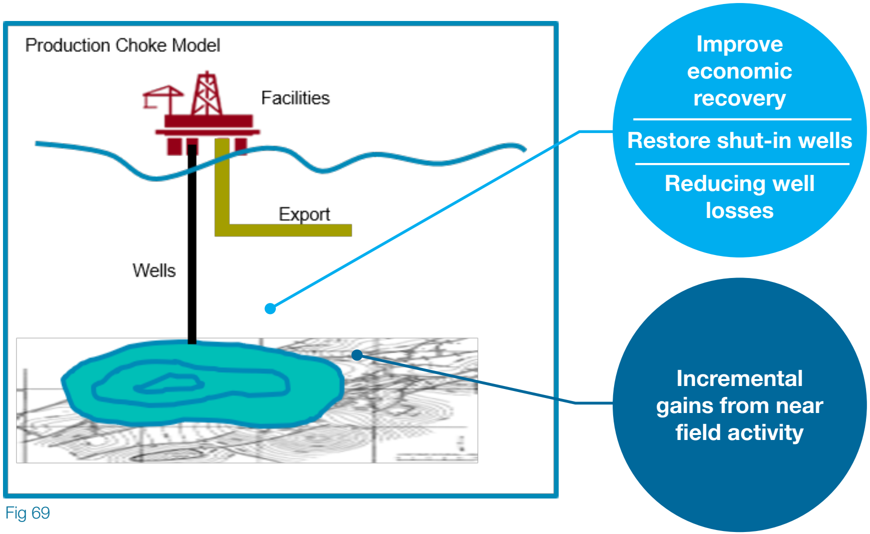


Fig 69

5. Plugging and abandonment

5.1 ‘Open water’ well plug and abandonment

Open water E&A wells are not connected with production infrastructure or surveillance systems and their integrity cannot be easily monitored.

E&A wells are normally abandoned immediately after the rig operations are complete. However, this has not always been the case and there is a legacy of open water wells that have been suspended on the UKCS.

There are around 240 open water suspended E&A wells on the UKCS distributed across the basins (see Figure 70).

The average age of these wells is 27 years, raising the issue of mechanical integrity and all require to be permanently abandoned.

12 operators hold 70% of the wells, with a further 28 operators holding the remaining.

