North Sea Transition Authority

Wells Insight Report 2022

Open Report

Key Wells Insights

New Wells

10 E&A Wells spudded

62 Development wells completed

2629 UKCS wells in operations[1]

970 Of these are Shut-in or Plugged (i.e. over 1/3)

~1/2 of UKCS fields[1] have more than 20% of Shut-in or Plugged wells

WI Activity

>75% of fields
below 50% surveillance rate

~80% of fields
below 30% maintenance & intervention rate

WI Returns

£6-10/boe
Cost of reserves unlocked through restoration and optimisation intervention in 2021

Well Decom

>2000
wells
Planned for decommissioning in the next decade

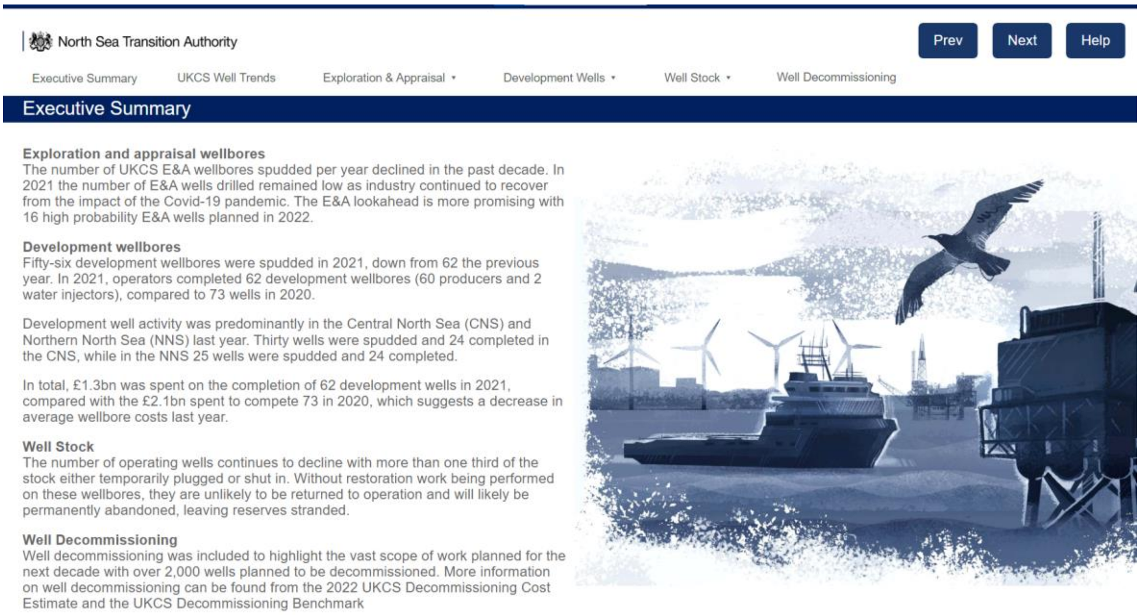
[1] Excludes fields which – to our knowledge - have planned Cessation Of Production

North Sea Transition Authority

Wells Insight Report 2022

This report displays performance and trends of exploration, appraisal and development wells in the UKCS across all regions and by various infrastructure type. If you would like to provide any feedback on the report we would be delighted to hear from you. Please follow the link below

Feedback form



Exploration and appraisal wellbores
The number of UKCS E&A wellbores spudded per year declined in the past decade. In 2021 the number of E&A wells drilled remained low as industry continued to recover from the impact of the Covid-19 pandemic. The E&A lookahead is more promising with 16 high probability E&A wells planned in 2022.

Development wellbores
Fifty-six development wellbores were spudded in 2021, down from 62 the previous year. In 2021, operators completed 62 development wellbores (60 producers and 2 water injectors), compared to 73 wells in 2020.

Development well activity was predominantly in the Central North Sea (CNS) and Northern North Sea (NNS) last year. Thirty wells were spudded and 24 completed in the CNS, while in the NNS 25 wells were spudded and 24 completed.

In total, £1.3bn was spent on the completion of 62 development wells in 2021, compared with the £2.1bn spent to compete 73 in 2020, which suggests a decrease in average wellbore costs last year.

Well Stock
The number of operating wells continues to decline with more than one third of the stock either temporarily plugged or shut in. Without restoration work being performed on these wellbores, they are unlikely to be returned to operation and will likely be permanently abandoned, leaving reserves stranded.

Well Decommissioning
Well decommissioning was included to highlight the vast scope of work planned for the next decade with over 2,000 wells planned to be decommissioned. More information on well decommissioning can be found from the 2022 UKCS Decommissioning Cost Estimate and the UKCS Decommissioning Benchmark

The 2022 Wells Insight Report shows a continued reduction to the number of wells spudded on the UKCS over the past 20 years.

This may also be due to the limited capital available for E&P activity in the UKCS. This is hindering efforts to get exploration wells drilled and smaller companies are finding it harder to secure funds for further investment in oil and gas.

While the reduction in drilling activity continued in 2021, it did so at a slower pace than the previous year. In total, 66 wells were spudded in 2021, down from 71 in 2020, and 141 in 2019.

As was the case in 2020, most E&A wells spudded in 2021 were in CNS and NNS.

NSTA insight:

•*The above trend reflects the mature nature of the UKCS and the ongoing recovery from the Covid-19 pandemic in 2020-21.*

UKCS well stock

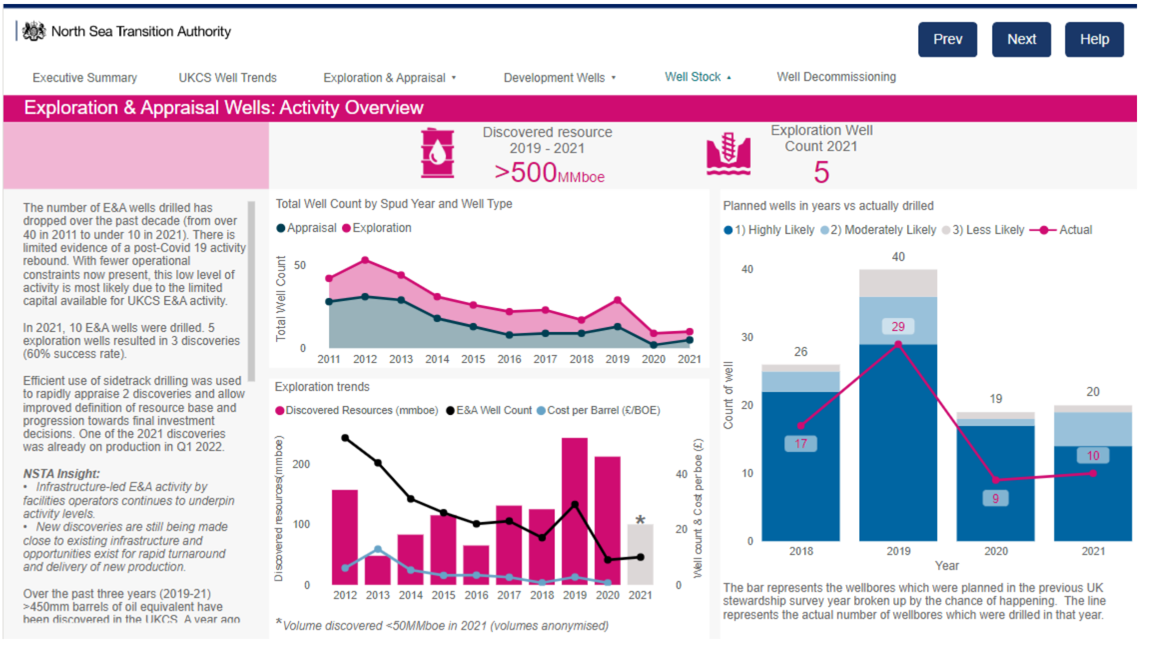
The well stock is the total number of production wells in the UKCS which are either operating, temporarily plugged or shut-in. Newly drilled wells can be added and those set for decommissioning can be removed.

The total UKCS well stock (operting, shut in and plugged) total remained consistent from 2017 to 2021.

The number of completed operating wells in the UKCS reduced from 1,772 in 2020 to 1,661 in 2021.

NSTA insight:

• *With many assets reaching the end of their economic lives, many wells will be shut in due to fields reaching cessation of production (COP).*



The number of E&A wells drilled has dropped over the past decade (from over 40 in 2011 to under 10 in 2021). There is limited evidence of a post-Covid 19 activity rebound. With fewer operational constraints now present, this low level of activity is most likely due to the limited capital available for UKCS E&A activity.

In 2021, 10 E&A wells were drilled. 5 exploration wells resulted in 3 discoveries (60% success rate).

