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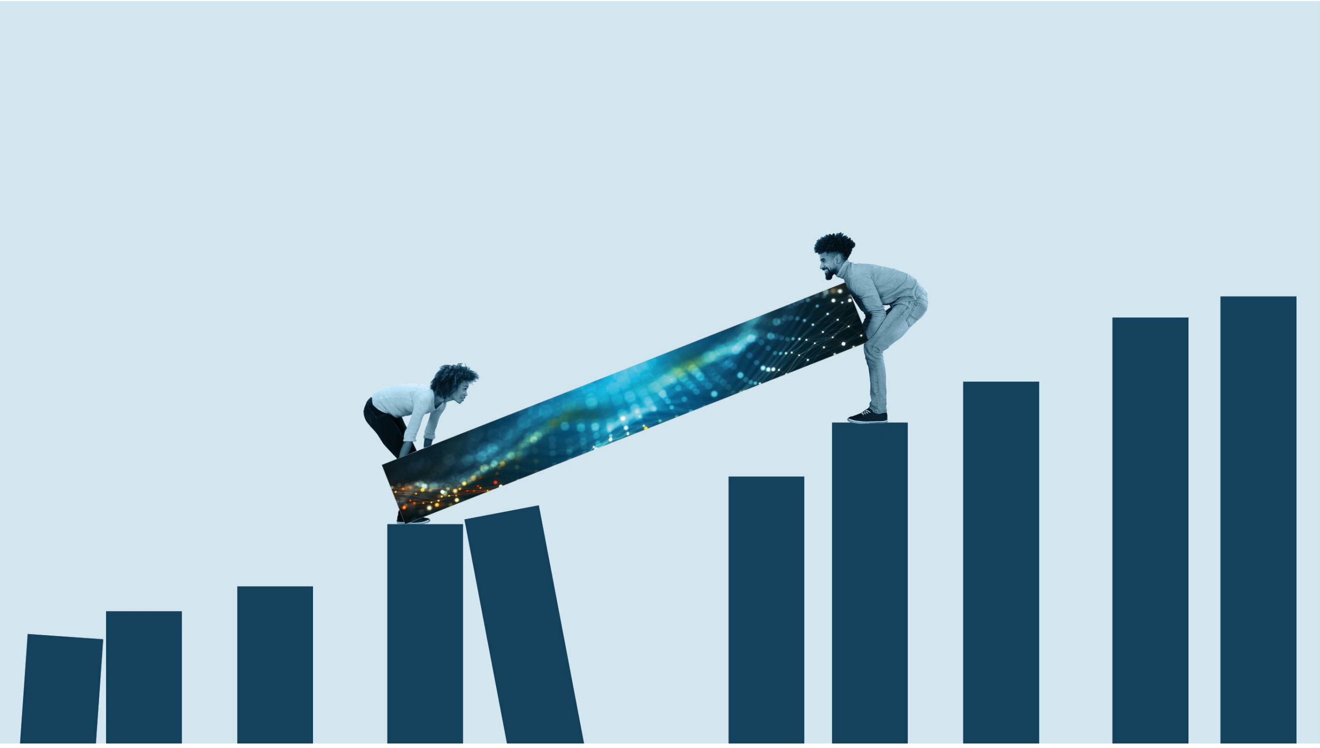
The need for new technology to improve competitiveness



What makes an oil and gas province competitive?

The prospect of attractive returns is fundamental for attracting investments. Traditionally Net Present Value (NPV) and similar economical metrics have been used to assess the return of petroleum projects. If high commodity prices are expected/assumed, this may cause a drive for adding volumes as we saw from 2005 and until the oil price slump in 2013. Enterprises in the petroleum industry reacted to the oil price fall by requiring robustness against low oil prices, putting more emphasis on reducing costs. New projects had to demonstrate low break-even prices, in terms of $/bbl, in addition to high NPV to become sanctioned.

The advent of shale oil in North America has highlighted the importance of yet another metric – the lead-time from investment decision to production. Motivated by the uncertainty about future oil prices and CO_2-costs, investors now are looking for faster returns in addition to high value (high NPV) and robustness (low break-even).

More recently investors and enterprises have become increasingly concerned about the carbon footprint of their investments and operations. This is partly driven by an expectation of rising CO_2-emission costs, and partly by stakeholders concerns for climate change and expectations for action.

A fundamental premise for operations is the acceptance in the society. This "license-to-operate" is fragile and is dependent upon the sector's ability to operate safely without major accidents and spills, and the ability to deliver on a credible roadmap for the industry's role in the energy transition.

Going forward we therefore believe that the competitiveness of the NCS depends on the ability to find, develop and deliver cost-efficient resources faster and with lower CO_2-emissions.

The NCS competitiveness and the need for improvements is discussed over the next sub-sections for the following competitiveness contributors:

- Improved safety
- Reduction of GHG emissions
- Finding and maturing new resources (volumes)
- Attractive costs
- Lead times

Continual safety improvement in a time of change

The Norwegian oil and gas industry's ambition is to be world leading in health, safety and environmental performance. Returning safely from work and not experiencing work related health problems, is a value which is embedded in the zero-accident philosophy widely adopted in the industry.

Furthermore, accidents and work-related health problems have implications on business opportunities, revenue, and profit. Safety incidents harm companies' and industry's reputation and challenge the "license to operate", cause production down-time, and may erode shareholder value. Examples are numerous, ranging from small incidents like the accidental discharge of 1 m^3 of hydraulic oil from the Eirik Raude drilling rig in the Barents Sea in 2005 causing a three-week delay and a dent in stakeholders' support to Barents Sea operations, to catastrophic accidents like the Macondo explosion, resulting in 11 fatalities, an oil spill of 780 000 m^3, and company costs of more than 65 billion USD.

The zero accidents vision and the no harm principle set the ambition for HSE efforts. However, incidents, accidents, and exposure to working environment hazards still occur. To guide the industry in its endeavor to realize the vision, the principle of continuous improvement is widely applied.

The HSE standards of the Norwegian petroleum industry are recognized to be among the highest in the world. One important reason for this is the continuous efforts made through the Norwegian tripartite cooperation between regulators, employer organizations and trade unions. As Figure 12 shows, this is surprisingly not reflected in international injury statistics collected by the International association of Oil and Gas Producers (IOGP, 2021), where European oil producing countries appear to have poorer lost time injury rate (LTIR) than other regions such as Asia, Russia and Africa where working environment regulations are believed to be less stringent.

The apparently poor safety performance of the European region is less pronounced in the statistics on fatalities, see Figure 13, where the European region is in the middle of the investigated regions. We believe that the reporting accuracy increases with accident severity, and that the lack of correlation between LTIR and Fatal Accident Rate (FAR) numbers reflects diverging reporting practices rather than actual safety performance. OG21 has therefore not used the IOGP statistics as the basis for identifying safety gaps and measures, but instead used data and analyses from the Norwegian Petroleum Safety Authority (PSA) to discuss trends and improvement needs.