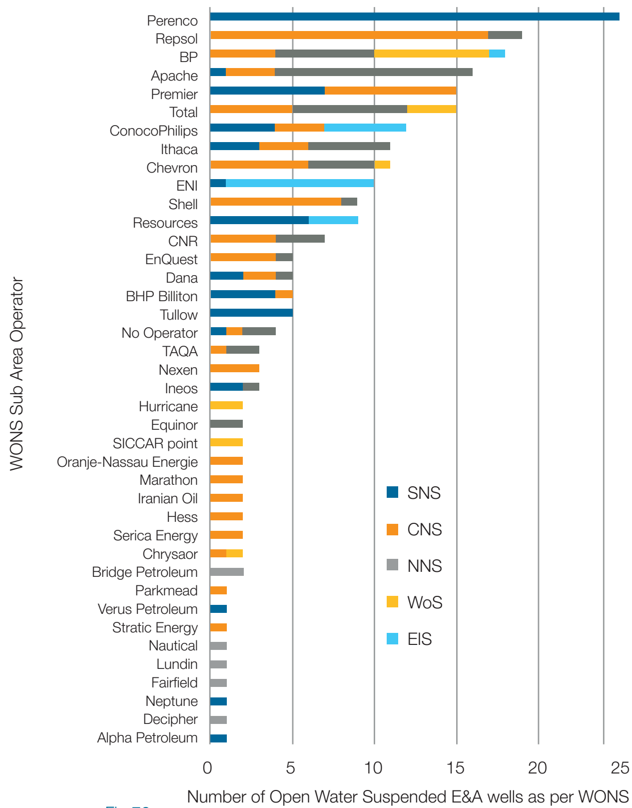


Fig 70

Suspended E&A wells by area

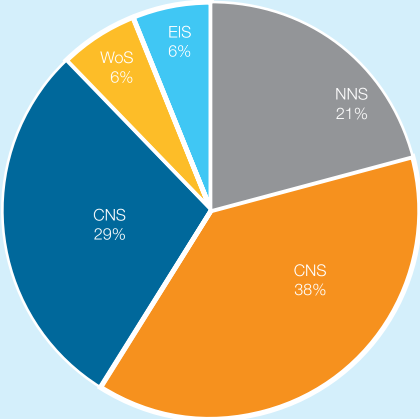


Fig 71

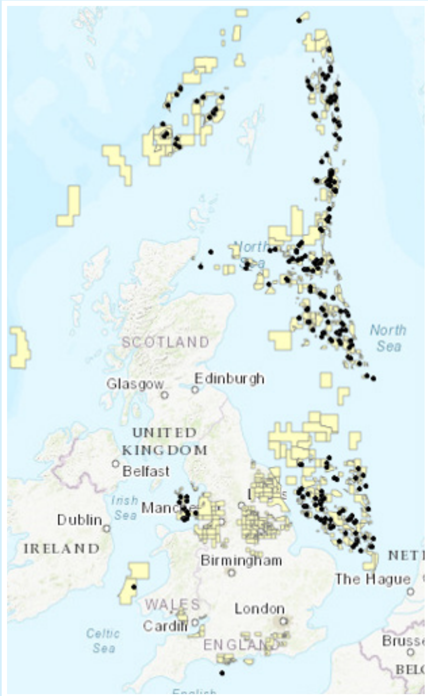


Fig 72

Sub area operator doesn't necessarily mean P&A liability owner

The scope of work to permanently abandon these wells will vary based on the well condition and the number and type of barriers in place. There are various categories of intervention (see table opposite) covering most of the circumstances. Categories 1, 2.1, and 2.2 correspond to interventions which can be carried out with intervention vessels, whilst Category. 3 activities will require a rig.

OGA analysis shows that just over 50% of the P&A scope of open water suspended P&A wells may be undertaken without rigs, and that similar intervention categories can be clustered together by location.

The concentration of the wells in terms of company ownership and spatial distribution suggests that significant efficiencies may exist, and the OGA has been engaging operators on discussions to promote an efficient liquidation of the scope of work through industry collaboration, including:

- Information sharing on scope and abandonment plans
- Sharing of experience and lessons learned on P&A execution
- Campaigns to achieve economies of scale, through higher rig and crew utilisations, fast learning curves and continuity of crews
- Visibility over future rig and service demand profiles, for effective planning by the supply chain
- Opportunity for novel and efficient contracting

	Definition
1	The well has been sufficiently suspended that final abandonment only requires removal of the wellhead
2.1	The well has one annulus uncemented. An additional permanent barrier is required to abandon the well. This type of well may be abandoned with a drilling rig or a well intervention vessel.
2.2	The well has two annuli uncemented. An additional permanent barrier is required to abandon the well. This type of well may be abandoned with a drilling rig or a well intervention vessel.
3	The suspended condition of the well is not suitable for a full abandonment without significant intervention. The abandonment will require a rig.
4	The well has not been categorised into one of the above.

