Technologies to improve NCS competitiveness

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RYSTAD ENERGY

Index

Summary: Future demand scenarios and NCS competitiveness as a supply source

Main findings	Description
Large spread in possible demand outcomes for oil	• We are coming from a world of steady demand growth of +1% over the last 10 years driven by a strong underlying growth in global GDP. Both policy changes to comply with 2DG scenarios, energy efficiency and alternative fuel sources are placing pressure on the demand outlooks on top of geopolitical fluctuations. • There is a large spread in possible demand outcomes: from *moderate growth scenarios* of 0.5-1% annually going forward to *peak demand scenarios* with peak between 2025 and 2030 with an average decline of between 1-2% per year. In 2050 these two scenario groups have 113 mmbbl/d and 59 mmbbl/d in annual demand, respectively. • There is a viable pathway to the peak oil demand scenarios. Almost 60% of the demand is driven by the transport sector. All of the transport sectors, with the exception of aviation (6%), will likely have access to economical substitutes in the short to medium-term. For light duty vehicles (26%), the effect of increased adoption of electric vehicles in line with car manufacturers' targets will impact oil demand by -1.8 mmbbl/d in 2025, enough to send overall global demand in decline.
Fundamental differences between scenarios on the role of gas in EU28s energy mix	• EU gas demand is in decline in all scenarios, but the angle of the slope varies significantly. Two scenarios have been applied for EU28 gas demand, IEAs New Policies and average of 2DG scenarios in European Commissions strategic vision, *A Clean Planet for All.* There is a principle difference in how EU, in this policy document, view the role of gas in the EU28s energy mix compared to IEA and Norway (Equinor). It is important to note that the document has yet to be ratified by the European Parliament. EU is to adopt and submit their strategy by early 2020 to UNFCCC as requested by the Paris Agreement. • Norway and Equinor market Norwegian gas as part of the solution in EUs shift towards more sustainable energy supply, both in replacing coal short-term, but also as a part of solving the problem of intermittence from renewable sources. • EU, through their recent «Clean Planet for All» policy document, leaves less room for gas use in meeting 2DG targets both in residential and commercial, power and industrial applications. Intermittence is to be solved through green energy storage and digitalization, not gas power plants. On the other side, should this policy vision be enacted, this could open new business models for Norwegian gas, i.e. hydrogen production from methane coupled with CCS.
New competitiveness metrics	• There has been a shift in how we measure competitiveness, going from materiality pre-downturn towards robustness during the downturn, and towards sustainability going forward. • In the downturn, extreme focus on cost have shifted breakeven down and improved lifting costs significantly, and will remain important going forward. • Looking forward, we observe increased public perception (especially domestically) and pressure on carbon intensive industries together with rising CO_2 prices. Investors places higher risk on carbon intensive industries now than before. Having a carbon effective production will likely be a competitive advantage. Also, with uncertain demand outlooks and volatile commodity prices, short payback time is as important as ever.
NCS is currently very competitive on most dimensions - only beaten by shale	• Competitiveness of the NCS has been measured along three dimensions: volumes, cost and emissions. On the volume side, NCS has the highest recovery rate of the conventional resources, and lead times for the subsea tie-backs are comparable to onshore fields with exception of shale. Net volume additions have been flat for the NCS and for offshore in general, but shale has added 3.3 mmbbl/d in additional production over the last five years, growing their market share considerably. • On costs, both breakeven and lifting costs are impressive for the NCS, ranking 2nd only after shale, and better compared to other offshore segments. On lifting cost we are surprisingly close to onshore segments given the complexity of producing oil offshore. Exploration costs per barrel found are not competitive compared to other offshore regions in the time span evaluated. This is a function of high well cost and few resources found. • On emissions the NCS is ranked number 1 or 2 on all metrics, with almost negligible flaring compared to peers.
NCS competitiveness will likely be challenged as the portfolio of fields mature **-** **Producing hosts and exploration are most sensitive to the low carbon scenario**	• NCS is vulnerable to improved competitiveness from other supply sources. Exploiting oil and gas in harsh offshore environments from relatively small fields (future) is an challenging venture compared to large fields in more benign regions. The current favorable competitiveness is not a result of advantageous natural conditions, but despite them. Improved operational efficiency, reduced flaring and application of mature technologies in other supply segments could easily and quite rapidly challenge NCS as a top performer, i.e. improvement in recovery rates in onshore Middle East or shale could displace significant volumes. • Going forward a larger share of Norwegian fields with standalone hosts are approaching tail-end production. Per barrel metrics like lifting cost and emission intensity will se a natural increase as the portfolio of fields mature and possibly to levels were they could struggle to be competitive with the currently available technologies. In a low carbon scenario, several of these hosts are at risk of shutting down when discriminating on emissions. Still, in this scenario there will likely be more room for NCS volumes than other supply segments. • In the low carbon scenarios, exploration is seeing the highest sensitivity when we discriminate on costs. Based on our estimates, half of the prospective undiscovered volumes on the NCS are at risk in a low carbon scenario, and especially gas exploration could see a significant haircut as the low carbon scenario calls for limited new gas needed in the EU beyond what is left in the tail from currently producing fields.

Source: Rystad Energy research and analysis

Summary: Technologies to improve NCS competitiveness

Main findings	Description
Volumes: interdependency between hosts and tie-backs	• The NCS volumes are divided into two large buckets: existing fields with standalone facilities (hosts) and new tiebacks (wellhead or subsea) from current discoveries or Yet-To-Find (YTF) volumes. These are interlinked, the tie-backs needs a host to be able to process and market their volumes and hosts need new volumes to be able to keep unit costs and emission intensity down. • Large field centers on the NCS are maturing, these are or will become the most emission intensive on the NCS as they approach tail-end production unless measures are taken. Lifting costs as measured per barrel will similarly increase as the fields approach tail-end production. In a low carbon scenario where we discriminate on emissions, 25 of 38 field centers are at risk of shutting down. These field centers are vital to secure future NCS volumes. From a volume perspective this can be accomplished by adding additional volumes through IOR/EOR measures volumes from the underlying (large) reservoirs or securing new volumes from nearby tiebacks. Upgrading existing infrastructure for IOR/EOR measures is technically challenging, often marginal when discounted and historically emission intensive through high power demand. • The discovery portfolio is full of small fields and discovery sizes are declining. This implies that there will likely be few standalone facilities in the pipeline. 75% of new volumes on the NCS will likely be wellhead or subsea tie-backs in need of existing hosts. These tie-backs could have a different ownership structure making it difficult to arrive at commercial terms and a more marginal economy that is sensitive to large modifications on the hosts that they are tying into.
Costs: drilling largest cost element and platform maintenance important to secure hosts	• When disaggregating the cost structure on the NCS, drilling and completion is the large single cost element and account for over 40% of the total costs on the NCS in the period. It has application in all parts of the E&P life cycle, exploration (wildcats and appraisals), development, production phase (infill drilling) and decommissioning (P&A). Other large cost elements include topside facilities (18%), subsea facilities (11%) and platform maintenance (18%). • Given the large cost base, technologies to improve drilling efficiency will therefore have high absolute impact. They also have the benefits short-lead time to and multiple applications (wells) to test and apply new technology. During the down-turn this drilling and completions was one of the segments where application of new technology was pivotal in bringing the costs down. • Technologies that attack platform maintenance, one of the largest opex buckets, will be important to keep hosts competitive and secure lifetime for future volume, both in-field and tie-backs. The effect will often be reduced need for offshore manning that also have cascade effects into other cost buckets like logistics and internal opex.
Emissions: it is all about gas turbines on hosts	• With the limited amount of flaring on the NCS, the largest emission source upstream is gas turbines (85%). There are two ways to attack the emissions from gas turbines, improved energy efficiency on the platforms and turbines (less gas use) or switch to clean power supply. The switch to clean power supply has up to recently been addressed by power from the onshore grid. • Looking at the power demand on the platforms the majority of this relates to water injection pumps and gas compression for injection and gas lift. These IOR techniques have been the main reason for the very competitive NCS recovery rates. A large part of the resource potential on the NCS lies in increasing recovery and the majority of the contingent resources on the NCS lies in already producing fields. It is vital to realize these volumes without increasing emission intensity in order to sustain the competitiveness of hosts on the NCS.
High value in closing technology gaps	• Based on the evaluation, there is high value in closing the 17 focus technologies chosen by the TTA groups. Single technologies have the potential to deliver additional volumes equivalent to elephant fields, combined deliver a state budget in cost savings, and make the NCS CO_2 neutral. • All, but one technology (predictive maintenance) target a subset of NCS fields. There is no silver bullet, we are reliant on multiple technologies to target all volumes, cost and emissions to improve NCS competitiveness across the board
Key observations from technology evaluations	• <u>No single technology with large impact on both volumes, cost and emission:</u> There are several technologies with compound effects on both volumes, cost and emissions. Although with high impact on volumes and cost, the impact on emissions is less substantial as none of these target the main issue: emissions from gas turbines • <u>Technologies with high impact on emissions are expensive:</u> with the exception of Compact CCS, all of the high impact technologies have abatement costs above the current CO_2 price. This implies that it is currently not economically feasible to adopt them. Floating offshore wind has the potential to see significantly reduced costs with industrialization (larger wind farms) and economies of scale. • <u>Most of impactful cost and volume enhancing technologies are digitalization technologies:</u> Many of these interplay with each other, i.e. wired pipe feeds data into real-time field models and automated drilling control. • <u>Several impactful volume enhancing technologies have short lead times that can compete with shale:</u> In the competition with shale, lead times are important, and many of the technologies require larger greenfield developments or extensive brownfield modifications which takes time from FID to implementation. There are however four technologies in the sample that have significant volume contributions and lead times below 2 years. • <u>Drilling technologies are by far the most agile:</u> Most drilling technologies have an adoption time equal to the time it takes to plan a well, 6-18 months. These are by far the most agile of the technologies and may be the reason why these have seen the highest adoption during the downturn • <u>Subsea processing technologies could be vital in solving host & tie-back issues:</u> During the cross-industry workshop, subsea processing technologies were widely discussed as technology to resolve host issues rather than boosting production in its ability to debottleneck topside constraints and improve energy efficiency

Source: Rystad Energy research and analysis

Summary: Historical NCS cost development and the role of technology

Main findings	Description
Impressive cost reductions for both opex and capex segments in the period 2014-2018	Following the oil price collapse in 2014 we have observed impressive cost reductions both in opex and capex categories: Opex: • Observed cost reductions from 2014 to 2018 between -23% - and -37%. Reductions are largest within *Logistics,* which is the most asset heavy opex segment, highly influenced by reductions in day-rates for OSVs and helicopters. • Activity has been more stable in this segment than the capex heavy segments which are more dependent on sanctioning activity. Capex: • Observed cost reduction from 2014 to 2018 of between -39% and -46%. Reductions largest within the *Drilling* which has seen reduced activity, slashed day rates and improvement in drilling efficiency. • Activity within capex segments are highly dependent on sanctioning activity, which has been to a large degree halted up to 2016, but development of the Johan Sverdrup fields has to some degree bridged the trough in upstream investments in the period. • Investments on the NCS had a positive development in 2018, where NCS was among the first offshore regions to recover. Impressive developments in breakeven prices on greenfield projects is a key reason behind this recovery.. Also brownfield projects, exemplified by the Petoro portfolio development, has had a positive development on both cost and volumes.
Efficiency improvements observed across all segments	Opex: Detailed segment by segment walkthrough where activity, price and efficiency have been separated reveal an average efficiency improvement of -23%, it is the maintenance-heavy segments that have seen the largest improvements in efficiency. Capex: Disaggregating spend is more complex for capex as contracts are awarded across multiple segments. Based on case examples from Johan Sverdrup and Johan Castberg we observe efficiency improvements between -8% and -24%. Dedicated analysis on the drilling speed (relevant for only part of the drilling cost) show that we are on average drilling twice as fast as measured in meters drilled per day in 2018 compared to 2014.
New technologies have been more important in capex than opex segments where change in philosophy has been the main source of efficiency improvement	Opex: Change of philosophies and work processes is the prevalent driver of efficiency during the downturn. New technology in terms widespread adoption is expected to be early elements of predictive maintenance technologies, but they have yet to see material effect. The contribution from «knowledge» is observed in new maintenance philosophies and work processes that has been the most important elements in improving efficiency.. Capex Efficiency improvements in projects sanctioned and developed during the downturn is to a larger degree a result of standardization and simplification than implementation of new technology. Implementation of new hardware and software in drilling operations has had a lower threshold with more applications and lower lead time. Dual derricks, MPD-technologies, drilling decision support software has played a part during the downturn as newer rigs have taken larger parts of the market. Apart from software and hardware contributions, efficiency gains within drilling has perhaps seen larger gains from incentivizing rig owners, one team approaches, utilizing the capabilities of the rigs to the fullest, and challenging existing work processes and methods to unlock better performance.
Case example: Twice as high efficiency improvements in the cases where new technology have been applied	• By looking at how each individual drilling rig has performed on the NCS, we have been able to quantify what part of the improvements are related to new hardware and what are improved work processes and incentivized rig owners. Based on the rig types (semi, jack-up, platform), design and build year, we have placed the rigs in two categories: new and old. • Both categories have seen impressive efficiency improvements, but new rigs have outperformed old rigs with +100% improvement in meters drilled per day compared to +50% improvement for older rigs. Simplified, for this segment, we can state that half of the improvements in drilling efficiency is a result of new technology and the other half a result of improved work processes. • Other observations include high learning effects when drilling back to back wells.

Source: Rystad Energy research and analysis

Recommendations where OG21 can play a direct role

<table>
<tr><th>Recommendation</th><th>Rationale</th><th>OG21s role</th></tr>
<tr><td>OG21 should be explicit on the carbon challenge in their strategic objectives</td><td>OG21’s strategic objectives reflect well the balance that should be taken when making technology decisions. The first three pinpoints that both volumes, cost and the environmental impact are to be equally considered when developing new technologies. However, minimizing environmental impact have multiple components, where reducing emissions is one of many. Given the magnitude of the emissions challenge, it should be named explicitly. Consider adding reducing NCS emissions as a dedicated strategic objective and include other environmental aspects under a general HSE* objective.</td><td>Evaluate when conducting the next strategy revision</td></tr>
<tr><td>Provide additional guidance to R&D funding for selected technology areas</td><td>A main finding is that the selected technologies are well reflected in the current OG21 strategy. In this study the selected technologies have been ranked according to their likely effects on volumes, cost and emissions on the NCS. Even tough the list of selected technologies cannot be regarded as a comprehensive prioritization, the assessment provide sufficient granularity to suggest the following recommendations:
• <u>Digitalization technologies</u> – bridges costly interfaces between technology areas, unlocking hidden system value and shortens lead time, the latter an important competitiveness metric. Should see prioritization in funding across the TTA groups.
• <u>Emission technologies</u> – clear need to lower abatement costs of emission technologies, objective of funding should be to reduce the investment cost for technologies that minimize or eliminate emissions from turbines. Improvement needed for both new greenfield developments and brownfield retrofits.
• <u>Subsea processing technologies</u> - business cases for these have historically been about increasing the resource potential, but technology could have a wider role in debottlenecking hosts and improving emission intensity trough improved energy efficiency. This interplay should see increased attention.
• <u>Drilling technologies</u> – Has seen an impressive impact of new technology in improving efficiency during the downturn. Drilling costs constitute a large part of the cost base and have short lead times from application to contribution. Should continue to see prioritization of funding,
• <u>Exploration technologies</u> – there is uncertainty regarding the volumes needed from undiscovered fields in the long term. Application of new exploration technologies will likely not have volume contributions from frontier wildcats before 2030, given R&D time and lead time from discovery to production for stand-alone facilities. However, new exploration R&D is mostly about better subsurface understanding, and improving this have high value for producing fields and with significantly shorter lead times. Adding more volumes to producing hosts will improve NCS competitiveness on both lifting costs (as measured per barrel) and emission intensity. Also, securing new discoveries near hosts (ILX) will be important to have optimal utilization of existing infrastructure. R&D funding for exploration technologies should be based more on its value for producing fields and near field exploration than for its value for frontier exploration with long lead time and more uncertain volume contributions in the long term.
• <u>New technologies to market Norwegian gas</u> – Regardless of a possible policy shift from the EU that will impact demand for NCS gas, technologies that convert gas to alternative fuels or clean power should see increased funding. Technology development to find alternate ways to market gas could be a pathway to a new industry for Norway and secure the value of our natural resources. It could also enable stranded “undiscovered” gas volumes in the Barents Sea.</td><td>Provide advise to the government on R&D funding covering these technology areas</td></tr>
<tr><td>Holistic approach to policy instruments for technologies addressing the emissions challenge</td><td>The system borders set down for technology funding are being challenged by the magnitude of the emission challenge. The oil and gas value chain are seeing increased interplay with both the power, CO_2 and hydrogen value chains. Examples of this include:
• Offshore wind and offshore grid – large scale industrialization needed to bring costs down
• Gas extraction, hydrogen/ammonia production and CCUS
• CCUS and CO_2 for EOR
• Power from shore and onshore power grid capacity
Long term vision and direction is necessary to address the emission challenge, where oil and gas is only a part of it and multiple interest groups exists. Policy instruments that are system restricted may lead to suboptimal R&D initiatives.
Two concrete measures to be evaluated:
1. Joint strategic advice from OG21 and ENERGI21 on cross-system challenges
2. Mechanisms to receive cross system grants from PETROMAKS2, DEMO2000, ENERGIX, MAROFF, ENOVA, GASSNOVA, CLIMIT R&D (RCN part) and Innovation Norway– either through funding from multiple funds for one project or dedicated fund for cross system projects. Early examples of this already exist with Innovation Norway’s PILOT-E and joint calls for proposals from multiple funds (MAROFF/PETROMAKS/ENERGIX).</td><td>Advocate for a holistic approach to R&D strategy and funding towards reducing NCS emissions</td></tr>
</table>

*HSE: Health, environment and safety

Source: Rystad Energy research and analysis

Recommendations where OG21 can play an indirect role

Recommendation	Rationale	OG21s role
Advocate for infrastructure perspective towards hosts	Keeping the right hosts available for new tie-backs will be important in maintaining NCS competitiveness on low cost volumes, lifting cost on hosts and overall emission intensity. Optimizing the topside infrastructure on the NCS could be a path in achieving that, but will likely see high friction between operators as they will advocate for their own host. Below are some possible measures to alleviate this friction and incentivize optimal use of topside infrastructure: • Regulatory possibility to separate the topsides from the underlying fields, similar to the NCS gas infrastructure and oil pipeline networks, by allowing for owners that are not oil companies to acquire positions. Likely high appetite from infrastructure investors based on recent deals in the UKCS and NCS pipelines. • Standardized tie-back tariff agreements: Fixed tariff agreements for tie-backs to hosts based on cost share principles. Will also improve lead time on subsea tie-backs as host negotiations can be source of project delay. • Government intervention through unitization measures to secure host optimization: Unitizations are costly and takes a long time, should be considered last resort. Regulatory backing for unitization for existing fields may be necessary to obtain.	**Advocate for evaluation of suggested and other measures to optimize NCS topside infrastructure by authorities and industry organizations**
Industry initiative to evaluate regulatory changes on CO_2 emissions	A push for regulatory change from the industry itself might be beneficial for the industry in securing license to operate down the road. There is likely low political will to subsidize the oil and gas industry in its efforts to reduce emissions. Possible new regulatory measures on the NCS must be evaluated on how they affect NCS competitiveness on other metrics, like costs and volume, to ensure that petroleum production is not diverted towards other and more emission intensive petroleum provinces. However, NCS has a history of having higher CO_2 taxes than other petroleum provinces, resulting in reduced flaring, more gas injection and subsequently higher recovery rates. Possible regulatory measures to be evaluated: • Self-imposed CO_2 tariff on the NCS, where the additional tariff goes to a CO_2 -fund along the lines of the NO_X-fund, from where E&P and service companies can apply for receiving grants to implement emission reducing measures on the NCS. • CO_2 per boe threshold for hosts – will incentivize maximum resource utilization around hosts and optimal use of host infrastructure.	**Advocate for evaluation of suggested and other measures by industry organizations**

Source: Rystad Energy research and analysis

Index

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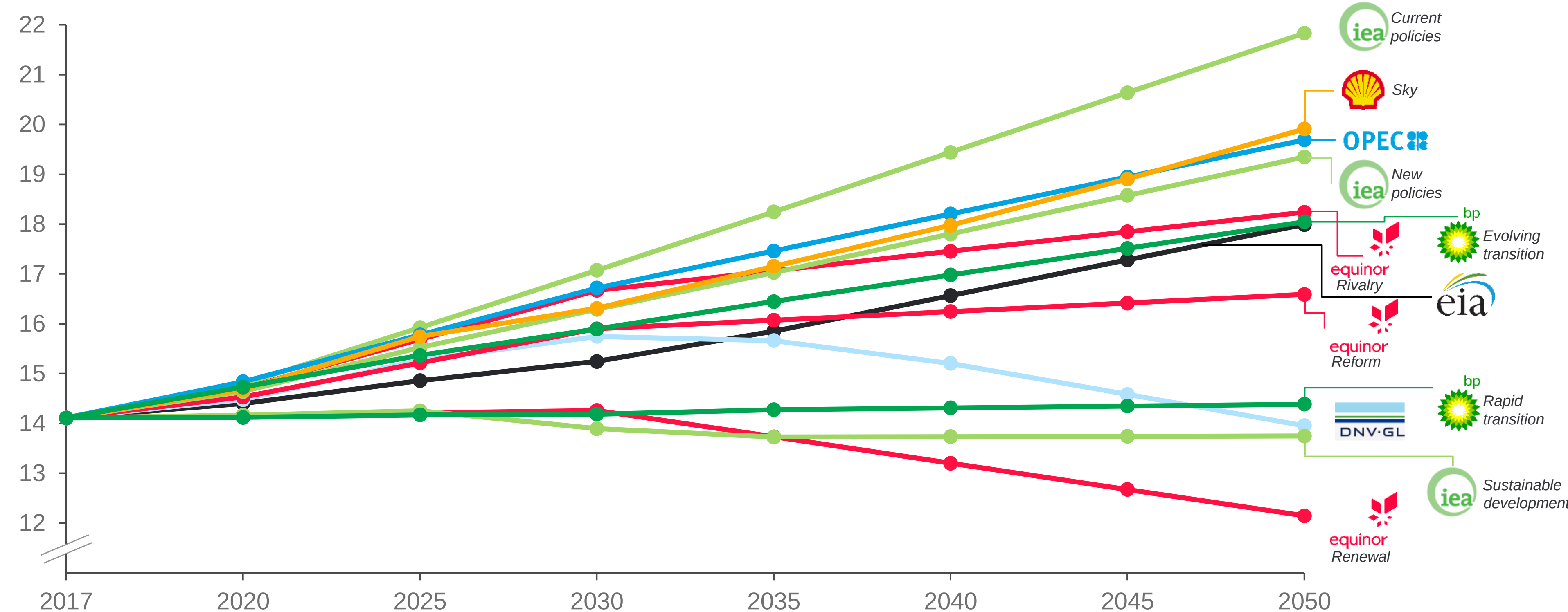
We assess future NCS competitiveness based on distinct demand cases for liquids and gas

	Region	Reference case	Low carbon case
Liquids	**Global demand** *As the oil market is largely a global and commoditized market, we approach demand for NCS liquids from a global perspective*	*Average* **Moderate growth scenarios** **2025:** 105 mmboe/d **2050:** 113 mmboe/d *'17-'50 CAGR: +0.5%* iea *New policies*; equinor *Rivalry*; bp *Evolving transition*; eia; equinor *Reform*; OPEC	*Average* **Peak demand scenarios** **2025:** 97 mmboe/d **2050:** 59 mmboe/d *'17-'50 CAGR: -1.5%* equinor *Renewal*; DNV·GL; iea *Sustainable development*; bp *Rapid transition*
Gas	**EU demand** *The gas markets are regional in nature. Norwegian gas is preferred in Europe politically, and is favorably positioned economically due to existing infrastructure.*	**IEA New Policies scenario** *Outlined in the World Energy Outlook of 2018* **2025**: 472 bcm/y **2050**: 375 bcm/y *'17-'50 CAGR: -0.6%* iea *New policies*	*Average of* **below 2DG scenarios** *Outlined in the "Clean Planet for all"-report issued by the EU* **2025**: 373 bcm/y **2050**: 122 bcm/y *'17-'50 CAGR: -4.0%* *Average of <2DG*

Source: Rystad Energy research and analysis

Projected total global energy demand vary widely between scenarios

Total Primary Energy Demand (TPED) of different scenarios*
Gigatonne of oil equivalent

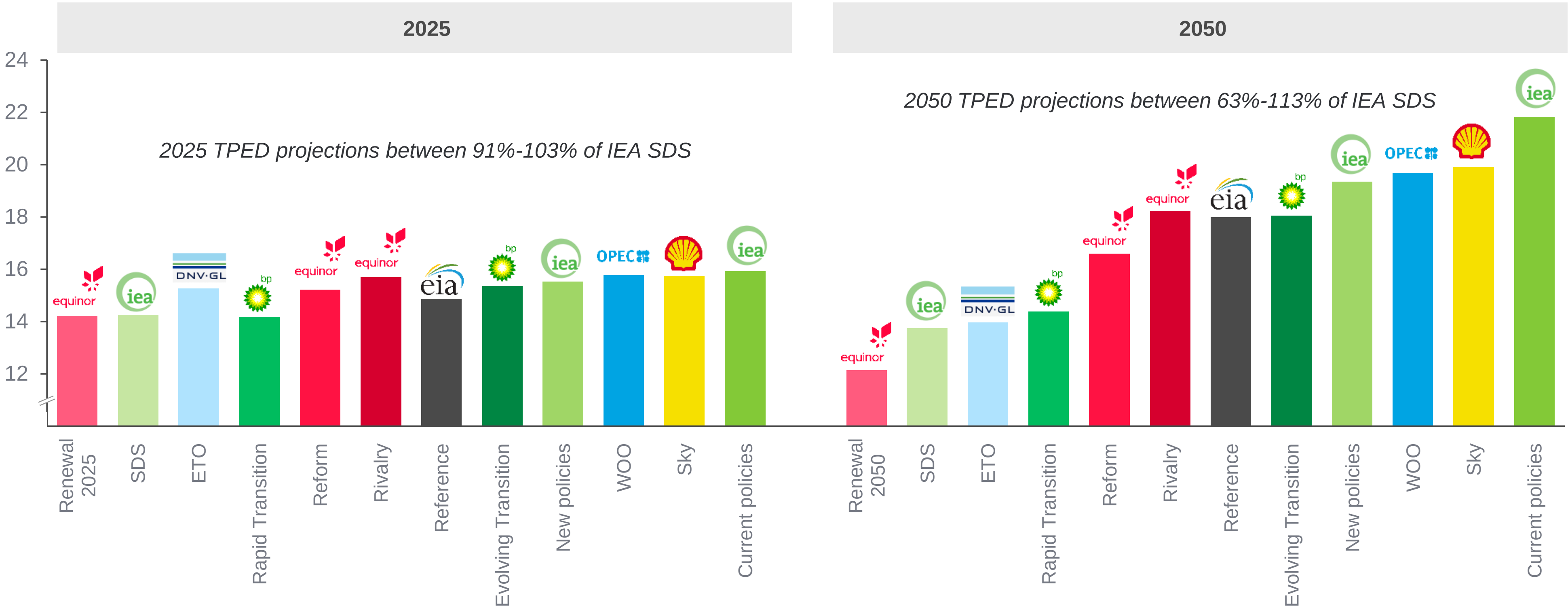


- Total Primary Energy Demand (TPED) is a common measure of global energy demand, and it is an important metric in any future scenario
- Numerous scenarios are available from different corporations, research institutions and agencies
- Some scenarios are best-estimates; other merely explore possible pathways given a set of assumptions and goals
- The chart displays the development of TPED in 12 widely discussed scenarios from 7 well known providers
- Evident is the large spread in future energy demand, reflective of the different approaches and broad set of assumptions in each scenario

* Indexed to IEA 2017 levels as different providers define units and markets differently
Source: Rystad Energy research and analysis; IEA WEO 2018; Shell Sky 2018; OPEC WOO 2018; BP EO 2019; EIA International Energy Outlook 2017; Equinor Energy Perspectives 2019; DNV GL ETO 2018

Scenarios differ in total energy demand in the long term – mostly in line short term

Total Primary Energy Demand (TPED) of different scenarios*
Gigatonne of oil equivalent

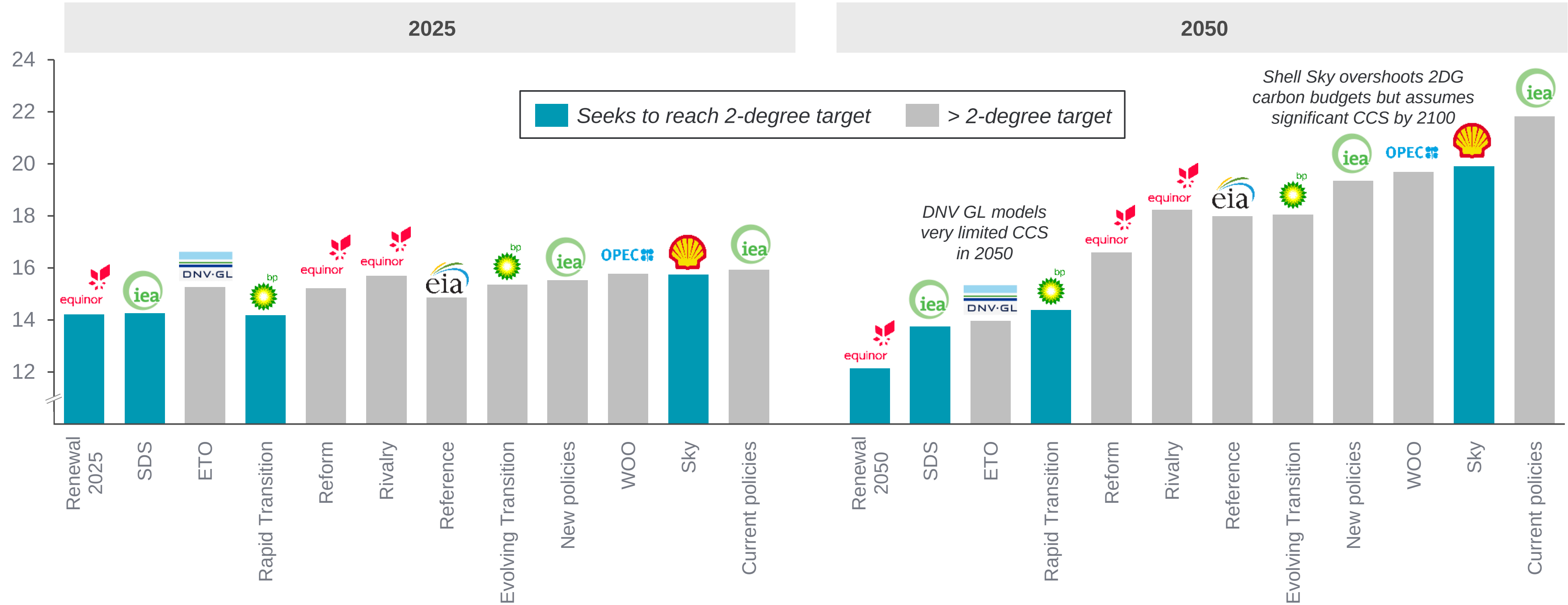


- The variation in TPED projections naturally increase with time as assumed developments in GDP, policy, technology and infrastructure take time to manifest
- Projections for 2025 vary much less than projections for 2050; 2025-projections all lie in a 12% range of IEA SDS, while the range for 2050-projections is in a 50% range.
- Generally, scenarios seeking a more sustainable future, project lower future TPED compared to "business as usual" scenarios.
- Worth noting is DNV GL's Energy Transition Outlook which presents a best-estimate scenario where TPED is decoupled from GDP growth, indicating improved energy efficiency

* Indexed to IEA 2017 levels as different providers define units and markets differently
Source: Rystad Energy research and analysis; IEA WEO 2018; Shell Sky 2018; OPEC WOO 2018; BP EO 2019; EIA International Energy Outlook 2017; Equinor Energy Perspectives 2019; DNV GL ETO 2018

Total energy demand is not decisive in reaching sustainable targets

Total Primary Energy Demand (TPED) of different scenarios*
Gigatonne of oil equivalent



- Scenarios compliant with the <2DG goal of the Paris Agreement are generally in the lower range of projected TPED, with the exception of Shell's Sky-scenario and DNV GL's Energy Transition Outlook
- The Shell Sky scenario forecast emissions to decrease dramatically after 2040, and introduce significant carbon capture and storage in the second half of the century. Shell believes the Sky-scenario prevent temperature increase in excess of 2 degrees
- DNV GL ETO project 2050 TPED-levels in line with the Paris Agreement-compliant scenarios from Equinor, IEA and BP; but is not itself compliant. This scenario is a best estimate, not a 2-degree scenario
- The aforementioned anomalies illustrate that total energy demand does not tell the full story; assumptions on electrification, carbon capture and storage (CCS) and power mix is as important to future carbon emissions as total energy demand

* Indexed to IEA 2017 levels as different providers define units and markets differently
Source: Rystad Energy research and analysis; IEA WEO 2018; Shell Sky 2018; OPEC WOO 2018; BP EO 2019; EIA International Energy Outlook 2017; Equinor Energy Perspectives 2019; DNV GL ETO 2018

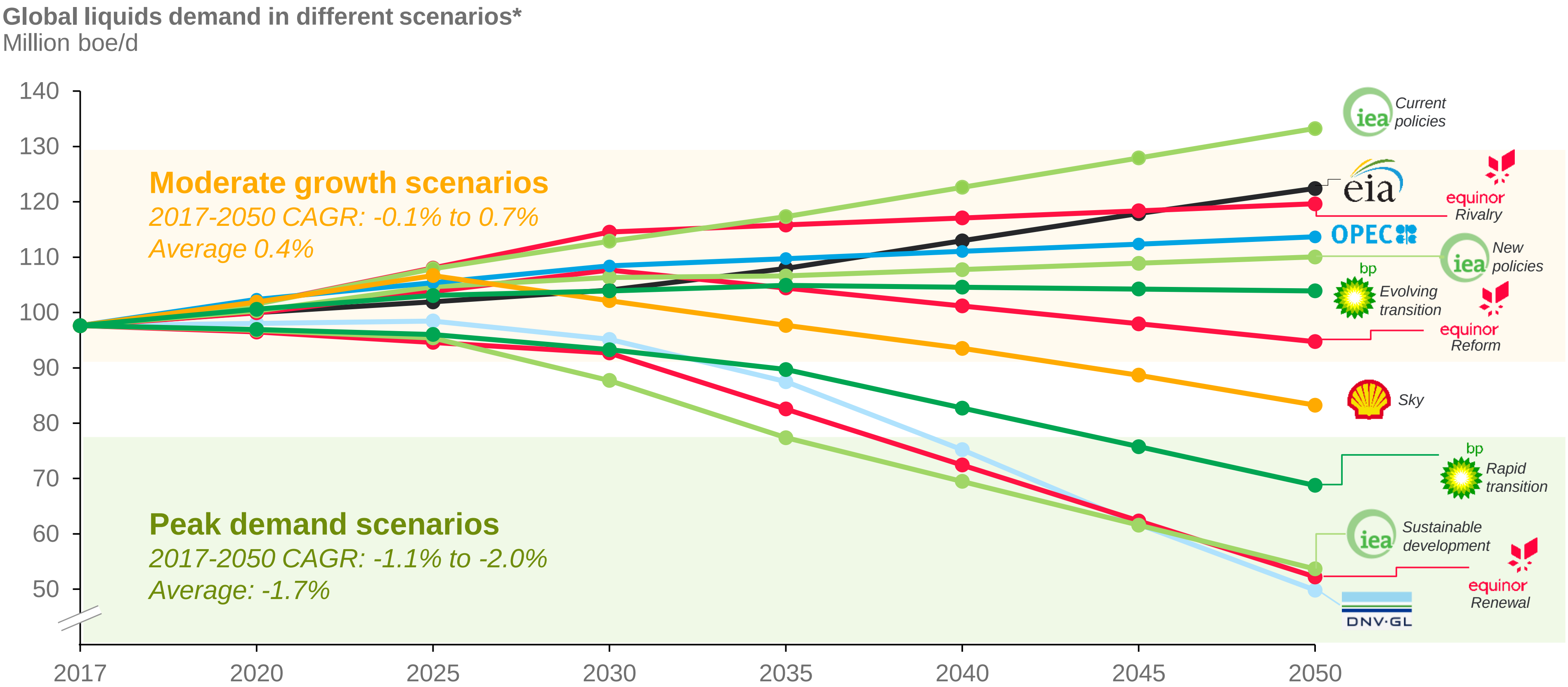
Scenarios are representations of the future, with differing pathways to achieve the objectives

	Approach	Key assumptions: TPED*	Key assumptions: 2DG	Key assumptions: CCS	2050 TPED composition	2050 demand*: Liquids	2050 demand*: Gas
IEA Current Policies	*Likely future if no new policy is enacted; high TPED-growth and low renewables share*	↑	X	X	Oil, Gas, Coal	↑ 133 Mboe/d	↑ 6214 bcm
Shell Sky	*Technically possible, but challenging pathway to achieve the goals of the Paris Agreement. Relies on CCS to meet 2DG.*	↑	✓	✓	20 %, 13 %, Nuclear, Other renewables	↘ 83 Mboe/d	↘ 3086 bcm
OPEC World Oil Outlook	*Reference case considering developments in economy, policies and technology*	↑	X	-	28 %, 25 %, Hydro	→ 114 Mboe/d	↑ 5768 bcm
IEA New Policies	*Announced policies are enacted, resulting in weaker TPED-growth and more renewables.*	↑	X	X	28 %, 24 %, Bioenergy	→ 110 Mboe/d	↑ 5609 bcm
BP Evolving Transition	*Scenario where continued GDP growth leads to increased energy demand.*	↗	X	X	28 %, 26 %	→ 104 Mboe/d	↑ 5653 bcm
EIA Reference	*Modelled projections of long-term world energy markets based on current trends.*	↗	X	-	33 %, 27 %	↗ 122 Mboe/d	↑ 5817 bcm
Equinor Rivalry	*Describes a volatile world where climate change is not a political priority, and geopolitics play an important role*	↗	X	X	32 %, 21 %	↗ 120 Mboe/d	↗ 4518 bcm
Equinor Reform	*Build on recent and current trends within market and technology development.*	↗	X	X	28 %, 23 %	↘ 95 Mboe/d	↗ 4518 bcm
BP Rapid Transition	*Scenario where climate policies across sectors are implemented.*	→	✓	✓	23 %, 30 %, 20 %	↓ 69 Mboe/d	↗ 5093 bcm
DNV GL Energy Transition Outlook	*Model-based best-estimate future scenario where TPED growth is limited and renewables increase substantially*	→	X	X	17 %, 22 %, 31 %	↓ 50 Mboe/d	→ 3609 bcm
IEA Sustainable Development	*Integrated strategy to achieve the goals of the Paris Agreement.*	→	✓	✓	19 %, 22 %, 23 %	↓ 54 Mboe/d	→ 3597 bcm
Equinor Renewal	*Future trajectory supported by strong, coordinated policy intervention to reach 2DG.*	↘	✓	✓	21 %, 21 %, 21 %	↓ 52 Mboe/d	↘ 3013 bcm