Figure 13. Fatal accident rate – five year rolling average by region (IOGP, 2021).

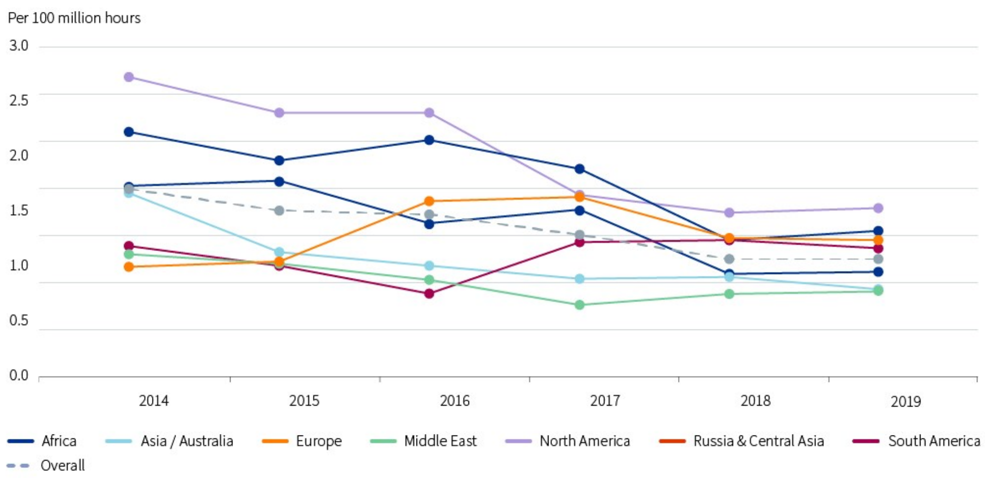
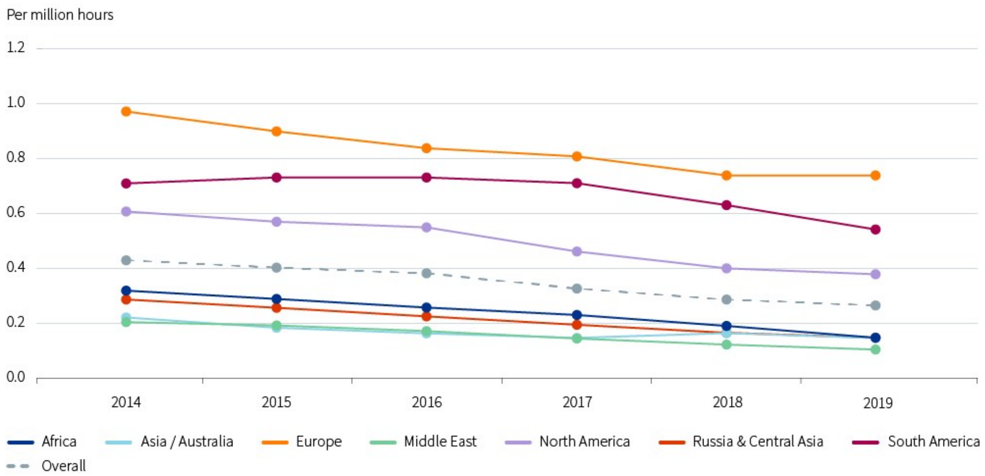
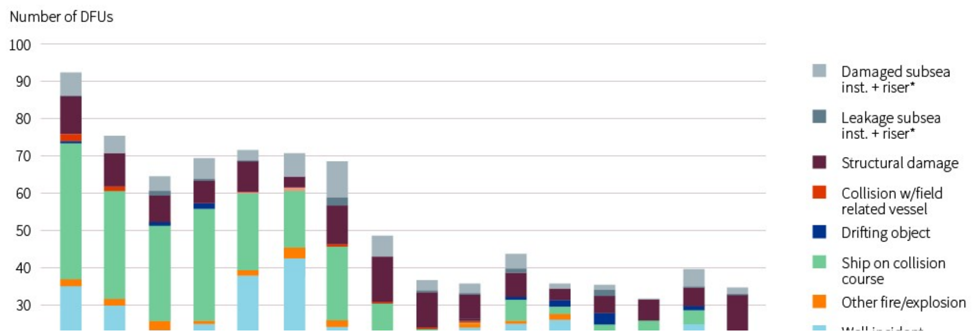


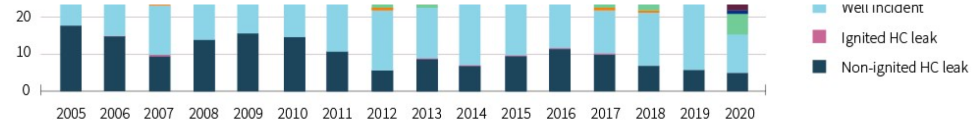
Figure 12. Lost time injury rate – five-year rolling average by region (IOGP, 2021).



In the latest version of its report Risk level on the NCS (RNNP), the PSA concludes that the safety in the Norwegian petroleum industry remains high. The number of offshore incidents with a major accident potential is down, where especially the numbers of hydrocarbon leaks and well control incidents in 2020 were historically low, (PSA, 2021).

Figure 14. Number of incidents with a major accident potential on the NCS (PSA, 2021)





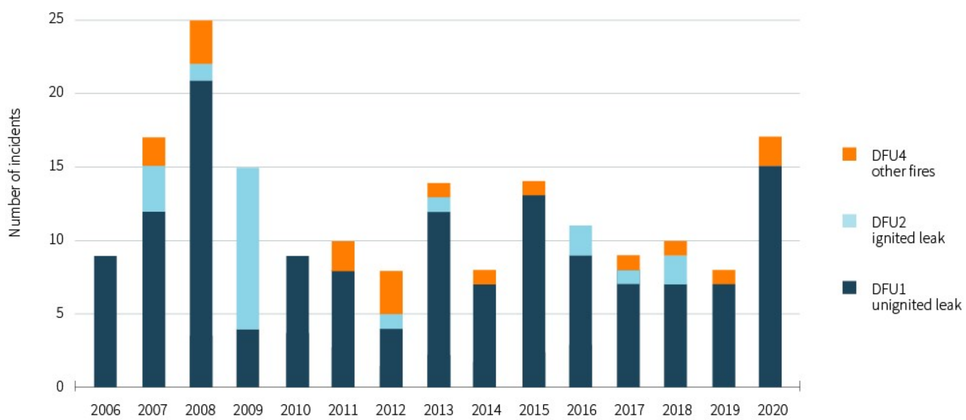
* within the safety zone

However, the trend on some indicators causes concern:

- A sharp increase in incidents with major accident potential at the onshore plants in 2020.
- A noticeable increase in structural incidents such as incidents involving dynamic positioning and mooring systems for mobile and floating installations, structural cracks, and waves on deck.
- Postponement of planned maintenance, especially the increase in maintenance backlog for HSE-critical equipment onshore.
- Negative trend in test results for safety-critical valves on offshore facilities.