Fig 73

Suspended E&A wells by category

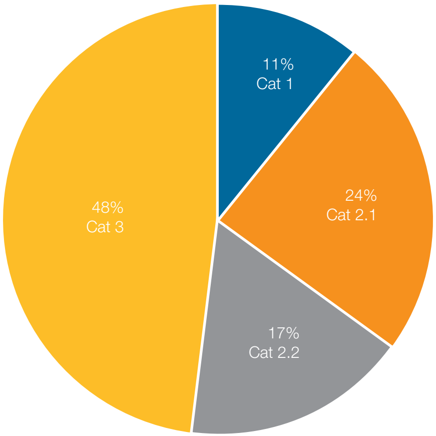


Fig 74

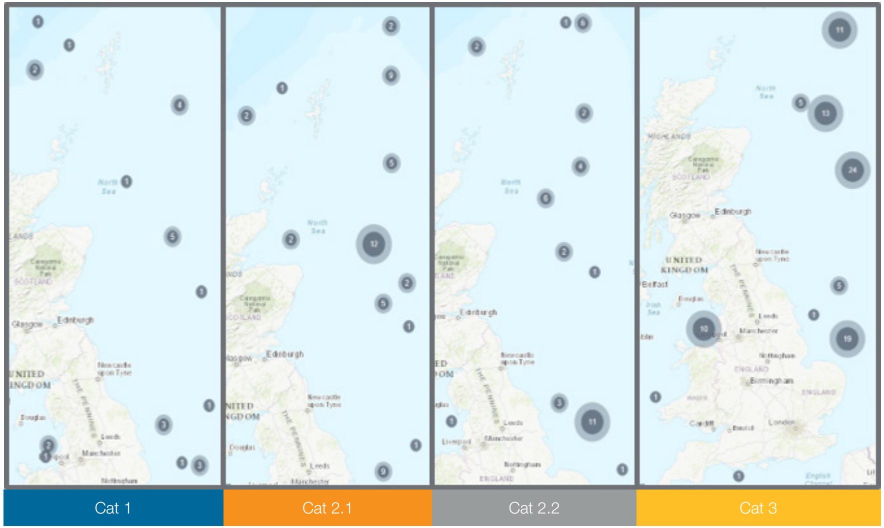


Fig 75

5.2 Development well plug and abandonment

The total UKCS 2017 decommissioning cost (P50) amounts to £58 billion. The wells total decommissioning costs is £26.3 billion, representing 45% of the overall cost

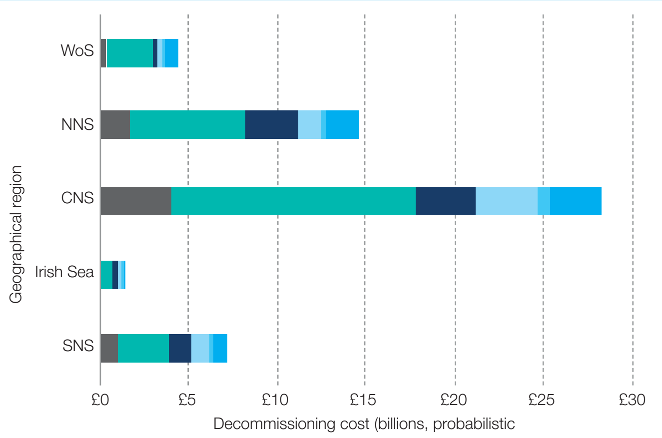


Fig 76

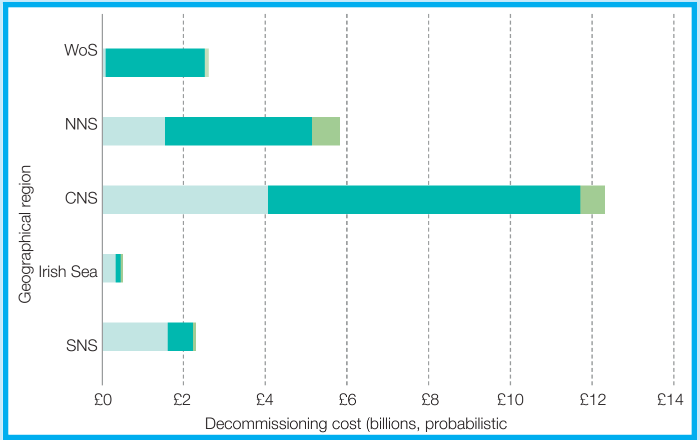


Fig 77

- Owners costs (Project management facilities running costs)
- Topsides removals - (making safe, topsided prep, topsides removal
- Subsea infrastructure - (Subsea removals site remediation, monitoring
- Well abandonment
- Substructure removals
- Onshore recycling & disposal

Source: 2018 Decommissioning Cost Report

There is large uncertainty on the future P&A activity profile, since operators have frequently postponed P&A activity in the past. However, in 2017 the number of plugged and abandoned wells has seen a dramatic increase to 163 actual abandonments (140 predicted in the 2017 survey), with more wells being plugged and abandoned than drilled on UKCS.