Efficient use of sidetrack drilling was used to rapidly appraise 2 discoveries and allow improved definition of resource base and progression towards final investment decisions. One of the 2021 discoveries was already on production in Q1 2022.

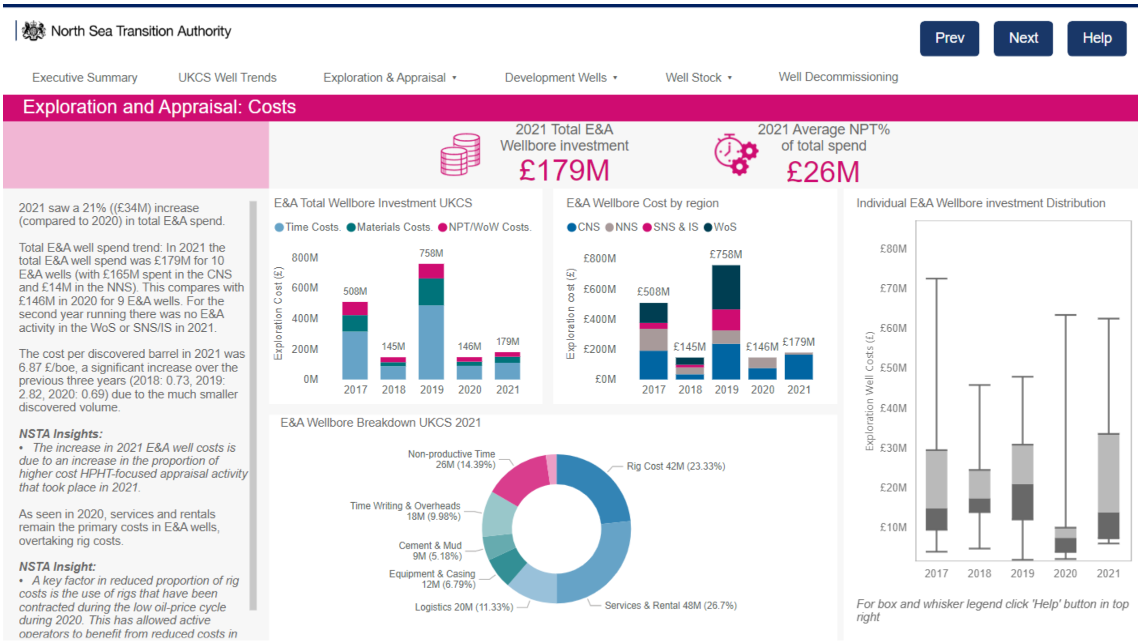
NSTA Insight:
• Infrastructure-led E&A activity by facilities operators continues to underpin activity levels.
• New discoveries are still being made close to existing infrastructure and opportunities exist for rapid turnaround and delivery of new production.

Over the past three years (2019-21) >450mm barrels of oil equivalent have been discovered in the UKCS. A year ago this value was >550 MMboe for the period from 2018-2020. In 2021 only 26 MMboe was discovered compared with 212 MMboe in 2020.

In 2021, a slightly higher percentage of planned wells were drilled compared to 2020. In 2021, 20 wells (of which 14 were classed as “highly likely to be drilled”) were planned and 10 were delivered (50%).

This compares with 9 of 19 (47%) wells planned in 2020. Prior to the Covid 19 pandemic this value was 73% (29 delivered of 40 “highly likely to be drilled”) in 2019.

NSTA Insights:
• The volatility of the annual discovered resource number is high and will remain so while only a small number of exploration wells are being drilled each year.
• Access to funding has become harder for North Sea E&A operators and this is having a negative impact on activity levels.
• It has become harder for companies to farm out exploration opportunities and enter the drilling phase of the exploration licences.
• Alongside this, there has been a hiatus in petroleum licence round activity. The previous licences were awarded late in 2019 in the 32nd Round.
• The number of active licences has fallen as work programmes have been completed and licences relinquished in the absence of funding to move into the drilling phase.
• The current petroleum licensing round (Autumn 2022) will be the first opportunity in 3 years for companies to access relinquished opportunities again.



2021 saw a 21% ((£34M) increase (compared to 2020) in total E&A spend.

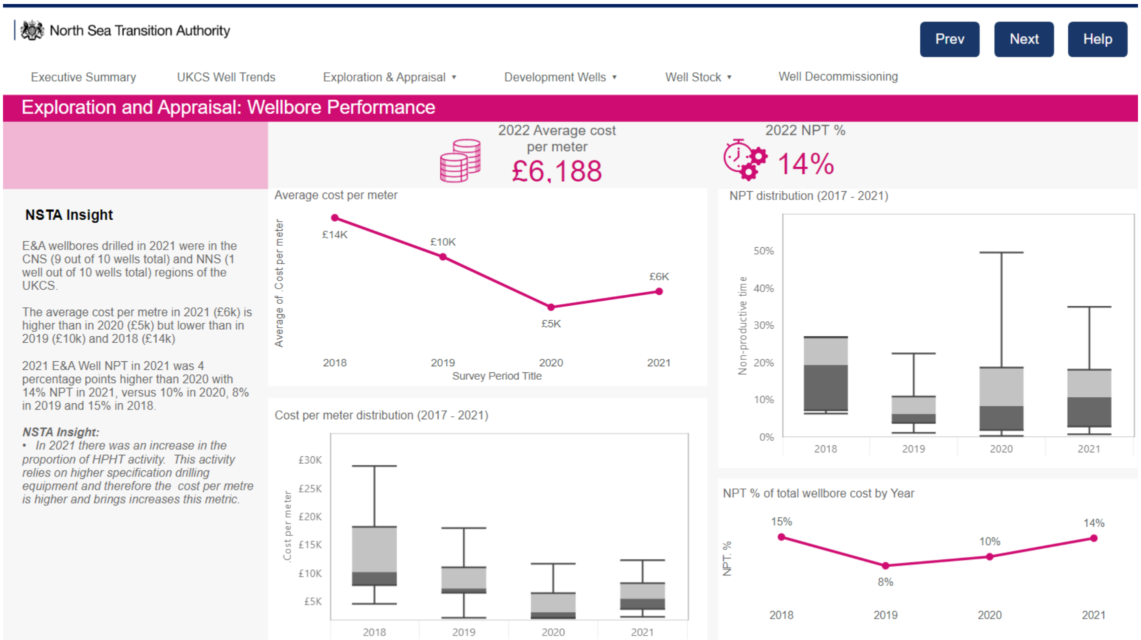
Total E&A well spend trend: In 2021 the total E&A well spend was £179M for 10 E&A wells (with £165M spent in the CNS and £14M in the NNS). This compares with £146M in 2020 for 9 E&A wells. For the second year running there was no E&A activity in the WoS or SNS/IS in 2021.

The cost per discovered barrel in 2021 was 6.87 £/boe, a significant increase over the previous three years (2018: 0.73, 2019: 2.82, 2020: 0.69) due to the much smaller discovered volume.

NSTA Insights:
• The increase in 2021 E&A well costs is due to an increase in the proportion of higher cost HPHT-focused appraisal activity that took place in 2021.

As seen in 2020, services and rentals remain the primary costs in E&A wells, overtaking rig costs.

NSTA Insight:
• A key factor in reduced proportion of rig costs is the use of rigs that have been contracted during the low oil-price cycle during 2020. This has allowed active operators to benefit from reduced costs in this important part of the cost base.

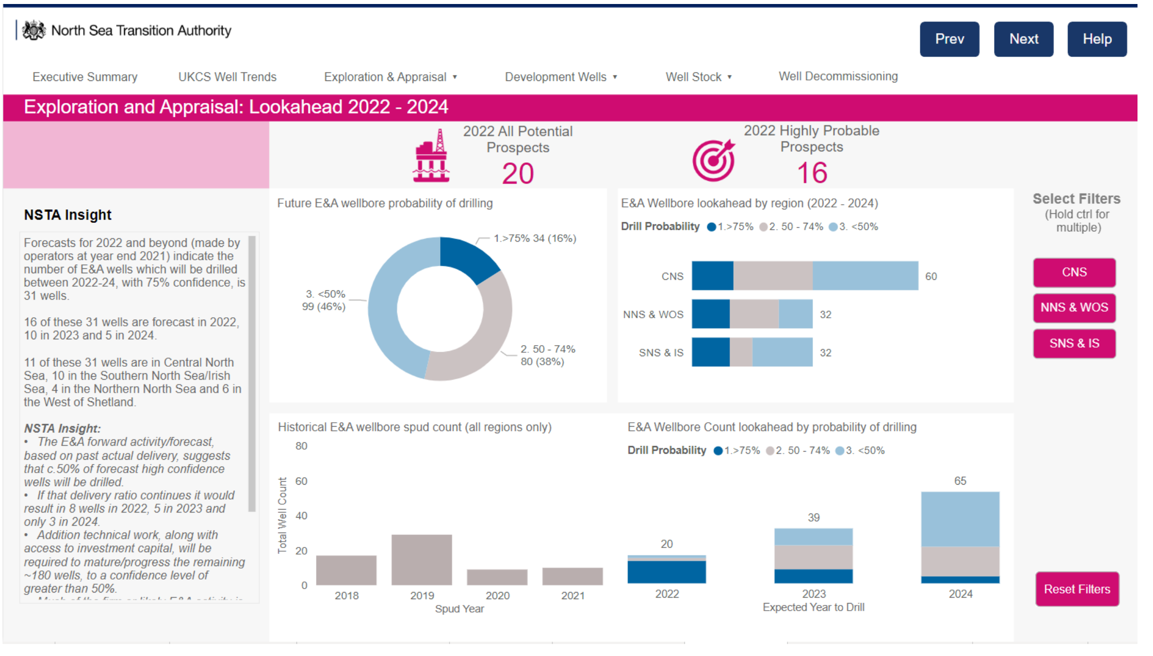


E&A wellbores drilled in 2021 were in the CNS (9 out of 10 wells total) and NNS (1 well out of 10 wells total) regions of the UKCS.