However, it is important to state that the RNNP is a tool used to analyze trends over several years that require action or attention. Each report does provide a "snapshot" for a single year, but the formulation of R&D challenges and priorities is based on the trends observed over years.

Figure 15. Number of incidents with a major accident potential on onshore plants (PSA, 2021)



The further development of the NCS to stay competitive on costs, volumes, emissions and lead times, will require efficiency improvements, where the introduction of digital technologies, new business models and work processes, are central elements. New technology and the accelerating pace of changes introduces new hazards and risks that will have to be managed in the spirit of the zero accidents philosophy.

A continual improvement of HSE performance requires management attention and prioritization, as well as improved understanding of HSE risks, hazards, and under-lying causes. OG21 has in Section 4.1 identified several areas where new knowledge and technology could contribute to a continued positive trend in HSE performance on the NCS.

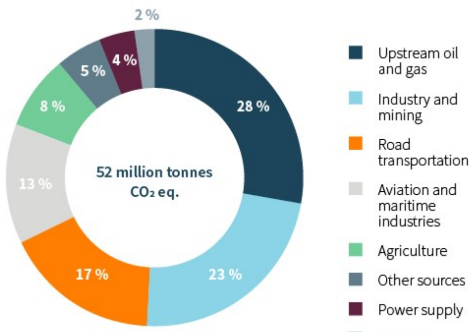
Operational GHG emissions to be reduced

Greenhouse gas emissions (GHG) from the NCS production measured as kg CO_2 per barrel produced (CO_2-intensity), are the lowest among petroleum provinces globally, (Rystad Energy, 2021). This is largely a result of the ban on regular gas flaring introduced in 1974, and the introduction of a petroleum CO_2-tax in 1991.

Figure 16. GHG emission intensity from O&G provinces (Rystad Energy, 2021)

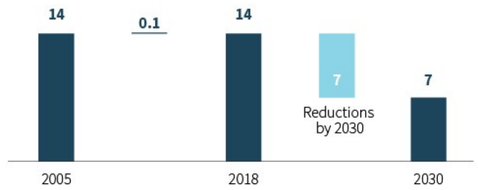
Still, the petroleum production is a significant contributor to the total Norwegian GHG emissions, as Figure 17 shows.

Figure 17. Norwegian GHG emissions per sector in 2018 (Rystad Energy, 2021)



The Norwegian petroleum industry represented by the Konkraft collaboration, launched ambitious GHG emission targets in 2020 aiming for a 40% reduction in operational GHG emissions by 2030 as compared to the 2005 level, and further reducing the GHG emissions to near-zero by 2050. As part of the temporary tax changes for the petroleum industry agreed in the parliament in June 2020, the parliament asked the industry to further strengthen its 2030 target to a 50% reduction by 2030, see Figure 18. (Konkraft, 2021).

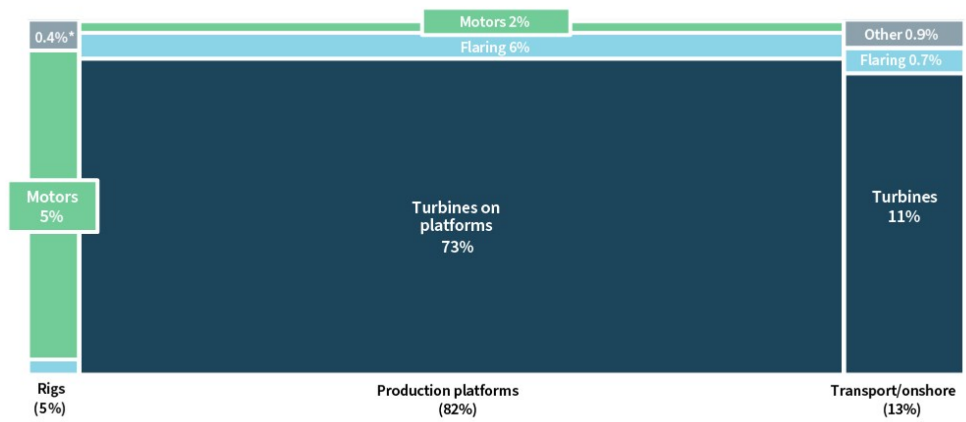
Figure 18. GHG emissions from the Norwegian petroleum industry and near-term reduction ambition
(Rystad Energy (2021) based on Konkraft (2021))



All numbers in million tons CO_2 equivalents

The main contributor to CO_2-emissions on the NCS is turbines, generating energy for the operations, see Figure 19.

Figure 19. Upstream CO_2 emissions in 2018 distributed on source (Rystad Energy, 2021)



*Includes other greenhouse emission gases in addition to CO_2

Source: Norwegian Oil & Gas; NPD; SSB; Rystad Energy research and analysis

The turbines are combustion engines running on natural gas, with thermal efficiencies dictated by fundamental thermodynamic laws and the load characteristics. Without bottom-cycle or heat recovery, offshore gas turbines typically have thermal efficiencies in the 30-35% range. The alternative use of the gas in modern combined cycle power plants onshore have a thermal efficiency above 60%, with a corresponding reduction in CO_2-emissions. In addition, capturing CO_2 for sequestration would be easier on large onshore plants. The case for electrification of the NCS with power from shore based on the Norwegian power mix or from other renewables, is hence strong from a technical CO_2 emissions perspective.

Konkraft has started the evaluations of how the 50% reduction ambition by 2030 could be met, see Figure 20. About 30% could be cut by projects already sanctioned and projects that are well matured, but not sanctioned, and a further 20% could be cut by projects currently in the concept phase. Approximately half of the necessary reductions would have to be cut by projects and measures that still need to be identified, matured and sanctioned.

Figure 21 illustrates that electrification from shore is the most important measure to meet the 2030 ambition. However, energy efficiency, reduction of flaring, and wind power have also been identified as important contributors by Konkraft.