Well stock associated with current cessation of production (CoP) projections

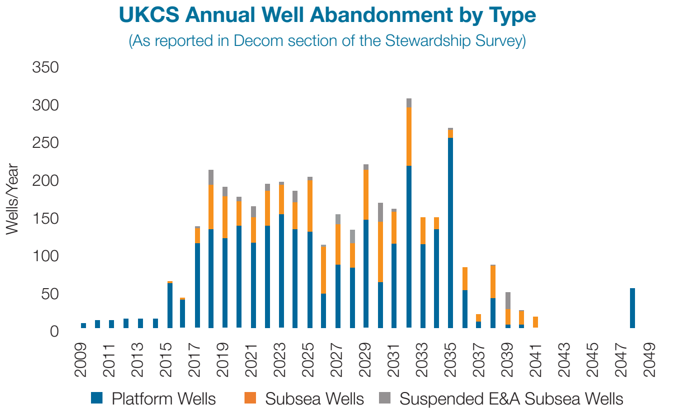


Fig 78

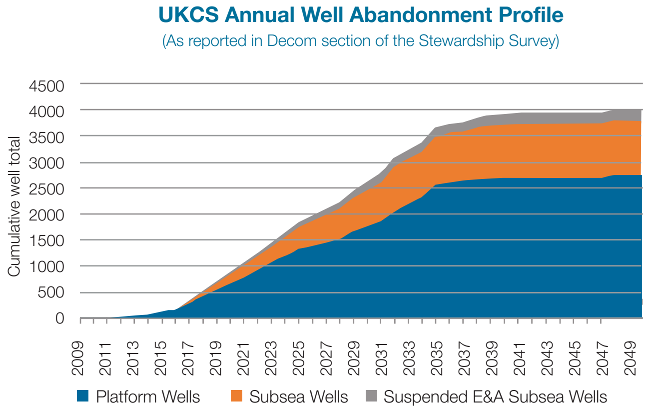


Fig 79

5.2 Development well plug and abandonment (Continued)

Costs and industry practices

Decommissioning operators in the NNS have improved platform well P&A costs very significantly, through a combination of new technology, leveraging batch P&A methods, de-risking through wellbore surveys when setting mechanical reservoir plugs, improved casing milling performance and using risk-based methods when defining scope. There are wide variations in operator performance, with certain operators having large fractions of their outcomes in the third and fourth quartiles, and other Operators predominantly in the first and second quartiles.

While platform well P&A costs have also improved in the SNS, these are much more incremental in nature. The obvious difference is that all platform well abandonments in the SNS are carried out via jackup rigs rather than platform rigs.

In 2016, £402 million was spend on 76 abandonments. In 2017, £446 million was spent on 163 abandonments. It can be seen that there has been a dramatic decrease in average P&A cost as displayed by the platform benchmark curve.

Change in platform P&A cost distribution: NNS & CNS

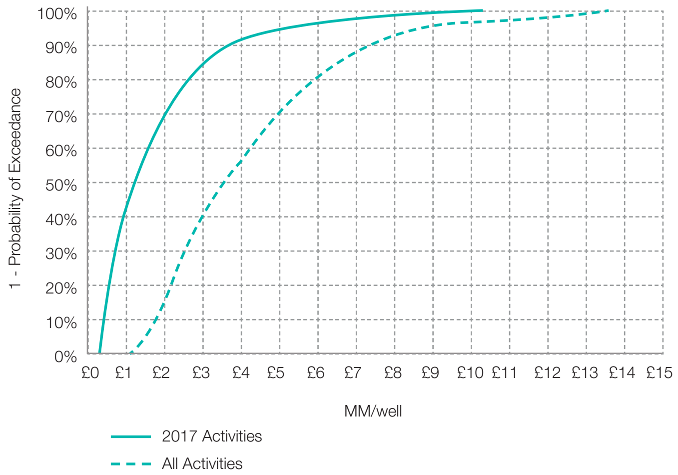


Fig 80

Through good practices, operators can reduce the cost of P&A and improve the value proposition for the supply chain through:

- New technology
- Campaign approach
- Coordination of logistics with other operators / other industries
- Innovative contracting
- P&A timed appropriately with respect to CoP of the asset (may be earlier)
- Work scopes completed offline or SIMOPS where possible

Little subsea development well P&A work has been completed compared to the numbers of platform wells now abandoned. There is a huge opportunity to apply learnings from this work, although sometimes not directly comparable, to inform the decisions made in future subsea P&A work. With well P&A costs accounting for 45% of the total decommissioning cost, this application of experience could significantly contribute to the 35% reduction in cost target.