The average cost per metre in 2021 (£6k) is higher than in 2020 (£5k) but lower than in 2019 (£10k) and 2018 (£14k)

2021 E&A Well NPT in 2021 was 4 percentage points higher than 2020 with 14% NPT in 2021, versus 10% in 2020, 8% in 2019 and 15% in 2018.

NSTA Insight:
• In 2021 there was an increase in the proportion of HPHT activity. This activity relies on higher specification drilling equipment and therefore the cost per metre is higher and brings increases this metric.



Forecasts for 2022 and beyond (made by operators at year end 2021) indicate the number of E&A wells which will be drilled between 2022-24, with 75% confidence, is 31 wells.

16 of these 31 wells are forecast in 2022, 10 in 2023 and 5 in 2024.

11 of these 31 wells are in Central North Sea, 10 in the Southern North Sea/Irish Sea, 4 in the Northern North Sea and 6 in the West of Shetland.

NSTA Insight:

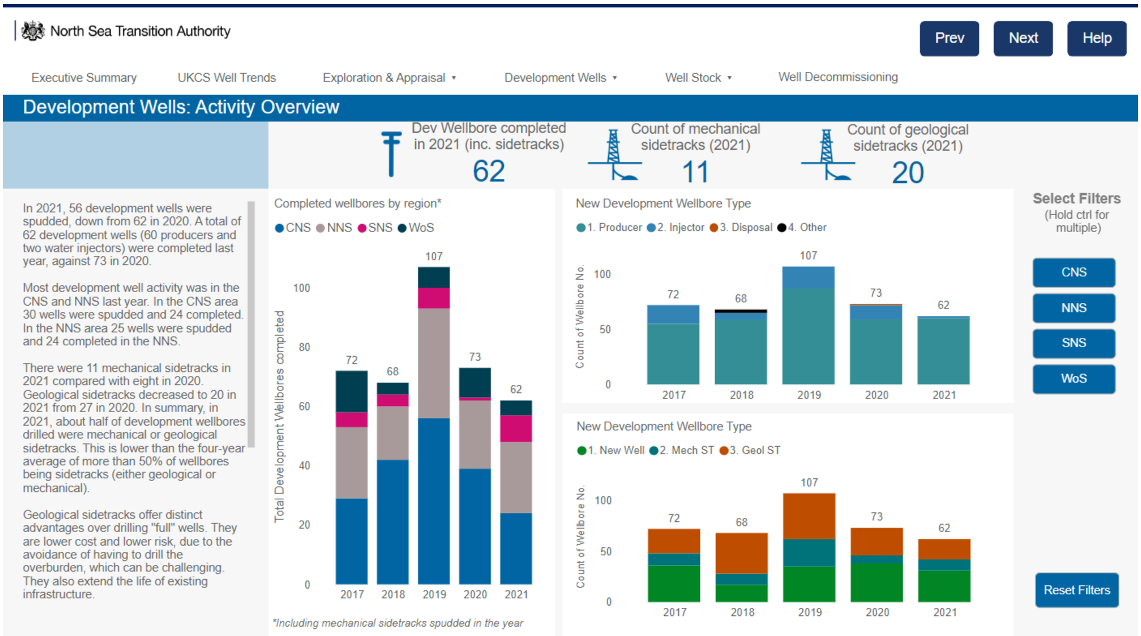
• The E&A forward activity/forecast, based on past actual delivery, suggests that c.50% of forecast high confidence wells will be drilled.

• If that delivery ratio continues it would result in 8 wells in 2022, 5 in 2023 and only 3 in 2024.

• Addition technical work, along with access to investment capital, will be required to mature/progress the remaining ~180 wells, to a confidence level of greater than 50%.

• Much of the firm or likely E&A activity is the result of deferred activity from 2020, due to the Covid 19 pandemic.

• Additional licence round activity is required to refresh the active exploration licence portfolio. The planned licensing round in autumn 2022 is expected to act as a catalyst for additional activity.



In 2021, 56 development wells were spudded, down from 62 in 2020. A total of 62 development wells (60 producers and two water injectors) were completed last year, against 73 in 2020.

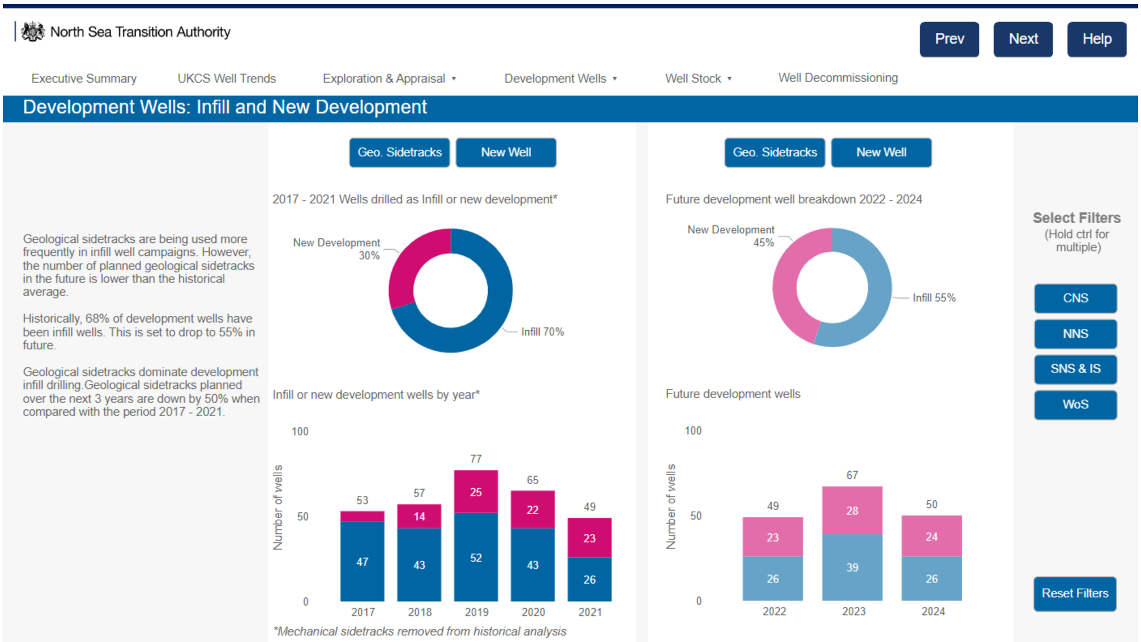
Most development well activity was in the CNS and NNS last year. In the CNS area 30 wells were spudded and 24 completed. In the NNS area 25 wells were spudded and 24 completed in the NNS.

There were 11 mechanical sidetracks in 2021 compared with eight in 2020. Geological sidetracks decreased to 20 in 2021 from 27 in 2020. In summary, in 2021, about half of development wellbores drilled were mechanical or geological sidetracks. This is lower than the four-year average of more than 50% of wellbores being sidetracks (either geological or mechanical).

Geological sidetracks offer distinct advantages over drilling "full" wells. They are lower cost and lower risk, due to the avoidance of having to drill the overburden, which can be challenging. They also extend the life of existing infrastructure.