Figure 20. Opportunity space for 50% GHG emissions by 2030 (Konkraft, 2021)

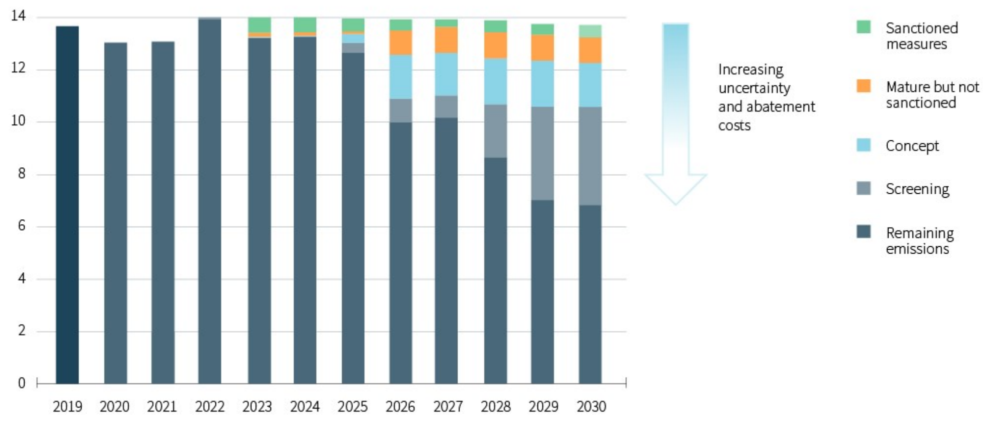
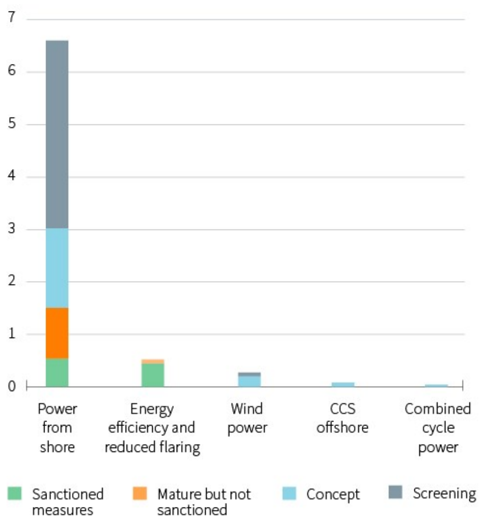


Figure 21. CO_2 abatement effect of opportunities according to Konkraft (2021)



As producing fields mature, their CO_2-intensity can be expected to increase unless measures are taken. Such measures include tie-back of new resources to increase the denominator in the metric, reduced water production through better reservoir drainage solutions or water separation downhole or on the seabed, and improved energy efficiency topside. Such measures, and other technology opportunities that could contribute to bring down GHG emissions, are described in Section 4.

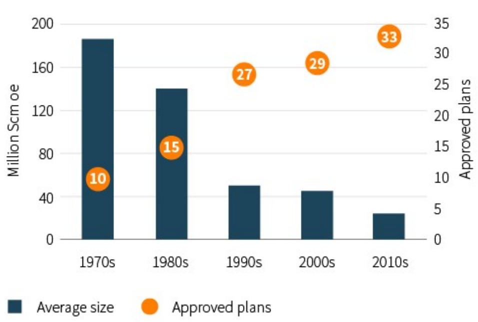
The GHG emissions from the consumption of hydrocarbons is considerably higher than the emissions from the production. This does not mean that production emissions are not important. Firstly, the NCS production emissions are a major contributor to national emissions. Secondly, as oil demand over time is reduced in the transportation sector due to electrification or substitution with low-carbon fuels, an increasing portion of the carbon will be locked in petrochemical products, which increases the relative importance of production emissions.

A maturing NCS with many small discoveries, substantial resources in existing fields and still the opportunity for large discoveries

3.4.1 Many discoveries on the NCS, but the average size is decreasing

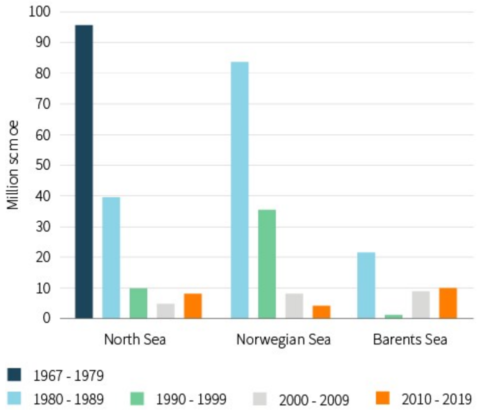
The NCS is maturing, which the average field development size per decade from the 70'ies and until today as shown in Figure 22, clearly indicates. At the same time the average number of field developments per decade has increased (NPD, 2019).

Figure 22. Average size at first PDO and number of approved development plans (NPD, 2019)



The large fields in the North Sea and the Norwegian Sea were mainly developed during the 70's and 80's, see Figure 23. With a few exceptions, notably the Johan Sverdrup field discovered in 2011, the discoveries and field developments have since then been relatively smaller. The Norwegian part of the Barents Sea is less explored, and a similar creaming curve for that basin is still not observed.

Figure 23. Development of average discovery size by region (NPD, 2020)



The NCS discovery portfolio in 2018 consisted of 85 discoveries with an average size of 49 million boe (NPD, 2019). The average discovery in 2019 and 2020 was approximately of the same size, see Figure 25. The average discovery on the NCS is small compared to many other provinces in the world, but the exploration success rate is high.

Figure 24. Discoveries by sea area and expected recoverable resources at 31 Desember 2018 (NPD, 2019)

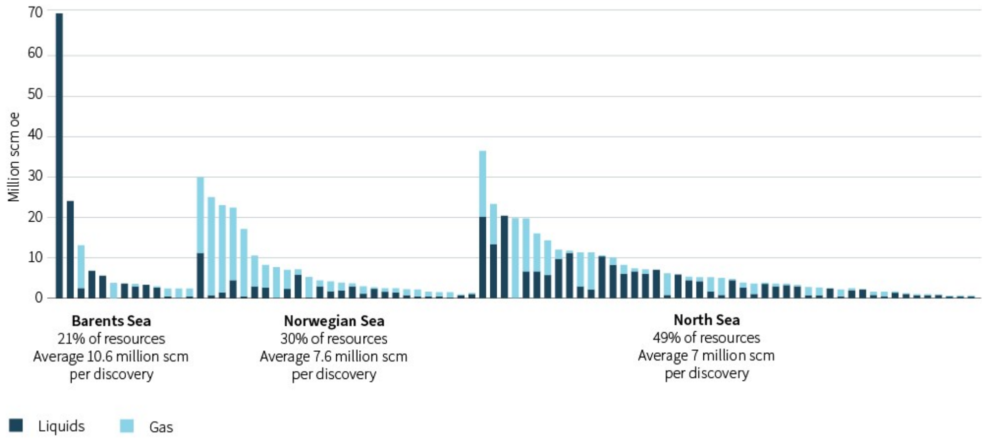
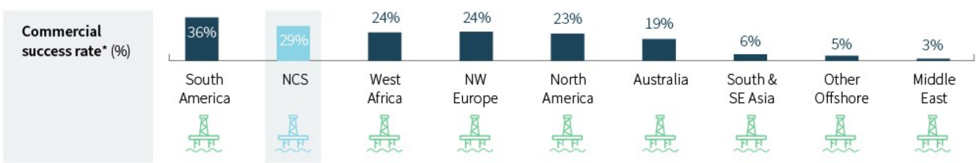


Figure 25. High exploration success rate in 2019/2020, but average discovery rate is relatively small (Rystad Energy, 2021)

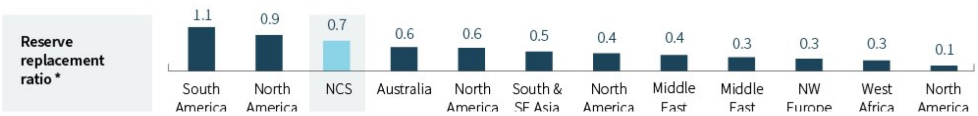


** Number of wildcats which lead to commercial discoveries divided by number of wildcats drilled. Only offshore. Includes only commercial discoveries where public information is available. Average of 2019 and 2020.*

*** Only offshore. Includes only commercial discoveries where public information is available. Average of 2019 and 2020.*

With a reserves replacement ratio (RRR) of 0.7, new discoveries on the NCS have not been able to replace the production over the last 5 years, as Figure 26 shows. In a global context, the RRR is competitive though. The RRR does not reflect reserves growth in existing fields.