* Indexed to IEA 2017 levels as different providers define units and markets differently

Source: Rystad Energy research and analysis; IEA WEO 2018; Shell Sky 2018; OPEC WOO 2018; BP EO 2019; EIA International Energy Outlook 2017; Equinor Energy Perspectives 2019; DNV GL ETO 2018

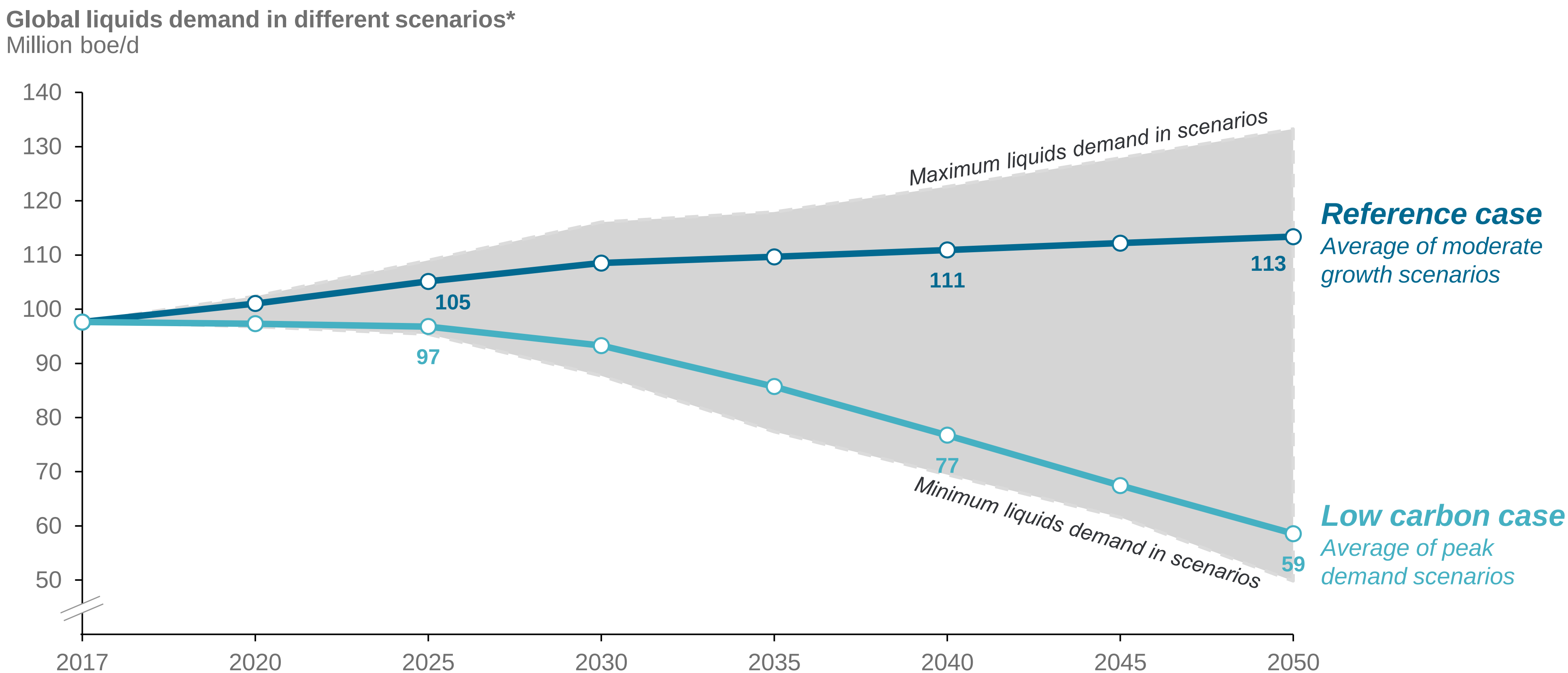
Scenarios describe two main pathways for liquids demand



- The projections for the demand of petroleum liquids vary significantly.
- The liquids demand projections mainly separate into two pathways:
  Moderate growth scenarios roughly in line with the historical trajectory, or peak demand scenarios where liquids demand is to peak in the coming years
- Falling liquids demand imply rapid electrification or efficiency gains in the oil-reliant transport sector, which in turn is dependent on technological development and/or large infrastructure investments

* Indexed to IEA 2017 levels as different providers define units and markets differently
Source: Rystad Energy research and analysis; IEA WEO 2018; Shell Sky 2018; OPEC WOO 2018; BP EO 2019; EIA International Energy Outlook 2017; Equinor Energy Perspectives 2019; DNV GL ETO 2018

Averages of moderate growth- and peak demand scenarios yield two distinct demand cases

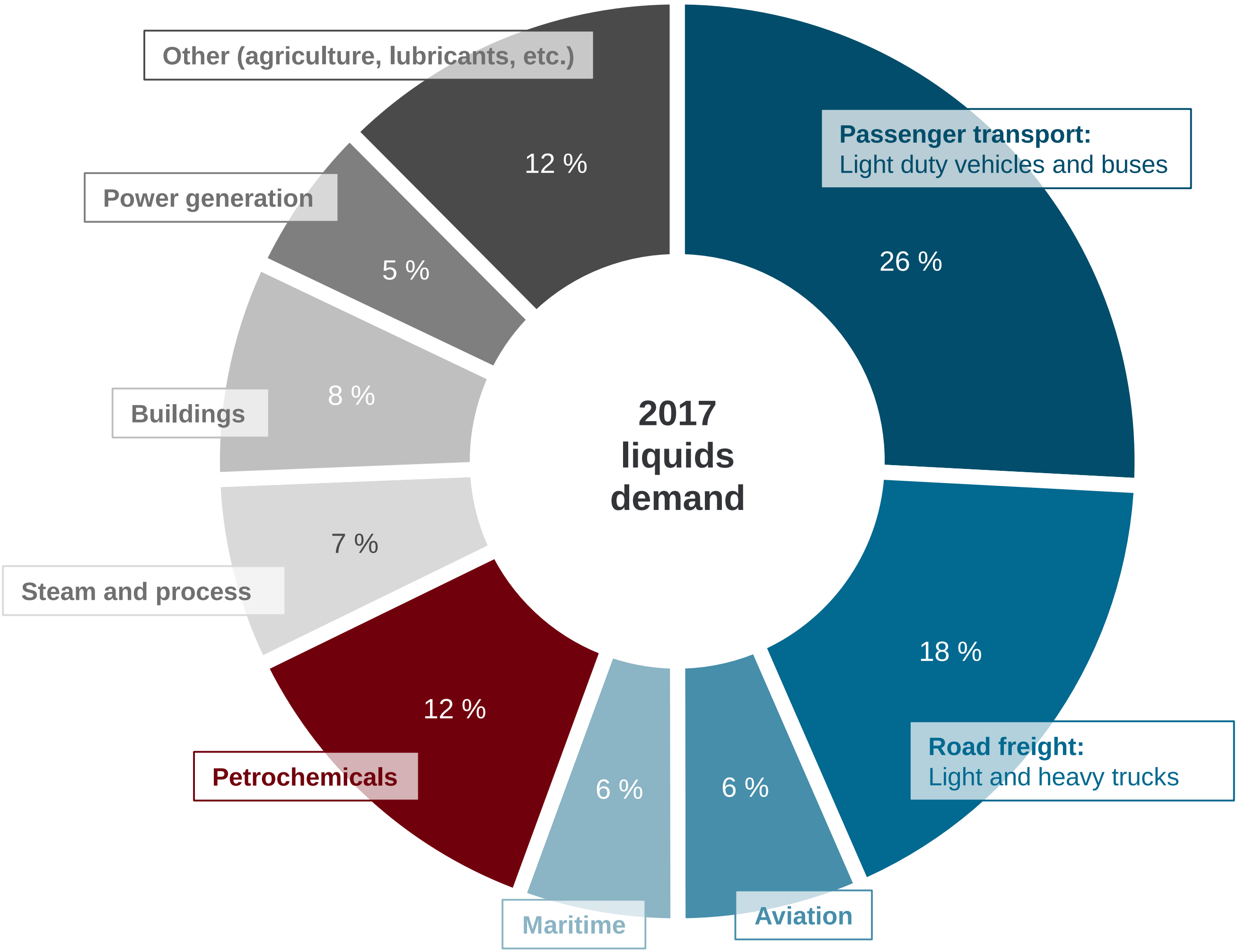


- We construct two scenarios for future liquids demand based on averages of the moderate growth- and peak demand scenarios: The reference case and the low carbon case, respectively
- These cases are used in our assessment of new technologies' potential impact on NCS competitiveness
- As different supply sources of petroleum liquids have different characteristics and compete against each other for market share, the two cases allow us to assess which NCS volumes can be expected in the supply mix both in a continued high demand-environment and in a world where oil demand is displaced by e.g. renewable alternatives

* Indexed to IEA 2017 levels as different providers define units and markets differently
Source: Rystad Energy research and analysis

Transportation makes up almost 60% of liquids demand – key sector if liquids demand is to decrease

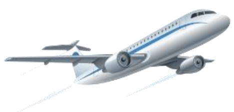
Sectoral share of global liquids demand in 2017 as reported by the IEA
Shares of total



- Road transportation accounts for almost half of total liquids demand, and any efforts to increase efficiency or electrify this sector will be important to reduce the consumption of oil
- The petrochemicals sector, predominantly related to plastics production, make up around a tenth of liquids demand. Demand for petrochemical feedstock is considered robust going forward
- Demand for liquids from the maritime and aviation sector together comprise 12% of liquids demand. Substitutes for petroleum liquids in these sectors are still early-stage

Source: IEA WEO 2018

Electric propulsion key substitute for land transport, several options for other segments

Technology	Share of oil demand (%)	Key oil substitutes: Short haul	Key oil substitutes: Long haul	Cost concerns	Timeline Indicative major uptake in fleet
Passenger transport 	26%	*Battery electric drive trains already proven in short haul and will be the end solution for passenger transport.*	*Battery electric also likely solution in long haul with the final challenge being long distance bus transport (coach models).*	*Battery electric vehicles is already a proven technology, and costs are expected to reach cost parity with ICE vehicles in the early 2020s.*	***2020-22*** *Likely year of cost parity*
Road freight 	18%	*Light commercial vehicles are already adopting battery electric drive trains and is the most likely future technology for this application.*	*Less certain future than short haul, but recent progress point towards electric as most promising technology. Fuel cells could also play a role.*	*Battery electric trucks are already cost competitive due to fuel costs high share of overall life cycle cost for these vehicles.*	***2025*** *Long haul limited supply capacity, Tesla (and others) needs to prove its case*
Aviation 	6%	*Currently, the most likely alternative to jet fuel is biofuel, but significant efforts are made to make short haul aviation electric**	*Long haul flights require fuels with high energy density, and biofuel seems like the most promising alternative to fossil fuels. Fuel cells could also play a role.*	*Bio jet fuel is currently substantially more expensive than oil based jet fuel, and will need to see substantial R&D and/or regulatory push to become competitive. Heavy investments in short haul electric, limited proof of concept.*	***2035-40*** *Technology still in its infancy*
Maritime 	6%	*The maritime sector will likely see the largest mix of fuel categories with both LNG (transition fuel), battery electric (+hybrid) and biofuel as substitution candidates.*	*LNG will play an important role as a transition fuel for deep sea shipping. Long term, biofuel is the most likely candidate, but could be challenged by fuel cells.*	*LNG is already cost competitive to oil based fuels, but have limited CO_2 omitting potential and will as such only provide a transitional solution. Biofuel is expensive and its adoption will likely hinge on regulations.*	***2025-30*** *LNG with proven technology, but limited fueling capacity. Biofuel still in its infancy as a shipping fuel*
Petrochemicals 	12%	*The main emission sources in the petrochemical value chain is process heat, typically from burning of natural gas, and end-of-life incineration and disposal of the plastics. The first source have little implication for oil demand, but the latter ultimately uses oil as the primary feedstock. The likely substitute is bioplastics which uses plant based feedstock, in addition to increased recycling.*		*Bioplastics are currently 1.5x more expensive than its fossil based competitors, and of inferior quality. This could obviously change in the future, but would require substantial R&D to be able to compete without regulations.*	***2030*** *Large scale adoption of bioplastics in non-recyclable plastics*

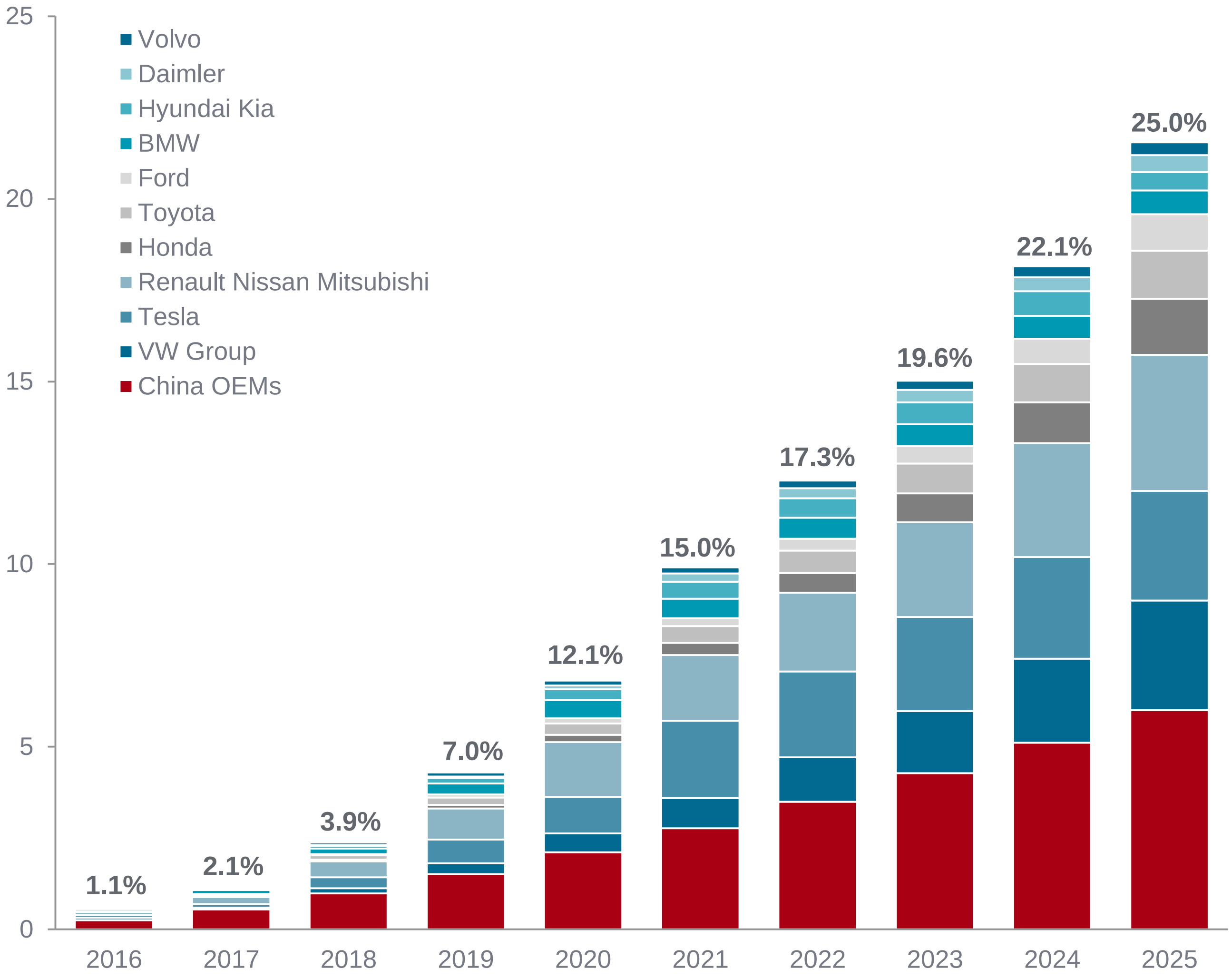
Battery electric · Hydrogen (H_2) fuel cell · Ammonia (NH_3) fuel cell · LNG (CH_4) · Biofuels · Bioplastics

*Electric aviation: Airbus, Boeing (Zunum), Siemens, Pipistrel, Uber, Bye Aerospace

Source: Rystad Energy research and analysis

Manufacturers' targets set EVs at 25% of total sales by 2025, potentially displacing 1.8 mmbbl/d

Electric vehicle sales targets by key manufacturers and % of global sales
Million vehicles

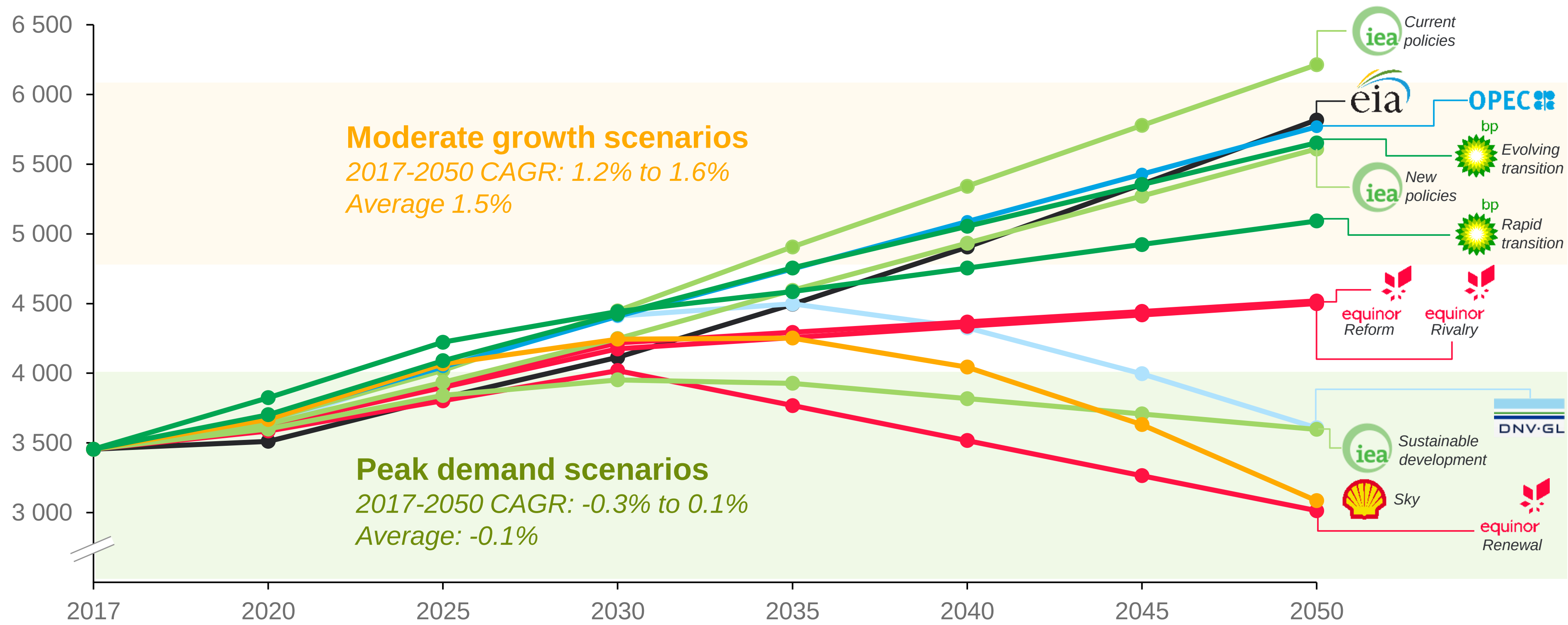


- The light duty vehicle fleet is the largest contributor to demand growth, expanding from the current 1 billion vehicles to 1.7 billion in 2040 in the base case. This fleet expansion is mainly driven by non-OECD, and especially China and India.
- We see electric vehicles (EVs) as the main risk to transportation related oil demand. With strong EV demand, the EV market is likely to be supply-limited in the medium term and the market will consume as many vehicles as manufacturers can produce. The car manufacturers' EV sales targets are thus good proxies of liquids demand risk.

Source: Rystad Energy research and analysis; vehicle manufacturers' communication

Although varied, the projections for global gas demand are more positive than for oil

Global gas demand in different scenarios*
Billion cubic meters/year



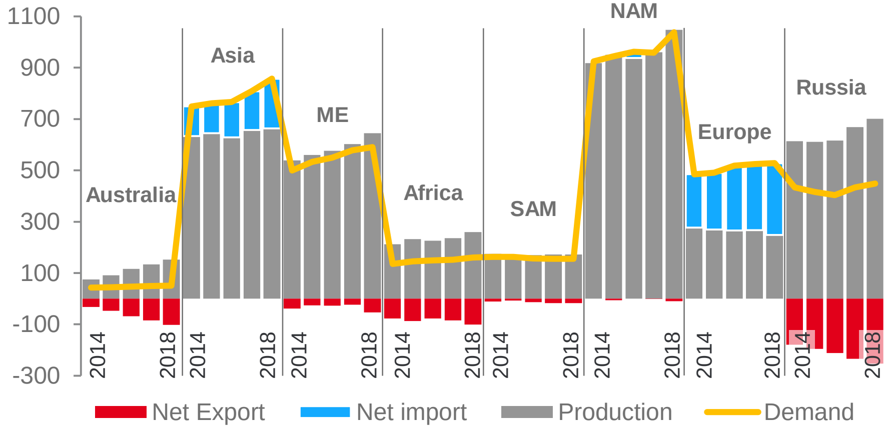
- As with liquids, the global demand for gas vary substantially among the scenarios in the long term
- The low carbon scenarios from Equinor and Shell assume lower gas demand in 2050 compared to 2017
- Gas demand is projected at the same levels as today in DNV GL's scenario, despite the high degree of electrification assumed in the scenario
- BP's Rapid Transition scenario on the other hand, which aims to comply with the Paris Agreement, project an increase in gas demand
- Higher growth rates both for moderate growth- and peak demand scenarios for gas compared with liquids indicate that gas is a preferred source
- For instance, IEA's New Policy-scenario growth rate to 2050 for liquids is 0.4% compared with 1.5% for gas

* Indexed to IEA 2017 levels as different providers define units and markets differently
Source: Rystad Energy research and analysis; IEA WEO 2018; Shell Sky 2018; OPEC WOO 2018; BP EO 2019; EIA International Energy Outlook 2017; Equinor Energy Perspectives 2019; DNV GL ETO 2018

Gas markets are regional, and Norwegian supply should be considered against EU demand

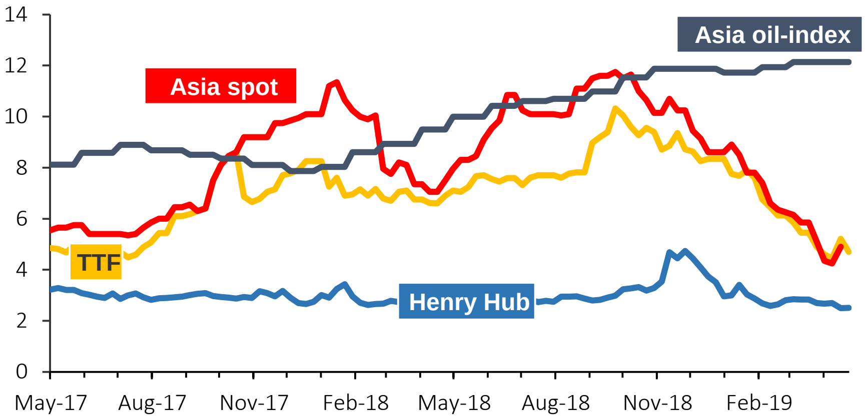
Regional balances reveal regional differences

Supply and demand of natural gas by continent 2014-2018
Billion cubic meters



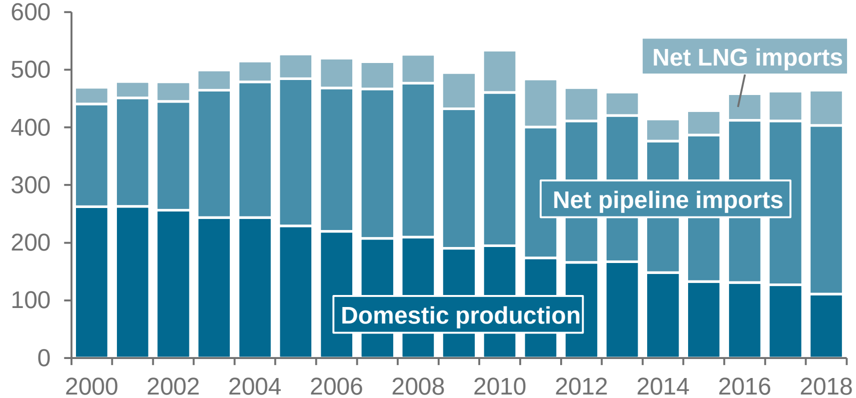
Price differentials indicate regional markets

International natural gas prices*
USD per million Btu



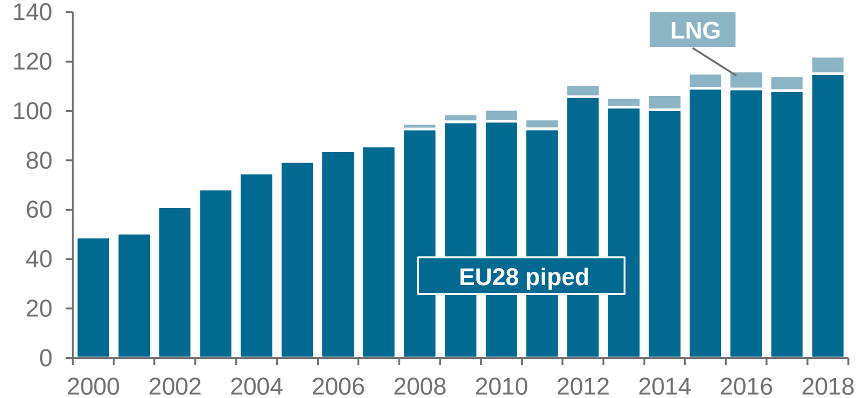
EU28 dependent on imports

EU28 natural gas balance
Billion cubic meters



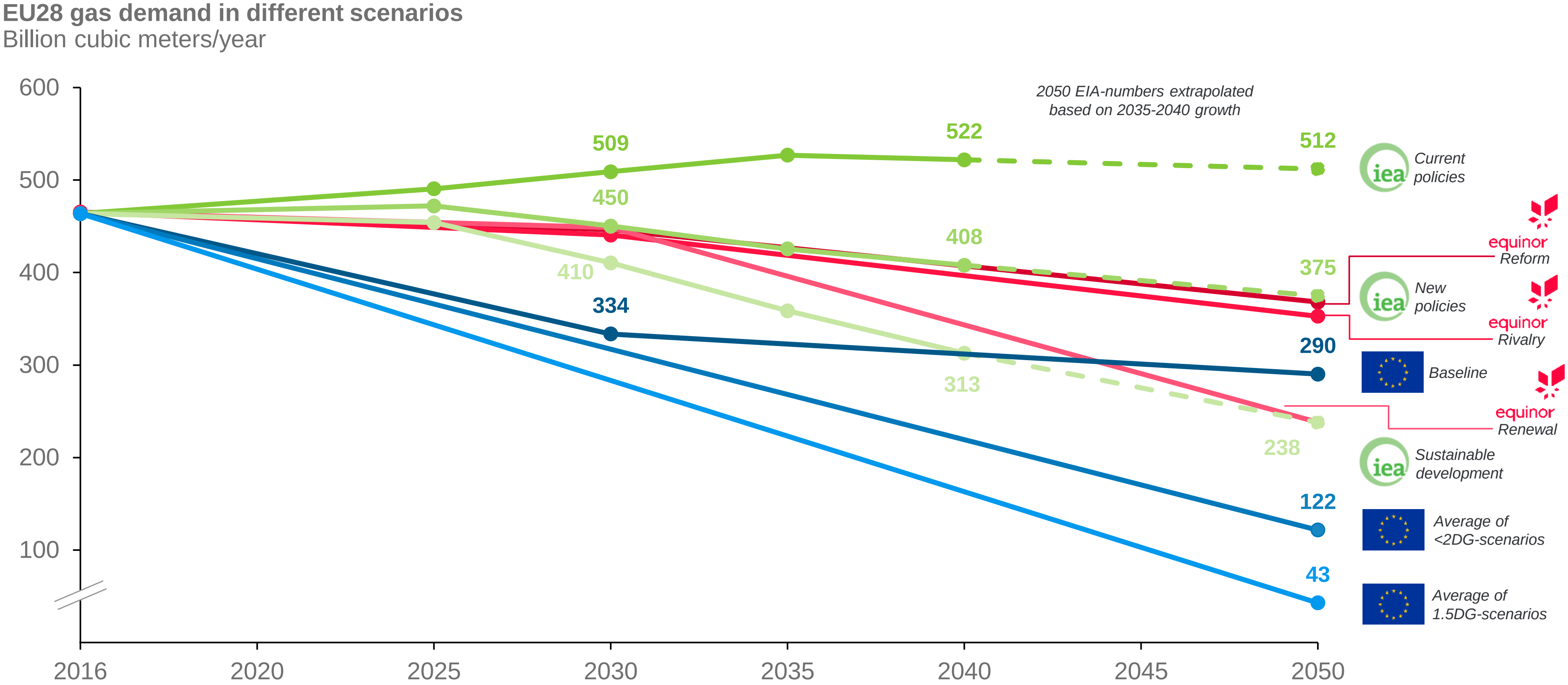
Norwegian gas for the most part piped to the EU

Norwegian gas exports by export mode and destination
Billion cubic meters



* Henry Hub and TTF prices correspond to the front month contract. Prices are weekly averages. Asia Spot prices are as reported by Refinitiv.
Source: Rystad Energy GasMarketsCube

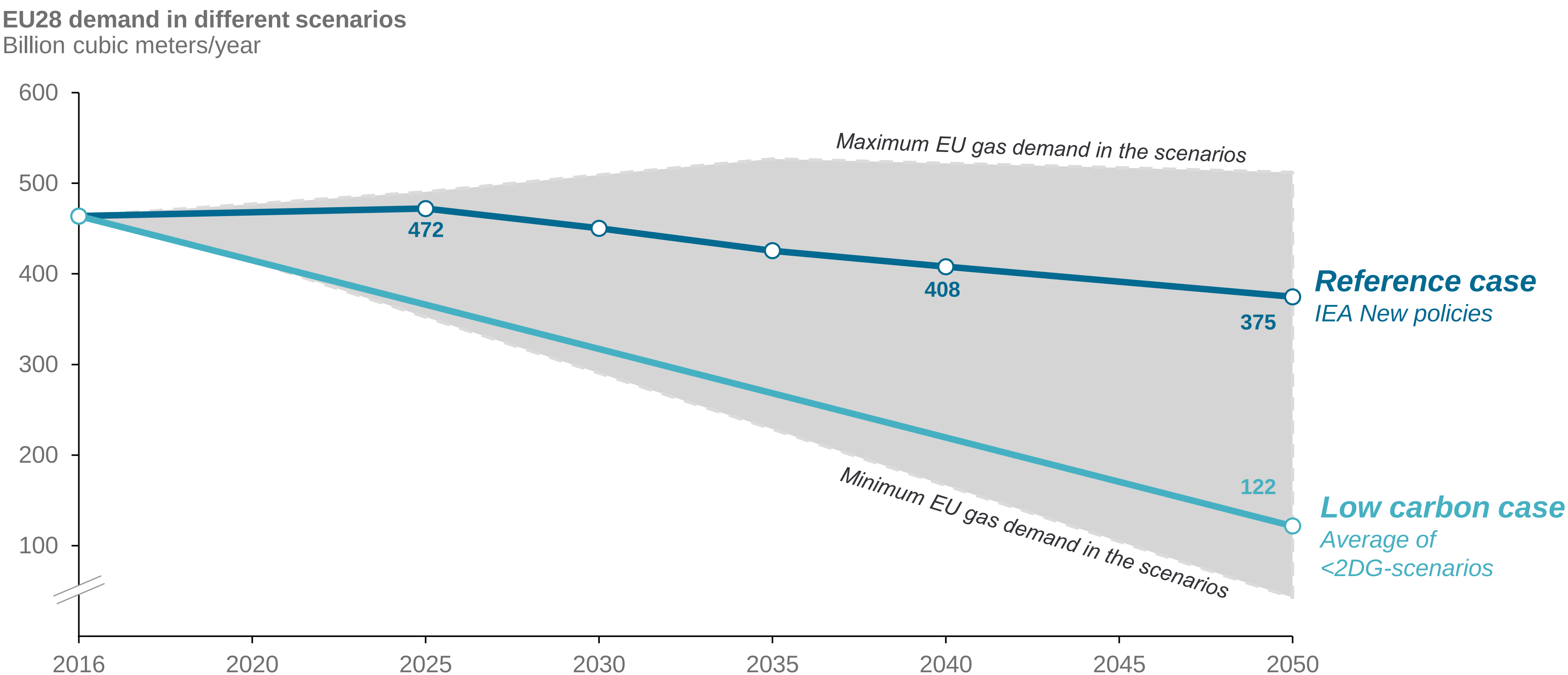
EU's vision for sustainable development leaves less room for gas in EU28s energy mix



- The European Commission issued in November 2018 a report dubbed "A Clean Planet for All". This report contain *"A European strategic long-term vision for a prosperous , modern, competitive and climate neutral economy".* The report is written to *"… confirm Europe's commitment to lead in global climate action"*, and should as such be read as a guiding document for European policymakers. It is important to note that the document has yet to be ratified by the European Parliament. EU is to adopt and submit their strategy by early 2020 to UNFCCC as requested by the Paris Agreement.
- The chart outlines a strategy that is compliant with the Paris Agreement, and a pathway for EU gas demand substantially lower than what IEA does in their Sustainable Development-scenario.

Source: Rystad Energy research and analysis; IEA WEO 2018; EU Commission; Equinor Energy Perspectives 2019

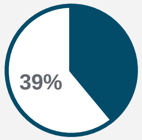
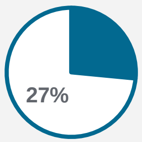
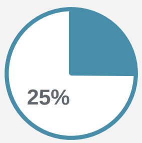
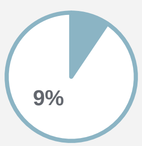
Both gas cases project reduction in EU gas demand – 74% reduction in low carbon case



- In order to sensitize our assessment of new technologies' potential impact on NCS competitiveness to EU policy we use the average of <2DG-scenarios as outlined in the "Clean Planet for all"-report issued by the European Commission as our low carbon case
- The well known New Policy-scenario issued by the IEA is used as our reference case
- The reference and low carbon cases project a reduction in EU 2050 gas demand compared with 2017
- IEA Current Policies assume only marginal increase in EU gas demand
- The scenarios indicate that Norwegian gas supply lacks exposure to a potential increase in global gas demand as most of Norwegian gas is piped to EU countries

Source: Rystad Energy research and analysis; IEA WEO 2018; EU Commission

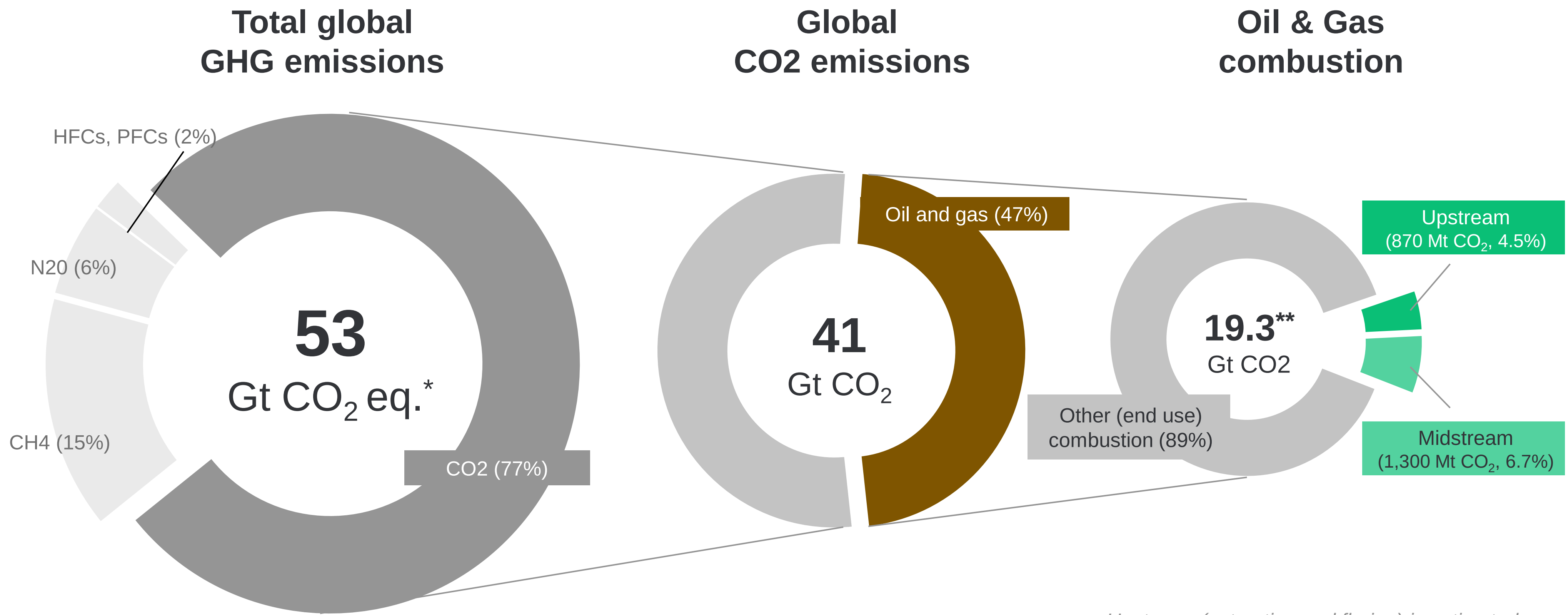
The European Commission sees cut in gas demand happening in all relevant sectors

End-use sector	Share of 2018 EU gas demand (%)	Demand shift	Strategy and development goals
Residential and commercial *Heating, cooking etc.*		• *Energy efficiency to play a central role in reaching net-zero greenhouse emissions by 2050* • *Reduce energy consumption through high renovation rates, better insulation, use of most efficient products and appliances, combined with smart homes and digitalization* • *Switch to renewable heating can play a role, both clean electricity and hydrogen are alternatives (i.e. H21-project in the UK, example of the latter)*	• *Put adequate financial instrument in place to enable transition* • *Ensure sufficient workforce with right skills and affordability* • *Target to improve EU's energy efficiency by at least 32.5% by 2030*
Power *Electricity production*		• *Deploy renewable power supply* • *Wind and solar in combination with nuclear already a significant and growing supply of electricity – offshore wind and ocean energy to increase its share*	• *Ensure smarter and more flexible energy system through improved energy storage, demand side response and management through digitalization* • *The target is to increase renewable energy to at least 32% of EU's final energy consumption by 2030, and to 53% by 2050*
Industrial *Manufacturing, refining, mining, agriculture etc.*		• *Utilize renewable power to produce carbon-free fuels and feedstock for the industry (hydrogen and synthetic liquids and gases)* • *Reduce energy needs in the production of industrial goods through increased recycling rates (circular economy), and in construction by using less energy intensive materials*	• *Stimulate R&D to reduce cost of breakthrough technologies* • *Incentivize the roll out of technologies, strategic value chains and increased circularity*
Other *District heat, fuel gas, transportation and other*		• *Electrify energy demand combined with deployment of renewables in the power sector*	

Source: Rystad Energy GasMarketCube; Rystad Energy research and analysis; European Commission "A Clean Planet for all"

Upstream and midstream account for ~10% of CO_2 emissions from oil and gas combustion

Overview of estimated GHG emissions and sources in 2015
CO2eq/CO2



CO_2 stands for 77% of the global anthropogenic greenhouse gas emissions.