NSTA Insights:

- *Development well activity trends reflect the maturity of the UKCS, where development well activity remains low/reducing.*
- *However, a significant increase in new development well activity is expected in 2025-26 when major new projects commence, particularly WoS.*
- *In the interim, the UKCS mature basin and its existing well infrastructure can be used to access new areas of a reservoir and increase recovery factors, via geological sidetracks from existing wellbores. Historically a significant number of infill and satellite accumulation wells have been drilled, which supplement the large projects.*

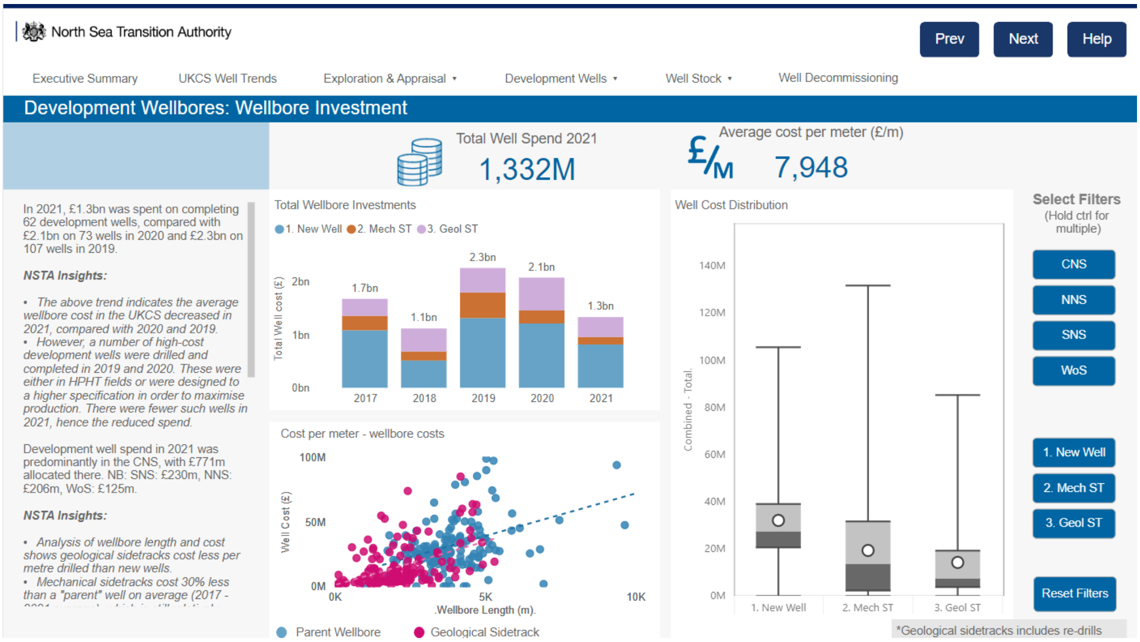


Geological sidetracks are being used more frequently in infill well campaigns. However, looking ahead, the number of planned geological sidetracks in the future is lower than the historical average.

The proportion of development infill wells historically has been 68%. When looking ahead, this proportion drops to 55%.

Geological sidetracks dominate development infill drilling. However, the number of geological sidetracks planned for the future is is reduced by 50% compared to the past 5 years.

NSTA Insight:
Mature fields may have limited options to sidetrack and redevelop fields. This accounts for the bulk of the decline of future well campaign



In 2021, £1.3bn was spent on completing 62 development wells, compared with £2.1bn on 73 wells in 2020 and £2.3bn on 107 wells in 2019.

NSTA Insights:

• The above trend indicates the average wellbore cost in the UKCS decreased in 2021, compared with 2020 and 2019.

• However, a number of high-cost development wells were drilled and completed in 2019 and 2020. These were either in HPHT fields or were designed to a higher specification in order to maximise production. There were fewer such wells in 2021, hence the reduced spend.

Development well spend in 2021 was predominantly in the CNS, with £771m allocated there. NB: SNS: £230m, NNS: £206m, WoS: £125m.

NSTA Insights:

• Analysis of wellbore length and cost shows geological sidetracks cost less per metre drilled than new wells.

• Mechanical sidetracks cost 30% less than a "parent" well on average (2017 - 2021 average), which is still relatively expensive.

• The average geological sidetrack is typically half the cost of drilling a new well from the surface. As such, they can provide an attractive, economical way of reaching a new target lying within reach of an existing well.

• The UKCS's existing infrastructure offers the opportunity and scope for old wells to be repurposed and geological sidetracks completed rather than new wells.

• In WoS there are too few wells to be used as geological sidetracks.

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Well cost distribution chart

• 1 New Well: In cases where wells are spudded and completed in one attempt, the average well cost is illustrated in the spud column.

• 2. Mech ST: This distribution only shows the cost of the portion of the well which has been sidetracked due to unplanned operational challenges.

Note: In these cases the cost of the mechanical sidetrack would be added to the original spudded well cost in order to reflect the overall well cost.

• 3. Geol ST: (includes redrills) This distribution only shows the cost of the portion of the well which has been geologically sidetracked. This represents wells which are drilled from an existing well to a new geological target.

*Note - Data reported for all individual wellbores. This is not the total amount of inefficiencies due to side-tracks and respuds.

Total Cost observations and insights
In 2021 the total Development well spend was £1.3bn (62 wells completed), significantly less than £2.1bn in 2020 (73 wells completed) and £2.3bn in 2019 (107 wells completed).

NSTA Insights:
• The above trend indicates the average wellbore cost in the UKCS decreased in 2021, versus 2020 and 2019.
• However, a number of high-cost development wells were drilled & completed in 2019 and 2020, which were either in HP/HT fields or the operator has designed the well to a higher specification in order to maximise the production return. There were less such wells in 2021, hence the reduced Development Well spend.

The trend for the well cost breakdown (time costs, materials, and inefficiency costs) has remained consistent in 2021 (and comparable to previous years), with time costs accounting for 57 % (£742m of £1.3bn total), materials/equipment 26% (£349m of £1.3bn total), and NPT/WoW inefficiency costs 17% (£240m of £1.3bn total),

NSTA Insight:
• Time related costs offer the biggest opportunities to reduce Development Well costs e.g. Rig Costs and Service/rental costs, etc.

The Central North Sea received the highest New Development Wells spend/investment in 2021. £771mm was spent on New Development Wells in the CNS area in 2021 (versus £1.1bn in 2020) with 73% (£563mm) of this being spent on the drilling costs.

The CNS New Development well spend of £771m was higher than the combined investment of all the other regions (SNS: £260m, NNS: 206m, WoS 125m).
NSTA Insights*:*
• The high Development Well spend in the CNS area (versus the other areas) was as a result of more fields in CNS performing well operations, combined with several expensive HPHT wells being drilling and completed.

CNS spend was lower in 2021 (£771m), versus 2020 (£1.1bn). The main cause of this is a function of fewer wells (24 across 14 fields) being drilled in 2021 vs 2021 (39 wells across 19 fields).

Drilling Cost Observations and insights

2021 Development Well Drilling Costs Breakdown: In 2021, Rig Costs accounted for 25% of total Drilling costs (versus 29% in 2020), and Services & Rentals for 22% (versus 20% in 2020)

NSTA Insights:
• Rig costs remain the primary cost in Development Well Drilling operations in 2021 (as they were in 2020). However, in 2021 there was a smaller difference in Rig Cost and Service & Rentals costs.
• A contributing factor in the lowering of rig costs is related to oversupply, coupled with the reduction in global drilling activity

West of Shetland (WoS) Drilling Waiting on Weather costs in 2021 (12%) are higher than the NNS (4%) / CNS (3%) regions. However, they were slightly lower than in 2020 (15%)

NSTA Insights:
• This illustrates the impact of the harsh WoS weather on wait-on-weather, versus other areas on the UKCS.
• The reduction drilling wait-on-weather in 2021, versus 2020, is likely associated to the optimisation of the WoS rig schedules to perform less weather sensitive drilling operations through the winter months.