Change in platform P&A cost distribution: SNS

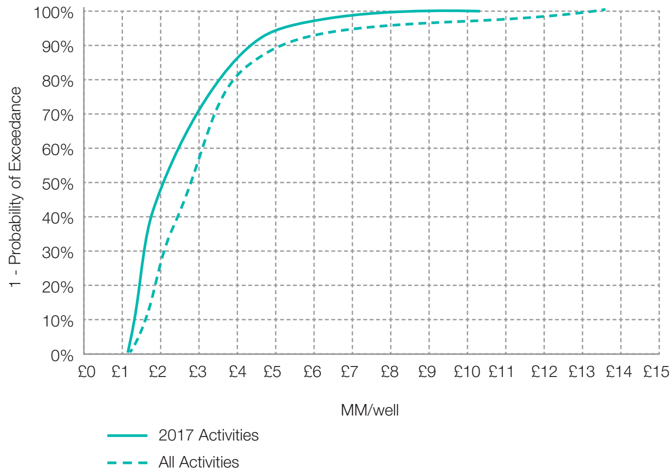


Fig 81

The following case studies illustrate the lessons being learnt on platform based activities

Conductor Cutting Success Story

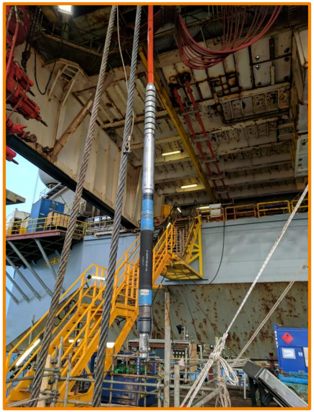
ConocoPhillips FORO ENERGY | Oil & Gas Authority

Technology delivers improved conductor cutting performance

- ConocoPhillips is engaged in a long-term plugging and abandonment (P&A) campaign in the UK Southern North Sea and has completed 61 wells to date using drilling rig and rig-less solutions.
- With approximately 80 wells still to P&A, as part of the continuing focus on cost reduction, ConocoPhillips engaged with FORO Energy to trial their innovative laser technology for conductor cutting.
- In evaluating P&A performance since the campaign began, duration improvements were being made in most phases from rig interfacing to retrieving completion tubing and setting final abandonment barriers. However there was no improvement to conductor cutting and retrieval operations, which ranged from between 2 and 9 days per well with an average of 3.5 days per well.
- Realising the extent of this inefficiency, ConocoPhillips has worked closely with FORO Energy to trial their innovative laser cutting tools and have successfully deployed these at three locations to date.
- Successful cut and retrieval on several multi-string conductors and improvements to the hardware and processes continue to be made to optimise performance.

Achievement based on:

- Extensive onshore trials and acceptance trials.
- The collaboration with the technology supplier to develop system suitable for deployment in the North Sea environment.
- Best performance to date is 2.2 days (vs 3.5 days average per well).



OGA Decom Team comments

Potentially valuable contributors to successfully reducing well P&A cost will be the support for development and, more importantly, the implementation of new technology, in cooperation with specialist service providers.

Key facts

- Southern North Sea conventional average conductor cutting and recovery duration was 3.5 days (range 2-9 days).
- With FORO, successful cut and recovery of multi-strings across three locations – 2.2 days is best performance to date.
- FORO Energy, the rig crew and ConocoPhillips continue to work on modifications to improve the robustness and durability of this technology for offshore use.

Collaborative Well P&A Success Story

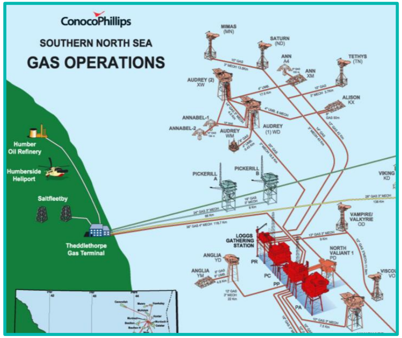
ConocoPhillips SPIRIT ENERGY bp Oil & Gas Authority

Collaborative well P&A drives down decommissioning costs

- The KX well (operated by ConocoPhillips) is located within a subsea manifold operated by Spirit Energy. The manifold also houses their Alison B3 well, which was planned to be plugged and abandoned (P&A).
- Opportunities were recognised and agreement was reached for Spirit Energy to also plug and abandon the KX well.
- Both wells contained synergies having originally been drilled back in 1995 by the same jack-up drilling rig so the completions, casing design, wellheads and trees were similar. Spirit Energy was also the owner of bespoke tooling interface equipment required for these wells.
- Spirit Energy is recognised for best practice within the industry for having a strong track record on Southern North Sea subsea well plugging and abandonments. They have previously performed four abandonments that required the same bespoke subsea tooling, a significant feature of the proposed work-scope, allowing learnings to be leveraged across wells.
- Using one jack-up rig to plug and abandon wells on the manifold meant that significant savings were realised on the rig move, interface and Dive Support Vessel (DSV) costs.
- Efficiencies were also realised through batch operations across the wells.