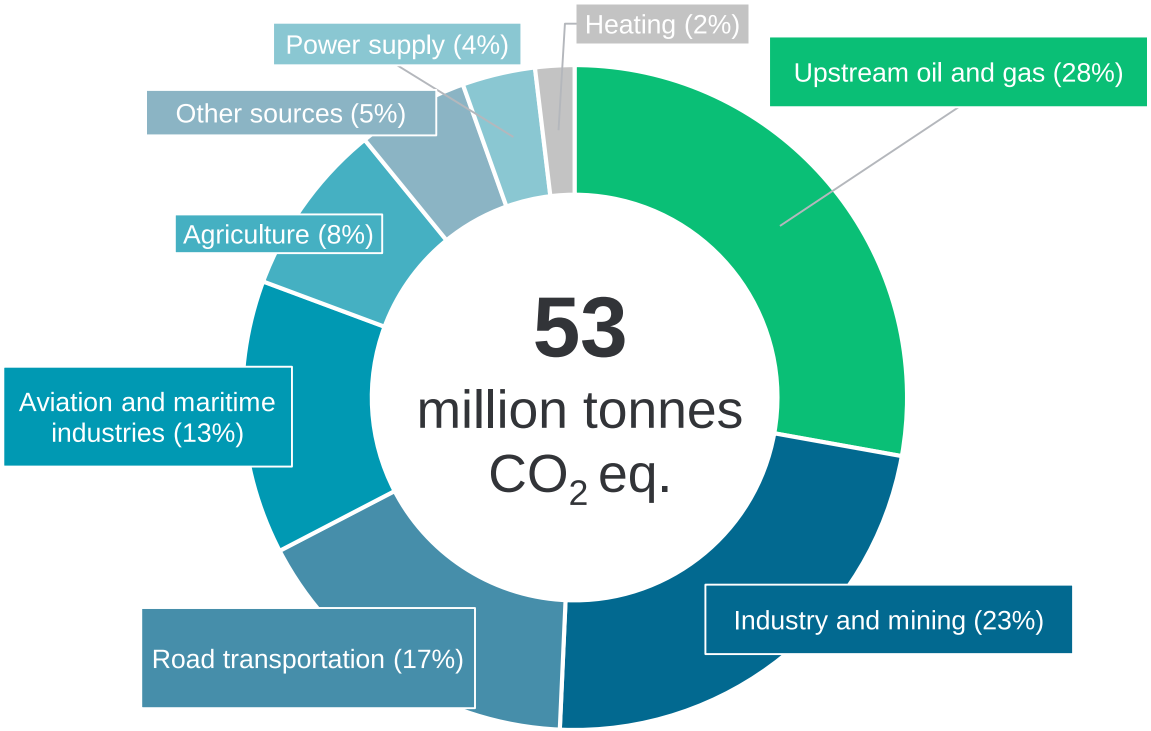
Combustion and flaring of oil and gas makes out about half of global CO_2 emissions

Upstream (extraction and flaring) is estimated to account for 5% of the total CO_2 emissions from oil and gas combustion. Midstream (incl. refining/processing and LNG liquefaction/regasification) account for ~6%.

*2010 estimates for non-CO2 emissions, 2015 estimates for CO2 emissions; **Assuming all emission in upstream and midstream from oil and gas combustion.
Source: IPCC, BP, SSB; Rystad Energy research and analysis

Upstream oil and gas activities account for the largest part of Norwegian emissions

Norwegian GHG emissions and sources in 2017 (Scope 1 – direct emissions)
Million tonnes CO_2 eq and percent of total



- Upstream activity on the NCS accounts for 28% of domestic GHG emissions, making it the largest source of emissions in Norway.
- The sector's large share of domestic emissions places it firmly in the searchlight of an increasingly emissions conscious public that is keen on reducing the country's carbon footprint.
- Public scrutiny of the industry requires that more attention is paid to emissions than the country's global share of emissions suggests. The NCS accounts for 1-2% of global upstream emissions and is generally less emission intensive than comparable countries.

* Scope 1 covers direct emissions
Source: Rystad Energy research and analysis, Statistics Norway (SSB)

Index

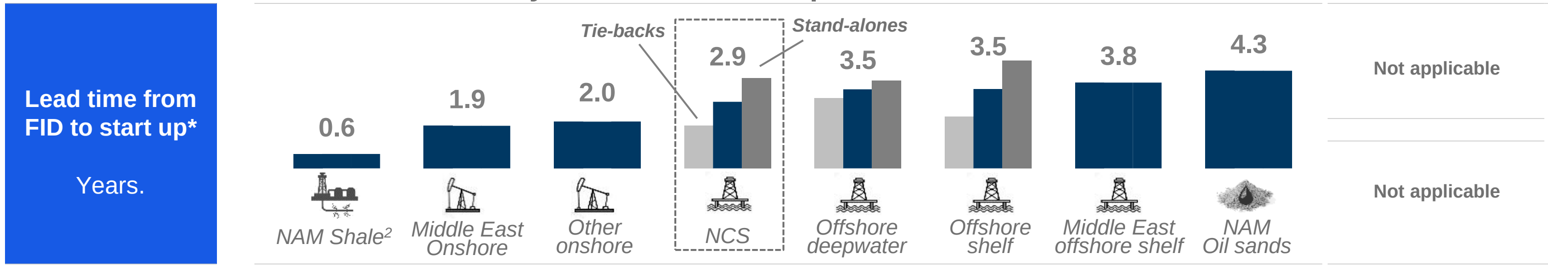
Change in competitiveness measures over time

	Upcycle 2007-2013	Downcycle 2014-2018	Future
Investment themes	***Materiality***	***Robustness***	***Sustainability***
New additional competitiveness metrics	**+ High value projects (NPV/DPI)**	High value projects **+ Low breakeven** **+ Cost effective production**	High value projects Low breakeven Cost effective production **+ Short payback time** **+ Carbon effective production**
Rationale	*Soaring commodity prices and high yields focus investments on the most material projects. DPI typical measure used in this time frame.*	*Detrimental commodity prices and limited access to capital switched focus from materiality to robustness.*	*High commodity price uncertainty and peak demand looming. Increased public perception and pressure on carbon intensive industries. Rising CO_2 prices.*
Downside	*High NPV is not the same as low breakeven, high risk if commodity price fail, results in heavy losses.*	*Does not account for lead-times. In competition with faster resources, offshore is less competitive*	*Short-sightedness. Fields developed for shorter timeframes with less flexibility*
	Volume	Cost	Emissions

Source: Rystad Energy research and analysis

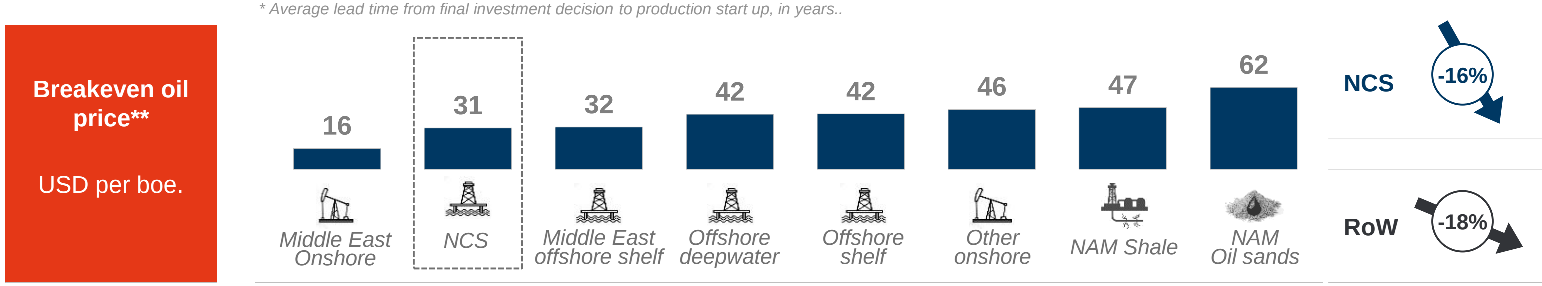
NCS very competitive on breakeven, costs and emissions, challenged on lead times

Key indicators for competitiveness in 2018 | **2014-2018** | **Comment**



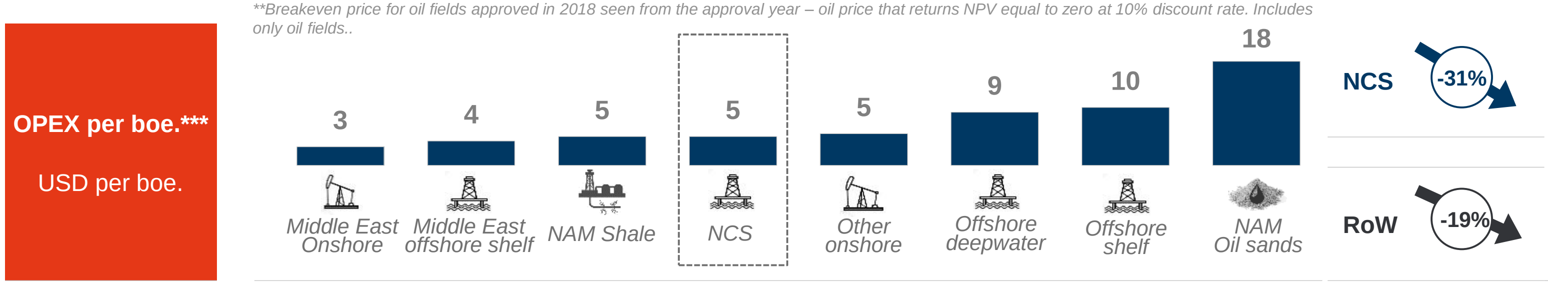
Long lead times pose a significant challenge to the NCS competitiveness in a world where rapid flexibility is required to capture new volumes. Averages of eight months from spud to production allows shale oil to serve volume demand first. NCS tie-backs are the most competitive offshore volumes.

** Average lead time from final investment decision to production start up, in years..*



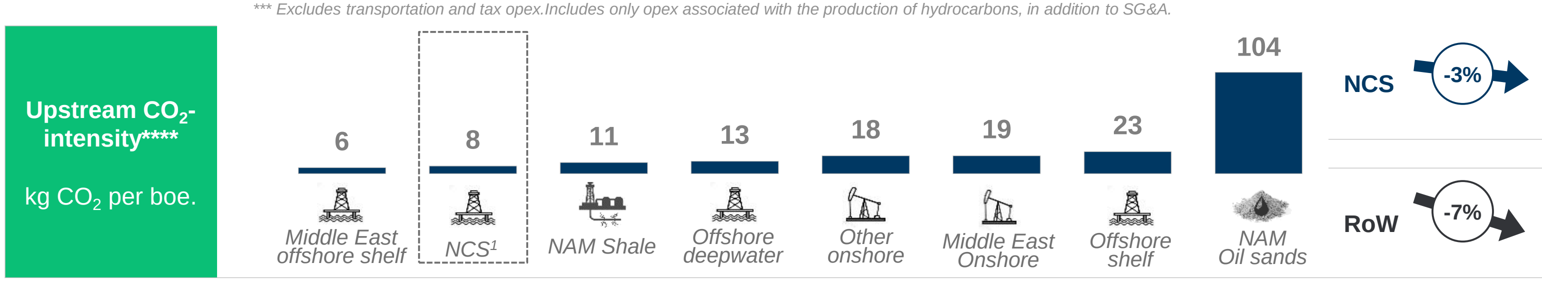
Breakeven prices came down significantly after 2014 with only the most competitive projects being sanctioned. The NCS competes well with other supply segments, but the recent upswing indicates a fast upward trajectory for breakeven if new volumes of scope are to be added.

***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. Includes only oil fields..*



Offshore projects demonstrate higher operating expenses than onshore, but the NCS is competitive with onshore fields despite the added challenges of offshore production. The maturing profile of NCS fields poses a challenge for the future as production declines while expenses remain.

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



Upstream CO_2 intensity is among the lowest on the NCS, in large thanks to limited flaring compared with others. Should others improve on flaring, NCS competitiveness could be easily more challenged. Emissions per boe is also expected to increase with large parts of the NCS production becoming tail-end.

*****Total yearly upstream CO_2 emissions divided according to supply segment production in the same year.*

1) Estimated based on 2017 data, underlying emission drivers and 2018 production. 2) From spud to first oil.
Source: Rystad Energy research and analysis, Rystad Energy UCube

NCS recovery rates are impressive, but lead times and low volume replacement is a challenge

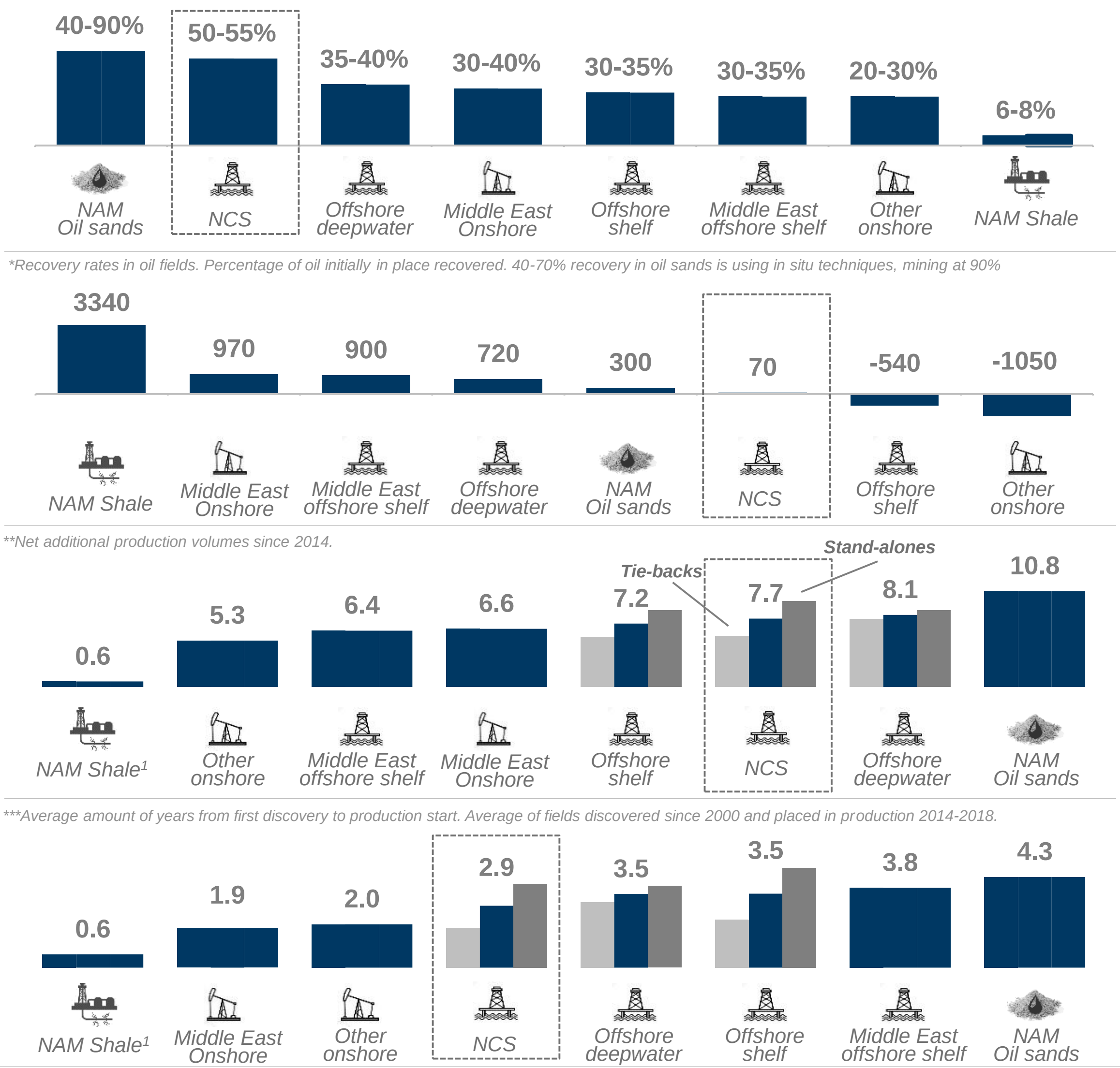
Key indicators for competitiveness in 2018

Recovery rate*
Percent of oil initially in place

Net additional volumes**
Million boe.

Lead time from discovery to production***
Years.

Lead time from FID to production****
Years.



*Recovery rates in oil fields. Percentage of oil initially in place recovered. 40-70% recovery in oil sands is using in situ techniques, mining at 90%

**Net additional production volumes since 2014.

***Average amount of years from first discovery to production start. Average of fields discovered since 2000 and placed in production 2014-2018.

****Average amount of years from final investment decision to production start. Average of fields discovered since 2000 and placed in production 2014-2018.

Comment

The high recovery rates on the NCS demonstrate a strong competitive case, but also implicates decreasing returns to further efficiency gains. Shale's 6-8% recovery indicate improvement potential. Competing regions have the potential to increase recovery significantly, with cheaper IOR techniques, where NCS will be reliant on novel technologies to further improve recovery rates.

NAM Shale has provided the largest volume additions to global production since 2014. Impressive productivity improvements in shale and the agility of the shale industry has increased their market share. Offshore excl. Middle East have only contributed to a marginal increase despite pre-2014 sanctioning wave been put into production in this period, the NCS is no exception.

Long lead times pose a significant obstacle to future competitiveness on the NCS if the region is to compete effectively with shale oil and Middle Eastern volumes. While lead times for tie-backs are comparable with conventional onshore and Middle Eastern projects, the average 7.7 year delay between discovery and production is too long for effective competition with shale volumes.

The emergence of shale oil has created a faster moving, more dynamic global supply and demand environment for oil, where flexibility and rapidity is essential in order to capture new volumes when demand increases. The NCS is currently losing out on volume growth due to long lead times, but has significant room for improvement which can bolster the region's competitiveness.

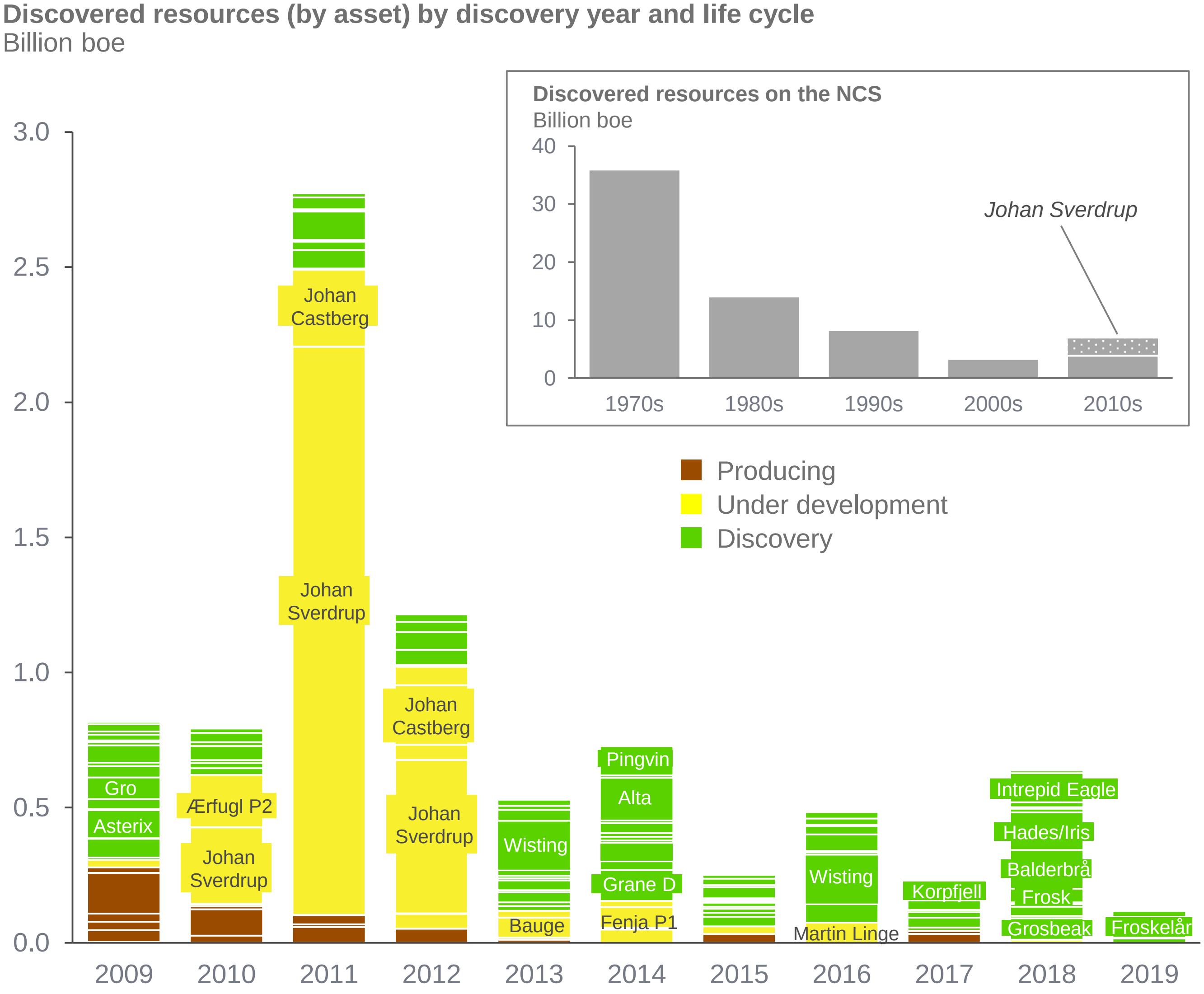
1) From spud to first oil.
Source: Rystad Energy research and analysis, Rystad Energy UCube

Offshore | Shale unconventional | Onshore conventional | Oil sands unconventional

RYSTAD ENERGY

Last five years characterized by disappointing exploration performance

Volume



- Apart from significant development projects such as Johan Sverdrup and Johan Castberg, the last ten years have been disappointing in terms of new discoveries
- During the last five years, no large discoveries have been made
- 2015 was a very disappointing exploration year with only ~270 mmboe in discovered resources
- 2018 was close to/almost back at 2014 level in terms of discovered resources, with 640 mmboe against 730 mmboe in 2014
- The past five years of exploration results confirm the trend of deteriorating prospectivity on the NCS

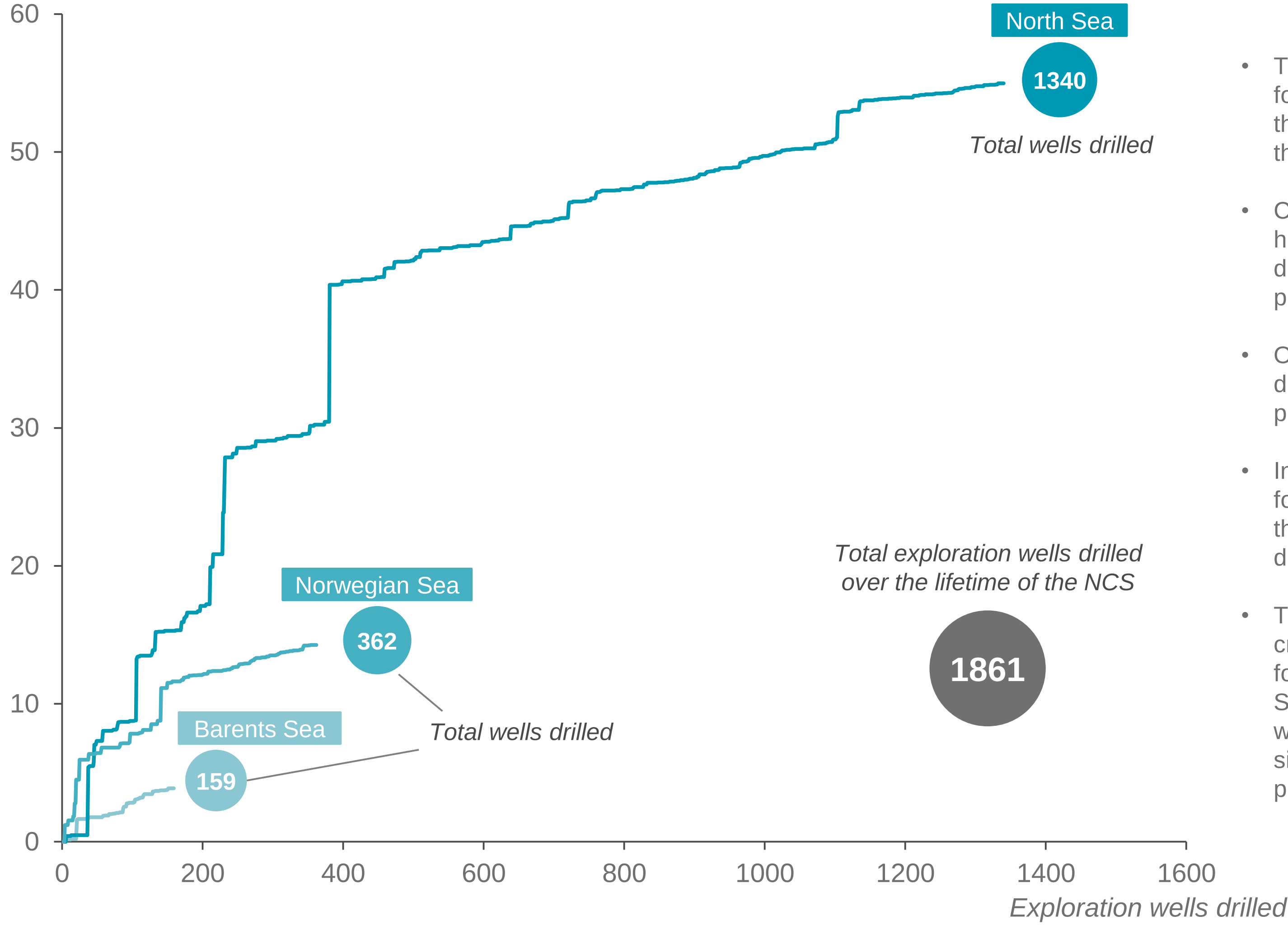
Source: Rystad Energy UCube

RYSTAD ENERGY

Barents Sea with disappointing exploration yield so far

Volume

Creaming curves for the three main NCS provinces
Billion boe discovered



- The graph shows the creaming curves for the three main provinces on the NCS: the North Sea, the Norwegian Sea, and the Barents Sea
- Creaming curves illustrate how operators high-grade their exploration, resulting in discovery of the largest and most profitable fields early on
- Over time, operators are expected to see diminishing returns on exploration as the province matures.
- In practice, large discoveries are still found after decades of exploration, e.g. the mega field Johan Sverdrup first discovered in 2010 in the North Sea
- The North Sea has the most aggressive creaming curved, the Norwegian Sea following a similar pattern as the North Sea until 100 exploration wells drilled, while the Barents Sea is lagging significantly behind the other two provinces.

Source: Rystad Energy UCube

Equinor's ambition of recovery implies significant production from existing fields

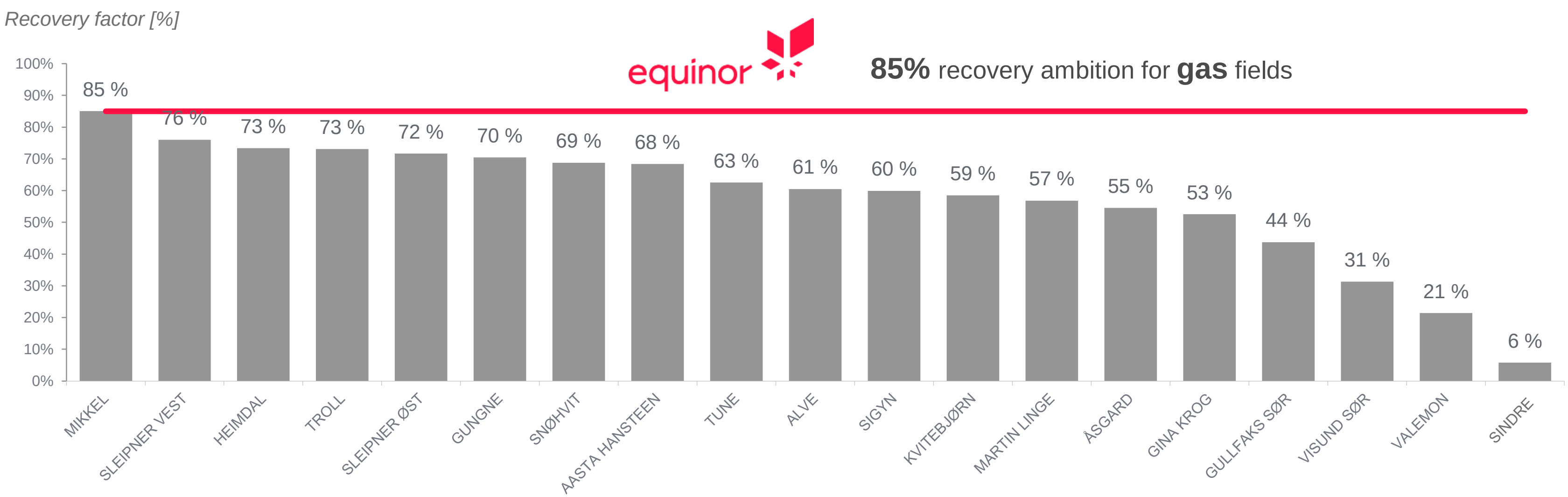
Volume

Equinor's currently planned recovery of its fields compared to long term ambition

Goal

85 %

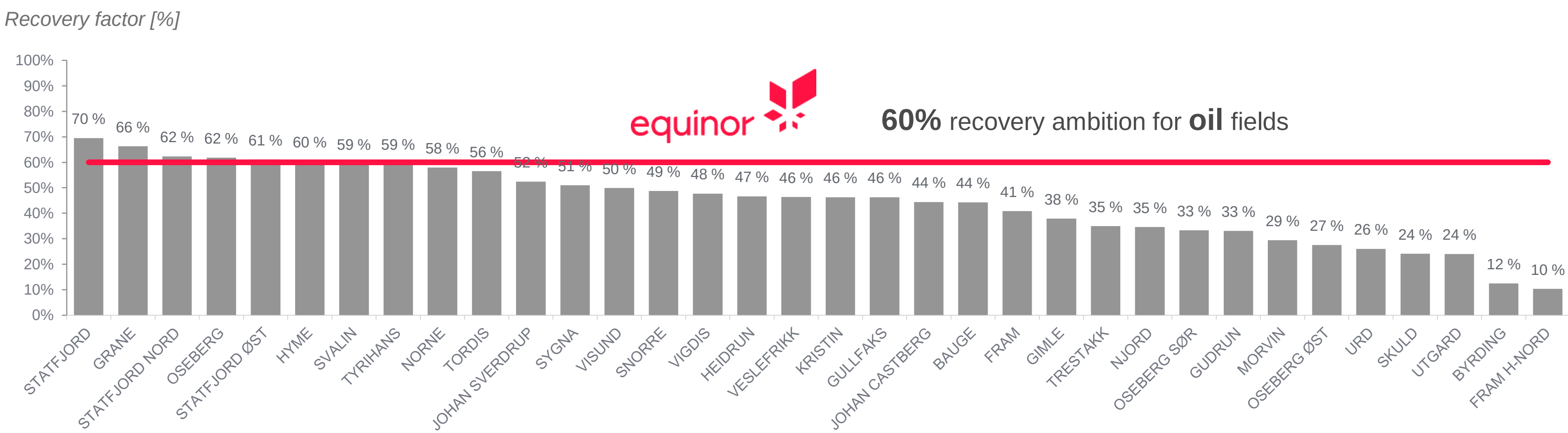
Recovery factor on **gas** fields



Goal

60 %

Recovery factor on **oil** fields



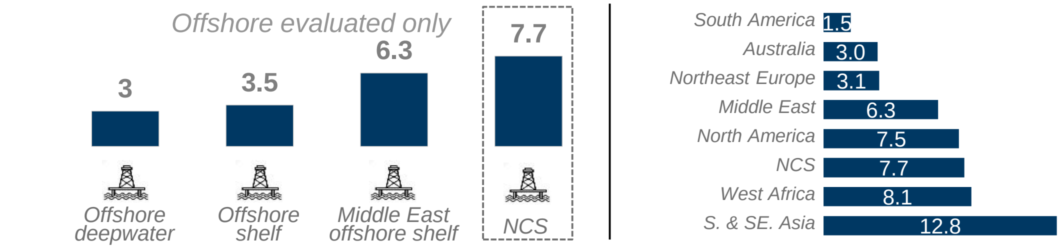
Source: Rystad Energy research and analysis

Opex and breakeven among the lowest for NCS, but struggling on the exploration scene

Key indicators for competitiveness in 2018 | 2014-2018 | Comment

Offshore expex per boe discovered*

USD per boe.



NCS -49%

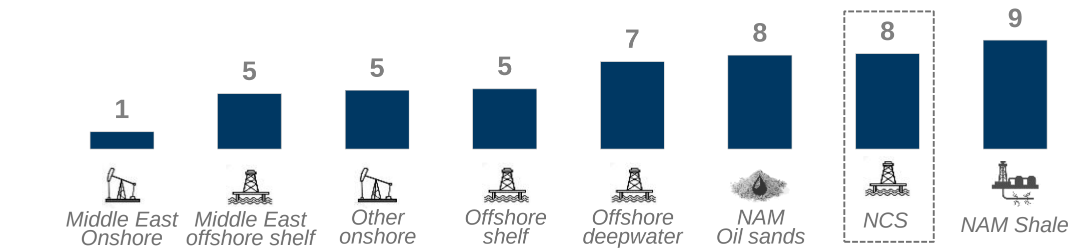
RoW -71%

The NCS expex per boe is higher than the average for other offshore supply segments, and despite a 49% decrease since 2014, this is less than the 71% decrease witnessed globally. The improvement is in part due to lower drilling costs and part due to more material discoveries

* Exploration expenses per found resources. Only offshore. Includes both technical and commercial discoveries where public information is available.

Capex per boe**

USD per boe.



NCS -75%

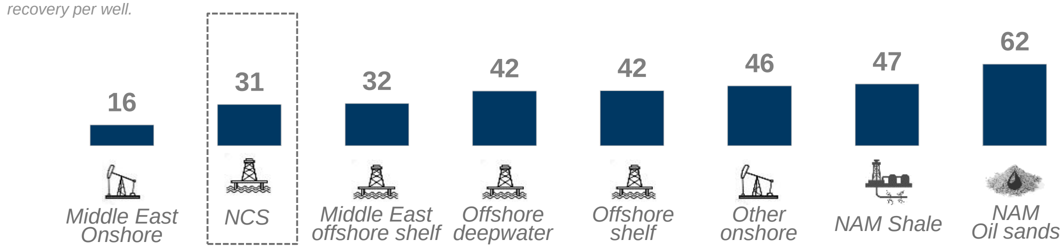
RoW -20%

Greenfield capital expenditures still remain high for the NCS, but are comparatively better than competing volumes from NAM shale. Operators' focus on capex since 2014 has paid off thanks to a 75% decrease in capex per boe, dwarfing the global trend of 20% reductions.

**Greenfield capital expenditures related to sanctioned oil and gas fields in current year for these fields. Well capex estimated through ultimate recovery per well.

Breakeven oil price***

USD per boe.



NCS -16%

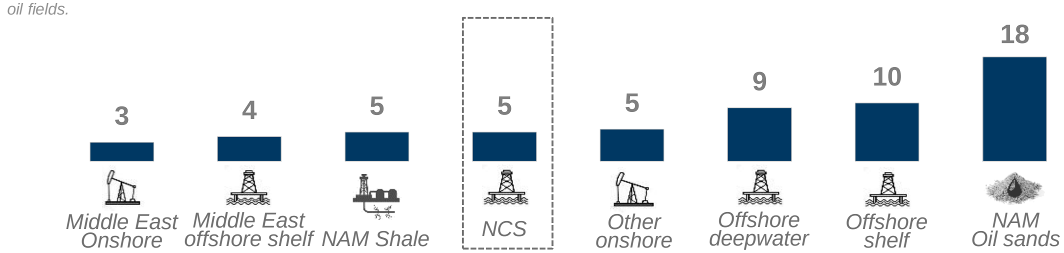
RoW -18%

Breakeven oil prices display a more even playing field, with many supply segments converging on the USD 40-47 per boe interval. The NCS competes effectively with Middle East offshore volumes on this metric, while onshore Middle East projects are still leagues ahead.

***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. Only oil fields.

Opex per boe****

USD per boe.