Completion cost observations and insights

2021 Development Well Completion Costs Breakdown: In 2021, Rig Costs accounted for 23% of total Completion costs (versus 25% in 2020), and Services & Rentals for 20% (versus 17% in 2020)

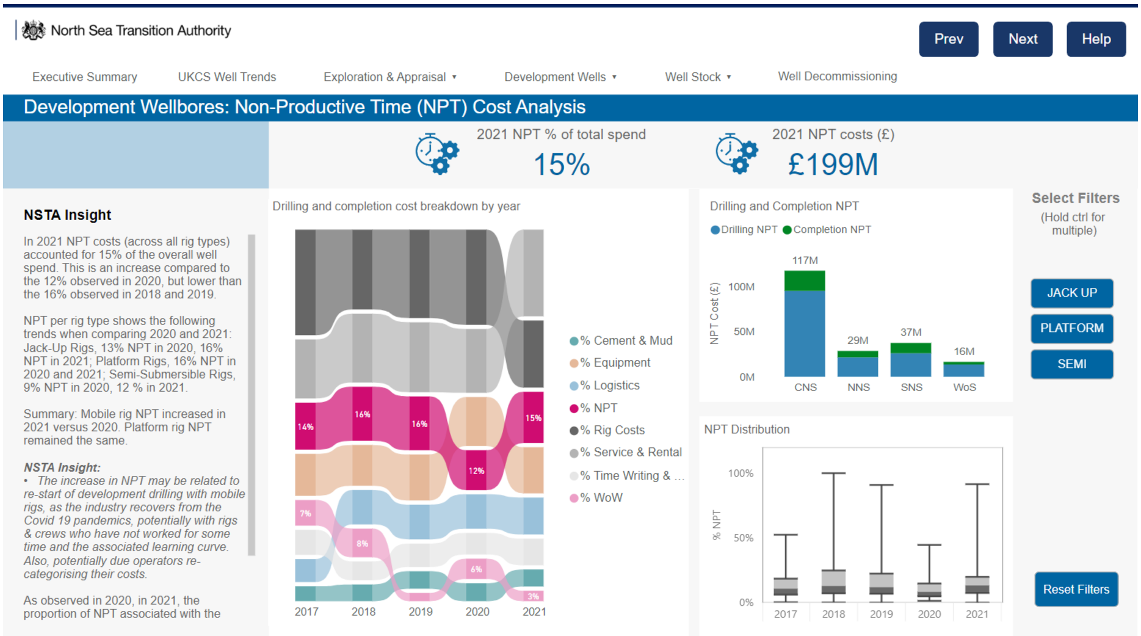
NSTA Insights:
• Rig costs remain the primary cost in Development Well Completion activities in 2021 (as they were in 2020). However, in 2021 there was a smaller difference in Rig Cost and Service & Rentals costs.
• A contributing factor in the lowering of rig costs is related to oversupply, coupled with the reduction in global drilling activity

In the CNS & NNS the completion equipment & casing costs are the highest proportion of the spend (CNS:23%, NNS 33%), versus WoS where 12% of costs are related to completion equipment & casing.

NTSA Insight:
• An explanation for this trend is considered related to artificial lift equipment required for the NNS and HPHT spec completions costs in the CNS.

WoS completion waiting on weather costs are 9% of the total completion costs.

NSTA Insight:
• This is considered good performance in the harsh WoS environment taking into account rig schedule optimisation to perform more weather sensitive completion operations through the summer months.



In 2021 NPT costs (across all rig types) accounted for 15% of the overall well spend. This is an increase compared to the 12% observed in 2020, but lower than the 16% observed in 2018 and 2019.

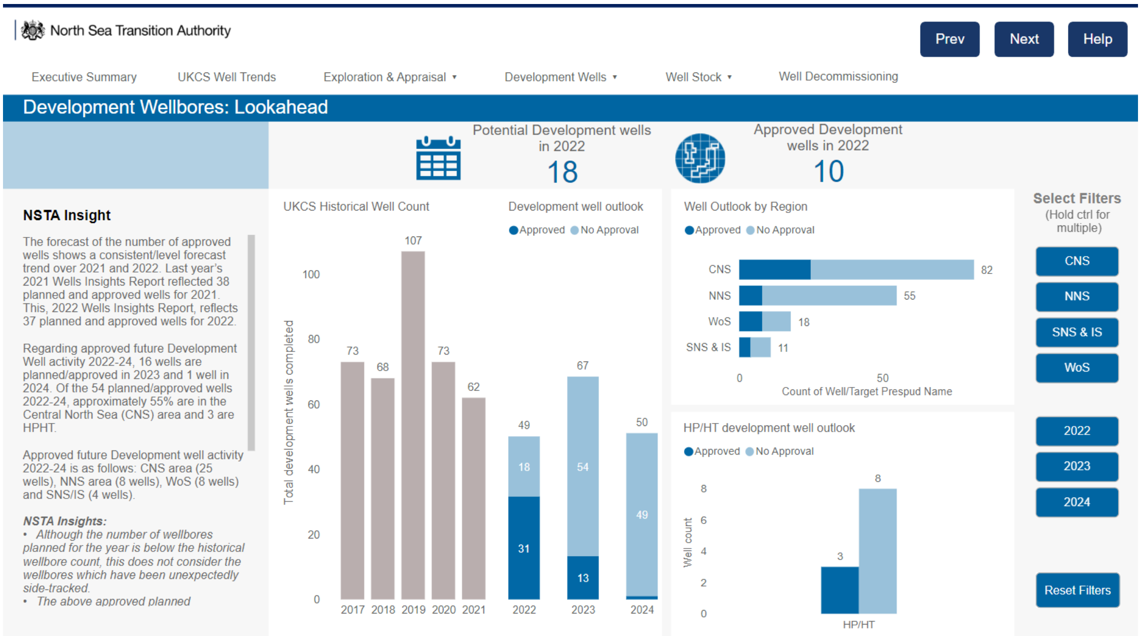
NPT per rig type shows the following trends when comparing 2020 and 2021: Jack-Up Rigs, 13% NPT in 2020, 16% NPT in 2021; Platform Rigs, 16% NPT in 2020 and 2021; Semi-Submersible Rigs, 9% NPT in 2020, 12 % in 2021.

Summary: Mobile rig NPT increased in 2021 versus 2020. Platform rig NPT remained the same.

NSTA Insight:
• *The increase in NPT may be related to re-start of development drilling with mobile rigs, as the industry recovers from the Covid 19 pandemics, potentially with rigs & crews who have not worked for some time and the associated learning curve. Also, potentially due operators re-categorising their costs.*

As observed in 2020, in 2021, the proportion of NPT associated with the drilling costs is approximately 75% of the overall NPT.

NSTA Insight:
• *The above trend is in line with the cost breakdown of drilling vs completion costs.*

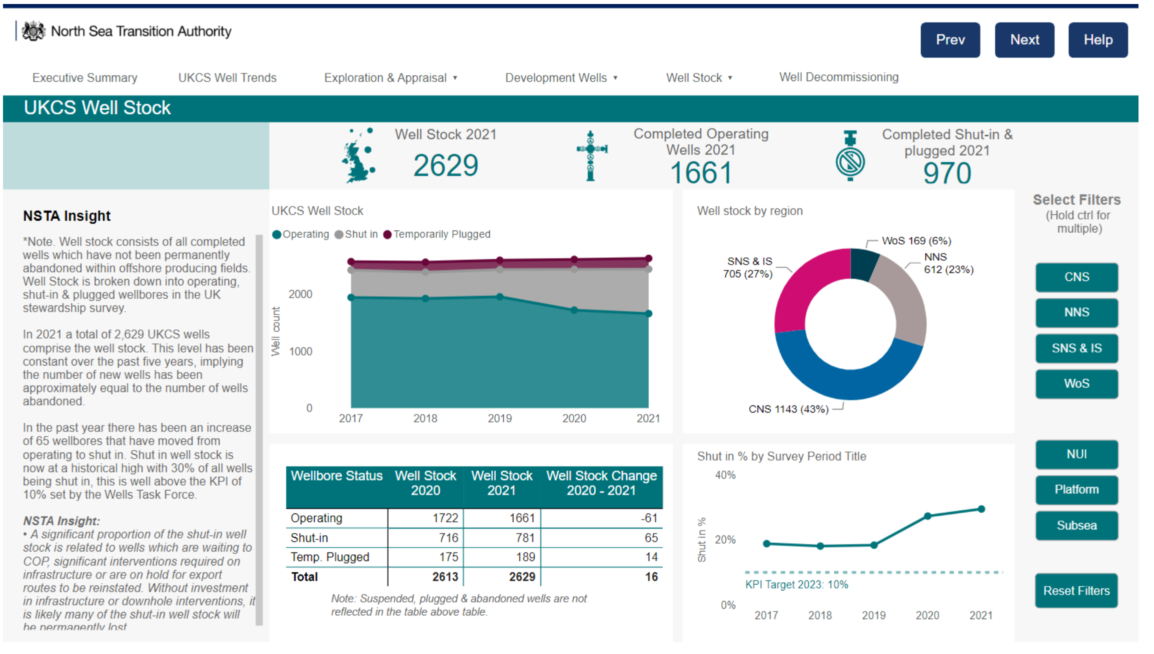


The forecast of the number of approved wells shows a consistent/level forecast trend over 2021 and 2022. Last year's 2021 Wells Insights Report reflected 38 planned and approved wells for 2021. This, 2022 Wells Insights Report, reflects 37 planned and approved wells for 2022.

Regarding approved future Development Well activity 2022-24, 16 wells are planned/approved in 2023 and 1 well in 2024. Of the 54 planned/approved wells 2022-24, approximately 55% are in the Central North Sea (CNS) area and 3 are HPHT.

Approved future Development well activity 2022-24 is as follows: CNS area (25 wells), NNS area (8 wells), WoS (8 wells) and SNS/IS (4 wells).