Figure 26. NCS reserve replacement ratio higher than most other regions
(Rystad Energy, 2021)



* Sum of sanctioned volumes by approval year over produced volumes from 2015 to 2020.

Offshore Shale unconventional Onshore conventional Oil sands unconventional

3.4.2 Existing infrastructure key to further NCS development

Existing infrastructure is key to the further NCS development:

- Realizing the large contingent resources in existing fields, indicated in Figure 2 in Section 4.
- Realizing the large portfolio of smaller discoveries that would require tie-back to a host.
- It encourages further exploration in the proximity of potential hubs.

Contingent resources in existing fields are of the same magnitude as the contingent resources in the discovery portfolio. Historically, operators in collaboration with suppliers on the NCS have been able to realize such resources with great success.

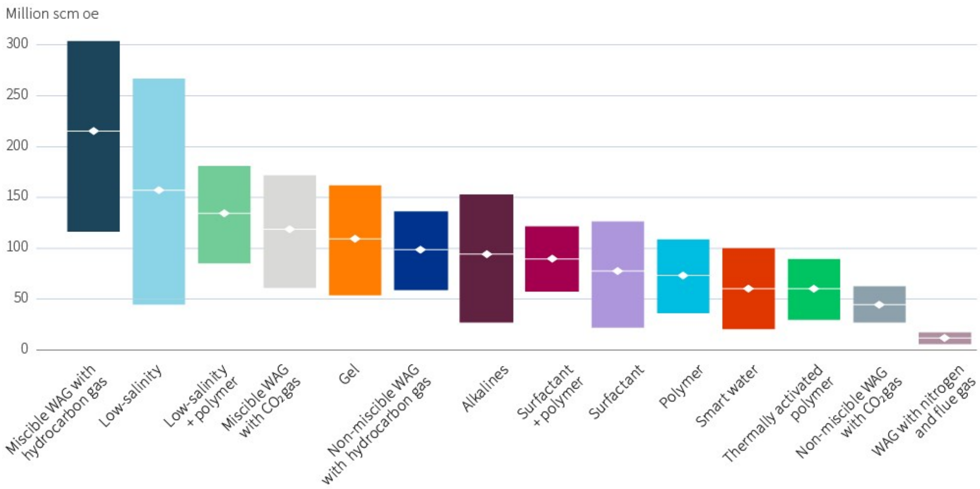
Looking forward, there are numerous projects in the pipeline that would improve oil recovery (IOR) from existing fields – Figure 27 shows specific but undecided projects reported to the NPD. Wells are the most important measure to realize new resources from existing oil fields, whereas low-pressure production is the measure that is favored for gas fields.

Figure 27. Projects and estimated recoverable volumes for oil by project category (NPD, 2019)

In addition, there is a substantial potential for improved recovery related to more advanced methods, the so-called Enhanced Oil Recovery (EOR) methods, see Figure 28. The figure presents the scaled potential for specific EOR methods summed up for 27 discoveries and fields included in an NPD study on the EOR potential (NPD, 2019). The scaled potential reflects operational criteria as well as economics.

Despite the potential large volumes such measures could provide, there are only few projects currently being considered, as Figure 27 shows.

Figure 28. Potential volumes from Enhanced Recovery Methods on the NCS (NPD, 2019)



IOR and EOR methods can provide large added volumes. When it comes to investment decisions, many of the methods fall short because of either high costs and/or high GHG emissions.

Most of the 85 discoveries in the NCS portfolio are too small to justify stand-alone developments, and would therefore require tie-back to existing infrastructure to become realized, as Figure 29 suggests. 86% of the discoveries are within a 40 km distance to a possible host discovery. Only 4 of the 85 discoveries are further than 60 km away from a potential host facility.

The size distribution of the discoveries and the proximity to potential host facilities, illustrate the importance of efficiently utilizing existing infrastructure for the further development of the NCS (NPD, 2019).

Figure 29. Resources and distances to possible host facilities for discoveries in the NCS portfolio (NPD, 2019)

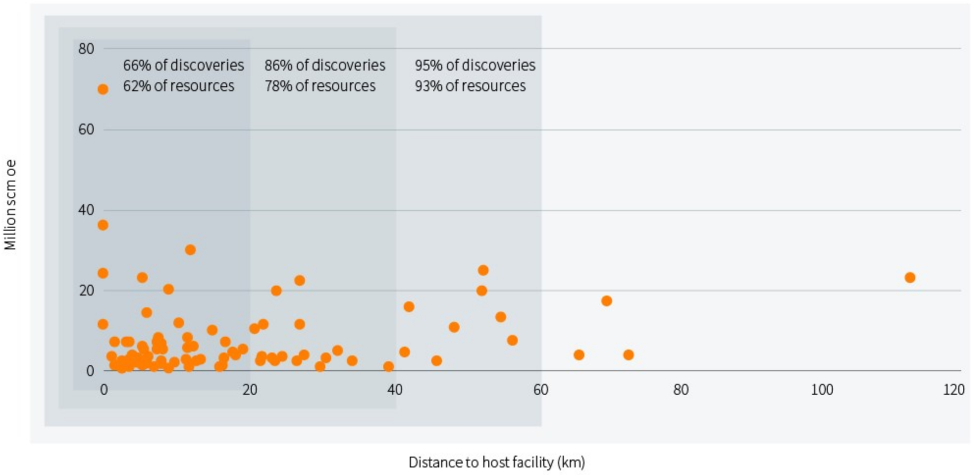
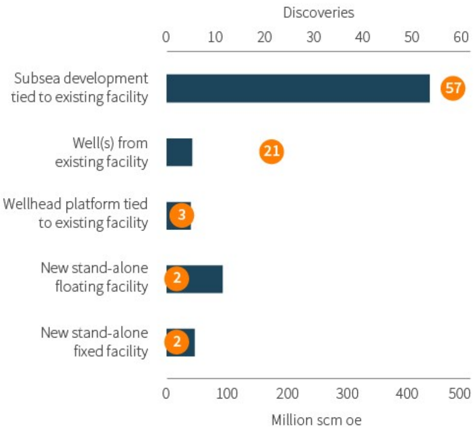
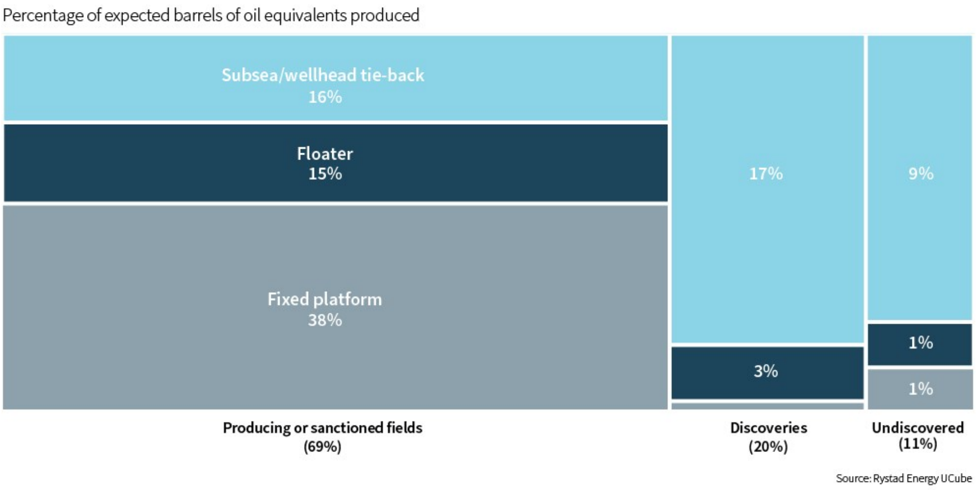