NCS -31%

RoW -19%

Strong reductions in operating expenses have contributed to placing the NCS in a favorable position, but the region's maturing profile will put pressure on operating costs per barrel as fixed costs remain while production volumes fall, thereby pushing up the per barrel expenses.

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

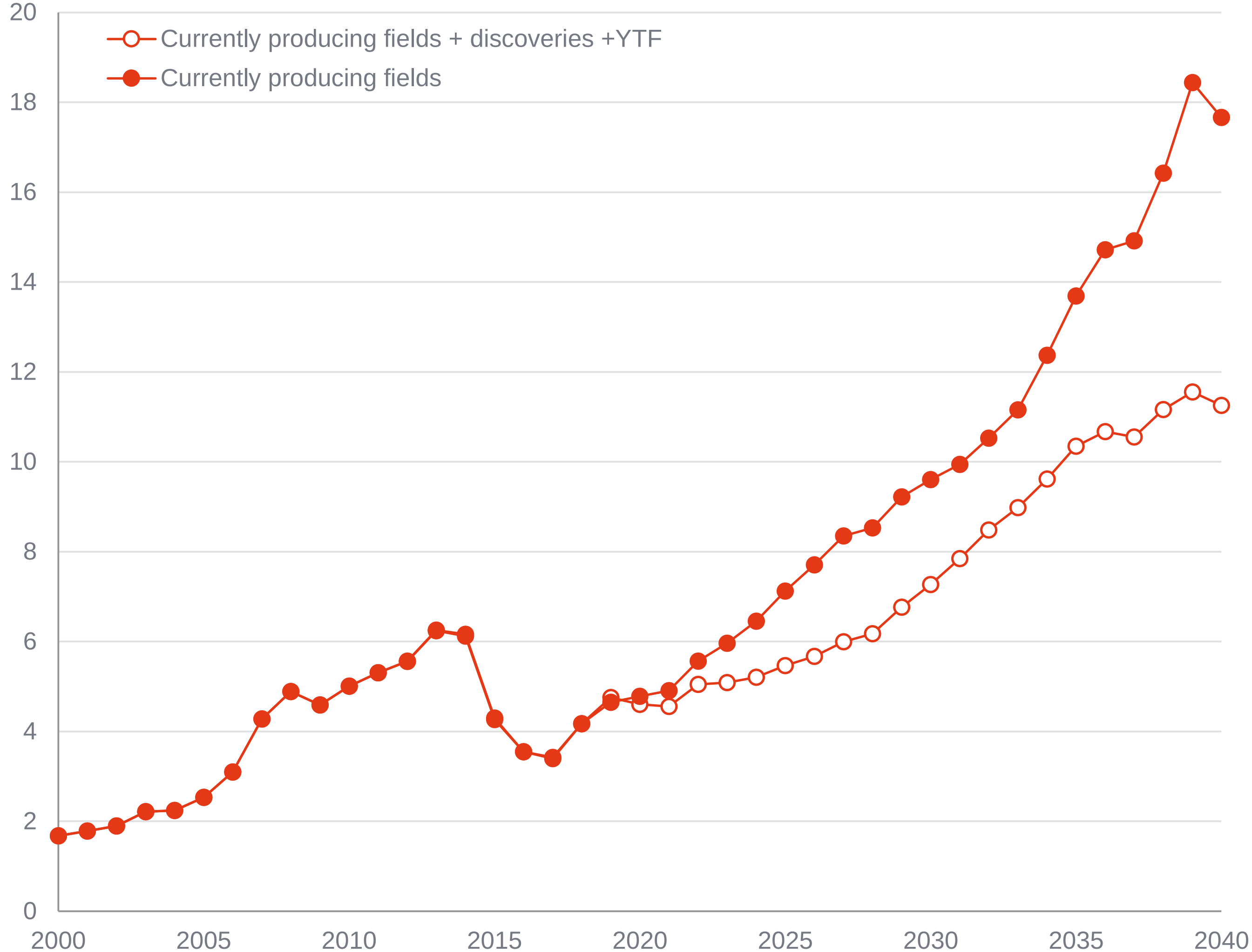
Offshore | Shale unconventional | Onshore conventional | Oil sands unconventional

Source: Rystad Energy research and analysis, Rystad Energy UCube

Even if the NCS has favorable fundamentals, lifting cost will increase if no measures are taken and production declines

Cost

Average lifting cost for NCS
Opex per boe produced*



- The chart show the average lifting cost on the NCS historically and expected levels going forward.
- As the shelf matures and production decline, the lifting cost per barrel will increase. This applies especially to producing fields
- In 2030 the lifting cost per boe is expected to have gone from below 4 to 10 USD/boe on average for currently producing fields. Some will be even higher. In 2030 production from currently producing fields account for 50% of the expected output from NCS.
- This will pose a challenge to the competitiveness of the NCS compared to younger basins as we see for the UKCS today.

*production opex only. SG&A and transportation tariffs not included
Source: UCube

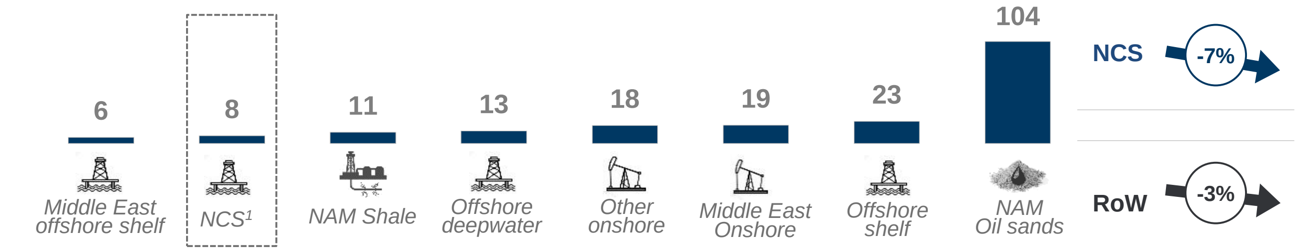
RYSTAD ENERGY

NCS is best in class in an increasingly emissions conscious industry

Key indicators for competitiveness in 2018 | **2014-2018** | **Comment**

Upstream CO_2-intensity*

Kg CO_2 per boe.

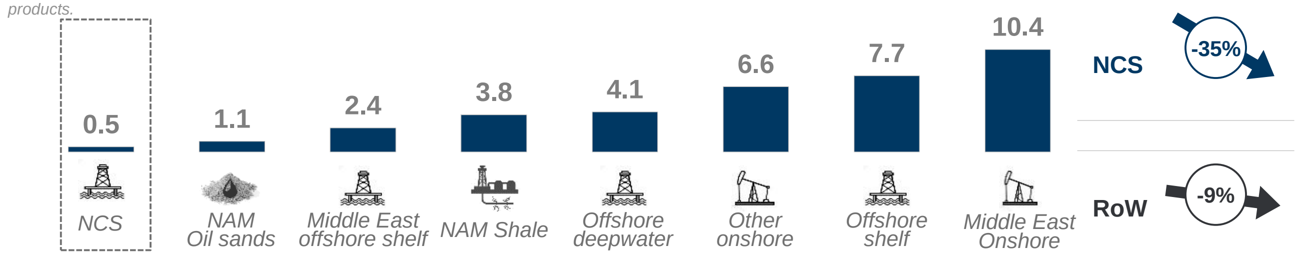


Middle East offshore and the NCS lead the field in upstream emissions. For the Middle East offshore fields much can be attributed to large field sizes, while a focus on efficiency has pushed the NCS to the top tier. This position will be harder to maintain as competitors potentially catch up.

*Total yearly upstream CO_2 emissions divided according to intra-segment production in the same year. Includes flaring, excludes end-use of products.

Upstream flaring**

Kg CO_2 per boe.

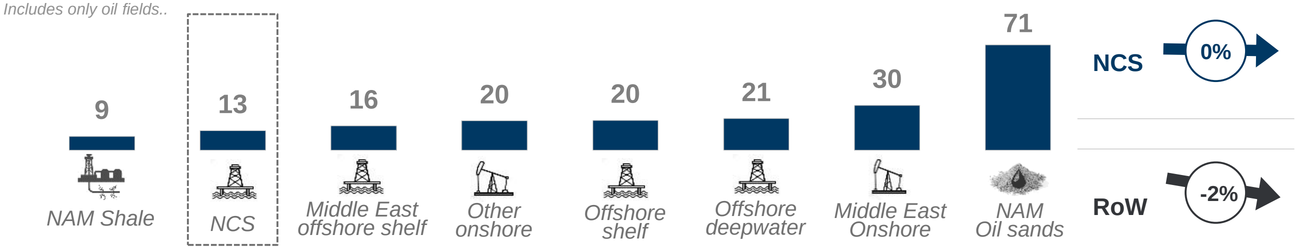


The NCS strong score on emissions is driven by increased focus on limiting flaring that has pushed CO_2 intensity from flaring on the NCS down by 35% since 2014 and increased the segment's leading position vis-à-vis competing suppliers.

**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. Includes only oil fields..

Midstream CO_2 intensity***

Kg CO_2 per boe.

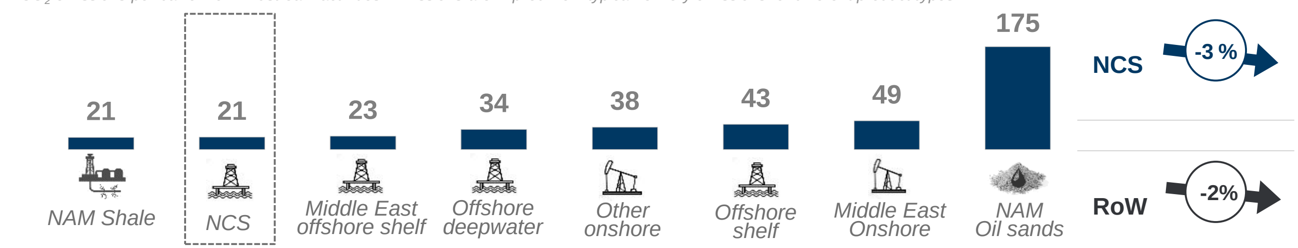


Due to the high proportions of light products such as gas and light oil, the NCS has one of the lowest implied emission intensities from midstream operations. As public attention towards emissions increases, current numbers indicate the NCS is a rational choice for low-emissions hydrocarbon production.

***CO_2 emissions per barrel from midstream activities. Emissions are implied from typical refinery emissions for different product types.

Overall CO_2 intensity****

Kg CO_2 per boe.



Continuing to be best-in-class will demand more strenuous efforts in the future as low hanging fruit from flaring reductions have already been picked, while shale volumes are already excelling on emissions and have more to gain from further efficiency improvements.

****CO_2 emissions per barrel from midstream and upstream activates.

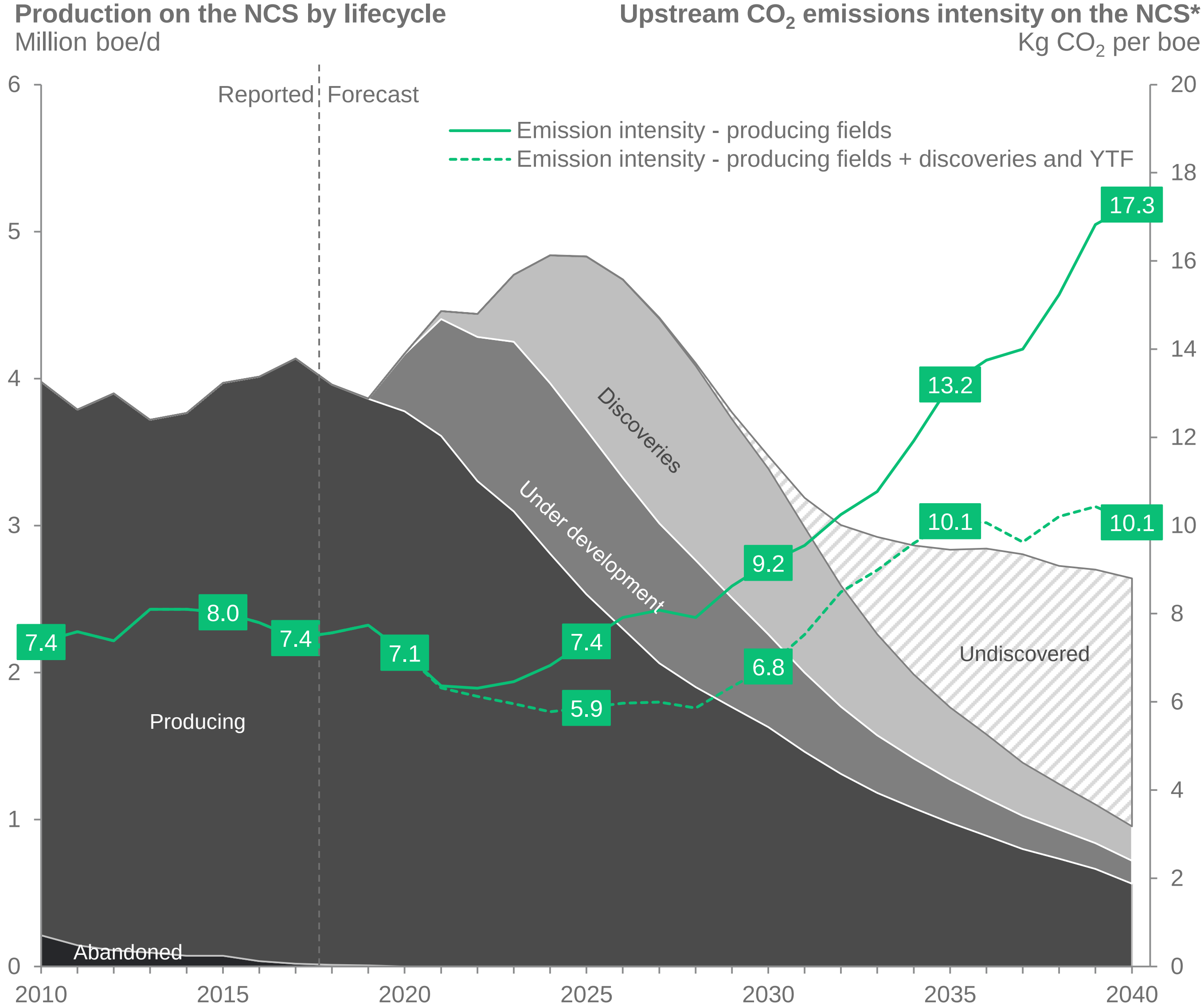
1) Estimated based on 2017 data, underlying emission drivers and 2018 production.
Source: Rystad Energy research and analysis, Rystad Energy UCube

Offshore | Shale unconventional | Onshore conventional | Oil sands unconventional

RYSTAD ENERGY

With NCS production in decline post 2025, CO_2 intensity increases unless measures are taken

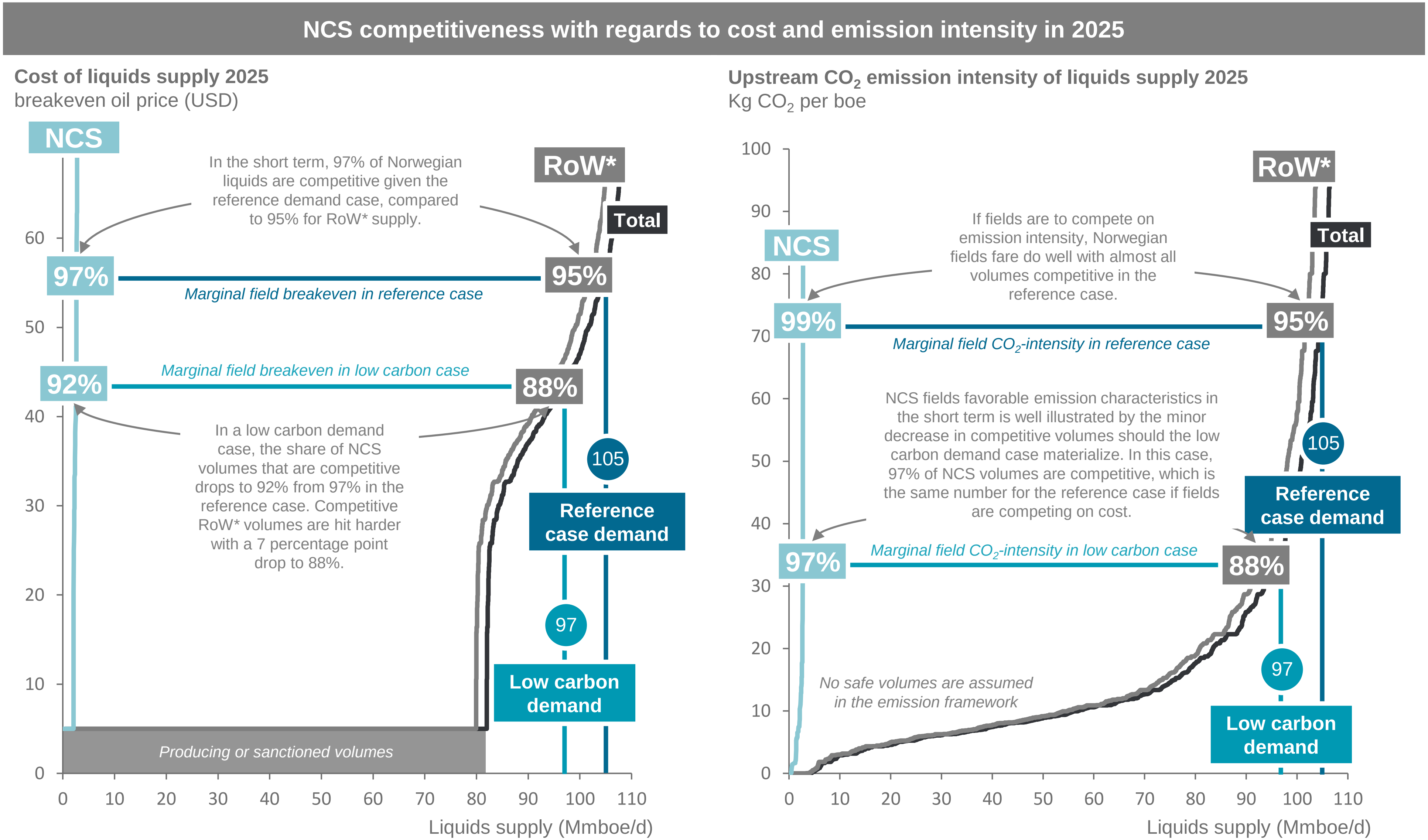
Emissions



- *The area chart shows production from all fields on the NCS, while the lines represent the weighted average emission intensity on the NCS from 2010 to 2040, the dotted line excluding discoveries and fields yet to be found.*
- *Emissions intensity is a metric for emissions generated per barrel of oil equivalents produced.*
- *From 2025 onwards, the NCS production is in decline. However, as shown on the previous slide, upstream CO_2 emissions remain relatively stable, despite production dropping as conventional fields mature. This is driven by more efforts required to extract late phase barrels, typically resulting in increased need for separation due to high water cut and increased injection activity to maintain reservoir pressure.*
- *This effect is particularly profound when looking at intensities for the NCS as we know it per today, i.e., only regarding producing fields and fields under development.*

*Fields to be electrified do not contribute to CO_2 emissions in the intensity metric, and includes Johan Sverdrup (all phases), Valhall West Flank, Martin Linge, and the remaining fields on the Utsira High after the startup of Johan Sverdrup phase 2 (Edvard Grieg, Gina Krog and Ivar Aasen); Source: Rystad Energy UCube; Rystad Energy research and analysis

In the short term, Norwegian liquids supply is competitive both on cost and emissions



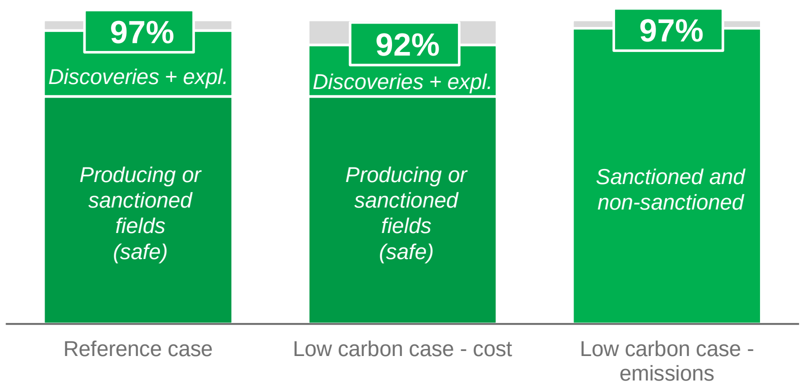
* Rest of world
Source: Rystad Energy UCube

NCS volumes are robust in the short term, but at risk in the long term should demand decrease

	Short term (2025)	Long term (2025-2050)

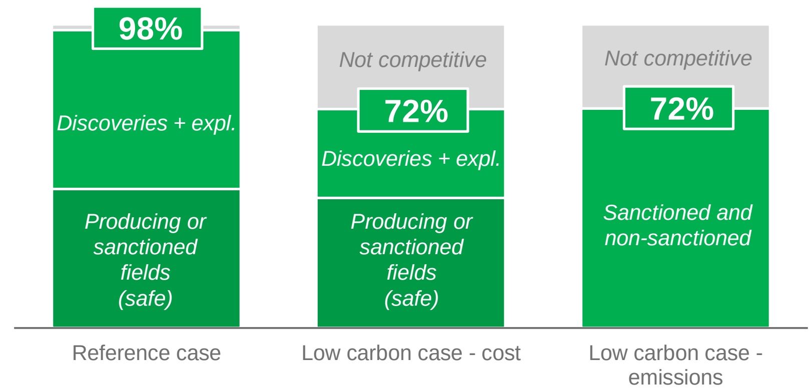
Liquids

Competitiveness of Norwegian short term liquids supply



Demand for Norwegian liquids is robust in the short term, although relatively more competitive on emissions compared to cost

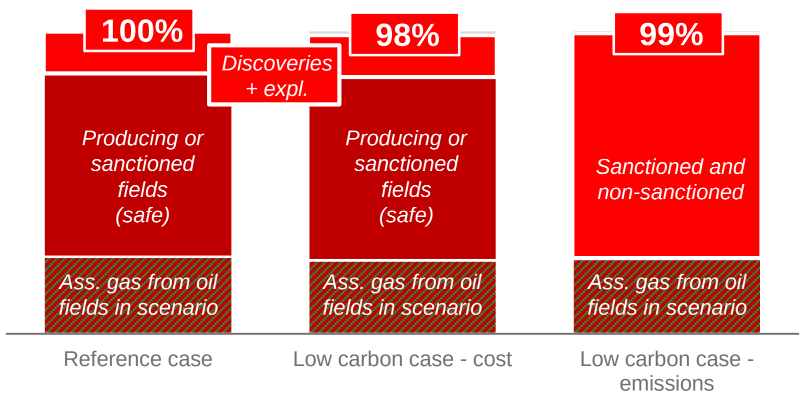
Competitiveness of Norwegian long term liquids supply



Long term, Norwegian liquids supply is very competitive in the reference case, but substantial volumes fall out should the low carbon scenario materialize

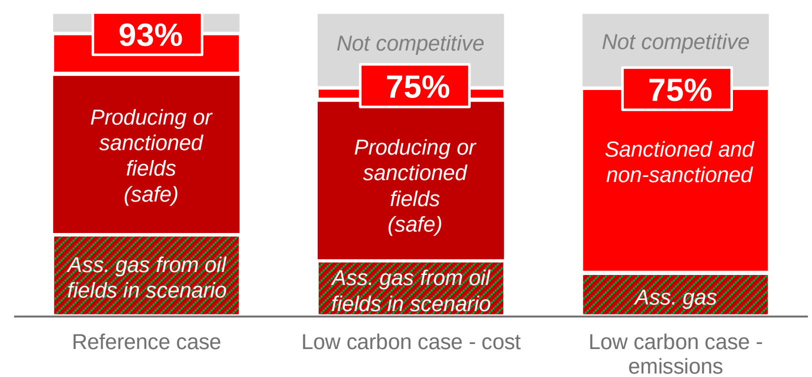
Gas

Competitiveness of Norwegian short term gas supply



Norwegian gas is cheap, clean and politically preferable and thus very robust in the short term given the high EU gas demand in the coming years

Competitiveness of Norwegian long term gas supply



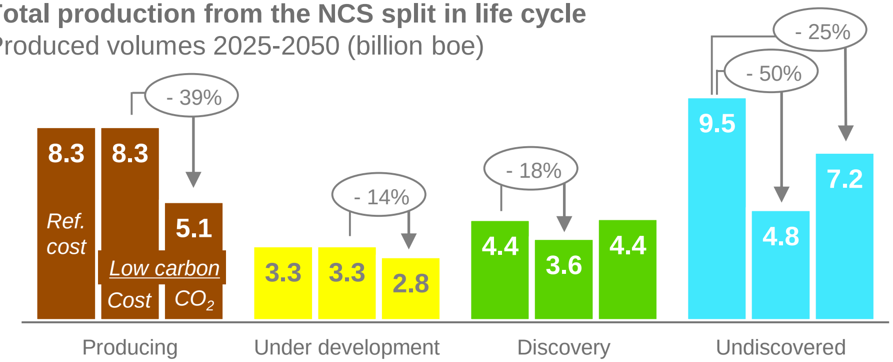
In the long term, demand for Norwegian gas is less certain as NCS gas face tough competition from cheap gas elsewhere and potentially decreased demand

Source: Rystad Energy UCube

In low carbon scenarios different volumes are at risk dependent on whether the decision makers are cost- or emission conscious – exploration and producing fields are most sensitive

Producing fields and expl. sensitive to low carbon scenarios

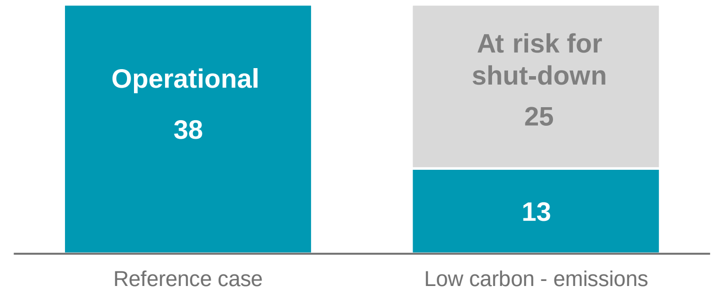
Total production from the NCS split in life cycle
Produced volumes 2025-2050 (billion boe)



Volumes from producing fields will likely be less CO_2-competitive, and around 40% of volumes from producing fields are taken out. Exploration need is substantially reduced in low demand scenarios.

Several of the current hosts at risk in a emission perspective

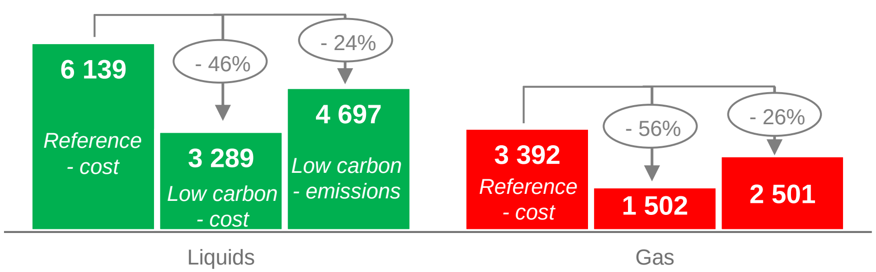
Long term competitiveness of current field centers*
Number of field centers



If volumes compete on emissions intensity in a future low demand scenario, around 65% of current hosts must shut down

Half of undiscovered volumes at risk in a cost perspective

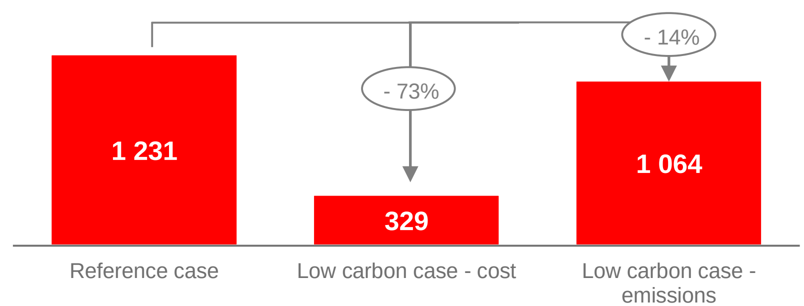
Call for long term exploration on the NCS
Produced volumes 2025-2050 (million boe)



Call for new liquids and gas volumes is reduced by around 50% and 25% in the low carbon cases discriminating on cost and emissions, respectively

Limited call for pure gas expl. in a low carbon scenario

Call for long term undiscovered non-associated gas from the NCS
Produced volumes 2025-2050 (million boe)



Most of potential new gas volumes from gas fields is unlikely to find a market should fields compete on cost in a low demand case. This assumes that the gas will not find alternative methods of delivery, i.e. through producing hydrogen or ammonia.

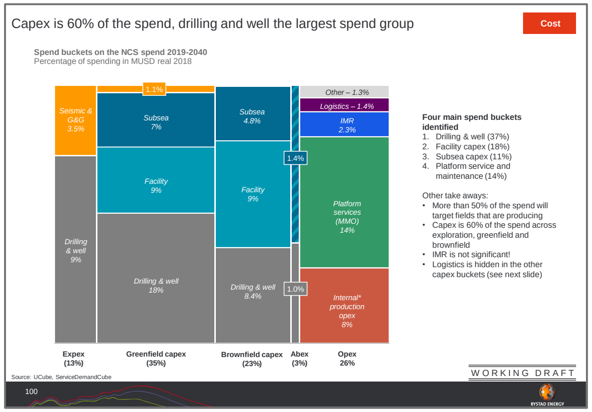
* Producing or sanctioned host assets
Source: Rystad Energy UCube

Index

Process of selecting and evaluating focus technologies to improve NCS competitiveness

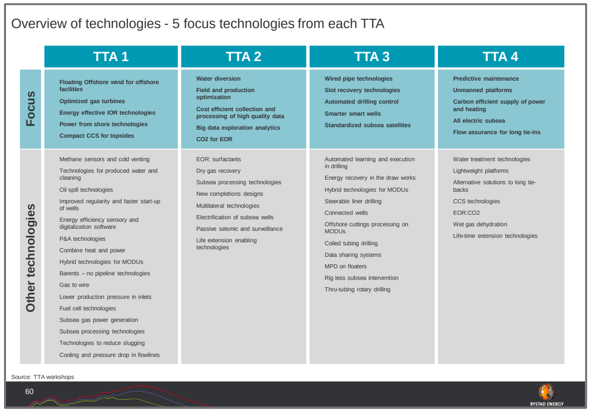
Bucket analysis
Understand volume, cost and emission drivers on the NCS

- *The outset for any technology evaluation is to find the application area. The larger the application area the larger potential of the technology*
- *Prepared for TTA workshops to aid the selection of focus technologies with high effect*
- *Investigated the largest buckets of volumes, spend and emissions on the NCS in a 2020-2050 timeframe.*



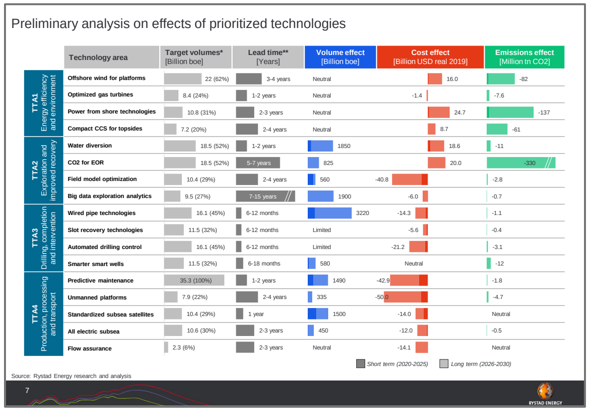
Suggest focus technologies for evaluation
Four TTA workshops

- *4 half-day workshops held with each TTA group.*
  - *TTA 1: Energy efficiency and environment*
  - *TTA 2: Exploration and improved recovery*
  - *TTA 3: Drilling, completion and intervention*
  - *TTA4: Production, processing and transport*
- *Selected a set of focus technologies that could have large effect on improving NCS competitiveness*
- *Provided input assumptions into the evaluation*



Evaluate focus technologies
Analyze effect of NCS in the period 2020-2050

- *Simplified business case evaluation of each technologies effect on the NCS in the period between 2020-2050.*
  - *Assed the technologies' potential to increase/accelerate volumes, reduce cost and reduce emissions*
  - *Short term and long term effects evaluated for each technology.*
- *Additional interviews and workshops conducted to understand application potential of each technology.*



Source: Rystad Energy research and analysis

RYSTAD ENERGY

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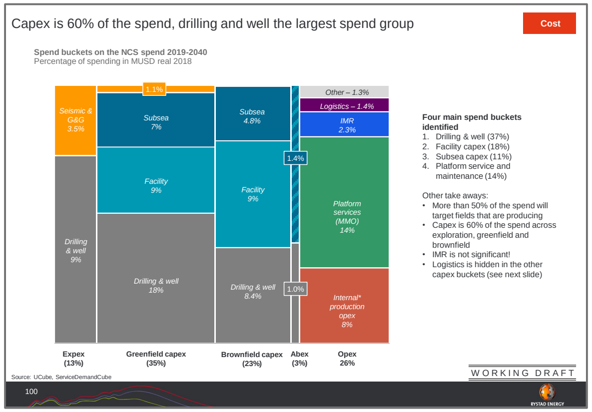

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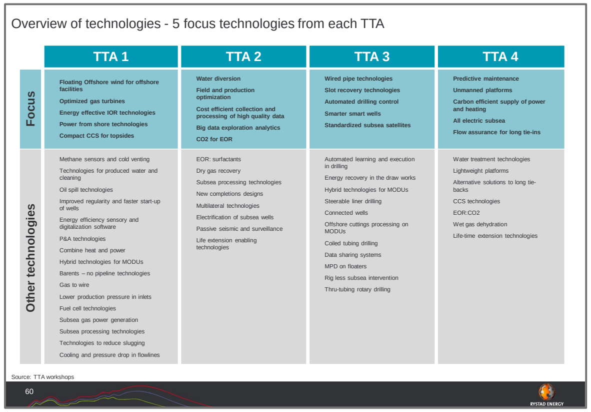

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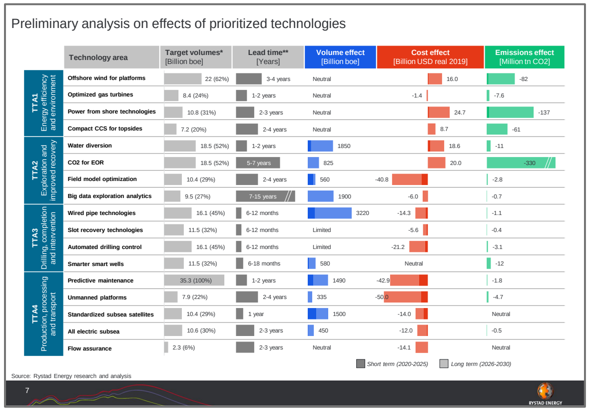


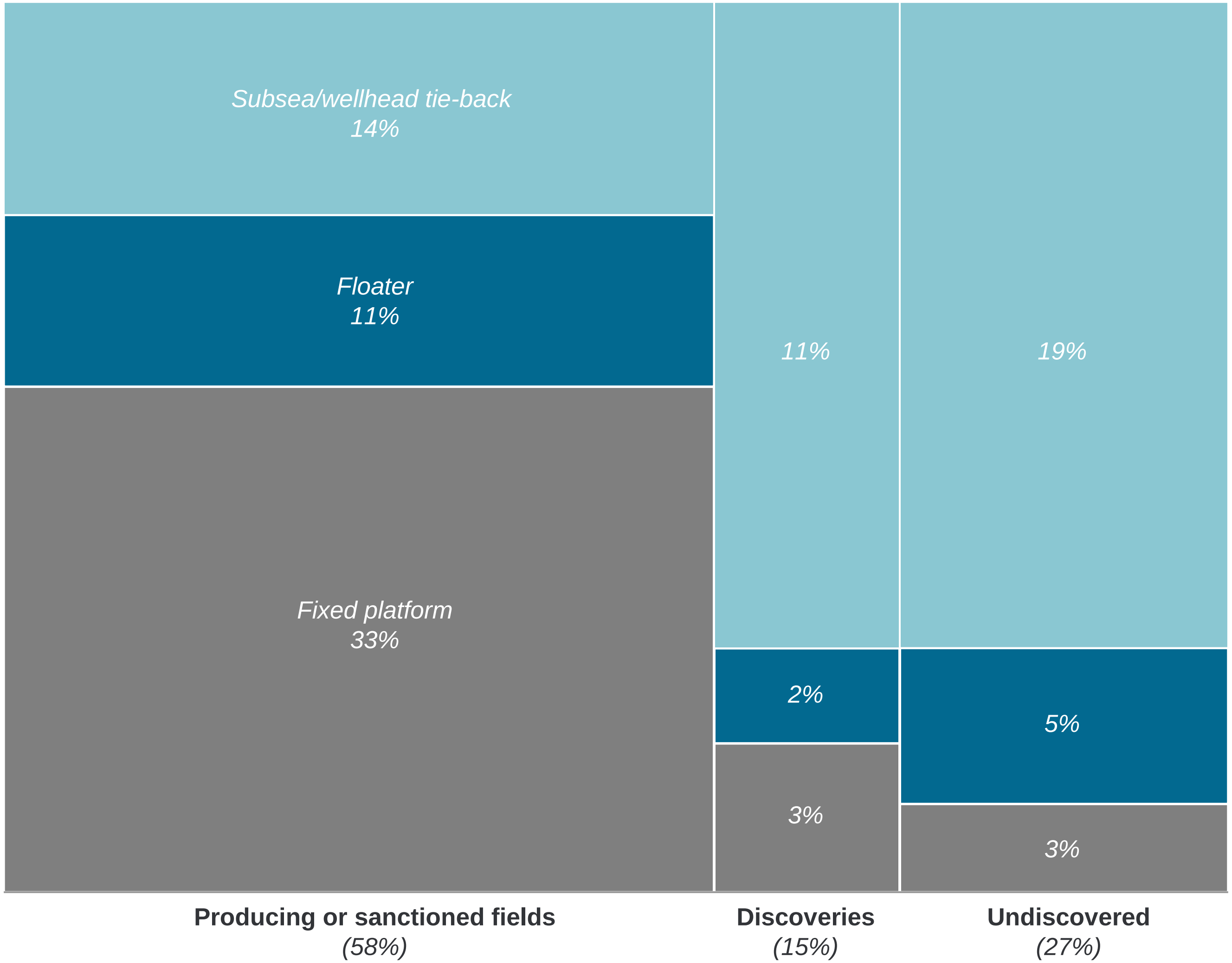
Source: Rystad Energy research and analysis