NSTA Insights:
• Although the number of wellbores planned for the year is below the historical wellbore count, this does not consider the wellbores which have been unexpectedly side-tracked.
• The above approved planned Development well activity trend reflects the mature stage of the UKCS where Development well activity remains low/reducing, until major new projects commence in 2025/2026.
• The current high oil/energy prices, combined with UK 'security of supply' considerations, may result in higher confidence levels in the industry and greater commitment to increased Development well activity.
• As the UKCS is a mature basin, the existing well infrastructure can be used to access new areas of a reservoir and increase recovery factors, via side-tracks from existing wellbores. Throughout the years there has always been a significant number of wells being drilled through infill drilling and satellite accumulation drilling which supplement the large projects.



*Note. Well stock consists of all completed wells which have not been permanently abandoned within offshore producing fields. Well Stock is broken down into operating, shut-in & plugged wellbores in the UK stewardship survey.

In 2021 a total of 2,629 UKCS wells comprise the well stock. This level has been constant over the past five years, implying the number of new wells has been approximately equal to the number of wells abandoned.

In the past year there has been an increase of 65 wellbores that have moved from operating to shut in. Shut in well stock is now at a historical high with 30% of all wells being shut in, this is well above the KPI of 10% set by the Wells Task Force.

NSTA Insight:
• A significant proportion of the shut-in well stock is related to wells which are waiting to COP, significant interventions required on infrastructure or are on hold for export routes to be reinstated. Without investment in infrastructure or downhole interventions, it is likely many of the shut-in well stock will be permanently lost.

Note: Well surveillance can be conducted either continuously (through downhole gauges) or collected as a part of intervention activity.

In 2021, a total of 678 wells had surveillance, up by 132 from 2020. This is a large increase, with the biggest change recorded WoS due to new wells having continuous monitoring (15% surveillance rate in 2020 vs 72% in 2021).

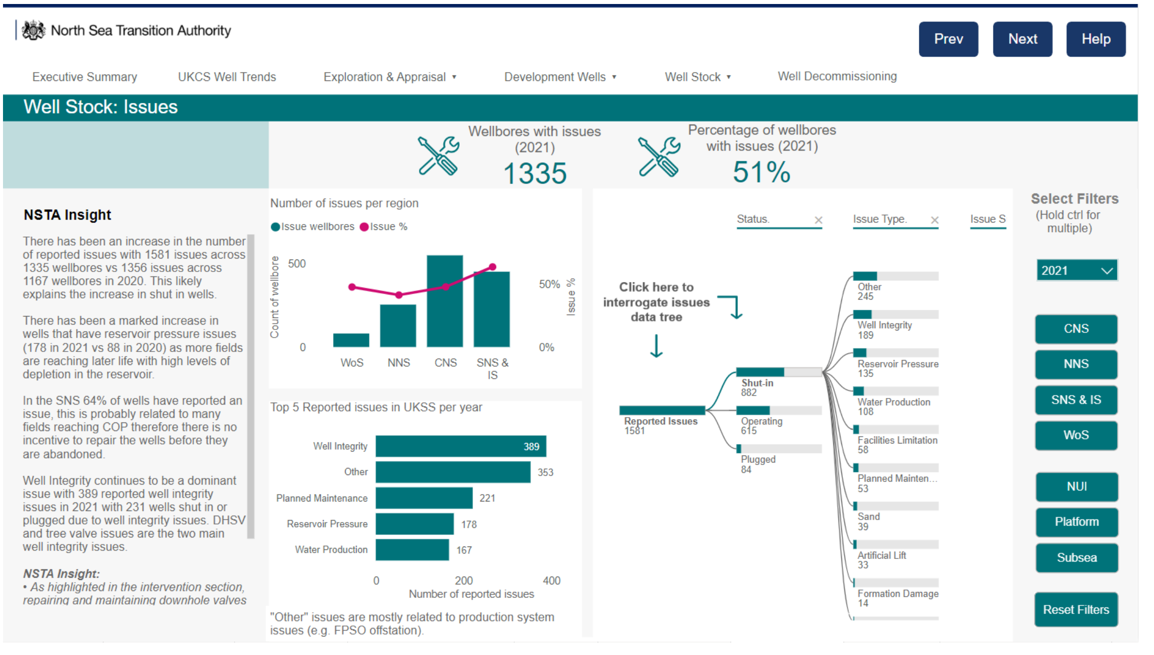
Last year, 26% of well stock had either primary (continual surveillance) or secondary (intervention-based activity) surveillance.

Subsea wells, which tend to be more expensive to perform surveillance through intervention, have a higher surveillance rate than normally unattended installations' wellbores due to the presence of downhole gauges.

This year it is possible to see how many wells had intervention-based surveillance (i.e. PLTs, calipers, P/T gauges). It can be seen that only 116 surveillance jobs were completed in 2021 which represents 4% of the well stock.

NSTA Insight:

• *It appears there could be an opportunity for operators to improve their surveillance, both on attended and unattended platforms to reach the 50% KPI established by the Reservoir and Wells Optimisation Group. It may be that with many fields reaching COP there is limited value in surveillance data.*



There has been an increase in the number of reported issues with 1581 issues across 1335 wellbores vs 1356 issues across 1167 wellbores in 2020. This likely explains the increase in shut in wells.

There has been a marked increase in wells that have reservoir pressure issues (178 in 2021 vs 88 in 2020) as more fields are reaching later life with high levels of depletion in the reservoir.

In the SNS 64% of wells have reported an issue, this is probably related to many fields reaching COP therefore there is no incentive to repair the wells before they are abandoned.

Well Integrity continues to be a dominant issue with 389 reported well integrity issues in 2021 with 231 wells shut in or plugged due to well integrity issues. DHSV and tree valve issues are the two main well integrity issues.

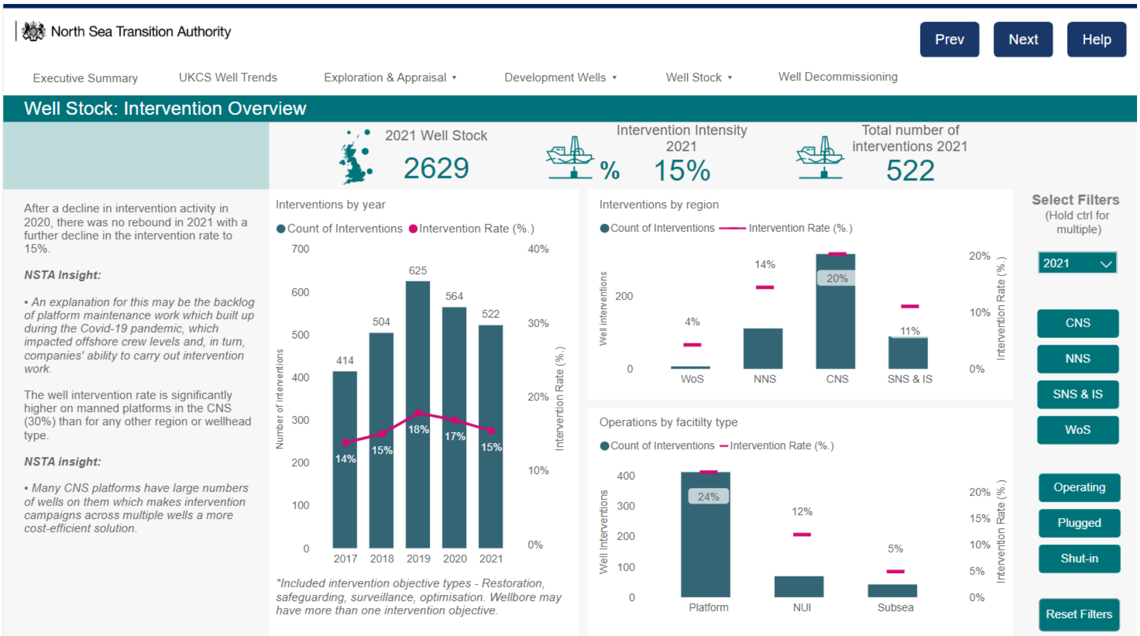
NSTA Insight:
• As highlighted in the intervention section, repairing and maintaining downhole valves can return significant value, both financially and hydrocarbon volumetrically. There is possible scope for more downhole valve operations to be conducted, allowing more production to be realised efficiently.

This is a new slide for this year to bring attention to how many wells are encountering well integrity issues in the UKCS.

There is a clear increase in wells that are shut-in or plugged due to well integrity issues especially since 2019. For the industry to meet the 10% shut in target set by the Wells Task Force then returning these wells to production is key.

The most common issue is Sub-Surface Safety Valve (SS
SV) issues, these are often easily remediated with the average cost of a SSSV repair being £350k in 2021.

NSTA Insight:
• With the reduction in intervention activity in 2020/21 the ageing well stock is encountering issues quicker than the interventions can remediate them. With the high commodity prices it is hoped that operators will look to re-instate production from these wells for a relatively low cost.