Figure 30. Most probable development solution for discoveries (NPD, 2019)



Realizing more resources on the NCS is a cross-functional task involving subsurface, drilling and well, and facilities disciplines, in close collaboration with safety and external environmental groups. This is reflected in the OG21 technology priorities described in Section 4.

Figure 31. Expected production from the NCS 2021-2050 (Rystad Energy, 2021)



A continued high attention to cost is required to stay competitive

Break-even prices on the NCS are currently competitive compared to other oil provinces (Figure 32). As Figure 33 indicates, this is mainly due to low operational costs, which again is caused by a cost-efficient infrastructure well suited for development of new resources in the fields or near-field tied back to hubs.

Although exploration costs (Expex) and capital costs (Capex) for new projects have come down considerably since 2014, Figure 33 clearly shows that Expex and Capex on the NCS are relatively high compared to the competition.

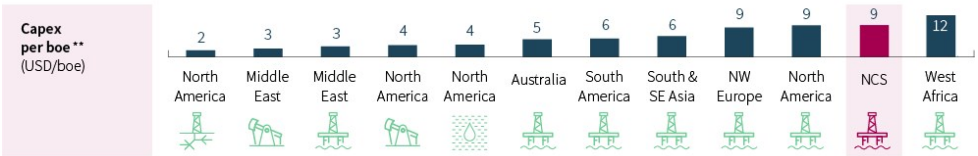
Figure 32. Break-even prices for oil fields sanctioned since 2018 (Rystad Energy, 2021)

** Breakeven price for oil fields approved in 2018 seen from the approval year – oil price that returns NPV equal to zero at 10% discount rate.*
Weighted average of 2019 and 2020.

Offshore Shale unconventional Onshore conventional Oil sands unconventional

Figure 33. Expex, capex and opex on the NCS (Rystad Energy, 2021)

** Exploration expenses per found resources. Only offshore. Includes only commercial discoveries where public information is available. Average og 2019 and 2020.*



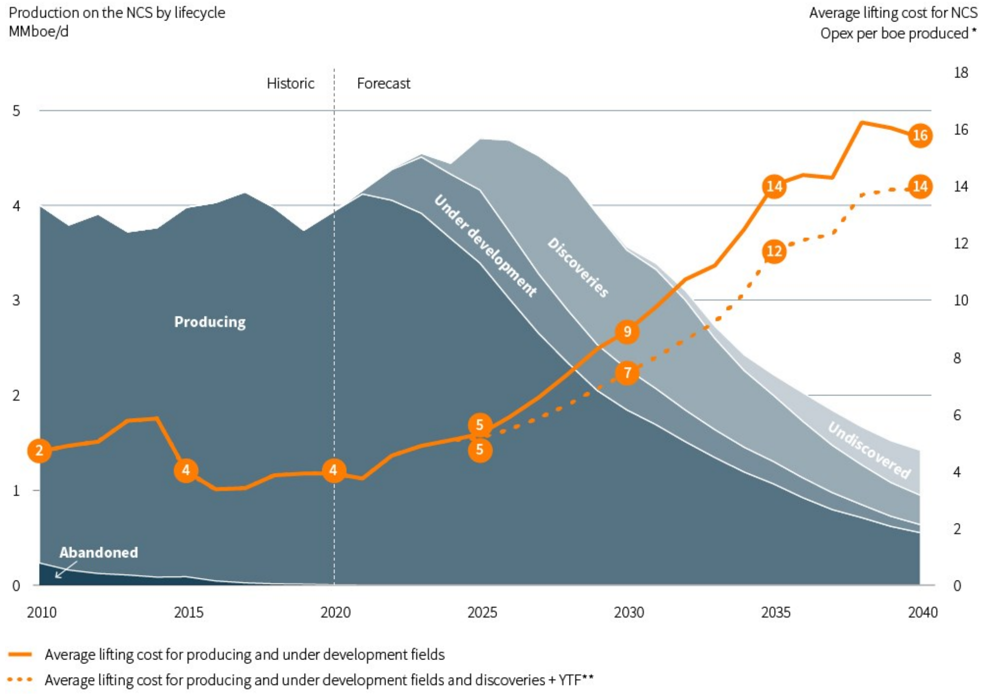
*** Greenfield capital expenditures related to sanctioned oil and gas fields in current year for these fields. Volume weighted average of 2019 and 2020.*

**** Excludes transportation and tax opex. Includes only opex associated with the production of hydrocarbons in addition to SG&A.*

Offshore Shale unconventional Onshore conventional Oil sands unconventional

To further underline the generic cost challenge, the currently favorable Opex level on the NCS contributing to the low break-even price, cannot be taken for granted. Operational costs remain largely at the same absolute level for an installation throughout its lifetime, and as the production from a field declines, the average lifting costs per barrel increase. Figure 34 illustrates this on an aggregated level for the NCS.