RYSTAD ENERGY

Almost 60% of total volumes left on the NCS lie in sanctioned fields

Volumes

Volume buckets on the NCS between 2019-2050
Percentage of expected barrels of oil equivalent produced



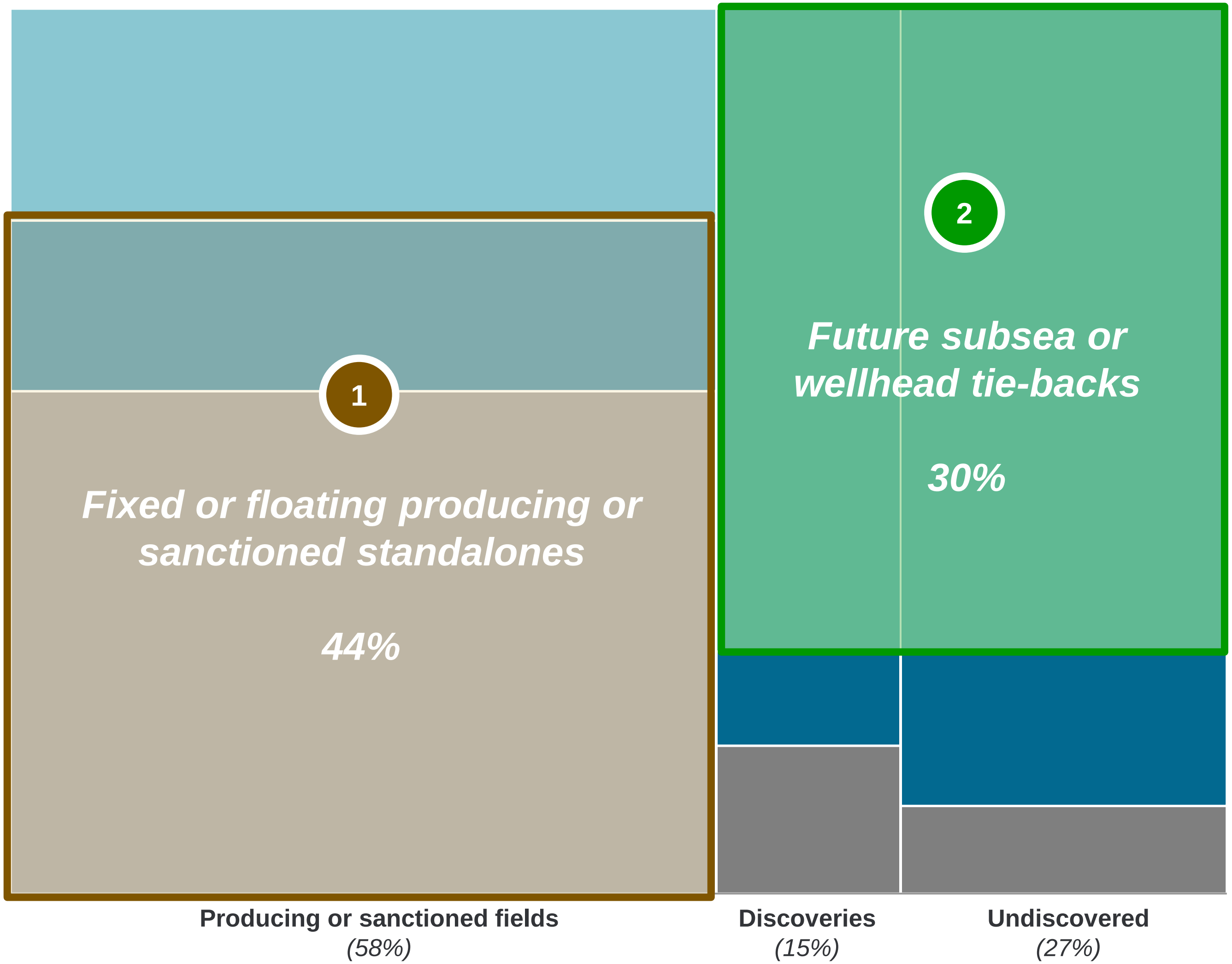
- The chart outlines production volumes on the NCS in the period 2019-2050 in terms of current status of the field and facility type.
- Fields that are yet to be sanctioned are expected to rely heavily on tie-back solutions, whereas currently producing fields (mostly in the North Sea) have been developed as stand-alones with fixed or floating production facility

Source: Rystad Energy UCube

About a third of future production is expected from future tie-backs

Volumes

Volume buckets on the NCS between 2019-2050
Percentage of expected barrels of oil equivalent produced



- The chart outlines production volumes on the NCS in the period 2019-2050 in terms of current status of the source field and facility type of that field
- Fields that are yet to be sanctioned are expected to rely heavily on tie-back solutions, whereas currently producing fields (mostly in the North Sea) have been developed as stand-alones with fixed or floating production facility
- As a result, we define two important buckets of future production volumes:

1 Producing and sanctioned standalones

- These volumes are already sanctioned as standalone developments with dedicated processing facilities

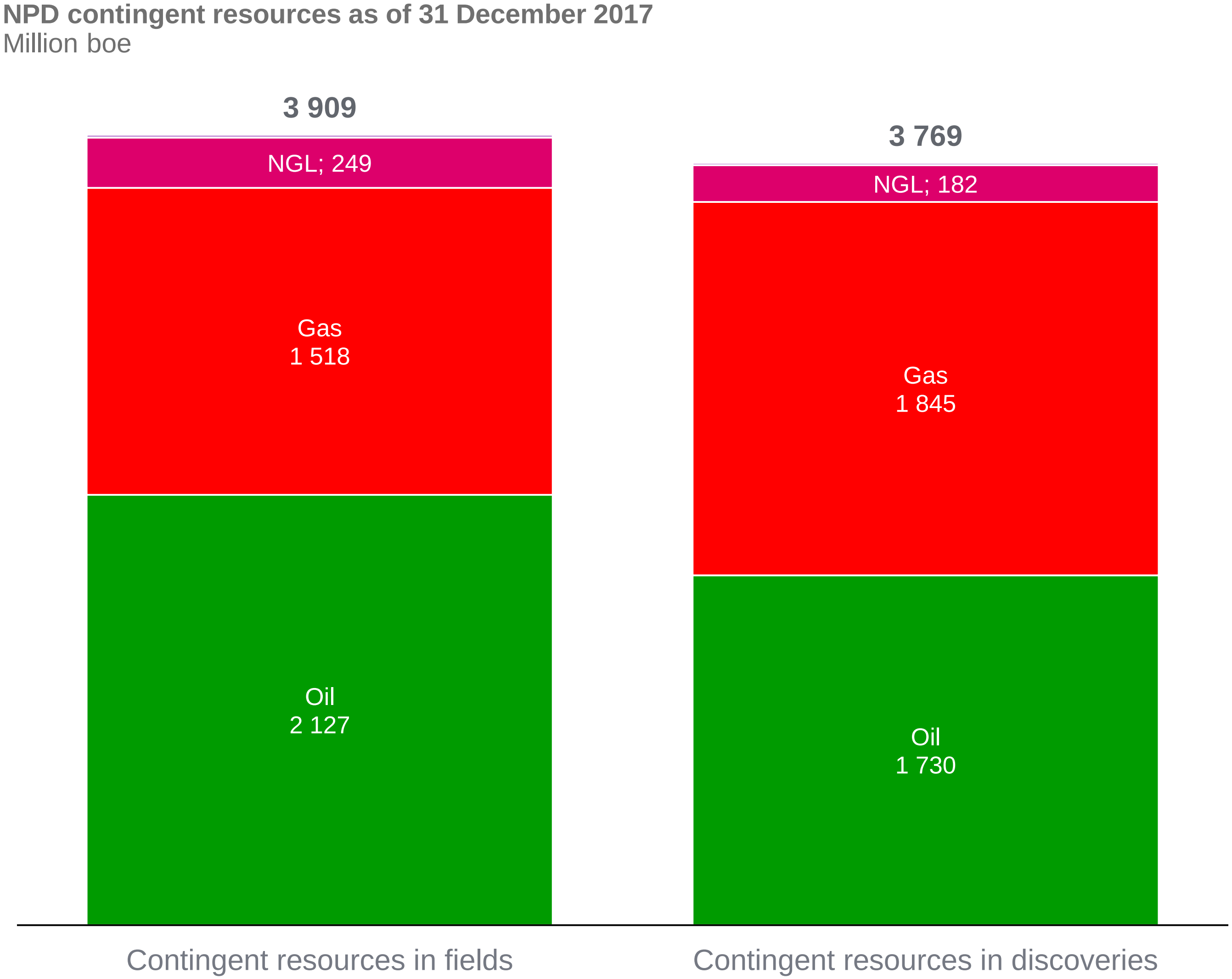
2 Future tie-backs

- Volumes from fields expected to be developed as subsea/wellhead tie-backs

Source: Rystad Energy UCube

Current potential in sanctioned fields equals potential in discoveries

Volumes



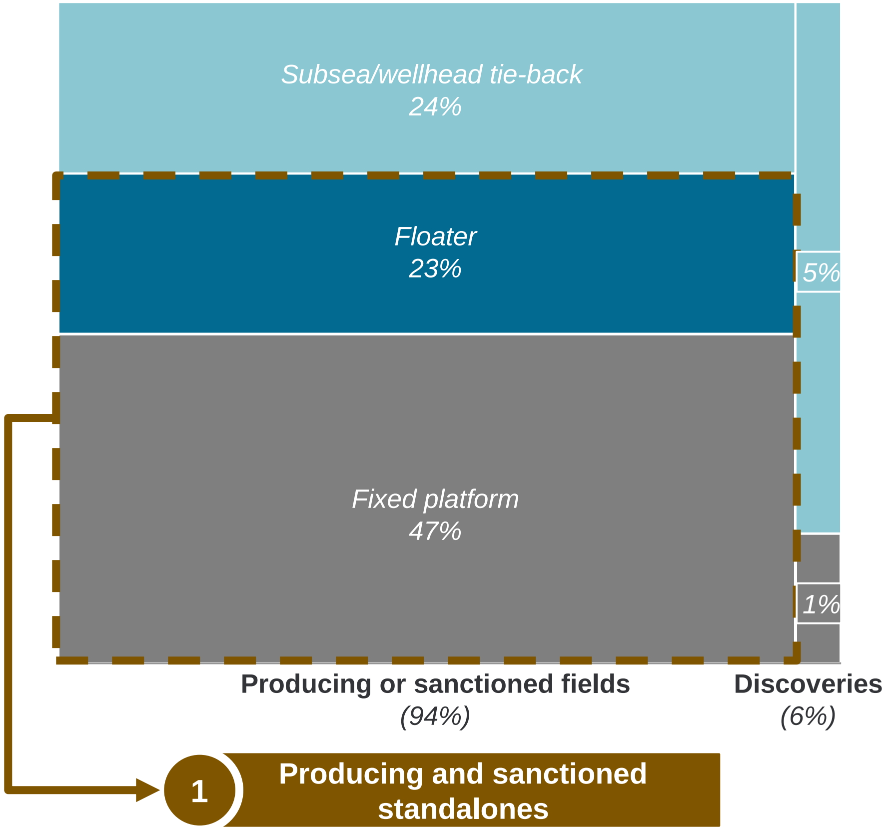
- The chart outlines NPDs accounts of contingent resources – resources that have been identified but are yet to be sanctioned
- Interestingly, current identified volume potential in fields is larger than in the combined portfolio of discoveries
- Moreover, non-sanctioned liquids resources in existing fields account for 31% of total contingent resources
- Thus, technology increasing oil recovery in existing fields (where infrastructure is already in place) will have a large impact.

Source: NPD Resource Report 2018

No impact of new concepts in the short term – focus on tie-backs in the long term

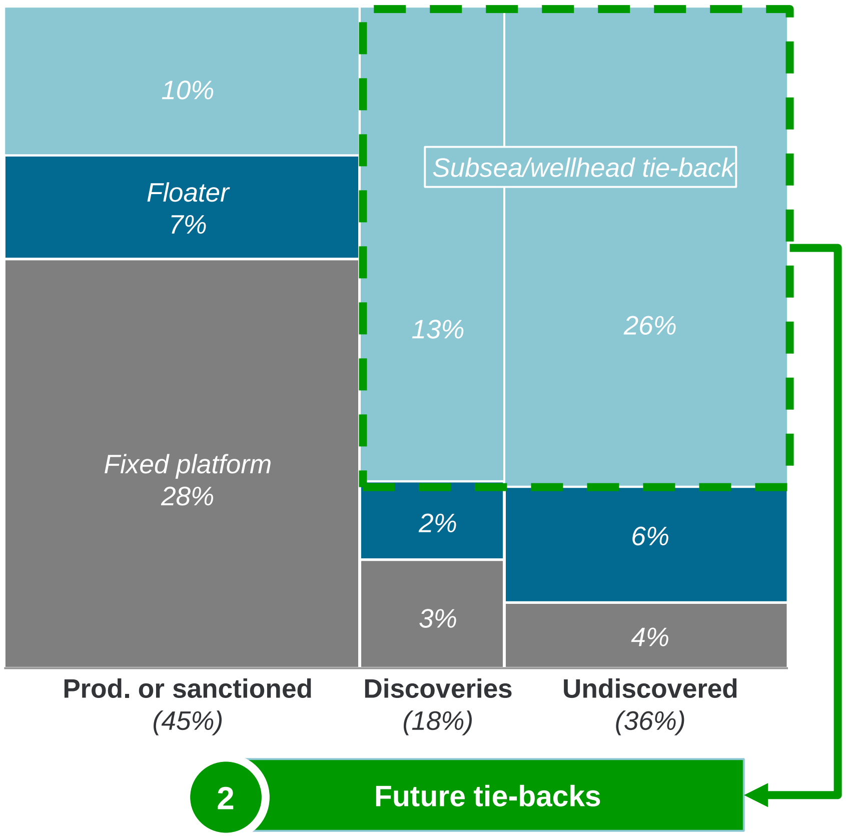
Volumes

Volume buckets on the NCS between 2019-2025
Percentage of expected barrels of oil equivalent produced



- 94% of expected production volume in the short term is already sanctioned and outside the scope for new development concepts
- Hence, technology that improves recovery in already developed fields is likely to have the most impact in the short term

Volume buckets on the NCS between 2025-2050
Percentage of expected barrels of oil equivalent produced



- In the long term, 39% of expected production is expected from undiscovered fields developed as tie-backs
- Thus, technology that enable successful exploration and resource effective development of these volumes will be important in the long term

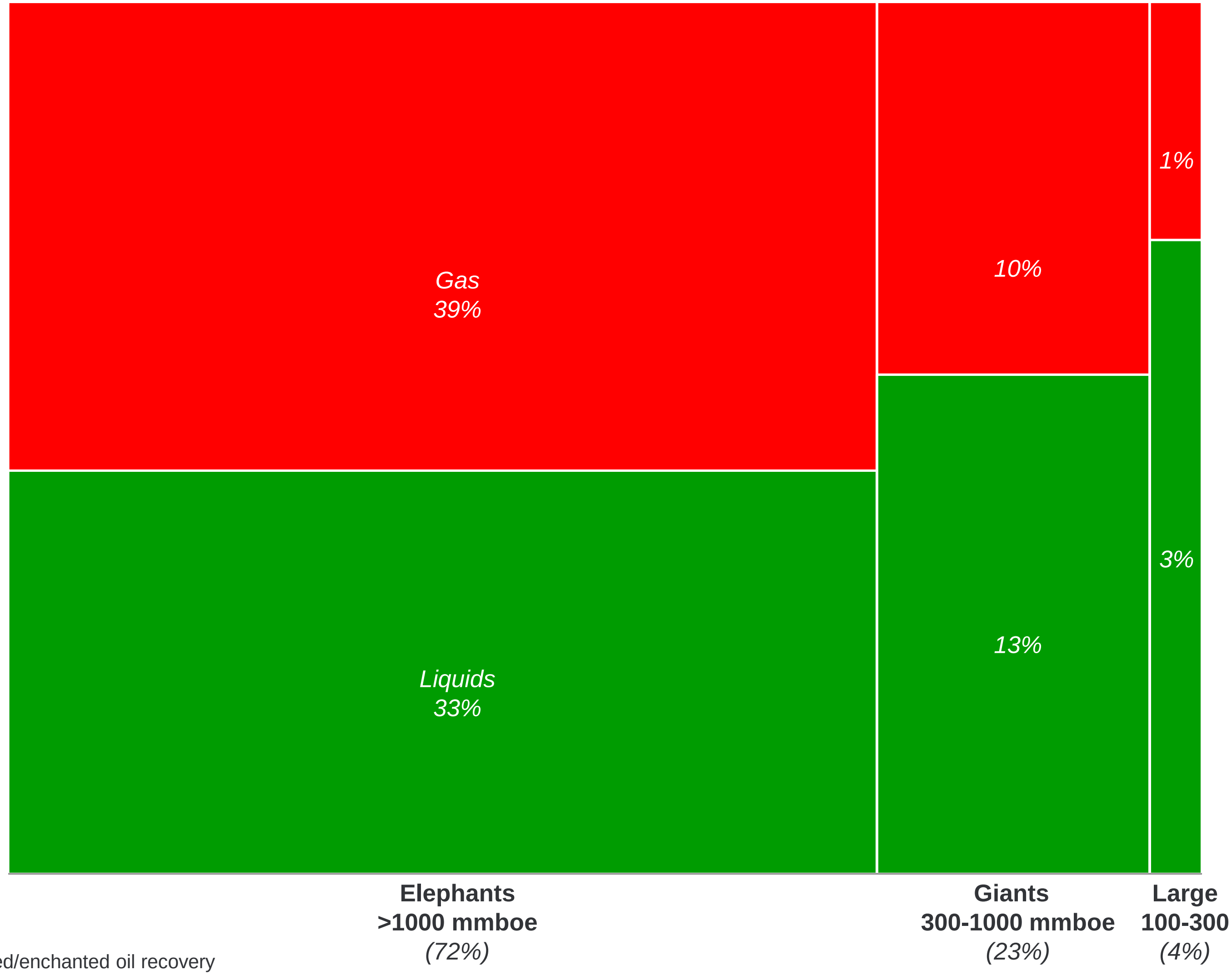
Source: Rystad Energy UCube

Large potential for IOR/EOR in producing and sanctioned elephant fields

Volumes

Volume buckets from sanctioned standalone fields on the NCS between 2019-2050
Percentage of expected barrels of oil equivalent produced

1 Producing and sanctioned standalones



- The chart outlines production volumes from already producing and sanctioned standalone fields on the NCS in the period 2019-2050
- Consequently, the potential for increased reserves is large by adopting technology that improves recovery rates by a few percent in the largest fields. For example the oil and gas volumes produced from elephant fields such as Johan Sverdrup, Aasgard, Troll, Oseberg and Ekofisk
- Currently, IOR/EOR* measures mainly target liquids. As the chart shows, there are substantial gas reserves in large producing or sanctioned fields. What can be done to increase gas recovery in these fields?

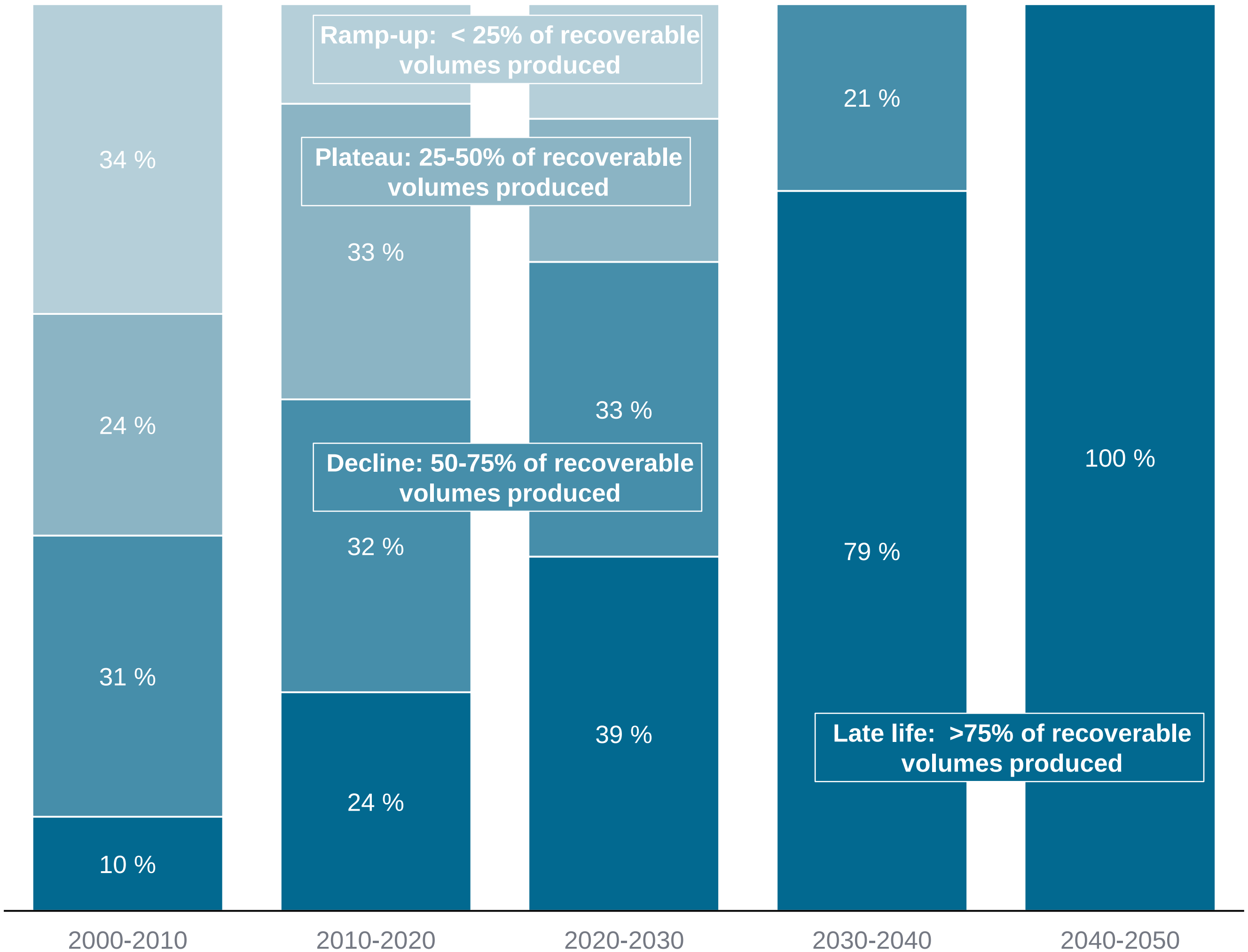
*Improved/enchanted oil recovery
Source: Rystad Energy UCube

Limited window for technology adoption as most fields enter tail production during the 2030s

Volumes

Maturity of producing and sanctioned standalone fields on the NCS in different periods
Share of total production

1 Producing and sanctioned standalones



- The chart outlines the maturity of producing and sanctioned fields at different time intervals.
- Willingness to invest in field at the very end of its production tail is low as the remaining volume base is limited.
- As such there is a window up to around 2030 (shorter for other fields) where investments in IOR and EOR technologies must be taken to make economically sense.

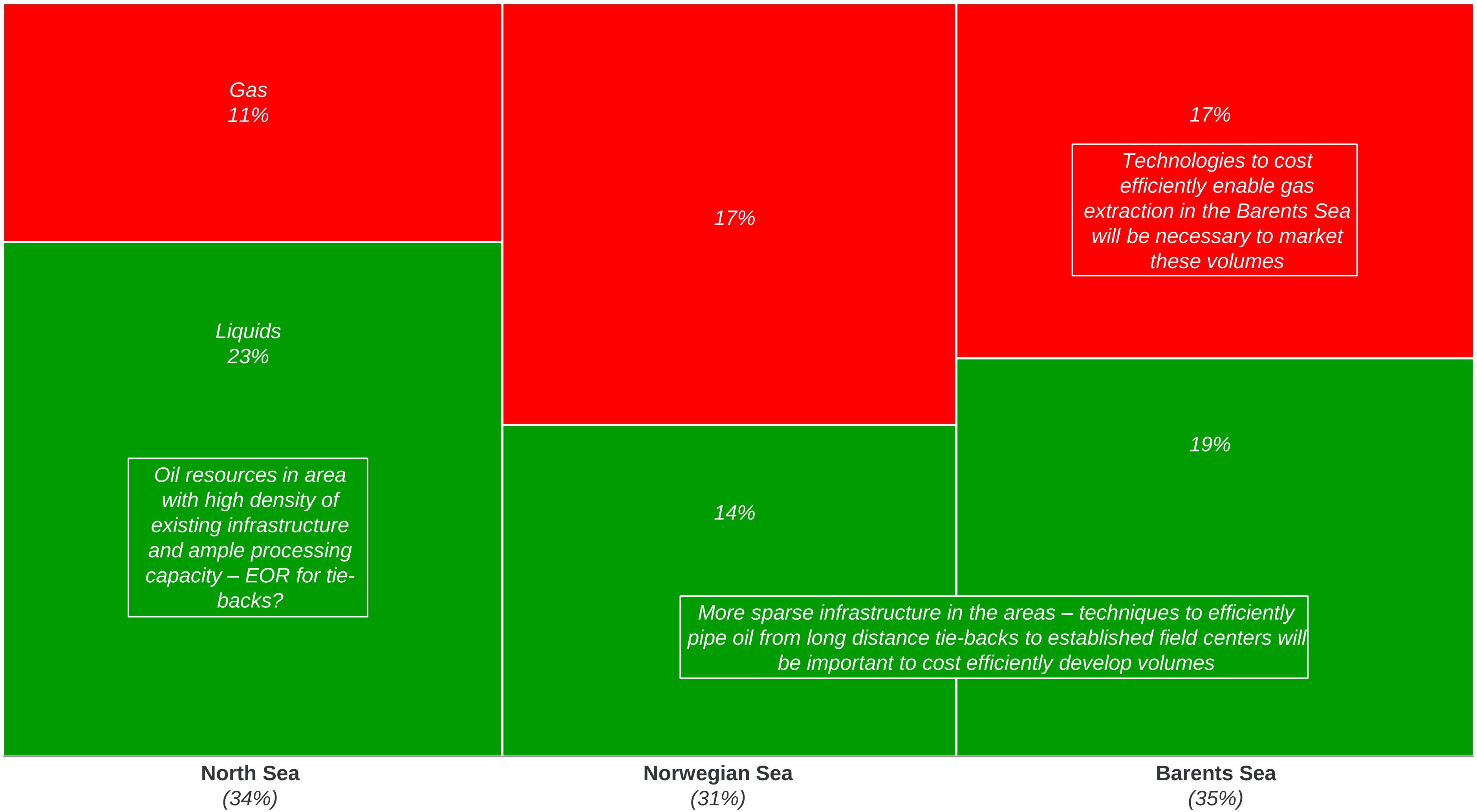
Source: Rystad Energy UCube

Tech could focus on increased oil recovery, flow assurance or gas evacuation

Volumes

2 **Future tie-backs**

Volume buckets from discovered and undiscovered tie-back fields on the NCS between 2019-2050
Percentage of expected barrels of oil equivalent produced

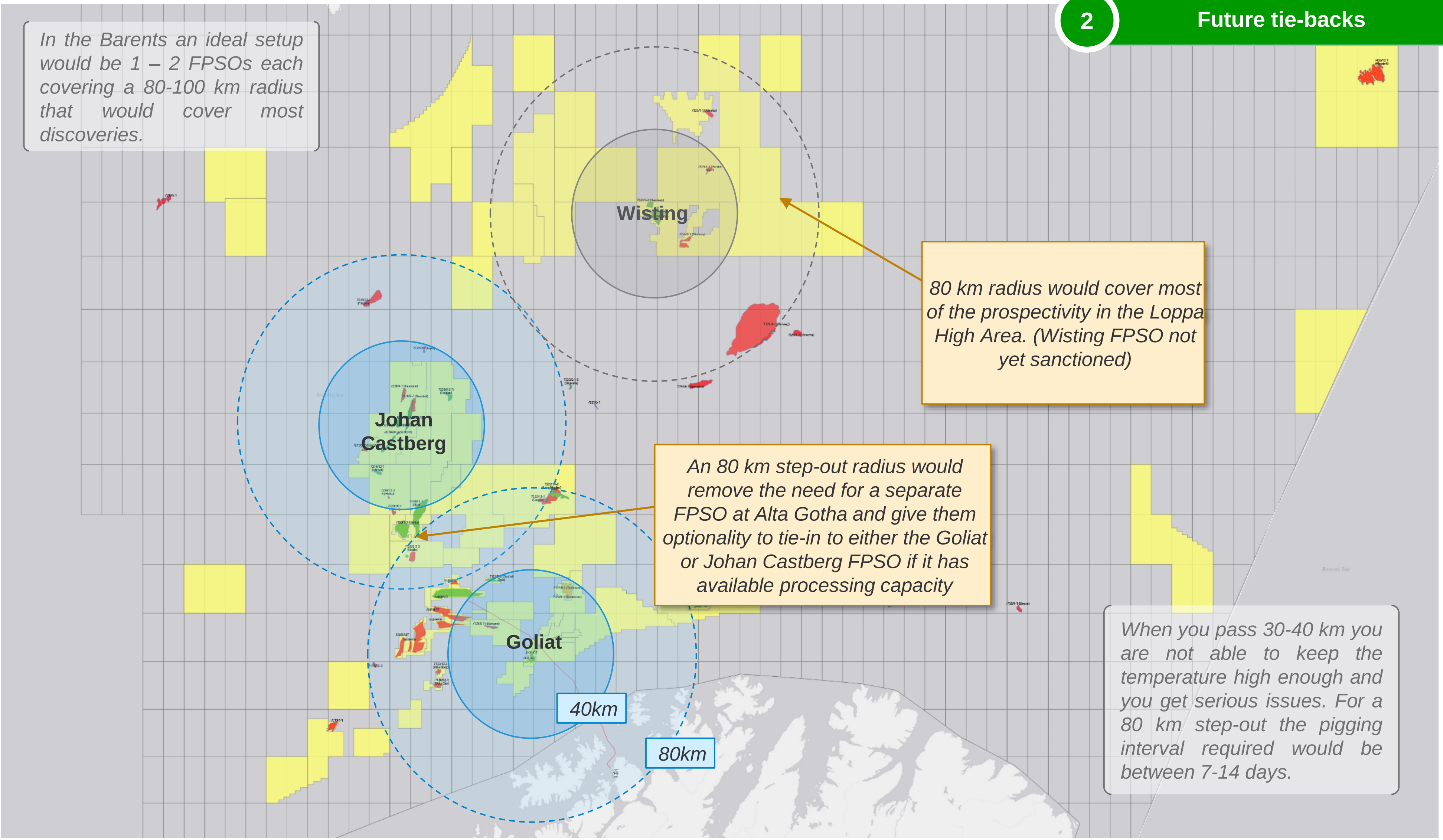


Source: Rystad Energy UCube

A key issue is to unlock volumes out of range of existing infrastructure

Volumes

2 **Future tie-backs**

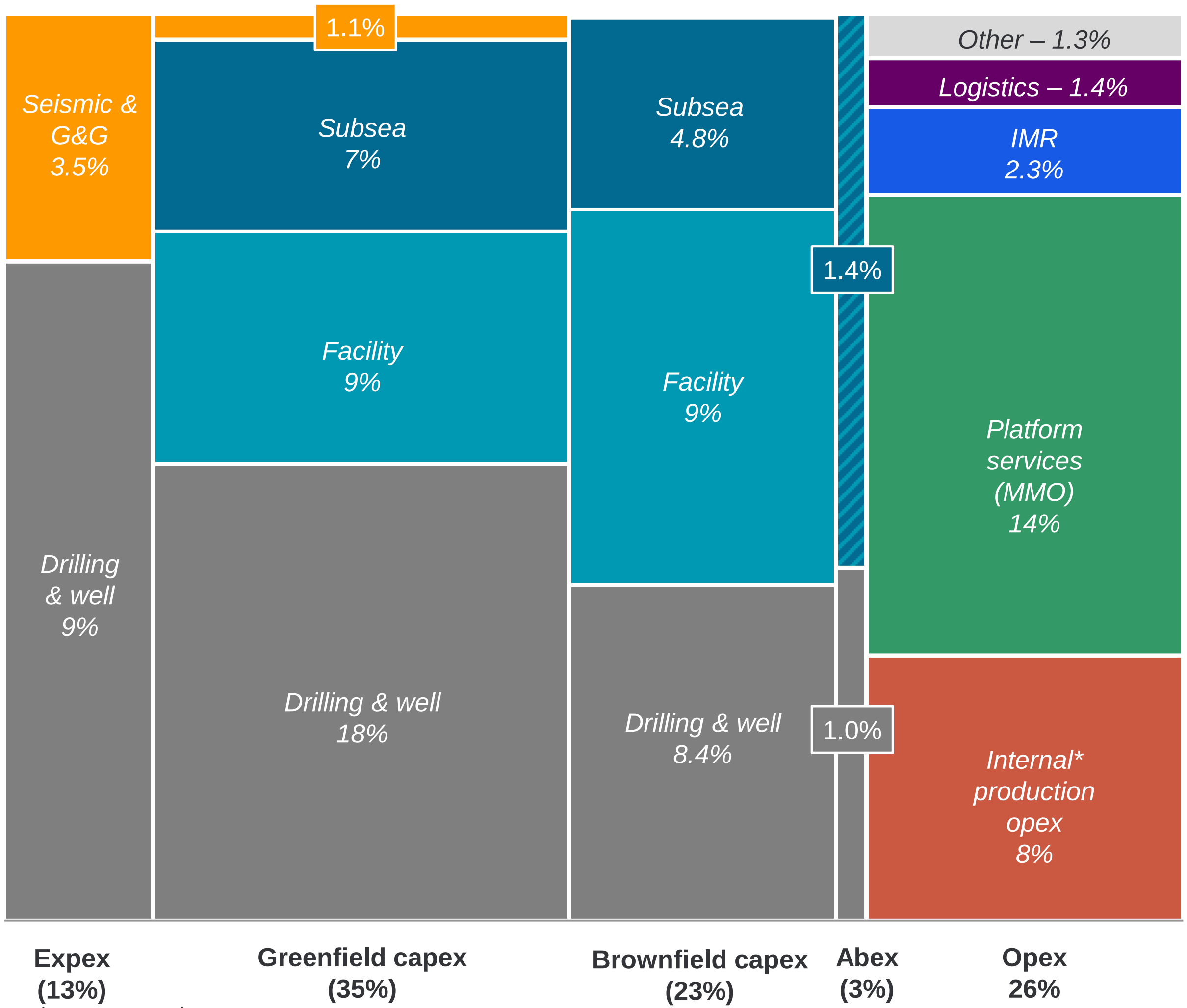


Source: Interviews; UCube; Rystad Energy research and analysis

Capex is 60% of the spend, drilling and well the largest spend group

Cost

Spend buckets on the NCS spend 2019-2040
Percentage of spending in MUSD real 2018



Four main spend buckets identified

1. Drilling & well (37%)
2. Facility capex (18%)
3. Subsea capex (11%)
4. Platform service and maintenance (14%)

Other takeaways:

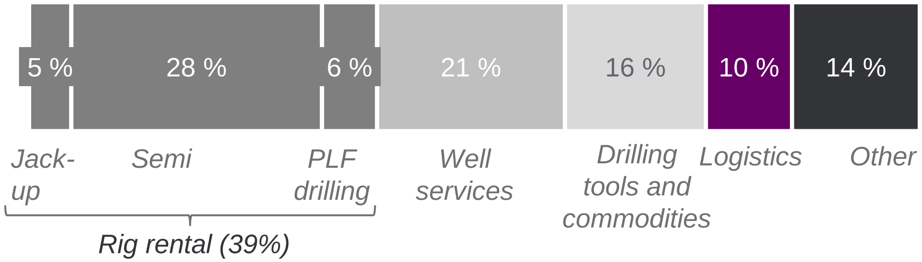
- More than 50% of the spend will target fields that are producing
- Capex is 60% of the spend across exploration, greenfield and brownfield
- IMR* is not significant
- Logistics is hidden in the other capex buckets (see next slide)

*IMR: inspection maintenance repair
Source: UCube, ServiceDemandCube

Deep-dive into cost components for the four spend buckets

Drilling & well

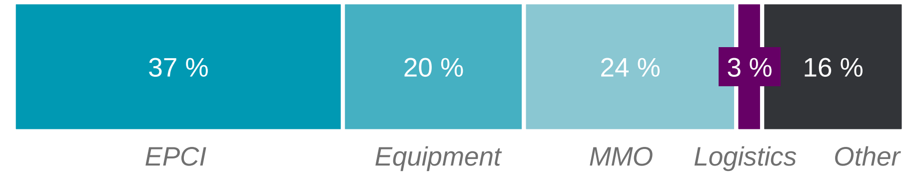
Drilling & well spend by component 2019-2040
Percentage



- Rigs are 40% of the total well cost, addressing time spent drilling is of high value.
- Three large associated buckets with well service, drilling tools and commodities and logistics. These are also highly time dependent.

Facility capex

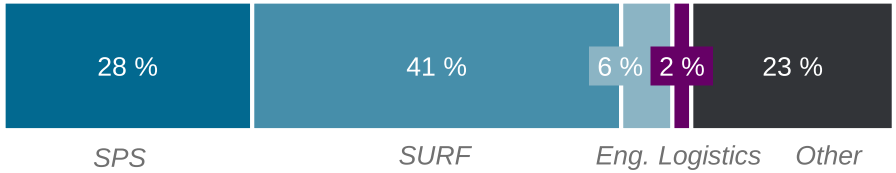
Facility capex by component 2019-2040
Percentage



- EPCI is the largest segment covering 37%, with equipment it covers more than 20%.
- MMO capex including large brownfield topside modules is 1/4 of the market

Subsea capex

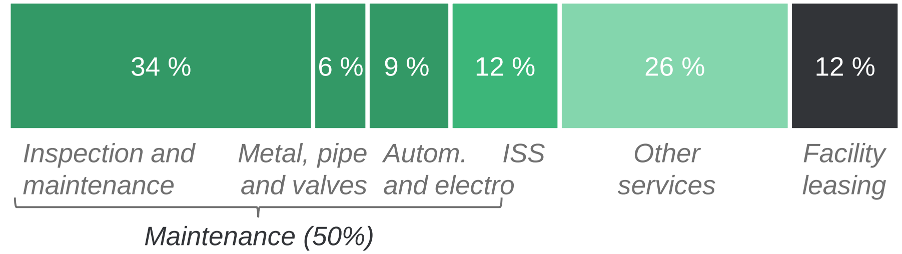
Subsea capex by component 2019-2040
Percentage



- Traditional contract scopes covers 70% of subsea capex. SURF most important as it includes installation.
- SPS system typically below 1/3 of the project cost.