After a decline in intervention activity in 2020, there was no rebound in 2021 with an intervention rate of 16%.

NSTA Insight:
• An explanation for this may be the backlog of platform maintenance work which built up during the Covid-19 pandemic, which impacted offshore crew levels and, in turn, companies' ability to carry out intervention work.

The well intervention rate is significantly higher on manned platforms in the CNS (30%) than for any other region or wellhead type.

NSTA insight:
• Many CNS platforms have large numbers of wells on them which makes intervention campaigns across multiple wells a more cost-efficient solution.

After a peak of activity in 2019, interventions decreased in the next two years, with reductions observed in safeguarding, optimisation and restoration activities.

In total, 36.2 mmboe of production was added as a result of well intervention activity in 2021, the lowest volume on NSTA records. The previous record low of 48.9 mmboe was in 2017.

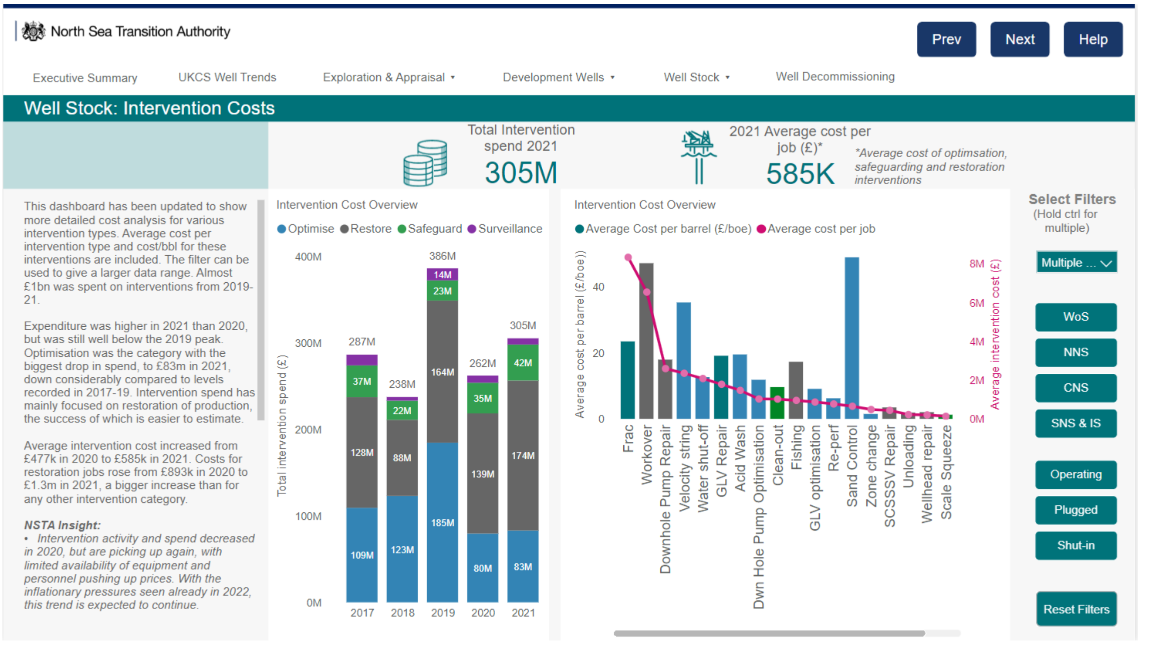
The specific findings by intervention categories are:

Safeguarding
• This is the most frequently performed intervention objective.
• Safeguarding often involves work to prevent flow assurance issues, using scale squeezes and chemical washes.
• Scale squeezes have the biggest impact on production, delivering 75,000 boe per application in 2021.

Optimisation
• The main optimisation jobs are re-perforations, water shut-offs and acid washes.
• Re-perforation jobs added 125,000 boe per application last year and water shut-offs added 211,000 boe per job. These are significant hydrocarbon volumes that can be added at a relatively low cost per barrel of £6 and £8, respectively.

Restoration
• Restoration jobs accounted for around 30% of interventions but provided 35% of the resource added in 2021.
• The main interventions in restoration are associated with downhole valves, pump repairs and wellhead maintenance.
• There were 36 SSSV repairs in 2021, adding total production of 3.1 mmboe/year.

Note* Please use active filters to drill into the individual intervention categories.



This dashboard has been updated to show more detailed cost analysis for various intervention types. Average cost per intervention type and cost/bbl for these interventions are included. The filter can be used to give a larger data range. Almost £1bn was spent on interventions from 2019-21.

Expenditure was higher in 2021 than 2020, but was still well below the 2019 peak. Optimisation was the category with the biggest drop in spend, to £83m in 2021, down considerably compared to levels recorded in 2017-19. Intervention spend has mainly focused on restoration of production, the success of which is easier to estimate.

Average intervention cost increased from £477k in 2020 to £554k in 2021. Costs for restoration jobs rose from £893k in 2020 to £1.3m in 2021, a bigger increase than for any other intervention category.

NSTA Insight:
• Intervention activity and spend decreased in 2020, but are picking up again, with limited availability of equipment and personnel pushing up prices. With the inflationary pressures seen already in 2022, this trend is expected to continue.

Intervention spend has decreased every year since 2017 in the CNS, partly due to a reduction in the average cost of interventions. However, the number of interventions in the CNS dropped 15% between 2020 and 2021. Spend on re-perforations in the CNS has continually decreased in recent years, from £47m in 2018 to £3m in 2021.

Last year £99m was spent on workovers, more than for any other type of intervention.
Workovers require the use of drilling rigs, which greatly increases costs. The cost/bbl for workovers in 2021 was £28.

Some of the most cost-effective interventions were scale squeezes (£1.5/bbl), wellhead repairs (£2/bbl), SCSSSV repairs (£3.5/bbl) and water shut-offs (£6.2/bbl) between 2019-21.

NSTA Insight:
• Well intervention represents a cost-effective way of increasing production and is likely to be increasingly attractive to industry, which is intent on boosting production while oil and gas prices are high.

This section has been added to our Wells Insight Report for the first time this year. Subsea well intervention activity levels have historically been low. This slide was created to raise awareness of the type of subsea intervention work which has been carried out and the degree of success achieved.

In the past five years there have only been 220 subsea interventions. Despite this, 53 mmboe per year was added, which is more than the 36.2 mmboe added from all 456 platform, subsea and NUI interventions in 2021.

NSTA Insight:

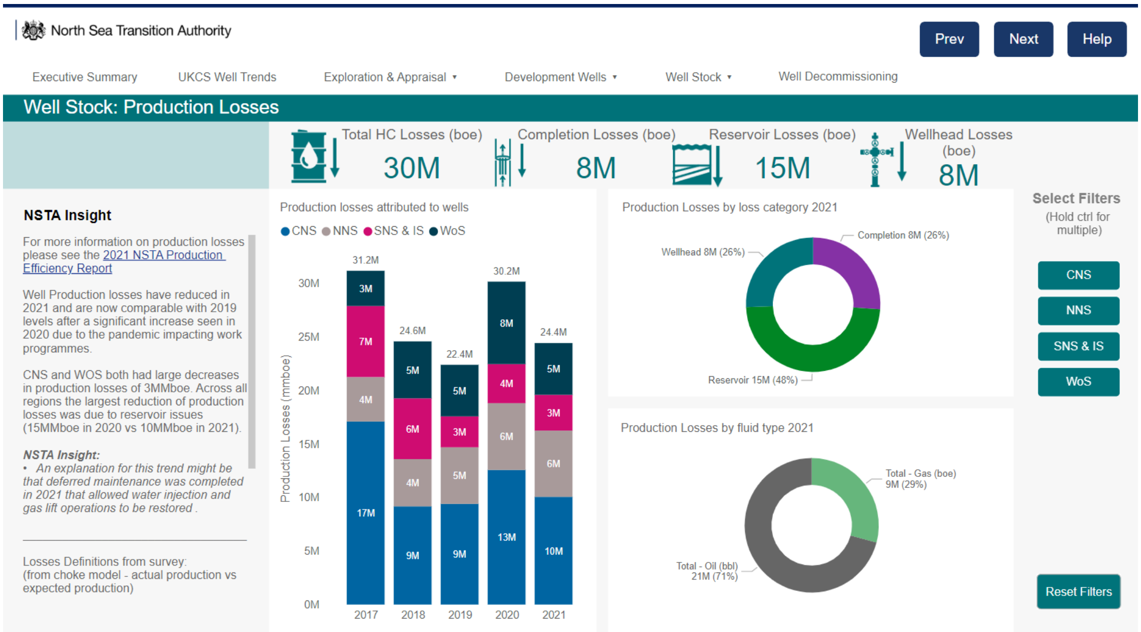
• Historically, the number of light well intervention vessels (LWIVs) in the North Sea has been low, limiting the number of subsea interventions which can be performed in the basin. With the generally low commodity prices from 2017-2021, it was uneconomic to intervene on wells unless they were large producers – hence the large volume of hydrocarbons added for relatively few interventions.