Figure 34. Average lifting costs as the NCS matures (Rystad Energy, 2021)



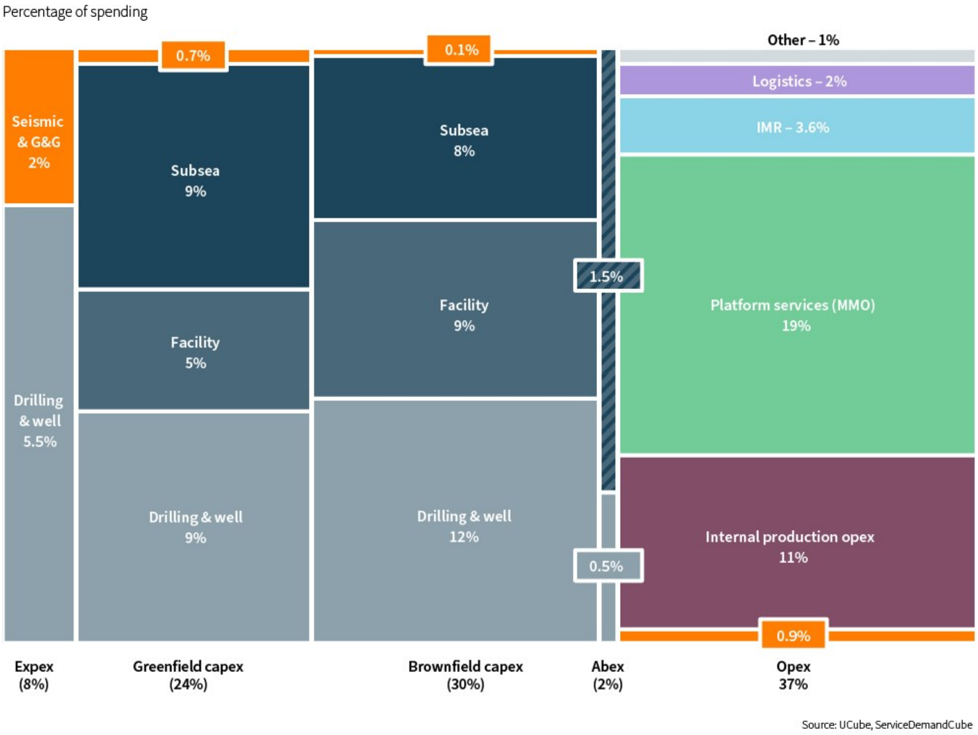
**Production opex only. SG&A and transportation tariffs not included; **only from opened areas*

Source: Rystad Energy UCube

As Figure 35 illustrates, we expect four main cost areas over the next two decades:

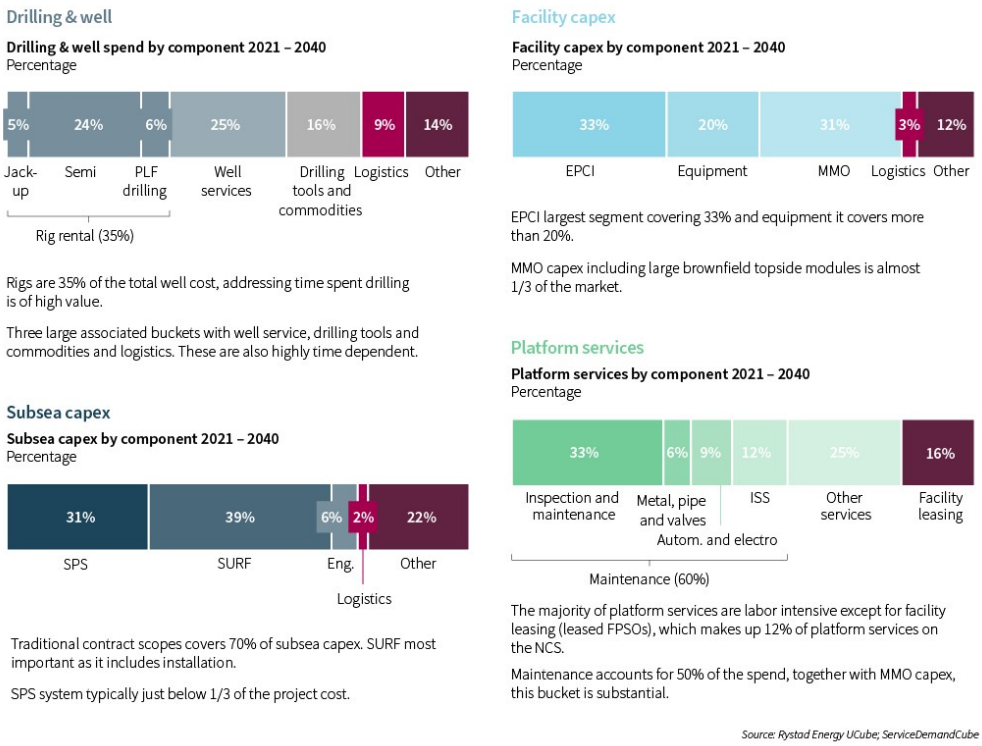
- Drilling and well (28%)
- Facility capex (14%)
- Platform service and maintenance (19%)
- Subsea capex (17%)

Figure 35. Expected main cost areas for the NCS year 2021–2040 (Rystad Energy, 2021)



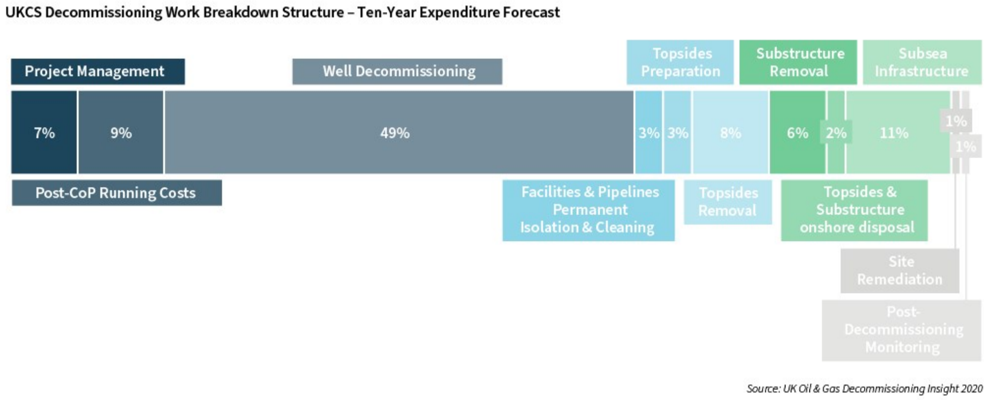
A deeper dive into the expected four main cost areas is shown in Figure 36.