Platform services

Platform services by component 2019-2040
Percentage



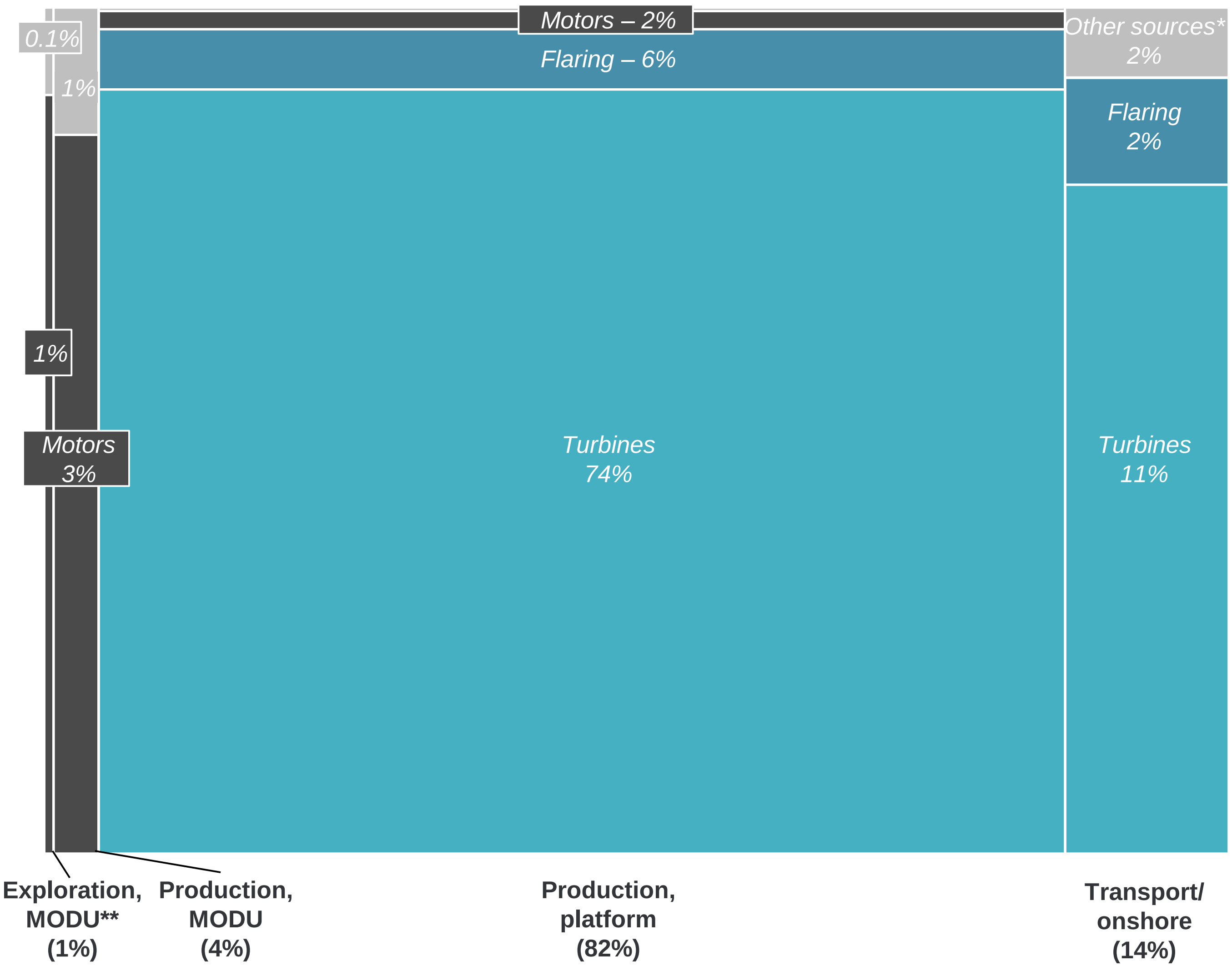
- The majority of platform services are labor intensive except for facility leasing (leased FPSOs), which makes up 12% of platform services on the NCS.
- Maintenance accounts for 50% of the spend, together with MMO capex, this bucket is substantial

MMO: Maintenance, modifications and operations, ISS: Insulation, scaffolding and surface treatment
Source: Rystad Energy UCube; ServiceDemandCube

Fuel combustion in gas turbines stood for 85% of upstream CO_2 emissions in 2017

Emissions

Upstream and midstream CO_2 emissions from the NCS in 2017, by emission source and activity
[% of the total 13.2 Mt CO_2 emitted]



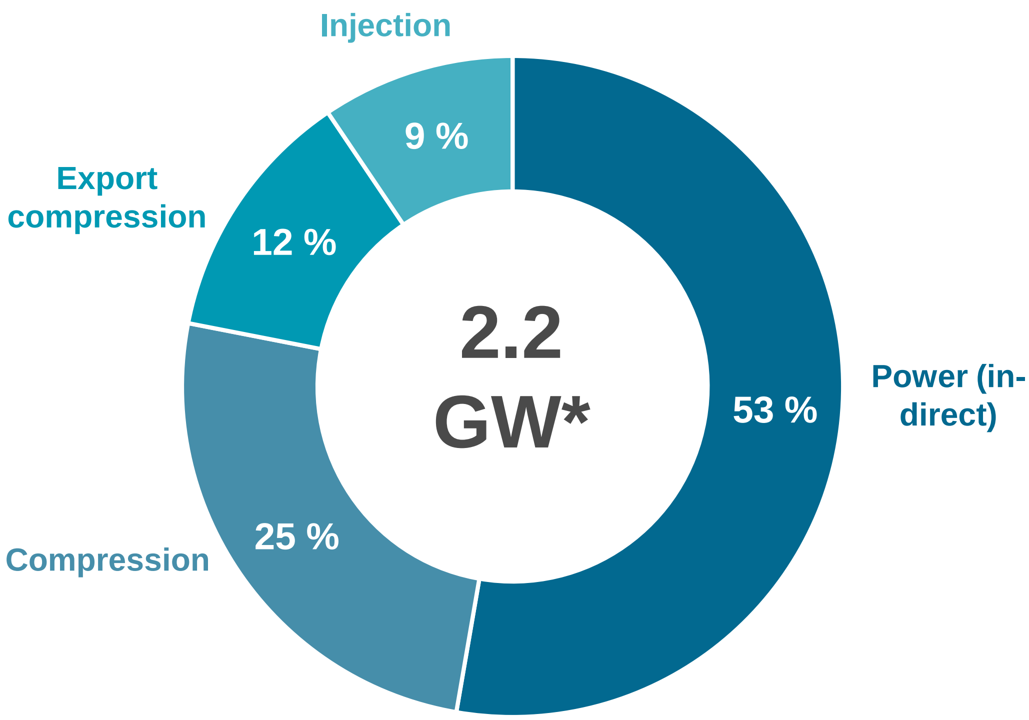
- The chart outlines CO_2 emissions from the NCS in 2017 in terms of activity and the emission source.
- Activity is defined as in which stage the emissions took place: Either exploration drilling from a drilling unit, in the production stage of a specific field – either from a drilling unit or a platform, or during transport/onshore. The latter bucket is due to NOROG including some onshore activity (e.g. Melkøya) and transport from onshore facilities (e.g. Kårstø) in their upstream reporting, although this is usually considered as part of midstream activities.
- Emission sources are split by four: Turbines, flaring, motors and other sources such as boilers and well testing.
- Platforms on producing fields are by far the largest emitters, and turbines made up 74% of the CO_2 emitted from platforms on the NCS in 2017.

*E.g. boilers, well testing, minor leakages** MODU: Mobile drilling units
Source: Norsk Olje and Gass; NPD; Rystad Energy research and analysis

Around 50% of turbine capacity installed on the NCS is used for power generation

Emissions

Power output from turbines installed on the NCS, by turbine usage and oil and gas fields
[% of normal turbine load in 2012, 2.19 GW]



- As previously stated, turbines stand for most of the emissions during oil and gas production in Norway. Investigating the use cases is important to understand technology application potential.
- The main direct applications for the turbines are power generation, compression and injection. More than 50% of the normal turbine load [in MW] is related to power generation which again can be used for utility, compression or injection.
- The generator turbines for power applications can more easily be replaced with electric power (part-electrification). A study for Norsk Olje and Gas from 2004 showed that such a partly electrification can reduce emissions on the NCS with 45%.
- A full electrification with power from shore also involves replacement of gas turbines driving compressors and pumps being replaced. This require more extensive modifications on existing platforms and is more costly.
- Gas turbines also generate waste heat that can be used in processing oil and gas. The energy use from the turbines are not shown in the graph, but can and are captured with waste heat recovery units on some NCS facilities.

*Turbines installed per 2012
Source: NPD; Rystad Energy research and analysis

Gas turbines on oil fields: Injection of water and gas compression for injection and transport accounts for 75% gas turbine emissions

Emissions

Turbine related emissions (electricity generation or mechanical energy generation)

Emission sources	CO_2 emission of typical offshore oil field* [%]	Description
Injection (water)	~50%	Water injection is usually the most energy intensive operation for oil fields and constitutes around 50% of power demand.
Gas compression	~25%	Gas compression for gas transport and/or injection constitutes around 25% of power demand for an oil field. For gas fields this is the main power demand
Utility	~20%	Covers support functions such as lighting, space heating. Fairly constant over lifetime. Constitutes around 20% of power demand for platform facility.
Oil export pump	~5%	Power demand related to oil export pump. Constitutes around 5 % of power demand for a typical oil field.
Total turbine CO_2 emission		Gas turbines constitutes the major part of the CO_2 emissions of a field. Can vary from 0% to 100%, but on average 85% for the NCS.

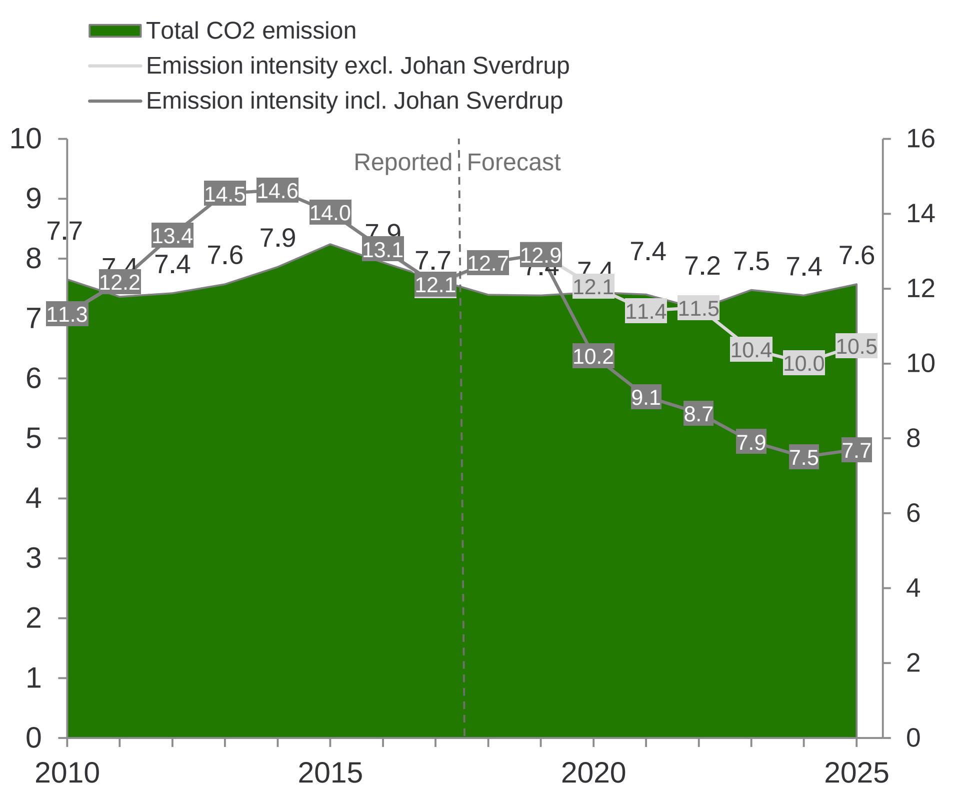
- The chart shows the distribution of emission of CO_2 on a typical oil field
- Water injection is the most energy intensive operation together with gas compression for oil fields, while gas compression for transport is the dominating power demand for gas fields. Environment and emission part of the organization is typically less involved when drainage strategy is chosen for a field development, could be an arena improvement and optimization.
- Emission from gas turbines on the platform varies based the degree of energy efficiency. The energy efficiency depends on optimization of the compressor design, efficiency of the gas turbine etc. On the NCS the emission related to use of gas turbines has for field such as Valhall been "removed" as a result of a power from shore solution

* Distribution of turbine CO_2 emission based on typical oil field on the NCS from Life of Energy performance, Stig Svalheim
Source: Rystad Energy Research and analysis; Life of Field Energy Performance, 2003, Stig Svalheim

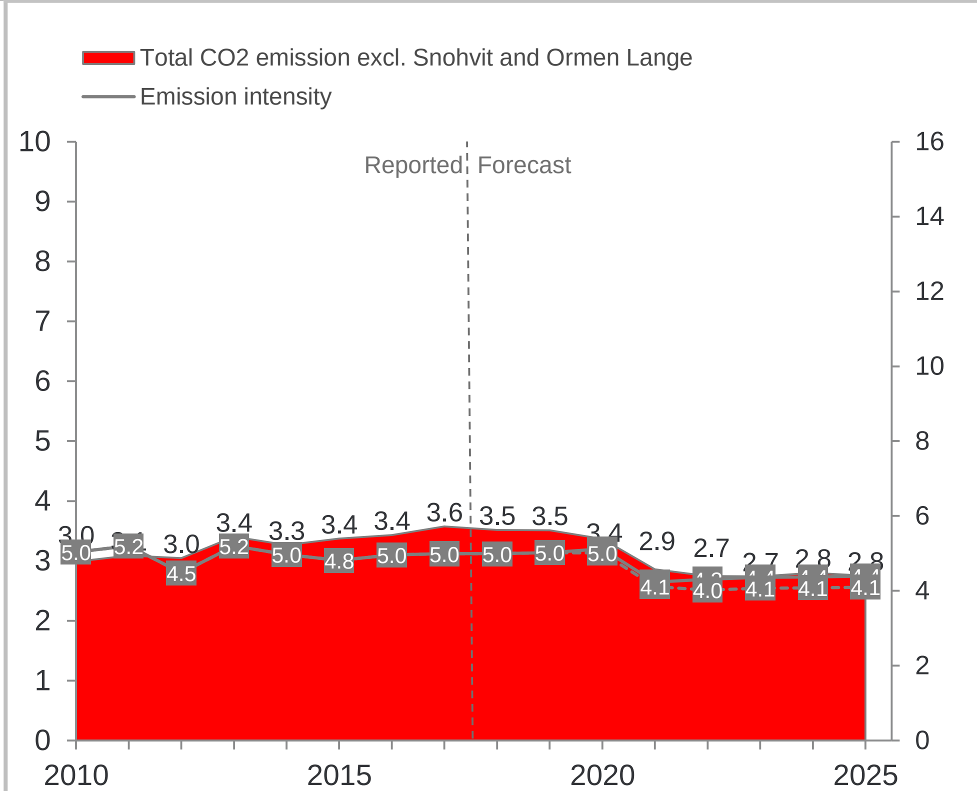
Oil fields emit most of the CO_2, and have intensities over double the size of gas fields

Emissions

CO_2 emissions from <u>oil</u> fields* on the NCS in the period 2010-2025
Million tonnes | Kg CO_2 per boe



CO_2 emissions from <u>gas</u> fields* on the NCS in the period 2010-2025
Million tonnes | Kg CO_2 per boe



The left and right charts show the amount of upstream CO_2 emitted in addition to the weighted average emission intensity for oil fields and gas fields on the NCS during production, respectively. Note that Snohvit and Ormen Lange are excluded from the right hand chart as the gas from these fields is processed onshore, and thus, their contribution to the numerator in the intensity metric would be too low. Also note that emission intensity for oil fields is shown both including and excluding Johan Sverdrup. Most fields in the country are in decline, and the overall intensity is hence better reflected by the higher figures depicted by the light grey line. Gas fields are more emission friendly both in absolute and relative terms. The total CO_2 emitted and the emission intensity for gas fields are, over the period, 58% and 62% lower than for oil fields, respectively (when comparing with intensity excluding Johan Sverdrup)

*An oil field is defined as a field which has a gas-to-oil ratio (GOR) up to 160%. Thus, gas fields have a GOR exceeding 160%; **Fields to be electrified do not contribute to CO_2 emissions in the intensity metric, and includes Johan Sverdrup (all phases), Valhall West Flank, Martin Linge, and the remaining fields on the Utsira High after the startup of Johan Sverdrup phase 2 (Edvard Grieg, Gina Krog and Ivar Aasen)

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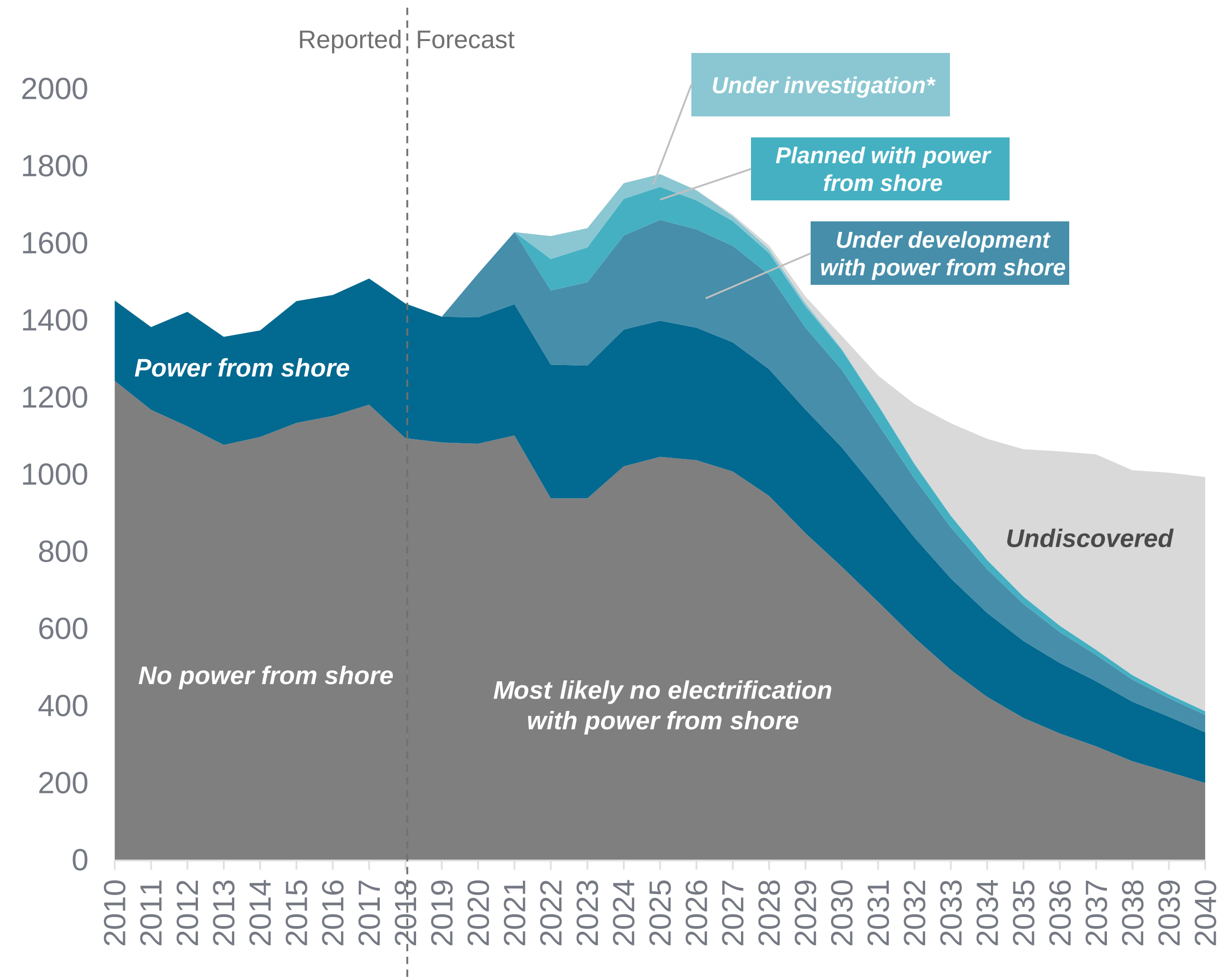
Significant potential for low carbon energy installations for energy supply

Emissions



The chart shows the oil and gas production on the NCS supplied with power from shore. In the coming years an increasing share of the production will be supplied with power from shore driven by the development of Johan Sverdrup and the planned electrification of the remaining Utsira High. Equinor has also identified the Sleipner area and Troll C as the most likely candidates for power from shore in their portfolio going forward.

The remaining production are less likely to be supplied with power from shore. This analysis supports the large potential for CO_2 emission reductions for technologies enabling low carbon energy installations for energy supply.

* Only includes production from the NCS (Sleipner East is a hub for assets on the UK continental shelf)

Source: Rystad Energy UCube; Rystad Energy research and analysis

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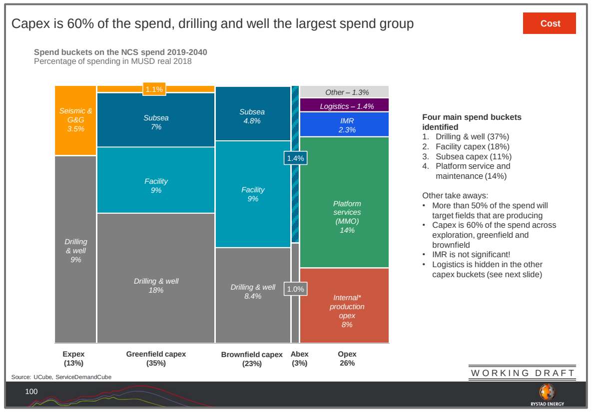
Process of selecting and evaluating focus technologies to improve NCS competitiveness

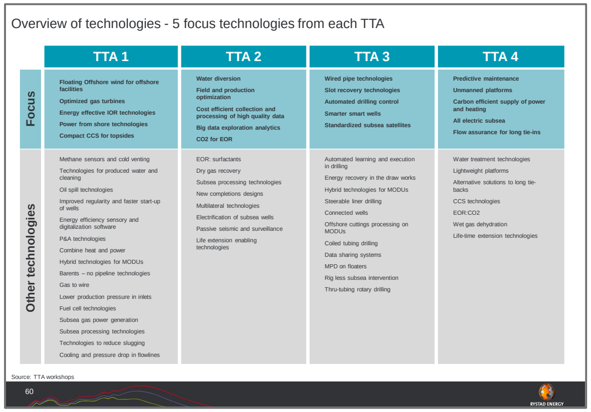
Bucket analysis
Understand volume, cost and emission drivers on the NCS

- *The outset for any technology evaluation is to find the application area. The larger the application area the larger potential of the technology*
- *Prepared for TTA workshops to aid the selection of focus technologies with high effect*
- *Investigated the largest buckets of volumes, spend and emissions on the NCS in a 2020-2050 timeframe.*



Suggest focus technologies for evaluation
Four TTA workshops

- *4 half-day workshops held with each TTA group.*
  - *TTA 1: Energy efficiency and environment*
  - *TTA 2: Exploration and improved recovery*
  - *TTA 3: Drilling, completion and intervention*
  - *TTA4: Production, processing and transport*
- *Selected a set of focus technologies that could have large effect on improving NCS competitiveness*
- *Provided input assumptions into the evaluation*



Evaluate focus technologies
Analyze effect of NCS in the period 2020-2050

- *Simplified business case evaluation of each technologies effect on the NCS in the period between 2020-2050.*
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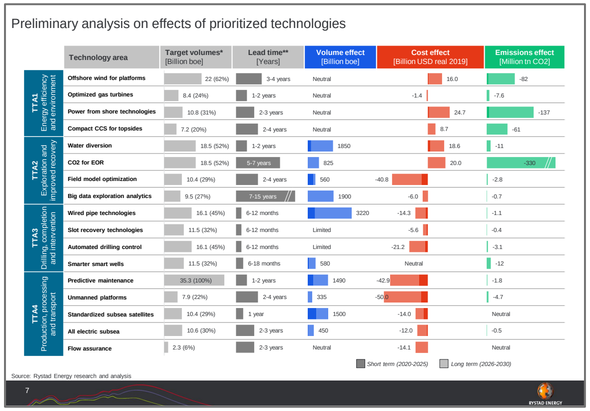
- *Additional interviews and workshops conducted to understand application potential of each technology.*



Source: Rystad Energy research and analysis

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Overview of technologies - 5 focus technologies from each TTA

	TTA 1	TTA 2	TTA 3	TTA 4
Focus	**Floating Offshore wind for offshore facilities** **Optimized gas turbines** **Energy effective IOR technologies** **Power from shore technologies** **Compact CCS for topsides**	**Water diversion** **Field and production optimization** **Cost efficient collection and processing of high quality data** **Big data exploration analytics** **CO_2 for EOR**	**Wired pipe technologies** **Slot recovery technologies** **Automated drilling control** **Smarter smart wells** **Standardized subsea satellites**	**Predictive maintenance** **Unmanned platforms** **Carbon efficient supply of power and heating** **All electric subsea** **Flow assurance for long tie-ins**
Other technologies	Methane sensors and cold venting Technologies for produced water and cleaning Oil spill technologies Improved regularity and faster start-up of wells Energy efficiency sensory and digitalization software P&A technologies Combine heat and power Hybrid technologies for MODUs Barents – no pipeline technologies Gas to wire Lower production pressure in inlets Fuel cell technologies Subsea gas power generation Subsea processing technologies Technologies to reduce slugging Cooling and pressure drop in flowlines	EOR: surfactants Dry gas recovery Subsea processing technologies New completions designs Multilateral technologies Electrification of subsea wells Passive seismic and surveillance Life extension enabling technologies	Automated learning and execution in drilling Energy recovery in the draw works Hybrid technologies for MODUs Steerable liner drilling Connected wells Offshore cuttings processing on MODUs Coiled tubing drilling Data sharing systems MPD on floaters Rig less subsea intervention Thru-tubing rotary drilling	Water treatment technologies Lightweight platforms Alternative solutions to long tie-backs CCS technologies EOR:CO_2 Wet gas dehydration Life-time extension technologies

Source: TTA workshops

17 focus technologies – many of the same technologies selected across the TTA groups

	Technology area	Description	TTA1	TTA2	TTA3	TTA4
TTA1 Energy efficiency and environment	**Offshore wind for offshore facilities**	*Clean supply source. Challenges with intermittence, will not replace gas turbines, but can reduce emissions.*	Chosen			Chosen
	Optimized gas turbines	*Systems and equipment that allows for peak shaving and hybrid solutions that seek to optimize gas turbine load to improve efficiency and reduce emissions*	Chosen			
	Power from shore technologies	*Large converters for long distance DC and issues with DC through turrets are identified as challenges. Long distance AC avoids costly topside modifications,*	Chosen			Chosen
	Compact CCS for topsides	*Compact capture technologies for offshore applications. Applied on exhaust gas from turbines and disposed through water injection.*	Chosen			
TTA2 Exploration and improved recovery	**Water diversion**	*Improvement of water sweep in oil reservoirs by injecting foam cement, gel and/or silicates. Reduces water produced and injected in addition to increased recovery*	Chosen	Chosen		Suggested
	CO_2 for EOR	*Increases recovery, but at a 2-3 year delay and with high cost. Delivery of point emission by ship and standalone subsea solutions on the horizon.*		Chosen		Suggested
	Field model optimization	*Data systems and models to facilitate faster modelling, real time updates, machine learning and optimal well placement*		Chosen		Suggested
	Big data exploration analytics	*Data systems and models to facilitate faster modelling, real time updates, machine learning and optimal well placement*		Chosen		
TTA3 Drilling, completion and intervention	**Wired pipe technologies**	*Live monitoring while drilling for better well placement. Look around- look ahead. Enables the use of new tools and sensors*			Chosen	
	Slot recovery technologies	*Existing and new wells are expected to be reused multiple times. More efficient slot recoveries will cut well capex and reduce rig days.*		Suggested	Chosen	
	Automated drilling control	*Increase adoption and widen scope (all aspects) - digitalization in drilling. Leads to reduction of NPT* and PT.*			Chosen	
	Smarter smart wells	*Monitor and control producers and injectors on oilfields to optimize production; eliminate unwanted products and maximize valuable products.*	Chosen		Chosen	Suggested
TTA4 Production, processing and transport	**Predictive maintenance**	*Interpretation of sensor data, modelling, digital twin software. Reduce down-time and man hours, increase life-time.*	Suggested			Chosen
	Unmanned platforms	*Autonomous operations and automation. Robotics and drone technology for simpler platforms with reduced opex and less emissions.*				Chosen
	Standardized subsea satellites	*Develop standard concepts for small tie-back fields to minimize need for engineering, accelerate projects and reduce costs*			Chosen	
	All electric subsea	*Umbilical-less solutions, subsea chemical storage, electric subsea actuators. Lower cost, better control, higher regularity and improved late-life flexibility*		Suggested	Suggested	Chosen
	Flow assurance	*Cold flow technologies, pipe-in pipe systems, heat tracing technologies. Technologies to deal with wax and hydrate formation over long distances.*	Suggested			Chosen

Chosen *Suggested*

*NPT: Non-productive time
Source: Input from TTA workshops; Rystad Energy research and analysis

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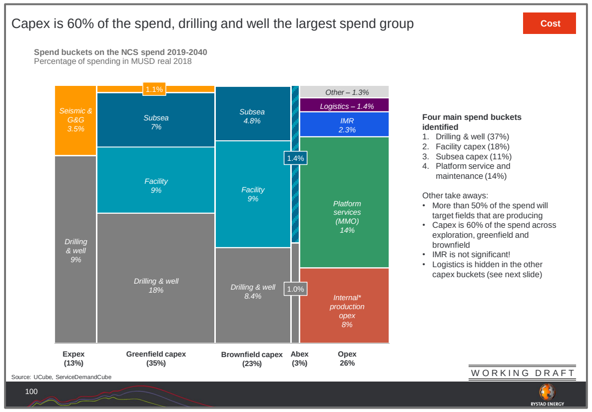

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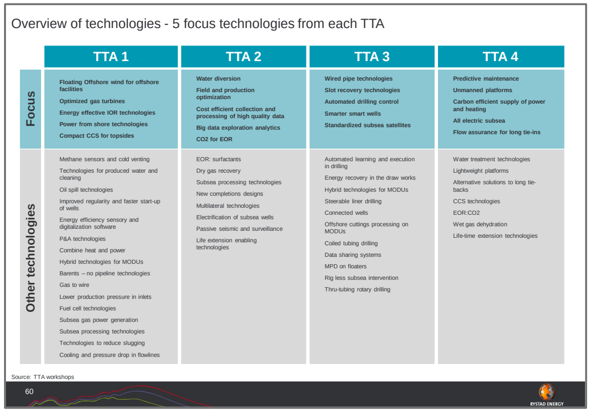

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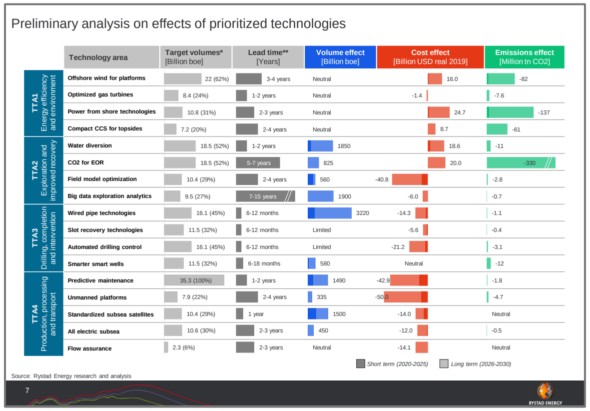

Source: Rystad Energy research and analysis

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Summary of assumptions on target fields and effects on volume, cost and emissions (1/2)

	Technology area	Target fields	Volume and lead time	Cost effect	Emissions effects
TTA1 Energy efficiency and environment	**Offshore wind for offshore facilities**	*Targets all fields that are served or planned served with power from shore. Aim to reduce gas turbine emissions.*	*No positive volume effects. Lead time based on Tampen Hywind project which is 3-4 years. Could come down with project experience.*	*Abatement cost for Tampen Hywind used as proxy, includes fuel gas savings, but excludes ENOVA support.*	*Reduction potential estimated to be 40% according to NOWITECH study, Tampen Hywind at 35% reduction, the larger the grid the more effect.*
	Optimized gas turbines	*Targets producing fields that are currently not served with power from shore.*	*No positive volume effects. Lead time typical of similar topside modification activities.: 1-2 years from decision to implementation*	*Reduced fuel gas consumption. A metric of 190 USD/per tonnes CO_2 saved has been calculated based on studies from SINTEF's EFFORT program*	*5% reduction is possible by using smaller (more optimal) gas turbines. The same effect is believed to be achievable through these measures.*
	Power from shore technologies	*Targets fields developed by FPSOs or that are further away from shore than 160km. Fields with power from shore are excluded*	*No volume effects, but likely some down-time during switch(not assessed). Lead time based on previous electrification projects*	*HVAC abatement cost from Snorre and Martin Linge used as examples. Very high Johan Castberg quotes deemed non-relevant for HVAC.*	*Assumes full electrification of all fields targeted. Will reduce upstream CO_2 emissions by 85%.*
	Compact CCS for topsides	*Targets new standalone facilities and brownfield FPSOs as current system requires free deck space and topside weight*	*No volume effects, but brownfield installations expected to give significant downtime (not assessed) Lead time for developments used.*	*Abatement cost below 500 NOK/CO_2. Issue with implementation is not cost, but deck space and weight restrictions*	*80% efficiency possible on capture of CO2 gas exhaust gas. New facilities assumed to be 100% electrical. Less effect on brownfield.*
TTA2 Exploration and improved recovery	**Water diversion**	*Oil fields that use water drive as recovery method. Small fields are excluded due to lack of sufficient wells and injectors.*	*2.5 -15% increase in recovery dependent on reservoir complexity (field by field evaluation) Can be done on well level – short lead time*	*6-14 USD per bbl gained based on selected case studies on the NCS (high uncertainty).*	*3-20% reduction in water injection which accounts for around 40% of gas turbine emissions on oil fields. Also, effects with reduced gas lift*
	CO2 for EOR	*Large oil fields on the NCS*	*Incremental recovery rates of 3-9%. Long lead time: 3-4 years lead time from FID to start-up + 2-3 years to realize effect after application.*	*Lower with subsea solutions, topside was placed in the +30 USD/boe range. CO_2 assumed delivered for free at field.*	*Reduction in emissions effect early in application before reproduction starts (2-7 years). Only CO_2 stored in reservoirs have been evaluated.*
	Field model optimization	*Non sanctioned fields*	*Improvement in lead time on new developments by 12 months. See wired pipe for improved well placement effect*	*Better placement of wells enable the extraction of the same volumes, but with fewer wells (20% improvement)*	*Lower emissions due less time spent drilling. 20% reduction in emissions from MODUs.*
	Big data exploration analytics	*Future discoveries*	*Improvement in discovery rate from 1:3 wells to 1:2.5. Very long lead time from application to volumes*	*Improvement in discovery rate from 1:3 wells to 1:2.5. Less wells will be needed to discover the same volumes*	*Reduction in emissions from MODUs at the same rate of reduced wells needed to discover the same volumes.*

Source: Rystad Energy research and analysis

See appendix for detailed assumptions and technology evaluations

Summary of assumptions on target fields and effects on volume, cost and emissions (2/2)

	Technology area	Target fields	Volume and lead time	Cost effect	Emissions effects
TTA3 Drilling, completion and intervention	**Wired pipe technologies**	*New wells, both exploration, development and infill. No effect on currently producing wells*	*20% higher productivity in wells due to better placement. Short lead time: 6-12 months from drill decision to production.*	*Improved stream of information to the surface enables better decisions. A combined efficiency gain of 7 ppt for both NPT and PT is likely.*	*Less time spent drilling = less emissions from MODUs. MODU emissions reduced by 7%.*
	Slot recovery technologies	*New oil wells. Slot recovery rates expected to decrease by 50% over the coming years as key large fields stop drilling towards EOFL*.*	*May in theory make marginal well target economical, but this has not been evaluated. 6-12 months lead time from decision to production.*	*Potential to go from 50 days to 20 days per slot recovery. 25 day improvement observed on Troll over the last year.*	*Corresponding reduction in emissions as days reduced during drilling operations by MODUs drilling development wells (3%)*
	Automated drilling control	*New wells, both exploration, development and infill. No effect on currently producing wells*	*Could allow for operators to drill more complex targets (not assessed). 6-12 months lead time from drill decision to production.*	*NPT savings by 5%-points and 10% increase in ROP applied as assumptions*	*Improved drilling efficiency of 15% to yield proportional reduction in emissions from MODUs drilling both exploration and development wells*
	Smarter smart wells	*New oil wells. Recompletions of existing not assessed.*	*Increase in recovery of 5%-points assumed, lower than water diversion as you do not get the same sweep effects.*	*Net effect assumed to be neutral to positive, opex savings should fully account for the added cost of the completion string.*	*Same effect assumed as for water diversion. Less water produced implies less turbine use for water injection*
TTA4 Production, processing and transport	**Predictive maintenance**	*All fields, current and future*	*Improved regularity through less downtime. 2-5%-points improved regularity due to better understanding of condition*	*Lower maintenance intensity drives reduction in offshore manning of 20-40%, and equipment spend of 7.5%*	*Reduced flaring due to less shut-downs. 3.5% of the emission on the NCS is due irregular flaring. Also reduced emissions from OSVs/Helis*
	Unmanned platforms	*All greenfield standalones and wellhead platforms*	*Improved regularity for the same fields. Benchmark of 3.5% from Krafla/Askja used. Lead time of 2-4 years dependent on size of facility.*	*50% opex reduction 30% reduction in facility capex*	*Reduction in emissions from gas turbines used to power utility functions on platforms, accounts for 20% of gas turbine emissions.*
	Standardized subsea satellites	*Smaller non-sanctioned subsea tie-back fields*	*Cut lead time from 2.7 years to 1 year. Might enable some fields due to cost reduction.*	*40% reduction in subsea capex based on efficiency gains from standardization stated by TechnipFMC.*	*No emissions effects.*
	All electric subsea	*All new subsea developments*	*Improved regularity due to better information and control of the XMT and well.*	*Reduced cost of umbilical (75%) and control systems (25%). Critical interfaces, like turret can be made simpler*	*Minor reductions in emissions due to less flaring as a result of higher regularity.*
	Flow assurance	*Smaller non-sanctioned oil and wet-gas fields currently not within feasible tie-back distance*	*No volume effects, but might act as enabler to some fields that are currently considered too small for a standalone development.*	*Might enable fields to be developed as tie-backs rather than standalone fields, which typically reduce facility capex by 40%.*	*May reduce flaring due to fewer shut-ins, but considered neutral due to power demand from heating etc.*