Achievement based on:

- Collaboration between operators and owners to minimise costs through knowledge sharing across the activities.
- Collaborative commercial behaviours to establish the framework to enable shared operations.
- Efficient execution.



OGA Decom Team comments

Both collaboration between operators and campaign execution at a large scale are identified as major opportunities in the industry to achieve significant decommissioning cost reductions and this is an excellent example that is indeed possible.

Key facts

- Batched operations between the two wells generated increased efficiency enabling full P&A to be completed 40% ahead of AFE duration estimates.

CNRI Ninian North Decom

CNR International | Oil & Gas Authority

CNRI milestone achievement announcement

- Completed 24 well P&A campaign on 28 February 2018, 3 months ahead of schedule
  Achievement based on:
- One-team approach, closely working together with the supply chain and selection of the right vendors and tools
- Optimal barrier selection through in-depth subsurface analysis
- Innovative approach for Xmas tree removal
- Continuously resetting the technical limits throughout the campaign

OGA Decom Team comments

Announcement supports messages from industry that delivering the cost reduction target is achievable through:

1. Ensuring lessons learned are implemented and shared
2. Innovative technical approaches are adapted
3. Working together closely with the supply chain
4. Continuous learning
5. Well planned P&A campaigns will ensure significant cost savings for the P&A activity and will result in reduced Operator post CoP cost

Key facts

- Average cost per well <P_{10} compared with the current NNS OGA P_{50} benchmark of £3.6 million
- Ninian North P&A campaign achieved a 40% schedule improvement per well compared to Murchison P&A campaign
- Ninian North decommissioning programme >35% cost reduction per well or per facilities tonne compared with Murchison

The OGA does not provide endorsements or investment recommendations..

6. Glossary

We use the number of wells in order to report the size of the UKCS well stock and its status, since wells are largely managed (with the exception of multilaterals) and decommissioned per surface location.

Annual drilling activity data is based on wellbore spuds.

All other annualised well delivery related data is based on the completion date, defined in this case as the date at which planned drilling operations on the wellbore were completed to leave it completed for production, abandoned or suspended (as per WONS).

Completed (Operating)
A wellbore that is currently active.

Completed (Shut in)
A wellbore that is shut in either at the tree valves or subsurface safety valve (usually only applied if the wellbore is intended to be shut in for 90 days or more).

Plugged
A wellbore that has been plugged with a plug rather than an abandonment barrier.

AB1
The reservoir has been permanently isolated.

AB2
All intermediate zones with potential to flow have been permanently isolated.

AB3 (Permanently Abandoned)
The well origin at the surface has been removed and will never be used again.

Active well stock
Consists of completed operating and complete shut in with fields with a DevUK code of 600, 700 and 799 (fields that have reserves). Codes 800, 899 and 900 have no reserves and production is suspended or ceased so these wells are not included.

New & Infill Wells
The New/Infill classification is derived as 'New' if the development is not yet in production, or began production after 1-Jan-2012; otherwise, it is 'Infill'.

Sub Area Operator
Current designated field operator and the responsible party for holding data.

Open water Suspended E&A well
An exploration or appraisal well that has not been tied back to infrastructure.

Exploration and Appraisal wells
Wells which are primarily drilled to gather subsurface information.

Development wells
Wells that are drilled to produce hydrocarbons.

MER UK
Relevant persons must take the steps necessary to secure the maximum value of economically recoverable petroleum is recovered from the strata beneath UK waters.

NPT
Non Productive Time, in this case defined as any operational, mechanical or geological based cost event (Excluding waiting on weather).

Contact us at:

oga.correspondence@ogauthority.co.uk

OGA Headquarters
AB1 Building
48 Huntly Street
Aberdeen
AB10 1SH

OGA London Office
4th Floor
21 Bloomsbury Street
London
WC1B 3HF

www.linkedin.com/company/oil-and-gas-authority
twitter.com/ogauthority

Oil & Gas Authority

Oil and Gas Authority is a limited company registered in England and Wales with registered number 09666504 and VAT registered number 249433979. Our registered office is at 21 Bloomsbury Street, London, United Kingdom, WC1B 3HF

www.ogauthority.co.uk