Figure 36. Four main cost areas for the NCS 2021-2040 broken down into cost elements (Rystad Energy, 2021)



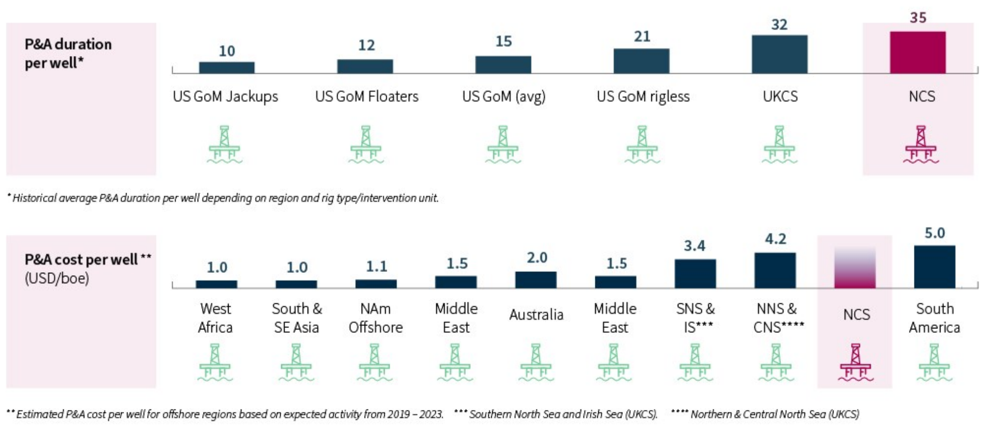
De-commissioning costs is a growing concern on the NCS. Many fields approach the end-of-life, and wells will have to be plugged and facilities removed. UK numbers suggest that plugging and abandonment of wells (P&A) contribute with 49% of de-commissioning costs, whereas removal of facilities, site remediation and monitoring combined contribute with around 34% of the costs.

Figure 37. Break-down of expected de-commissioning costs in the UK over the next decade
(Rystad Energy, 2021, based on numbers from UK Oil and Gas)



More than 3000 wells are going to be plugged and abandoned safely on the NCS over the next decades. A typical P&A operation on the NCS takes 35 days with the use of a mobile drilling unit. This is longer than P&A operations in other offshore petroleum provinces and it drives costs. More efficient P&A methods in addition to methods that would allow lighter vessels to be used for P&A, would have the potential to reduce costs considerably.

Figure 38 P&A durations and costs on the NCS compared with other basins (Rystad Energy, 2021)



Utilizing and extending the life of existing infrastructure contributes to cost-efficient development of new fields in the vicinity. This has a positive effect on NPV as some de-commissioning costs are moved into the future. An alternative use of facilities when the field approaches late-life or even after production has shut down, could have the same effects.

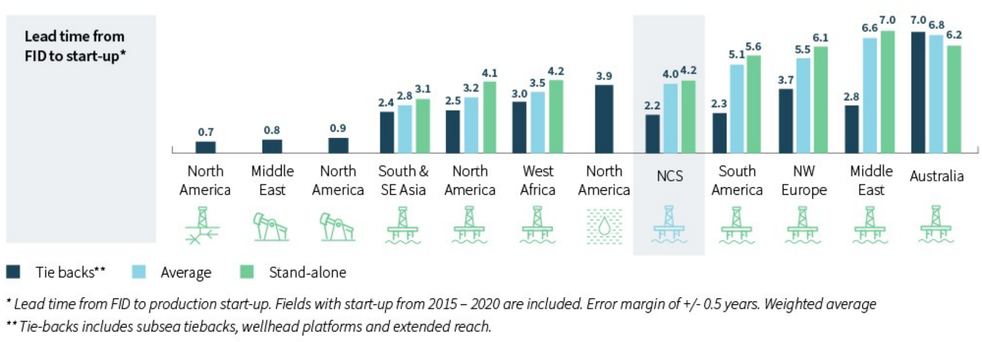
The cost challenge on the NCS remains high in all phases: exploration, field development, production and operations, and de-commissioning including P&A. Bringing costs down is an important driver behind the development and implementation of new technology for all these phases, as the discussion of OG21's technology priorities in Section 4 shows.

Reduction of lead time increasingly important

The lead time, measured as time from investment decision to production starts, is an increasingly important parameter when sanctioning new investments. Shorter lead times reduce uncertainties related to product prices, costs for emitting GHG gases, and policy development.

Onshore developments within conventional and shale stand out as the projects with the lowest lead times. The NCS is on the average compared to other offshore provinces on this metric. However, tie-backs to hubs, which is a very important field development solution on the NCS, compare very favorable to other offshore regions.

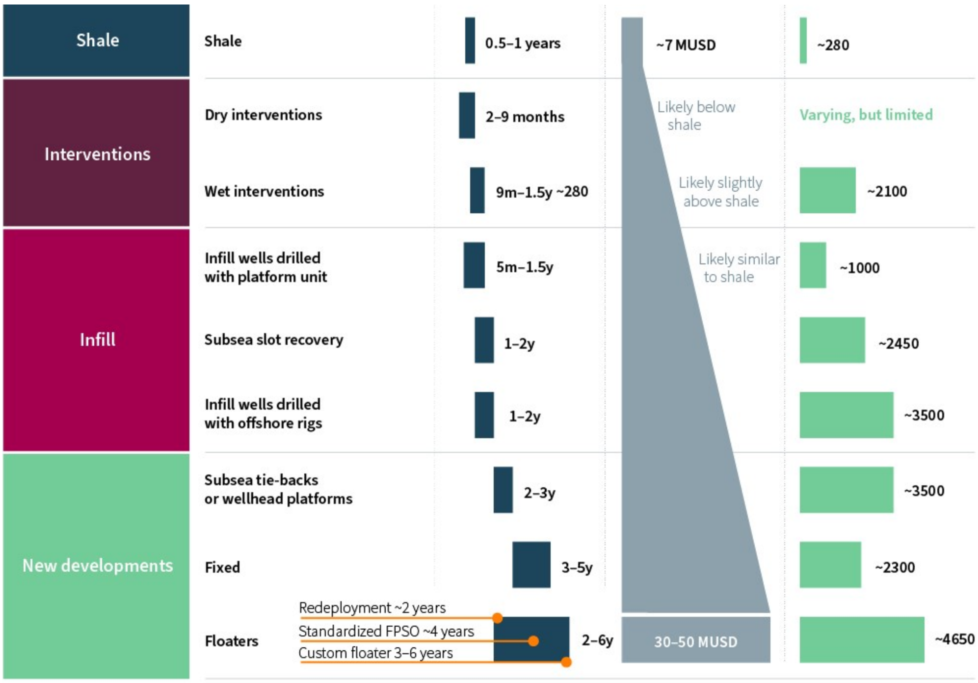
Figure 39. Lead times from investment decision to production start-up for O&G regions (Rystad Energy, 2021)



Some field development methods on the NCS offer lead times that are at par with the best industry performance. Well interventions and infill wells are examples that provide volumes with lead times ranging from months to less than 2 years.

Figure 40. Some field development methods provide competitive volumes at low cost and with short lead times (Rystad Energy, 2021)

	Different ways to add volumes	Lead time (Years)	Capex per well (MUSD)	Drilling emissions* (Tons CO_2 per well)



When considering new technology, the ability of the new technology to reduce lead time and accelerate production should be included.

← Forrige side

Neste side →