*EOFL: End-of-field-life; Source: Rystad Energy research and analysis

See appendix for detailed assumptions and technology evaluations

Preliminary analysis on effects of the selected focus technologies

	Technology area	Target volumes [Billion boe]	Lead time [Years]	Volume effect [Million boe]	Cost effect [Billion USD real 2019]	Emissions effect [Million tn CO_2]
TTA1 Energy efficiency and environment	**Offshore wind for offshore facilities**	22 (62%)	3-4 years	Neutral	16.0	-82
	Optimized gas turbines	8.4 (24%)	1-2 years	Neutral	-1.4	-7.6
	Power from shore technologies	10.8 (31%)	2-3 years	Neutral	24.7	-137
	Compact CCS for topsides	7.2 (20%)	2-4 years	Neutral	3.5	-61
TTA2 Exploration and improved recovery	**Water diversion**	18.5 (52%)	1-2 years	1850	18.6	-11
	CO_2 for EOR	18.5 (52%)	5-7 years	825	20.0	-330
	Field model optimization	10.4 (29%)	2-4 years	560	-40.8	-2.8
	Big data exploration analytics	9.5 (27%)	7-15 years	1900	-6.0	-0.7
TTA3 Drilling, completion and intervention	**Wired pipe technologies**	16.1 (45%)	6-12 months	3220	-14.3	-1.1
	Slot recovery technologies	11.5 (32%)	6-12 months	Limited	-5.6	-0.4
	Automated drilling control	16.1 (45%)	6-12 months	Limited	-21.2	-3.1
	Smarter smart wells	11.5 (32%)	6-18 months	580	Neutral	-12
TTA4 Production, processing and transport	**Predictive maintenance**	35.3 (100%)	1-2 years	1490	-42.9	-1.8
	Unmanned platforms	7.9 (22%)	2-4 years	335	-50.0	-4.7
	Standardized subsea satellites	10.4 (29%)	1 year	1500	-14.0	Neutral
	All electric subsea	10.6 (30%)	2-3 years	450	-12.0	-0.5
	Flow assurance	2.3 (6%)	2-3 years	Neutral	-14.1	Neutral

See appendix for detailed assumptions and technology evaluations

Short term (2020-2025) *Long term (2025-2050)*

Source: Rystad Energy research and analysis

Key take-aways from evaluation of focus technologies

Key Finding	Description	Focus technologies discussed
High value in closing technology gaps	• Based on the evaluation, there is high value in closing the 17 focus technologies selected by the TTA groups. Single technologies have the potential to deliver additional volumes equivalent to elephant fields, combined deliver a state budget in cost savings, and make the NCS CO_2 neutral. • All, but one technology (predictive maintenance) target a smaller subset of NCS fields. There is no silver bullet, we are reliant on multiple technologies to target all volumes, cost and emissions to improve NCS competitiveness across the board	• **All technologies**
No single technology with large impact on both volumes, cost and emission	• There are few technologies with compound effects on both volumes, cost and emissions. • Although with high impact on volumes and cost, the impact on emissions is not very substantial as none of these target the root issue: gas turbines. Example: Drilling efficiency technologies reduces emissions from MODUs and technologies that improve regularity reduces flaring.	• **Field model optimization** • **Big data exploration analytics** • **Wired pipe** • **Predictive maintenance** • **Unmanned platforms** • **All-electric subsea**
Technologies with high impact on emissions are expensive	• There are four technologies that have major impact on NCS emissions, all of them solving for clean power rather than improved energy efficiency. Common for all is that they are very costly, and all, with the exception of Compact CCS, have abatement costs above the current CO_2 price. This implies that it is currently not economical to adopt them. Floating offshore wind has the potential to see significantly reduced costs with industrialization and economies of scale.	• **Offshore wind for offshore facilities** • **Power from shore facilities** • **Compact CCS for topsides** • **CO_2 for EOR**

Most of impactful cost and volume enhancing technologies are digitalization technologies	• For cost and volume effects we observe that the most impactful technologies are digitalization technologies. Many of them interplay with each other:
	  • Wired pipe feeds data into real-time field models and automated drilling control
	  • Predictive maintenance are necessary for fully unmanned platforms
		• **Field model optimization**
		• **Big data exploration analytics**
		• **Wired pipe**
		• **Automated drilling control**
		• **Predictive maintenance**
		• **Unmanned platforms**

Several impactful volume enhancing technologies with short lead times that can compete with shale	• In the competition with shale lead times are increasingly important, and some technologies require larger greenfield developments or extensive brownfield modifications. Although large positive volume effects these may loose out due to long lead-times. • There are however four technologies in the sample that have significant volume contributions and lead times below 2 years.	• **Water diversion** • **Wired pipe** • **Smarter smart wells** • **Predictive maintenance**
Drilling technologies are by far the most agile	• Most drilling technologies have an adoption time equal to the time it takes to plan a well, 6-18 months. These are by far the most agile of the technologies and may the reason why these have seen the highest adoption during the downturn.	• **Wired pipe** • **Automated drilling control** • **Slot recovery technologies** • **Smarter smart wells**

Subsea processing technologies could be important in solving host bottlenecks	• During the cross-industry workshop, subsea processing technologies were widely discussed as technology to resolve host issues rather than boosting production:
	  • Less emissions, more effective, takes down power demand
	  • Removes key issue on hosts: deck space and weight
	  • Fairly mature, gap on subsea processing of produced water
	  • Less complicated commercial discussions with host
		• **Subsea processing (additional)**

Index

Implementation of technology more prevalent in drilling making up a significant part of capex

Cost elements	Reigning themes within NCS efficiency gains seen from 2014 to 2018	Technologies role in improving efficiency
OPEX	*Efficiency identified primarily within maintenance-related cost categories* *New maintenance philosophies* *Implementation of corrective and run-to-failure work processes* *Identification of inefficiencies in all operations to address and reduce unnecessary cost*	**Hardware**: Low **Software**: Low **Knowledge**: High *Change of philosophies and work processes the prevalent driver of efficiency during the downturn. New technology in terms of mass-implementation expected to be in relation to predictive maintenance philosophies currently being adopted by operators* *The contribution from «Knowledge» accounts for the implementation of new philosophies and work processes reducing inefficiencies*
CAPEX	*Breakeven of development projects considerably down throughout the downturn* *Costs down, resources up* *Market effects (pricing), standardization, simplification, and high degree of supplier involvement driving down cost* *Implementation of incentives and KPIs for rig owners* *Newer rigs with latest sees high efficiency and technology increasing market share*	**Hardware**: Med **Software**: Med **Knowledge**: High *Projects sanctioned and developed during the downturn have seen a larger degree of standardization and simplification as opposed to new technology. Implementation of hardware in drilling operations has a lower threshold. Dual derricks, MPD*-technologies, drilling decision support software has played a part during the downturn as newer rigs have taken larger parts of the market.* *Apart from software and hardware contributions, efficiency gains within drilling has perhaps seen larger gains from incentivizing service personnel, one team approaches, utilizing the capabilities of the rigs to the fullest, and challenging existing work processes and methods to unlock better performance.*

*MPS: Managed Pressure Drilling
Source: Rystad Energy DCube

Index

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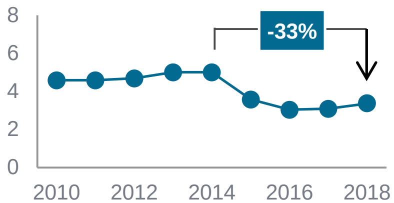
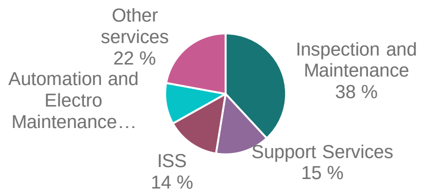
Production opex down 23% to 37% depending on segment

Cost elements	Production opex Billion USD (real 2019)	Segment splits 2018-numbers		Input factors

Platform services (MMO)

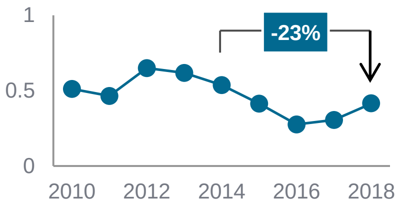


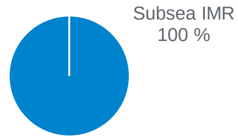


- Platform services is largely divided into maintenance related services, and other services such as catering and cleaning.
- This cost element is labor intensive and will as such develop according workforce and salaries.

- **Installed topside tons**
- **Contractor hours on topsides**

Subsea IMR

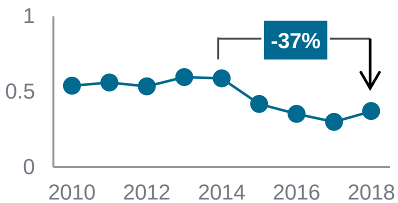


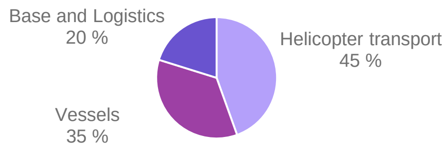


- Subsea IMR is an asset heavy segment with large contributions from IMR vessels and the underlying development of day rates

- **Vessel day rates**
- **Active subsea XMT trees**

Logistics

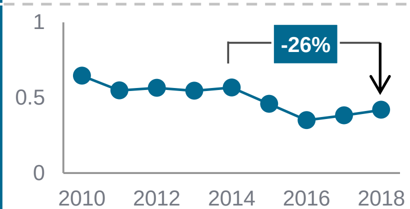


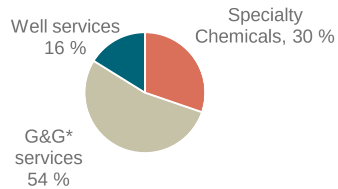


- The logistics segment is made up of helicopter transport, vessels (includes AHTS* and PSV**), and base and logistics spend
- The two first are asset heavy segments linked to helicopter and vessel supply, while base and logistics is related to the supply form onshore base operations

- **Vessel day rates and demand**
- **Helicopter pax and flight hours**
- **Base operations**

Other opex elements

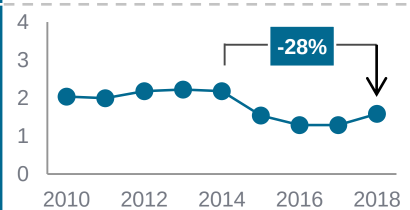


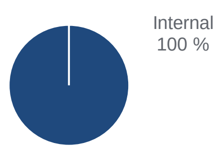


- Other opex elements covers specialty chemicals, which is well stimulation chemicals and different inhibitors, services related to geological and geophysical services, and well services, including platform drilling services

- **4D seismic shot**
- **Original resources under management**
- **Active NCS wellbores**

Internal production opex



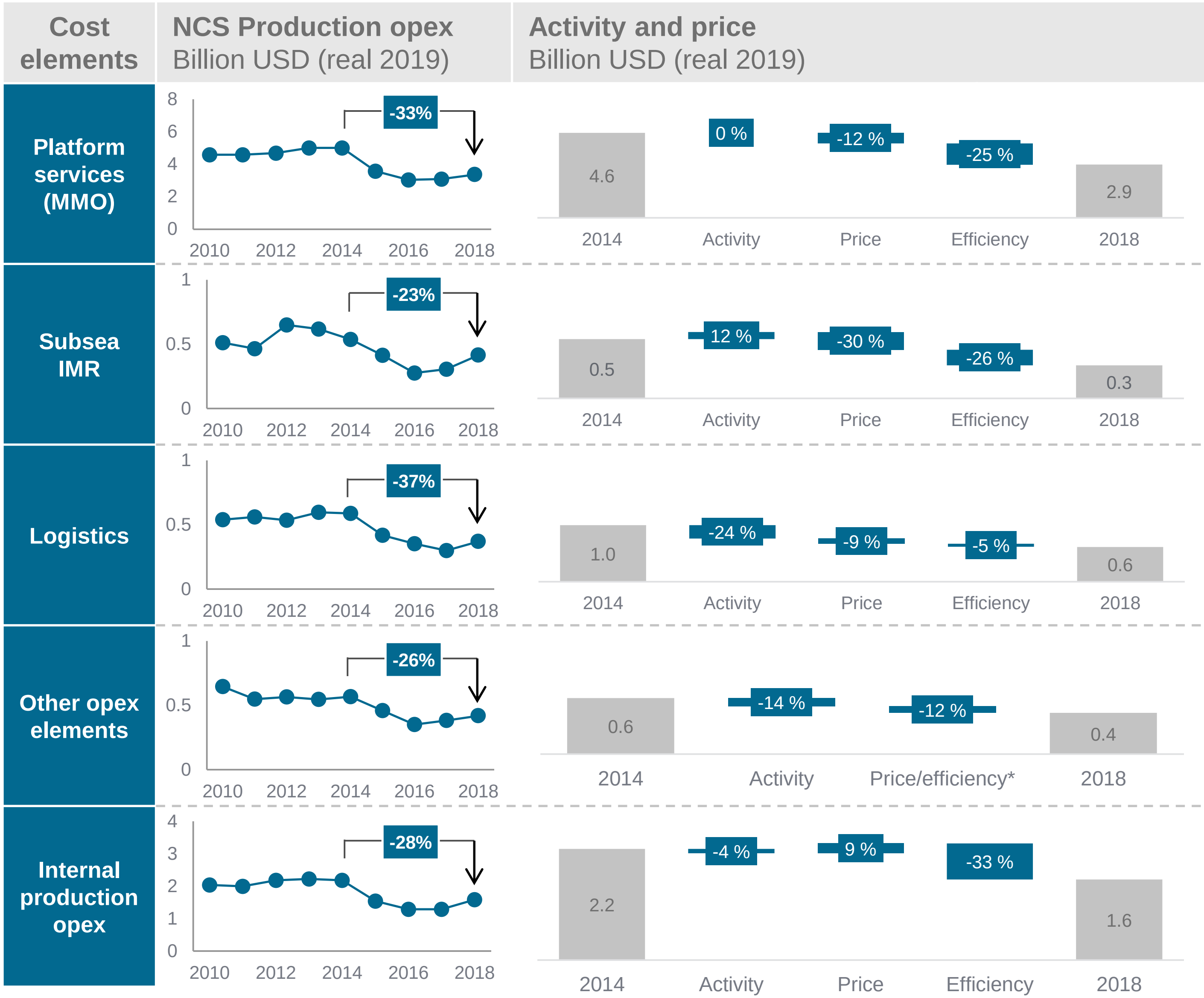


- The main cost element in internal production opex is salaries for onshore and offshore employees
- An other element is purchase of equipment and office appliances related to operations, while larger investments are capex elements.

- **Activity within the other opex elements**
- **NCS salaries**

*AHTS: Anchor handling tug supply vessel;** PSV:Platform Supply Vessel
Source: Rystad Energy DCube

Efficiency gains observed to center around maintenance-related cost categories



- The left summarizes the findings from the opex analysis with activity, price and efficiency implications
- Combining everything into a spend weighted average we arrive at 23% efficiency gains, 6% price reductions and 4% activity decrease
- Efficiency gains is observed to a higher degree in activities related to maintenance

Efficiency improvements on the NCS:

23%

What role has technology played?

*Excluded from contributing in the overall NCS efficiency analysis
Source: Rystad Energy DCube

Technology yet to make huge impact on the industry, changes driven by mindset/processes

Cost elements	NCS efficiency gain % change from 2014 to 2018	Main reason for efficiency improvements	Known technologies applied	Efficiency through: Hardware/software/knowledge
Platform services (MMO)	25 %	• Maintenance philosophies have changed throughout the downturn focusing more on corrective maintenance and run to failure, reducing resources spent on maintenance • Batch maintenance and lean philosophies applied to further improve efficiency	• Implementation software to reap benefits from sensors • More advanced AIM software started to be utilized • «Digital Worker» enhanced by technology being deployed on Wi-Fi-enabled platforms through «pads»	Low / Low / High *Sensors and software coming – change of philosophy driving efficiency*
Subsea IMR	Maintenance heavy 26 %	• Change in philosophy seen from operators like Equinor, manifesting in structural changes in e.g. cleaning and visual inspection jobs decreasing 70% to 80% from 2012-levels • More run to failure - control module replacements have been reduced by 50% in Equinor's IMR statistics	• AUVs* matured, but not substantially implemented yet, only a few autonomous pipeline AUVs. • Predictive maintenance systems on the horizon, but even current sensory data is yet to see material use.	Low / Low / High *AUVs coming – change of philosophy driving efficiency*
Logistics	5 %	• Sharing of both helicopter and vessels among operators has seen increased focus since the downturn, however limited application of these principles have actually occurred. • More lean offshore operation, less waiting time observed offshore through AIS data	• Pre-mooring with large AHTS to increase logistics efficiencies	Low / Low / Med *Sharing of logistics with limited applications – some changes in work processes*
Other opex elements	#N/A	• Other opex elements comprise of well services, G&G and specialty chemicals. Due to the complexity and fragmented elements price and efficiency has not been possible to split.	• OBS** seismic gained significant traction in this period, but is a high cost acquisition type, as per sq.km shot.	Med / Low / Med *OBS gaining momentum – generally push from operators to well services*
Internal production opex	Maintenance heavy 33 %	• Operators forced to address inefficiencies within their organizations during the dramatic oil price shock • Operators working smarter and creating leaner work processes to manage their fields	• «Digital Worker» enhanced by technology, both onshore and offshore • Decision support software	Low / Med / High *Operating companies implementing leaner work processes, enhancing workers with software*

*AUV: Autonomous Underwater Vehicle; ** OBS: Ocean Bottom **Seismic**
Source: Rystad Energy DCube

Increased maintenance efficiency likely caused by reduction in maintenance

Reigning maintenance theme

Pre-2014: High oil price	2014 – 2018: Low oil price	Future
Preventive	**Corrective**	**Predictive**
Prevalent during times of high oil price, when value of production is high. Production optimizing, fix before failure	*Prevalent during times of low oil price, when value of production is lower and cost-focus is high. Cost optimizing, run to failure*	*Technology driven maintenance philosophy balancing cost and production optimization*
Protects uptime	**Reduce maintenance cost**	**Improved uptime**
Higher maintenance cost	**Reduced uptime**	**Reduced maintenance cost**

Change in maintenance philosophy and work processes

Typically more ***run to failure (RFT)*** *now than before.*

Only **need-to-do** maintenance

"Everyone" are **reactive**, maybe with the exception of Equinor

The **issue of inefficient, non-value creating M&M** activity had been on the agenda internally for decades before it was finally addressed.

We have possibly **reduced days per job**, though still takes roughly the same time to replace modules as most of the time is spent on commissioning, not the replacement job

Bundling **maintenance and modifications in campaigns** to be more efficient. Planning carefully in terms of resources and timing of activities

See uptick in larger, ***better planned*** *IMR campaigns. This is likely because the operators want to reduce the large cost associated with vessel mobilization*

Both savings and higher uptime

Source: Rystad Energy research and analysis

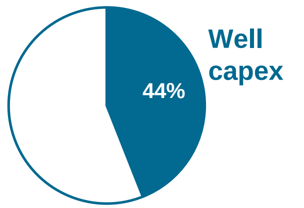
Index

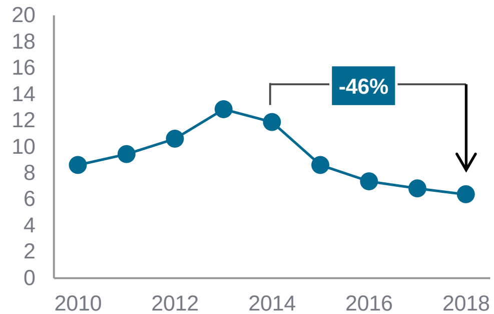
RYSTAD ENERGY

Capex categories down 40% to 45% in the 2014 to 2018 period

Cost elements	Segment split 2014 to 2018 (BUSD real 2019)	Segment development Billion USD (real 2019)	Input factors

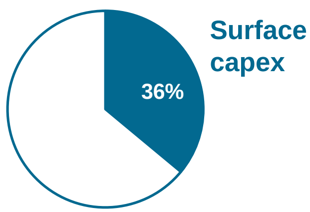
Drilling & Well

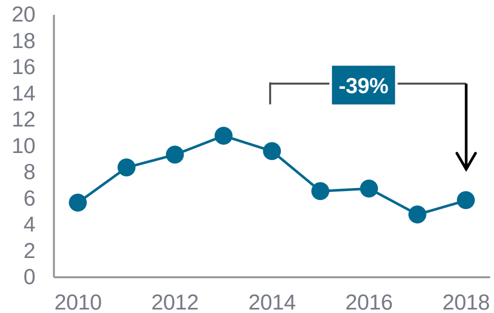




- Drilling days
- Rig rates & service rates
- Fixed well cost elements (consumables)
- Distance and frequency of transportation and vessels in relation to drilling operations

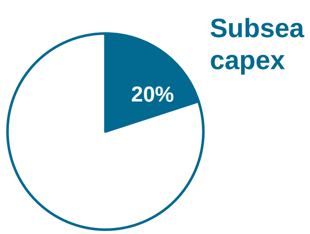
Facility

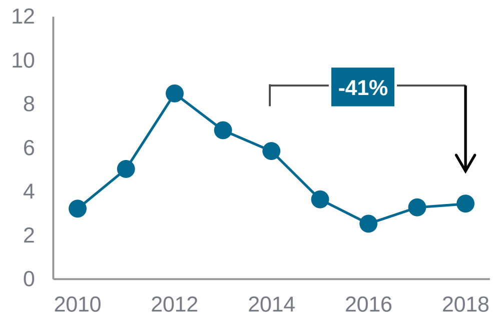




- EPCI contracts
- Pricing of topside modules
- Salaries
- Transportation and construction vessel

Subsea



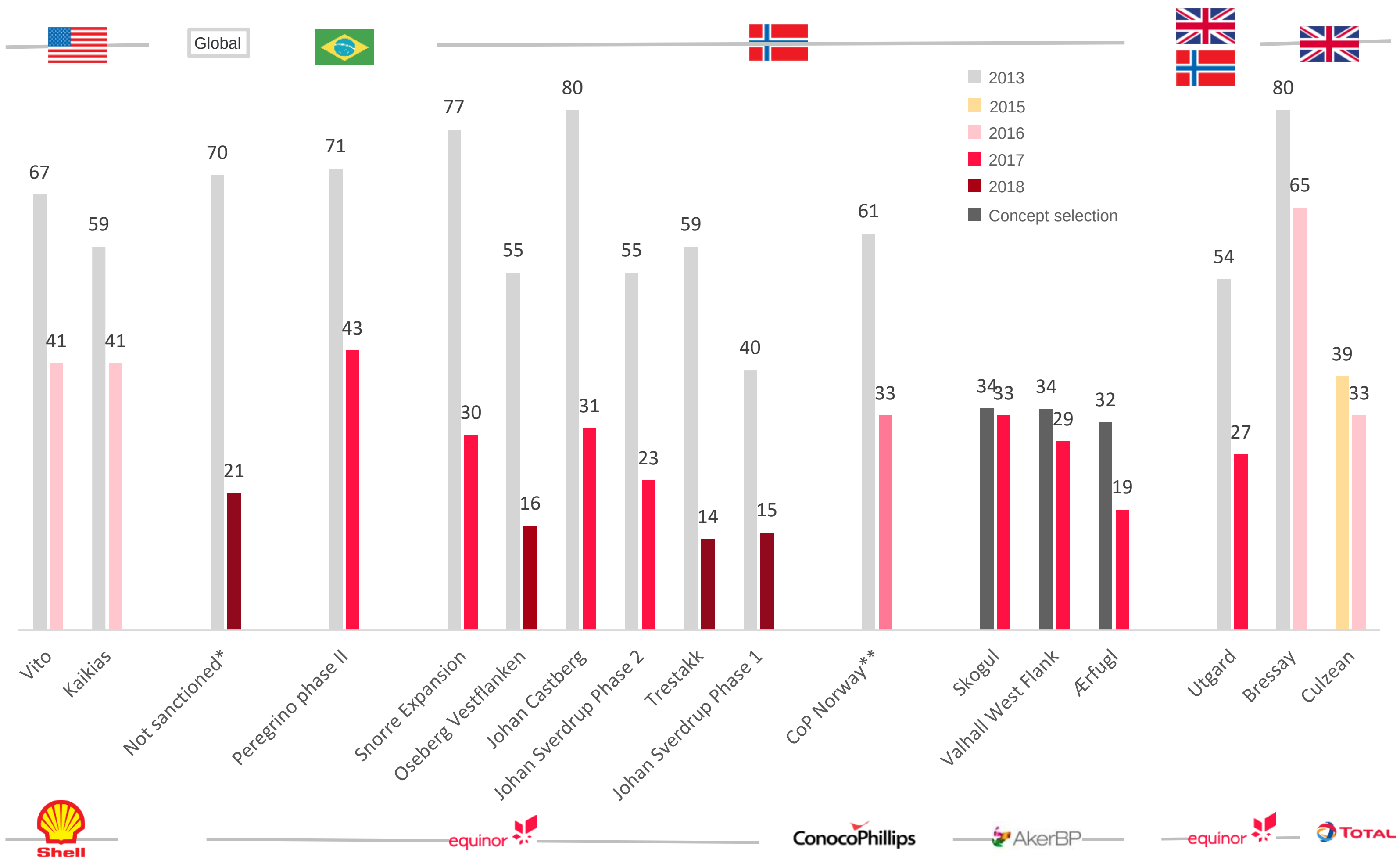


- # of XMTs installed
- Length flowlines and umbilicals
- Vessel/crew required to perform job
- FEED/engineering

Source: Rystad Energy DCube

Breakeven down 40-60% since 2013, some projects achieving up to 70% reduction

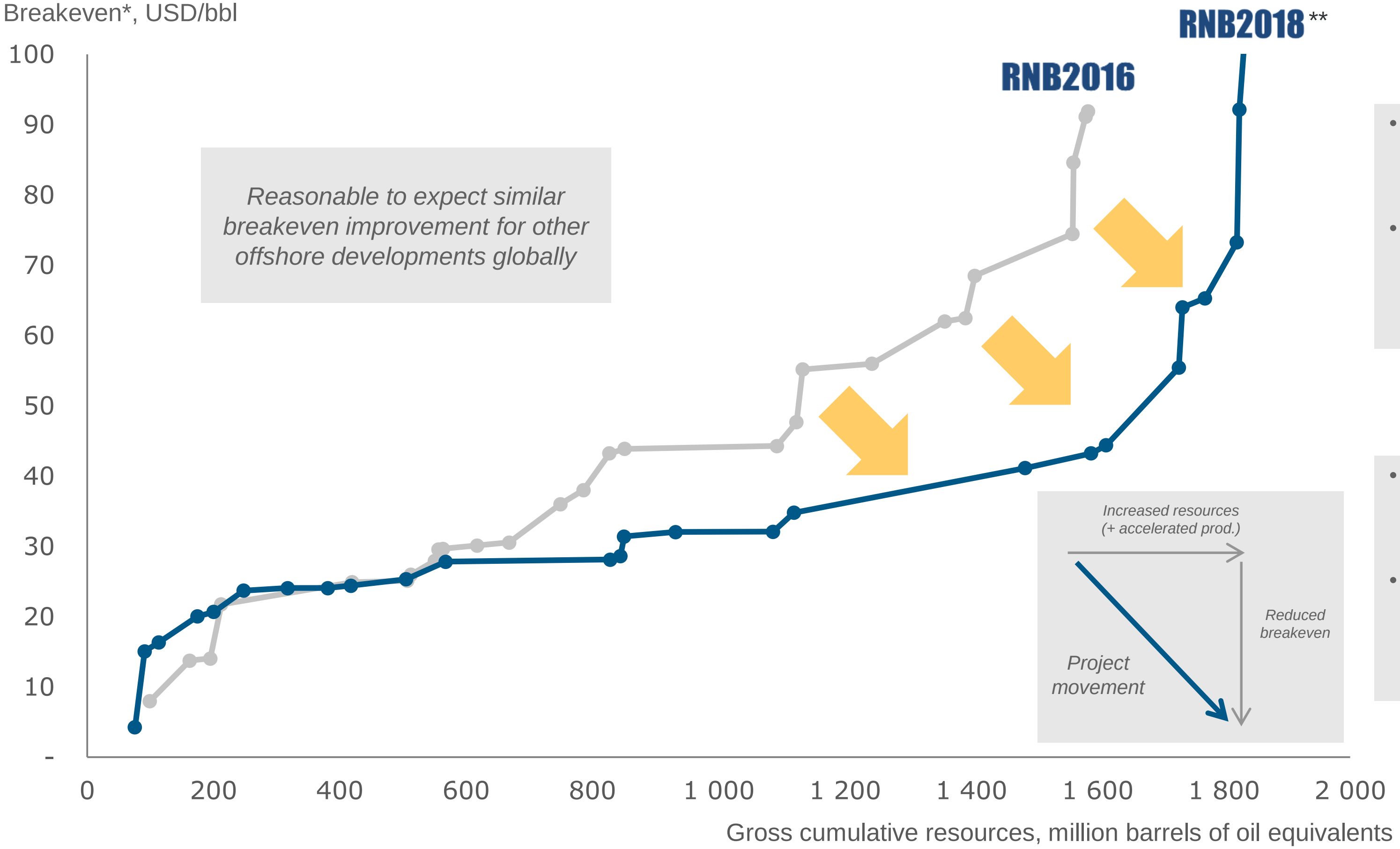
Examples of breakeven reductions
Brent USD/bbl



*2013: Statoil operated projects, planned for ~~sanction within~~ 2022. Volume weighted. 2017 and 2018: Statoil- and partner-operated projects, sanctioned since 2015 or planned for sanction, with start-up by 2022. Volume weighted. ** Projects included are Tommeliten Alpha, Tor II and Eldfisk North (full-cycle weighted average cost of supply, 2012 vs. 2016). Discount rates not known.
Source: Statoil Capital Markets Day 2016, 2017 and 2018, Shell, ConocoPhillips, AkerBP, Maersk Capital Markets Day 2016

Petoro has communicated substantial improvements in pre-FID project economics

Cost of supply for "like-for-like" contingent projects in the SDFI portfolio
Breakeven*, USD/bbl



RNB2016

- *Operator data on production and cost submitted to Norwegian authorities in **October 2015***
- *Submission timing was at the very start of the downturn indicating limited inclusion of cost deflation*

RNB2018

- *Operator data on production and cost submitted to Norwegian authorities in **October 2017***
- *Two years of cost deflation and improvements as well as higher resource base has significantly improved cost competitiveness.*

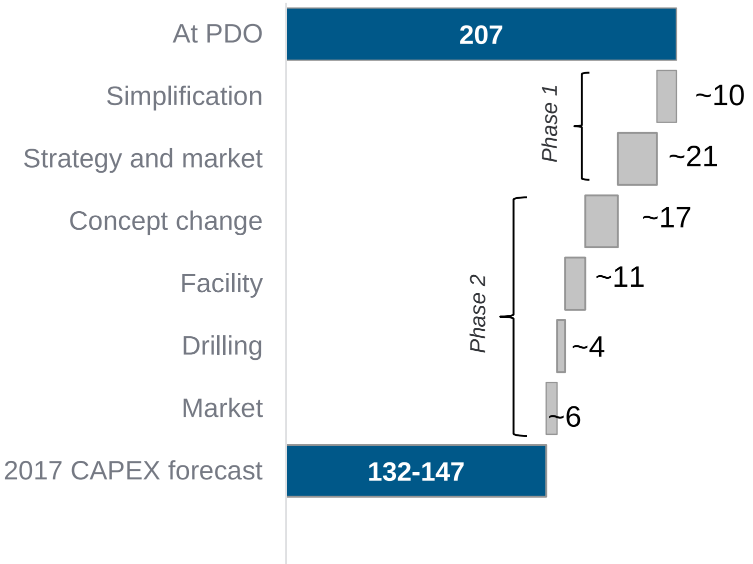
Petoro is a Norwegian oil company owned 100% by the Norwegian state. Its mission is to oversee the Norwegian State's Direct Financial Interest (SDFI) in Norwegian oil and gas fields. The project portfolio represents interest in about 75% of the remaining NCS discovered resources. As such the improved project economics provide a very good indication of general offshore breakeven improvements which should be relevant outside the SDFI portfolio as well

*Breakeven assumes 7.5% real discount rate and full tax position; ** RNB: revidert nasjonalbudsjett
Source: Petoro

Main capex reduction driven by standardization, efficiency improvements and simplification

Capex improvements 2015-2017

Capex improvement by cost component*
NOK billion[1]



Drivers of capex reductions

"We have asked our suppliers to provide the best standard solutions they have, and not always design special solutions in accordance with all our wishes" - ***Aker Solutions***

"Johan Sverdrup is also benefiting from the drilling and well improvement program in Equinor. We've drilled more wells than planned, more than one year ahead of plan, which has contributed greatly to cost reductions in the project" - ***Equinor***

"The standardization of equipment packages, copying of good solutions and doing things right the first time – in collaboration with our suppliers - has been critical to the positive developments that we see in the first phase of Johan Sverdrup" - ***Equinor***

- The Johan Sverdrup development is one of the five largest oil fields on the Norwegian continental shelf. The expected recoverable resources are between 2.1 and 3.1 billion barrels of oil equivalent, which makes the field one of the most important industrial projects in Norway in the next 50 years. The field is located on the Utsira Height in the North Sea, 160 km west of Stavanger. Phase 1 was approved in 2015 and will start-up late 2019, while the PDO** for phase 2 was approved by authorities in May 2019. The estimated capex savings is set at around 25% from PDO.
- Phase 1 saw a cost reduction of around 30 billion NOK, with an estimated cost reduction of 30-45 billion NOK for phase 2. The main drivers of the capex reductions for Johan Sverdrup for phase 2 are expected to be concept change and facility savings.

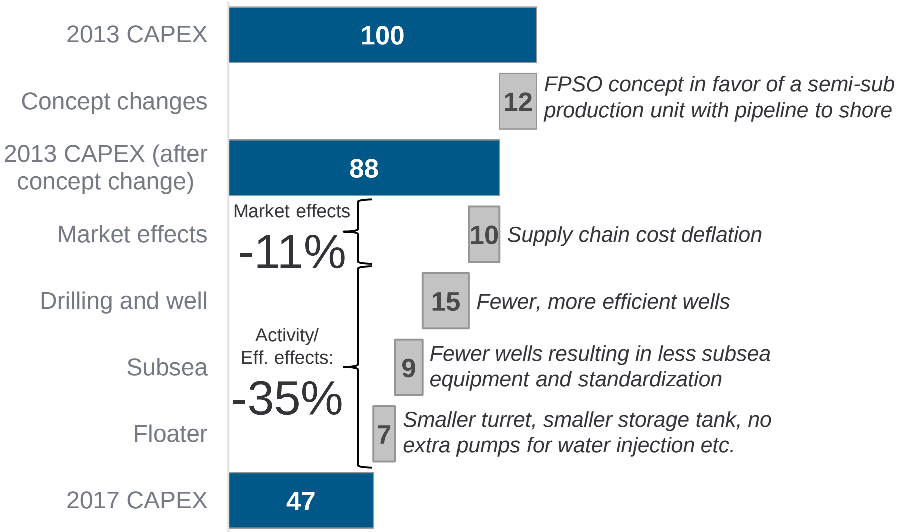
1) Numbers in nominal terms, currency adjusted. *Estimated based on Equinor September business update 2Q17; **PDO = Plan for Development and Operation.
Source; Rystad Energy research and analysis; Equinor; Aker Solutions; News articles

Case example: Johan Castberg (Equinor)

Main capex reductions driven by efficiency improvements and simplification

Capex improvements 2013-2017

Capex improvement by cost component
NOK billion[1]



Drivers of capex reductions

" We have worked with Statoil for two years to find the optimal FPSO-solution for Johan Castberg. To a large extent the work is about simplifying and remove everything that is not essential" - ***Aker Solutions***

" Removing large and heavy equipment is the most important in reducing development cost" - ***Aker Solutions***

" Fewer, more efficient wells have resulted in less subsea equipment, which again have resulted in a smaller turret" - ***Aker Solutions***

" .. Another factor [to the cost reduction] is the work done by the suppliers through improvement initiatives and the way they deliver their offerings, weather it is topside or subsea" - ***Equinor***

- The Johan Castberg development consists of the three oil discoveries Skrugard, Havis and Drivis. The proven volumes in Johan Castberg are estimated at between 400 and 650 mmbbl. The field is located approximately 100 kilometers north of the Snøhvit field in the Norwegian Barents Sea. The operator, Equinor, and the partners had to change the design concept in order to make the development economically viable. The PDO for Johan Castberg was approved in 2018.

- The main drivers of the capex reductions for Johan Castberg from 2013 to 2017 have been the development concept change, market effects, simplifications and efficiency improvements. In 2015 the development concept was changed from a semi-submersible production unit with pipeline to shore to an FPSO concept. The majority of the capex reduction has come from efficiency improvements and simplifications within the Drilling and Well, Subsea and Facility segments.