Since 2017 the most common subsea interventions have been scale squeezes (39) and wellhead repairs (23).

A total of 375 shut-in or plugged subsea wells are likely to require intervention for production to be reinstated.

NSTA Insight:

• In the current high commodity price environment, subsea intervention is a more economic investment. The NSTA encourages operators to collaborate in order to identify campaigns that can lower costs.



For more information on production losses please see the 2021 NSTA Production Efficiency Report

Well Production losses have reduced in 2021 and are now comparable with 2019 levels after a significant increase seen in 2020 due to the pandemic impacting work programmes.

CNS and WOS both had large decreases in production losses of 3MMboe. Across all regions the largest reduction of production losses was due to reservoir issues (15MMboe in 2020 vs 10MMboe in 2021).

NSTA Insight:
• An explanation for this trend might be that deferred maintenance was completed in 2021 that allowed water injection and gas lift operations to be restored .

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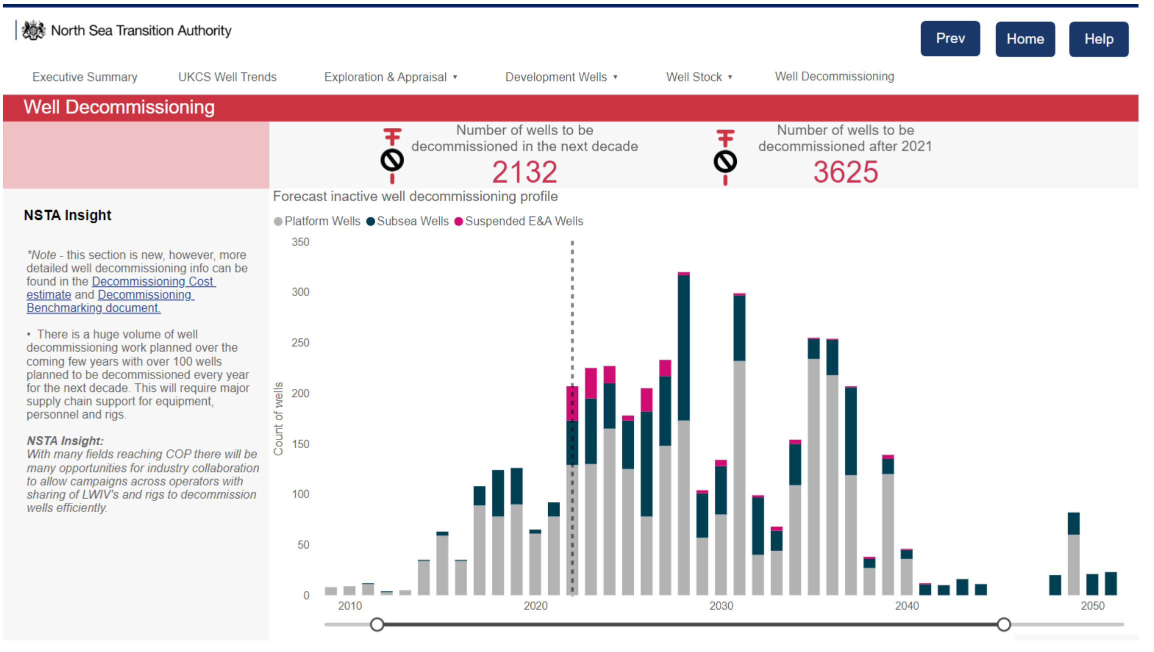
Losses Definitions from survey:
(from choke model - actual production vs expected production)

Completion: This covers losses associated with all aspects of the downhole equipment within the barrier envelope of the well, using the fact that a well is a system.

Reservoir : This covers all reservoir related losses e.g. lack of voidage.

Wellhead : This covers loss associated with wellhead equipment (excl completion) and operation (from the tubing hanger upwards to the Christmas tree and the wellhead system including annulus valves within the boundary of the well)



Note - this section is new, however, more detailed well decommissioning info can be found in the Decommissioning Cost estimate and Decommissioning Benchmarking document.

• There is a huge volume of well decommissioning work planned over the coming few years with over 100 wells planned to be decommissioned every year for the next decade. This will require major supply chain support for equipment, personnel and rigs.

NSTA Insight:
With many fields reaching COP there will be many opportunities for industry collaboration to allow campaigns across operators with sharing of LWIV's and rigs to decommission wells efficiently.

Glossary & Notes

Data Caveat

The data analysed in this report is obtained from two key source

The UKSS survey is an annual survey of Operator activity, linked by Well Registration No. to WONS, but sorted primarily on regulatory Completion date or (in the case of active wells) reported at year end (31st December).

The differences in the reporting protocol mean that the data analysed can only be a snapshot of a specific time frame and may not be representative of the whole picture.

This report is presented as a factual analysis of available data and is restricted to Field Area levels of detail to avoid identification of assets and to anonymise any data. More detailed analysis may be available on request, subject to NSTA approval.

Exploration and Appraisal volumes are the NSTA analysed values and may or may not align with the publicly announced volumes.

Insight Report Notes

Annual drilling activity data is based on wellbore spud date. All other annualised well related data is based on the regulatory 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). This is particularly important when discussing NPT and cost figures.

Glossary & Definitions

Sidetracks

A wellbore may be sidetracked for several reasons:

Geological - In most cases a geological side-track is planned to enhance subsurface information. A geological side-track is defined as a wellbore that is steered towards a different subsurface target than the previous wellbore. In the case of a geological side-track, total cost reporting will be the sum of the different cost categories.

Mechanical - In most cases these are unplanned wellbores, initiated due to operational issues such as hole instability, directional control or tool failure. In the case of a mechanical side-track, the reported costs of the side- tracked wellbore will be added to the NPT costs of the original wellbore.

Respud - If a well must be re-spudded, the costs of the original wellbore will be added to the NPT category of the respudded well.

Redrill - If an existing producing wellbore is side-tracked to a different geological location, this is classified as a re-drilled well. The surface location is preserved. In this case, the cost of the re-drilled wellbore is preserved as reported.

Regions

CNS – Central North Sea

NNS – Northern North Sea

WoS – West of Shetland

SNS & IS – Southern North Sea and Irish Sea (East)

Abbreviations & Definitions

COP – **C**essation **o**f **P**roduction - Production has ceased and all wells are shut in; redevelopment/re-use options have been reviewed and discounted and there is a clear intent by the licensees to proceed to decommissioning

Dev Wells - **Dev**elopment **Wells** - Wells that are drilled to produce or enhance hydrocarbon exploitation.

E&A – **E**xploration **and A**ppraisal Wells which are primarily drilled to gather subsurface information.

HP/HT – **H**igh **P**ressure **H**igh **T**emperature – Wells drilled into fields or areas where reservoir pressure exceeds 10,000 psi (690 bar) and/or reservoir temperature above 300 deg. F (149 deg C) is determined HP/HT.

Infill well - A well drilled for a development project that been in production for >5 years.

LWIV - **L**ight **W**eight **I**ntervention

MMboe – **M**illion **b**arrels of **o**il **e**quivalent.

NPT - **N**on-**P**roductive **T**ime – defined as the cost (as reported) of any operational, mechanical or geological event interrupting the effective delivery of a well and excluding any weather-related delays.

WONS - **W**ell **O**perations **N**otification **S**cheme – a transactional regulatory database containing details of well construction activities, production status and abandonment activities.

WoW – **W**aiting **o**n **w**eather, cost associated with drilling and completion activities that have been halted due to poor weather conditions.

Well Status

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 - A wellbore that has had the reservoir permanently isolated

AB2 - A wellbore with all intermediate zones with potential to flow permanently isolated

AB3 (Permanently Abandoned) - A wellbore that has had the well origin at surface removed and will never be used again

Losses Definitions from survey:

Completion: This covers loss associated with all aspects of the well jewellery within the barrier envelope of the well, using the fact that a well is a system.

Reservoir: This covers all reservoir related losses e.g. lack of voidage.

Wellhead: This covers loss associated with wellhead equipment (excl completion) and operation (from the tubing hanger upwards to the Christmas tree and the wellhead system including annulus valves within the boundary of the well)

Wellbore Environment

Platform – Wellhead is located on a well bay within a normally manned offshore platform

NUI – Normally Unmanned Installation - Wellhead is located on a well bay within an offshore platform which is either unmanned or temporarily unmanned.

Subsea – Wellhead is located on the seabed and is tied back to an installation on the surface.