1) Numbers in real terms 2016

Source; Rystad Energy research and analysis; Industry interviews; Equinor; Aker Solutions; News articles

Largest efficiency gains reported in facility capex

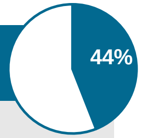
Cost elements	Market pricing 2014 to 2018	Market pricing comment	Efficiency gains from example cases	Efficiency comment
Drilling & Well	**-16%** to **-41%**	Avgerage new rig rate fixtures on the NCS has declined by 16% to 41% from 2014 to 2018 as demand for rigs have declined forcing rig owners to lower rates to secure jobs. Other rig-related services declining along with rig rates	**-9%**** to **-17%***	• Johan Castberg and Johan Sverdrup have seen reduction in drilling & well cost between 9% and 17% from fewer, more efficient wells, changing well structural design, and improvement programs reducing drilling time • Improved efficiency of known processes together with new contract setups has had the most pronounced effect. Less effect solely from implementation of technology.
Facility	**-20%**	Market price effects for Topside EPC reported to be around 20-25% Reduction in cost base for topside EPC contractors reported	**-8%*** to **-24%****	• Johan Castberg and Johan Sverdrup have seen reduction in facility cost from standardization package, scrapping non-essential equipment (simplification), and maturing forward concepts with suppliers • Focus on simplification. Removing large and heavy equipment have reduced costs significantly, e.g. smaller storage tank, smaller turret, fewer pumps • Reducing complexity as a trade-off to optionality
Subsea	**-30%**	Market price effects for Subsea reported to be around 30% Reduction in subsea market prices as a result of reduced cost base for suppliers and lower supplier margins	**-10%***	• Johan Castberg has seen reduction in subsea cost of 10% • Improved concepts through alliances (i.e. supplier-led solutions) • Less subsea equipment (XMTs, flowlines etc.) as a result of fewer, more efficient wells giving the same reservoir exposure for with fewer wellheads.

*Johan Castberg case example; **Johan Sverdrup Phase 2 case example
Source: Rystad Energy DCube; Industry interviews

TTA workshops reveal that Drilling & well has been the focal point of technology implementation

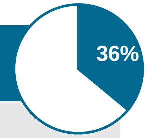
Key new technologies implemented in the period 2014-2018*

Drilling & Well



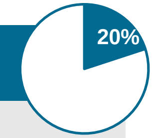
- Dual rig- and offline capabilities
- Larger rigs less affected by bad weather and NPT
- Drilling automation (NOVOS): Optimization of tripping speed
- Improved slot recovery techniques
- Downhole tools increasing ROP (e.g. Tomax anti-stall, deep resistivity/look-ahead)
- MPD/ Controlled Mud Level technology
- Perforate, wash & cement (PWC) P&A technologies
- Wired drillpipe
- More robust BHA electronics
- Better digital decision support
- ICDs/AICDs
- Reactive flex joints allowing more interventions per well

Facility



- Unmanned wellhead platforms
- One lift topside installation (Pioneering Spirit)
- Cutting cleaning offshore
- Polyester mooring

Subsea



- Heat-tracing and pipe-in-pipe
- Simplified subsea designs (CapX)
- Direct tie-in technologies (PLET-less solutions)
- Electric actuators (Hydraulic-less solutions)

*Based on inputs during TTA workshops
Source: TTA workshops

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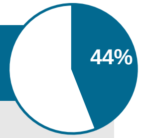
Key new technologies implemented in the period 2014-2018*

Drilling & Well



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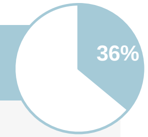

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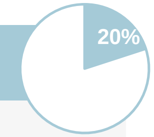


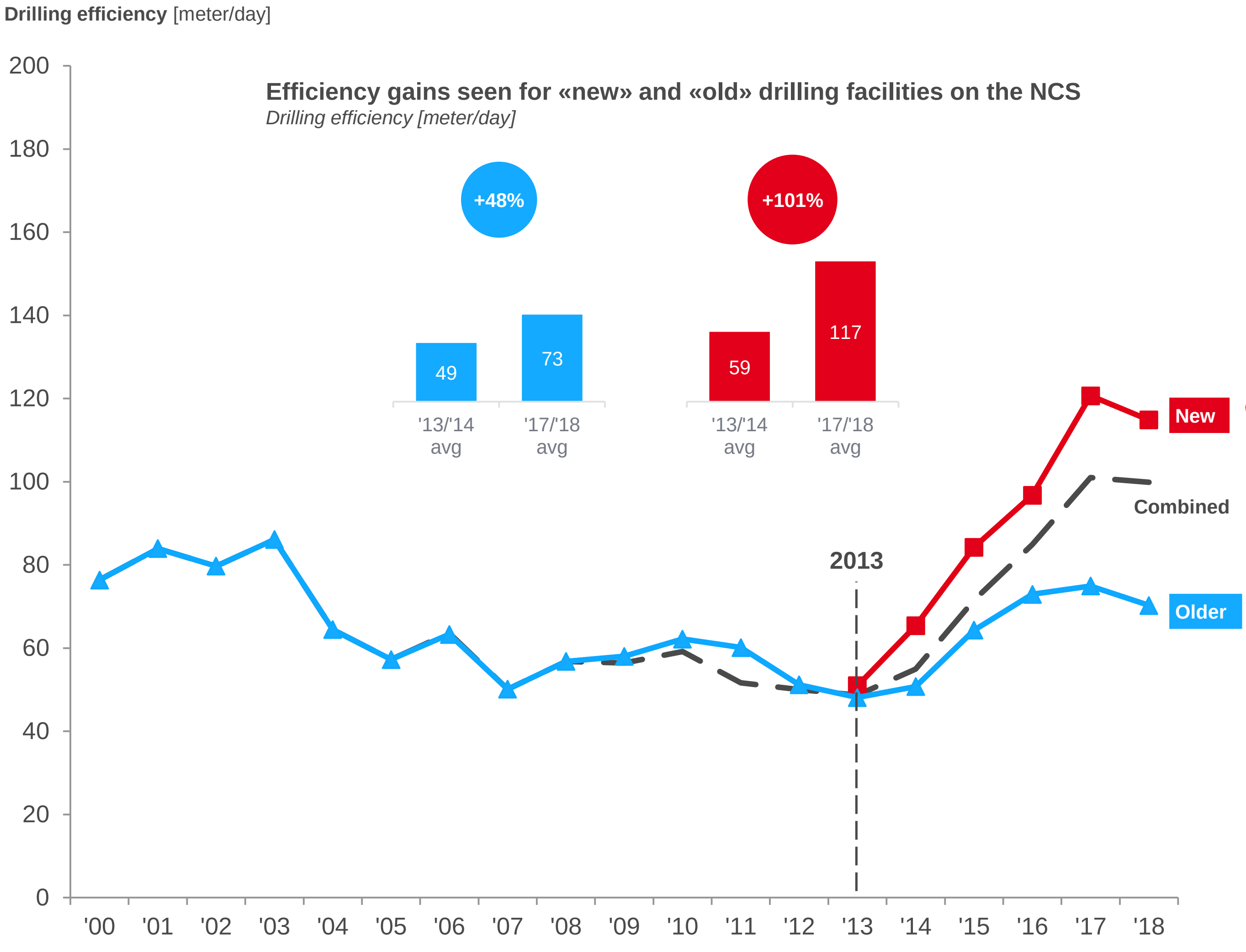
- Heat-tracing and pipe-in-pipe
- Simplified subsea designs (CapX)
- Direct tie-in technologies (PLET-less solutions)
- Electric actuators (Hydraulic-less solutions)

Deep dive to understand impact of technology in drilling & well

*Based on inputs during TTA workshops
Source: TTA workshops

Technology matters - newer rigs outperforming the “oldies” in terms of drilling efficiency

Drilling efficiency* across all drilling facilities on the NCS 2000 to 2018



What is defined as «new» drilling facilities

1 Floaters

- 6. generation floaters. These high-spec rigs have since 2011 taken over the NCS floater market, now making up 60% of meters drilled by floaters

2 Jack-ups

- Jackup model CJ70s less than 10 years old specifically made for the North Sea and water depths up to 150 meters. Dominating the NCS jack-up space

3 Platforms

- New platform drilling facilities is defined as platforms with major drilling package upgrades in the recent years

*Actual drilled formation: Measured depth minus water depth minus depth to kick-off point of sidetrack/multilateral divided on drilling days

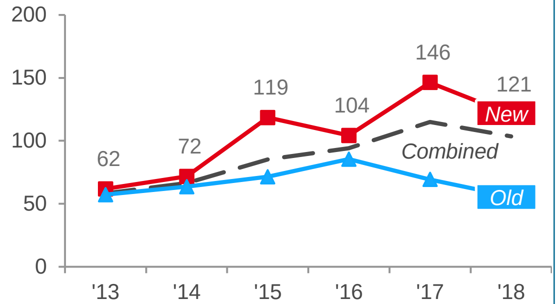
Sources: Rystad Energy research and analysis; Rystad Energy RigCube; NPD

New CJ70s jack-ups seeing the largest increase in drilling efficiency in the period

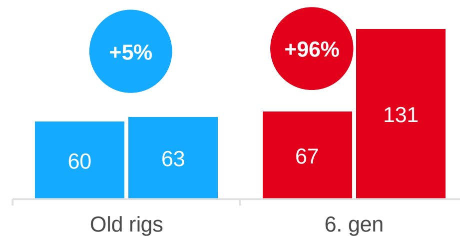
Rig segment	Drilling efficiency time series	Efficiency development '13/'14 avg. to '17/'18 avg.	Efficiency case stories
Floaters			
Jack-up			
Platform			

Floaters

Drilling efficiency [meter/day]

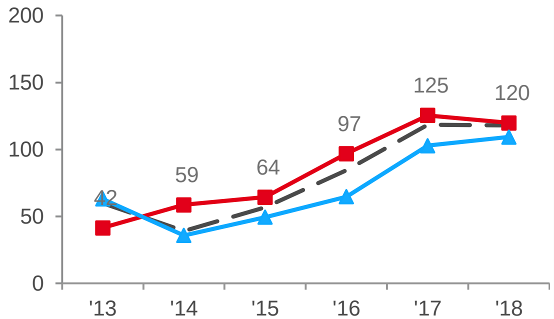


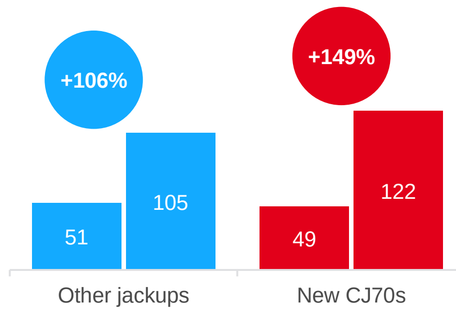
Drilling efficiency [meter/day]



- Improved multilateral drilling performance on the Troll Oil field
  - From 2010 to 2017 multilateral drilling rose from 33% to 48% in terms of meters drilled on the NCS, driven primarily by Troll
- More efficient greenfield development drilling as seen in the Johan Sverdrup Phase 1 and Maria developments

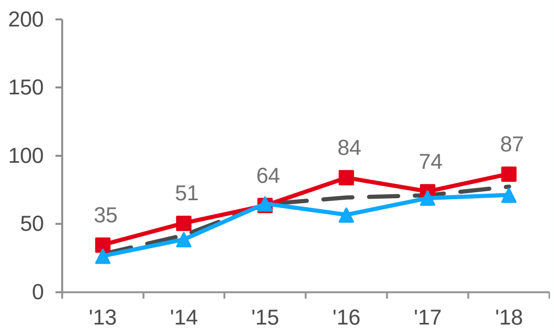
Jack-up

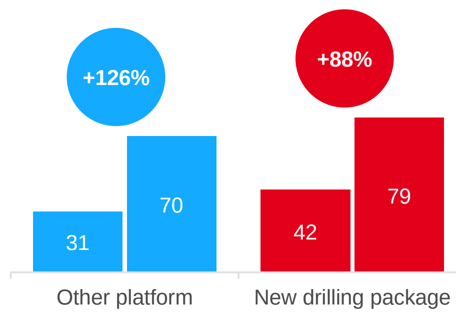




- More efficient greenfield drilling as seen during the Ivar Aasen development drilled by Maersk Interceptor
- More efficient brownfield infill drilling at Ekofisk and Eldfisk. Ekofisk accounted for ~30% of meters drilled by jack-ups on the NCS in 2018, while Eldfisk accounted for ~10%

Platform

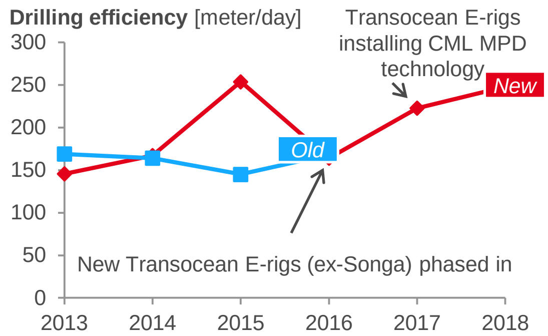




- More efficient brownfield drilling on the legacy fields on the NCS
  - Statfjord
  - Gullfaks
  - Oseberg
- Sidetracks is the name of the game in these legacy fields, re-using old wells to target additional resources
- Grane is among the newer fields with drilling tower, and has been very successful in multilateral drilling in the period

Sources: Rystad Energy research and analysis; Rystad Energy RigCube

Drilling efficiency gains expected when drilling multiple wells back-to-back

<table>
<tr><th>Rig segment</th><th>Case history</th><th>Comment</th></tr>
<tr><td>Troll Oil multilaterals</td><td>
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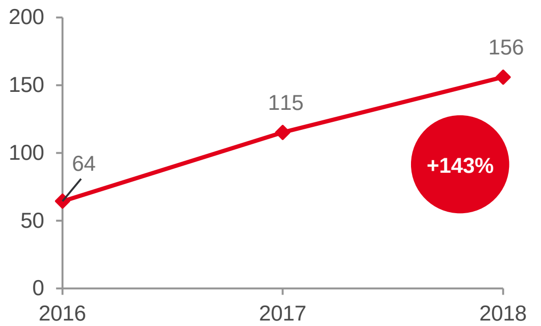
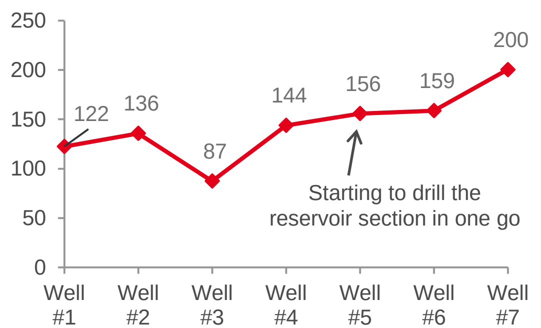
Troll Oil requires continuous drilling of complex multilateral wells in the 25 m thin oil zone. Currently, three 6. generation floaters are drilling TAML level 5 multilaterals on Troll Oil
In 2016, two new 6. generation rigs where phased in, replacing older rigs. The new rigs where Transocean Endurance and Transocean Equinox
In 2017, Closed Mud Loop (CML) systems where installed on the two Transocean E-rigs. CML is a Managed Pressure Drilling (MPD) technology the operator to control bottom hole pressure better and drill wells not «drillable» without CML
The drilling efficiency on Troll Oil extremely good, and is a result of utilizing the newest rigs and the technology that comes with it, in addition to utilizing add-on technology like CML, and the obvious benefit of drilling wells back-to-back in the same formations
</td></tr>
<tr><td>Johan Sverdrup Phase 1 development drilling</td><td>
</td><td>

The development drilling on Johan Sverdrup by semi-sub Deepsea Atlantic experienced immense efficiency gains from 2016 to 2018 when 20 wells were completed
Factors affecting efficiency where «one team»-approach with the drilling service provider on an integrated contract. Equinor implemented incentive bonuses for the contractors on company level and employee level, linked to explicit KPIs on performance
The same well design was used on the first 8 wells offering a very good opportunity to leverage lessons learned going into the next wells
The dual derrick capability on the rig was identified to offer tremendous efficiency opportunities in terms of pipe management and to operate and build BHAs
</td></tr>
<tr><td>Maria development drilling</td><td>
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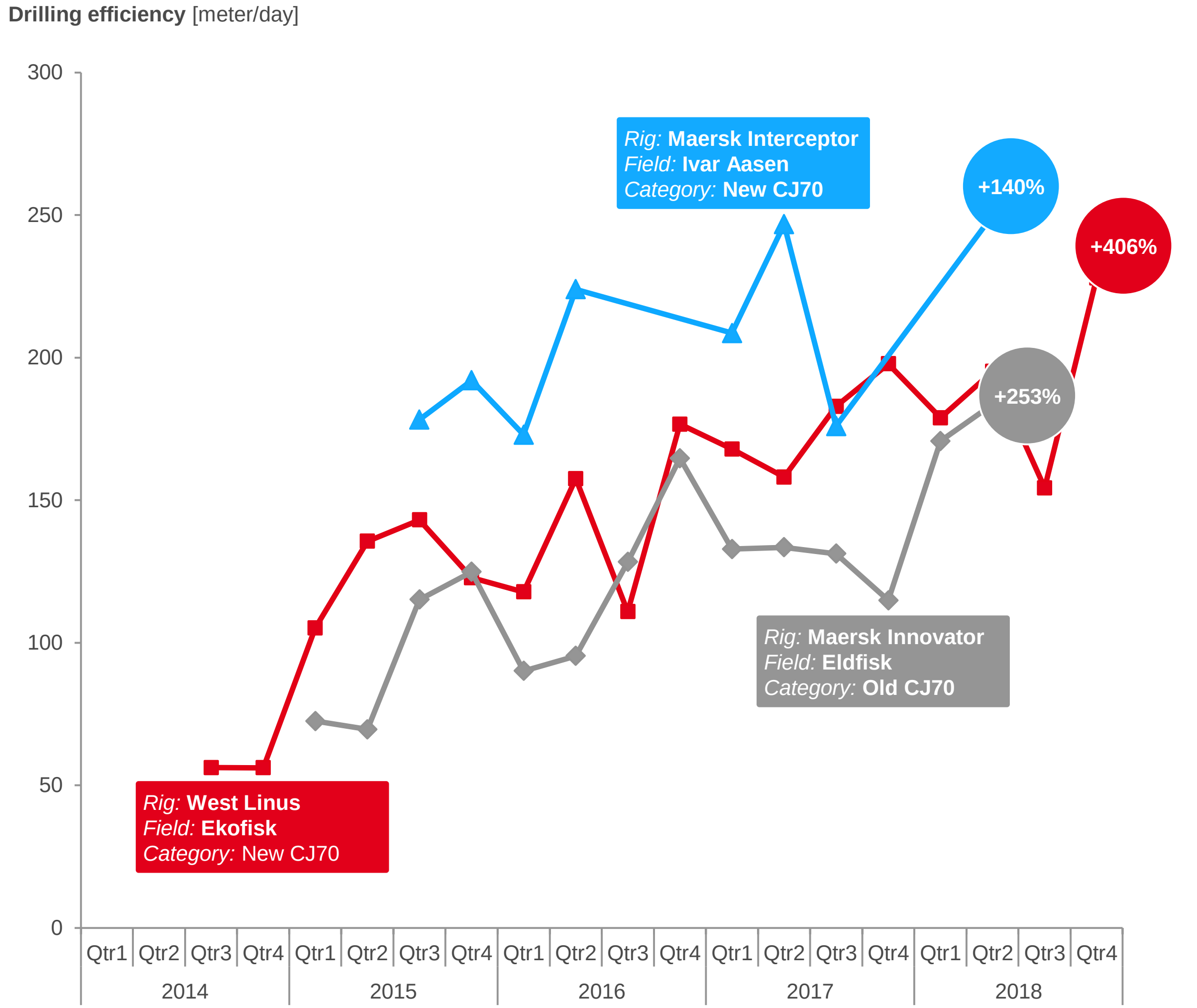
During the Maria development the operator implemented a precautionary measure not to drill more than 800 m in the reservoir section before pulling out of hole to check for pipe wear and replacing worn joints
Throughout the campaign of 4 initial horizontal wells, 600 joints of drill pipe was sent onshore for inspection due to visible wear, of those 100 was scrapped
Based on extensive testing and modelling confidence was gained so that the entire reservoir sections were drilled in one run
This practice was followed for the remainder of the wells in the development drilling campaign at the Maria field where the 6. generation rig Deepsea Stavanger was used
</td></tr>
</table>

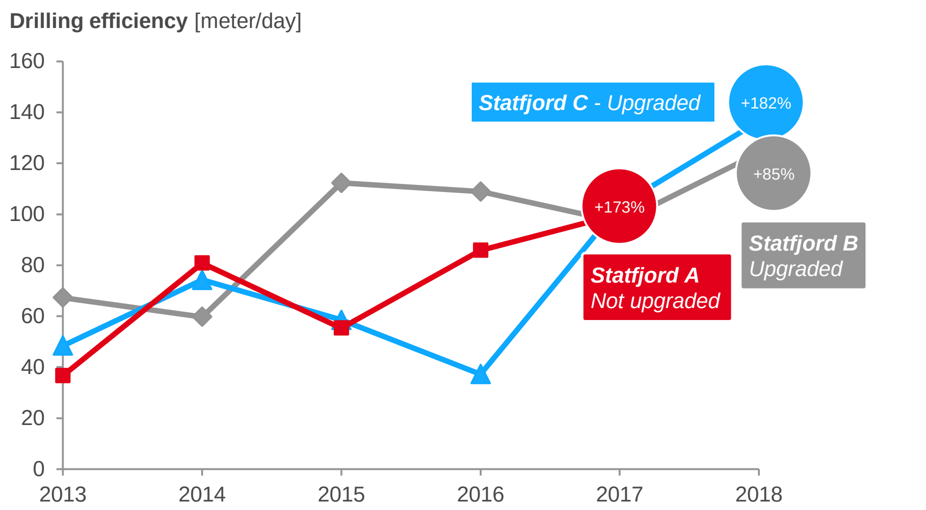
Sources: Rystad Energy research and analysis; Rystad Energy RigCube; OTC-27592; OTC-27592; SPE-194548

Jack-up efficiency share floater characteristic – multiple wells back-to-back boosting efficiency

Rig segment	Efficiency improvement observed	Comment
Jack-up drilling		• The graph to the left is showing the drilling efficiency from three CJ70 rigs operating on the NCS: Maersk Interceptor at Ivar Aasen, West Linus at Ekofisk, and Maersk Innovator at Eldfisk • All three rigs have seen major improvements in efficiency within a 4 to 5 year period starting with the oil price collapse in 2014 • As observed in the graph, continuous drilling on one field yield efficiency gains • The more wells drilled, the less uncertainty you face going into the next well and the more iterations of the same work processes, perhaps discovering incremental efficiency gains in those processes • West Linus and Maersk Interceptor are only 5 years old, while Maersk Innovator is 17 years old

Sources: Rystad Energy research and analysis; Rystad Energy RigCube

Large efficiency gains seen for platform drilling – even without upgraded drilling package

<table>
<tr><th>Rig segment</th><th>Case history</th><th>Comment</th></tr>
<tr><td>Statfjord</td><td>
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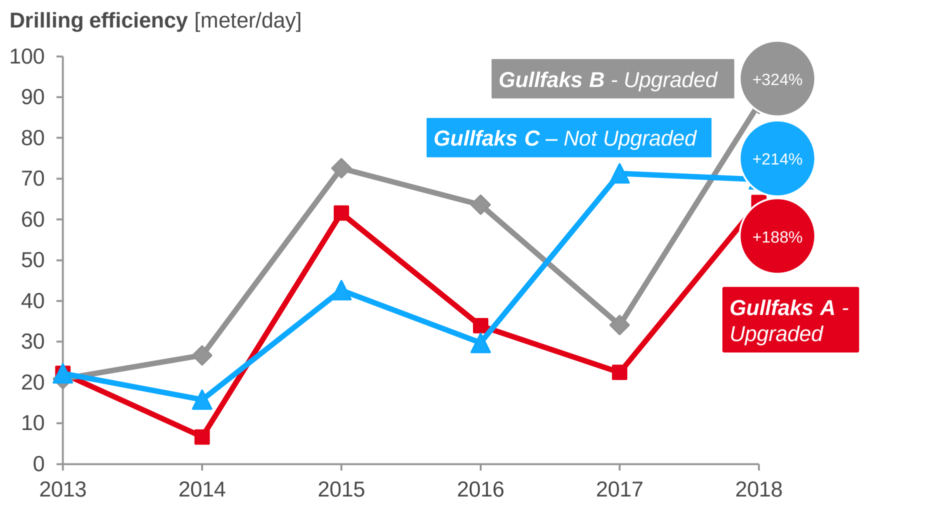
- The drilling package on Statfjord B and C was upgraded as a part of the Statfjord late life project in 2012. Statfjord A did not get any upgrades to the drilling package as it is the first platform to be decommissioned and is expected to stop production in 2022, and subsequently be removed
- Drilling efficiency for all three platforms has significantly improved from 2013 to 2018 (2017 for Statfjord A as no wells was completed from the facility in 2018)
- The finding suggests that other factors apart from the drilling package upgrade is at play – for instance structural changes to well design and incentives for service providers

</td></tr>
<tr><td>Gullfaks</td><td>
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- The drilling package on Gullfaks A and B was upgraded in the time period 2014 to 2015
- Drilling efficiency for all three platforms has significantly improved from 2013 to 2018 – for instance 324% for Gullfaks B in the time period. Gullfaks C, which has not been upgraded has seen efficiency gains of 214%, higher than Gullfaks A at 188% which has had its drilling package upgraded
- Inherent space deficiency on old platform rigs is not necessarily mitigated by smaller drilling package upgrades, and the much larger drilling efficiencies seen on 6. gen floaters and CJ70s can in part be contributed to the larger space easing drilling workflow

</td></tr>
</table>

Sources: Rystad Energy research and analysis; Rystad Energy RigCube

Index

17 focus technologies – many of the same technologies selected across the TTA groups

	Technology area	Description	TTA1	TTA2	TTA3	TTA4
TTA1 Energy efficiency and environment	**Offshore wind for offshore facilities**	*Clean supply source. Challenges with intermittence, will not replace gas turbines, but can reduce emissions.*	Selected			Selected
	Optimized gas turbines	*Systems and equipment that allows for peak shaving and hybrid solutions that seek to optimize gas turbine load to improve efficiency and reduce emissions*	Selected			
	Power from shore technologies	*Large converters for long distance DC and issues with DC through turrets are identified as challenges. Long distance AC avoids costly topside modifications,*	Selected			Selected
	Compact CCS for topsides	*Compact capture technologies for offshore applications. Applied on exhaust gas from turbines and disposed through water injection.*	Selected			
TTA2 Exploration and improved recovery	**Water diversion**	*Improvement of water sweep in oil reservoirs by injecting foam cement, gel and/or silicates. Reduces water produced and injected in addition to increased recovery*	Selected	Selected		Suggested
	CO_2 for EOR	*Increases recovery, but at a 2-3 year delay and with high cost. Delivery of point emission by ship and standalone subsea solutions on the horizon.*		Selected		Suggested
	Field model optimization	*Data systems and models to facilitate faster modelling, real time updates, machine learning and optimal well placement*		Selected		Suggested
	Big data exploration analytics	*Data systems and models to facilitate faster modelling, real time updates, machine learning and optimal well placement*		Selected		
TTA3 Drilling, completion and intervention	**Wired pipe technologies**	*Live monitoring while drilling for better well placement. Look around- look ahead. Enables the use of new tools and sensors*			Selected	
	Slot recovery technologies	*Existing and new wells are expected to be reused multiple times. More efficient slot recoveries will cut well capex and reduce rig days.*		Suggested	Selected	
	Automated drilling control	*Increase adoption and widen scope (all aspects) - digitalization in drilling. Leads to reduction of NPT and PT.*			Selected	
	Smarter smart wells	*Monitor and control producers and injectors on oilfields to optimize production; eliminate unwanted products and maximize valuable products.*	Selected		Selected	Suggested
TTA4 Production, processing and transport	**Predictive maintenance**	*Interpretation of sensor data, modelling, digital twin software. Reduce down-time and man hours, increase life-time.*	Suggested			Selected
	Unmanned platforms	*Autonomous operations and automation. Robotics and drone technology for simpler platforms with reduced opex and less emissions.*				Selected
	Standardized subsea satellites	*Develop standard concepts for small tie-back fields to minimize need for engineering, accelerate projects and reduce costs*			Selected	
	All electric subsea	*Umbilical-less solutions, subsea chemical storage, electric subsea actuators. Lower cost, better control, higher regularity and improved late-life flexibility*		Suggested	Suggested	Selected
	Flow assurance	*Cold flow technologies, pipe-in pipe systems, heat tracing technologies. Technologies to deal with wax and hydrate formation over long distances.*	Suggested			Selected

Selected *Suggested*

Source: Input from TTA workshops; Rystad Energy research and analysis

RYSTAD ENERGY

Offshore wind for offshore facilities: Description and target volumes, costs and emissions

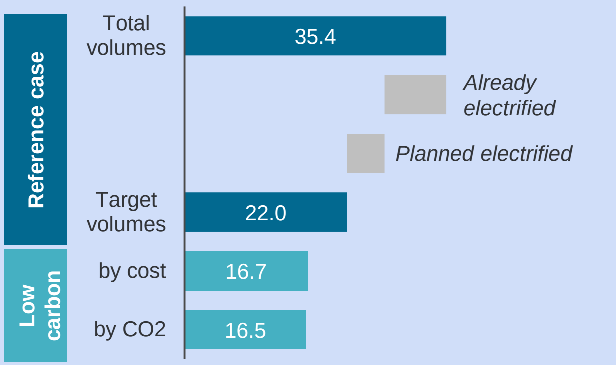
Offshore wind: Description and target volumes, costs and emissions

- *Offshore Wind could be used to replace power demand currently provided by gas turbines on NCS facilities.*
- *Its penetration is limited by its natural intermittency, the current lack of energy storage techniques and the stability issues it may inflict on relatively small offshore grids. Large intermittent energy consumers would mitigate these issues, but conventionally do not exist. Intermittent water injection is seen as an opportunity, but challenges exist.*
- *Equinor's Tampen Hywind project is a representative case study to evaluate this technology application potential for the NCS. The project connects the Gullfaks and Snorre platforms to a common grid, with 11 wind turbines with a capacity 88MW delivering an average power output of 50 MW to the Gullfaks and Snorre installation covering 35% of the power needed.* 210-270 thousand tonnes of CO_2 equivalents will be saved per year on average.

Target volumes

- *Targets all fields that are not currently or planned electrified from onshore*

Target volumes – production 2020-2050
Billion boe

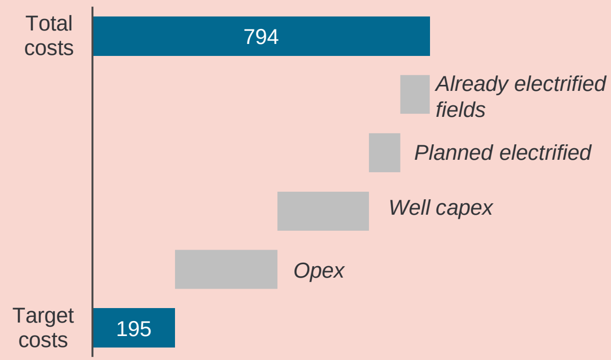


62%
of NCS reference volumes

Target costs

- *The main cost component of offshore wind falls under facility capex.*
- *There are also savings potential for opex, with reduced gas turbine maintenance, reduced fuel gas consumption, NO_x-tax and EUETS costs*

Target costs – upstream spending 2020-2050
Billion USD

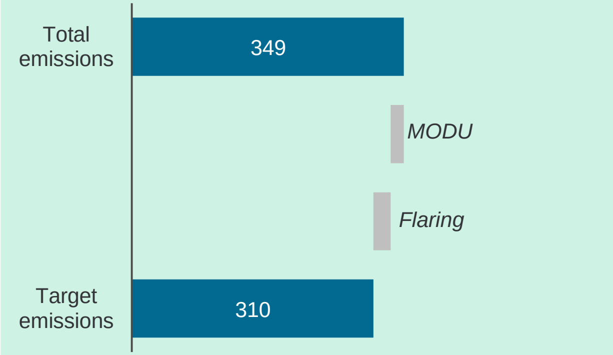


25%
of NCS costs

Target emissions

- *Emissions from gas turbines on the NCS*
- *It will target gas turbine use for indirect drive, motors and direct drive turbines cannot not as easily be substituted with power from offshore wind (see assumptions on the next page)*

Target emissions – upstream emissions 2020-2050
Million tonnes of CO_2 eq



89%
of NCS emissions targeted

Sources: Interviews; TTA input; NOWITECH; Hywind Tampen PUD; AKSO concept; Rystad Energy research and analysis

Offshore wind for offshore facilities: Assumptions and effects

Offshore Wind: Assumptions and effects

Volume effects

- *Lead time based on Hywind Tampen with FID sketched for September 2019 with start-up in 2022. As technology matures and with more project experience this lead time might be reduced.*
- *There will likely also be an effect of lost production during the installation and hook-up of the facilities, with prolonged shut-downs as the switch to offshore wind is conducted. This is not included in the estimates.*

Cost effects

- *The total investments for Hywind Tampen is estimated to 5 billion NOK (real 2019). This investment cover modifications on Snorre and Gullfaks, design and fabrication of wind turbines including foundation and cables, as well as installation activity. This equals to about 196 USD per tonnes CO_2 in discounted abatement costs. This cost could come significantly down with the industrialization of floating offshore wind with larger offshore wind farms, but as for the other technologies the current costs have been used.*
- *When you connect multiple platforms together in a grid, as for the Hywind case, you get the benefits of optimizing the use of gas turbines with the result of needing less turbines to cover the demand and reduced modification and maintenance costs. This saving is not included in the estimates.*
- *Also, less burning of fuel gas present a clear saving for the facilities as it could be sold instead. At the same time, you introduce new offshore facilities with 11 wind turbines that will need maintenance. The cost of this has not assessed, but will serve to counteract some of the positive cost saving effects in the operational phase.*
- *Savings on emission quotas are not included in any of the estimates for CO_2 reductions on any of the technologies assessed*

Emissions effect

- *A NOWITECH study assumes that the emissions from gas turbines on the NCS can be reduced up to 40% with the use of Offshore Wind. For the Hywind Tampen projected CO_2 emission reductions are 35%, at between 210-270 thousand tonnes of CO_2 reduced annually.*
- *According to data from NPD 53% of turbine usage on the NCS is used to generate power (indirect drive). These are the elements that could be targeted by Offshore Wind supply. The direct drive demand would require expensive modifications, and possibly extra gas turbines as back-up. Due to the intermittence it is not likely that all of the 53% of the power supply could be covered all year.*
- *The larger the grid (number of platforms) the more efficient use of gas turbines may be used, running a few turbines at full capacity rather than all turbines at half speed. Turbines at full capacity are more energy efficient. This effect is included in the overall CO_2 estimates.*

Time frame	**Volume growth potential**		**Cost savings potential**		**Emission reduction potential**	
	Total in period [Million boe]	***Daily*** [Thousand boe/d]	***Total in period*** [Billion USD real]	***Annually*** [Million USD real]	***Total in period*** [Million tn CO_2]	***Annually*** [Million tn CO_2]
Short term (2020-2025)	Neutral	Neutral	+0.8	+135	-5	-0.8
Long term (2056-2050)	Neutral	Neutral	+12.1	+485	-77	-3.1

Lead time: 3-4 years

Reduced maintenance and CO_2 tariff savings are not included in these estimates

Sources: Interviews; TTA input; NOWITECH; Hywind Tampen PUD; AKSO concept; Rystad Energy research and analysis

Optimized gas turbines: Description and target volumes, costs and emissions

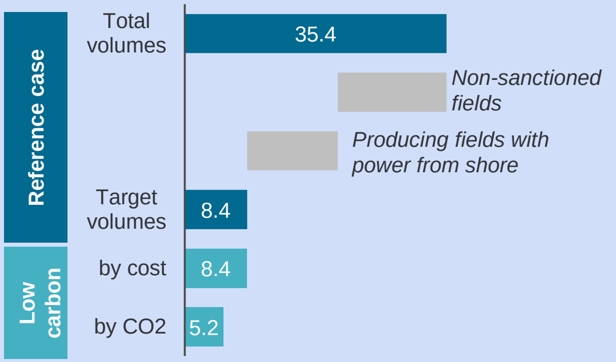
Optimized gas turbines: Description and target volumes, costs and emissions

- *Optimized gas turbines are described as a "low hanging fruit" requiring less topside modifications and spend to implement compared other pure emission reduction technologies. As such, heat recovery and combined cycle systems are not included in this technology grouping as they is more costly to implement. Most of the turbines on the NCS are single cycle.*
- *Peak shaving and hybrid systems with frequency converters on equipment that does not require steady drives are discussed solutions that need to be placed in a system approach to optimize gas turbine load.*
- *Potential exists to cut the use of complete turbines or run the turbines in use more efficiently. Half of the turbines on the NCS are running at 50-60% load.*

Target volumes

- *Targets producing fields that are not served with power from shore.*
- *Only retrofit effects assessed, future facilities assumed to have optimized systems in place.*

Target volumes – production 2020-2050
Billion boe

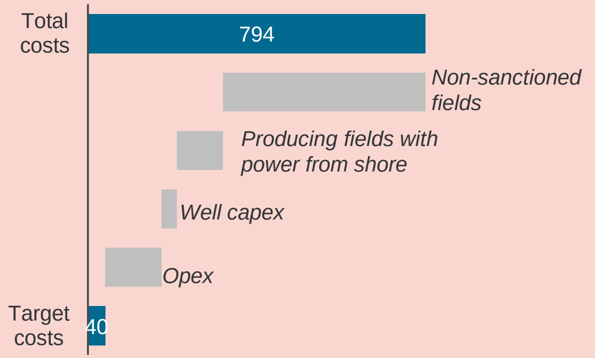


24%
of NCS reference volumes

Target costs

- *The cost components for optimized gas turbines belongs under topside facility capex on producing platforms that are not electrified from shore*

Target costs – upstream spending 2020-2050
Billion USD

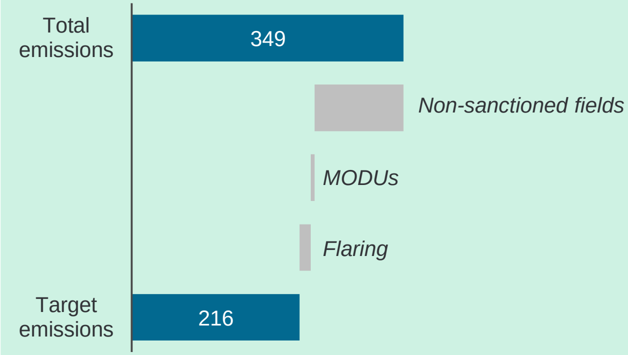


5%
of NCS costs

Target emissions

- *Emissions from gas turbines on from producing fields that have not been electrified from shore*
- *CO_2 emissions from flaring and MODUs are not targetable by this technology.*

Target emissions – Upstream emissions 2020-2050
Million tonnes of CO_2 eq



62%
of NCS emissions targeted

Sources: Interviews; TTA input; SINTEF EFFORT presentations and research articles

Optimized gas turbines: Assumptions and effects

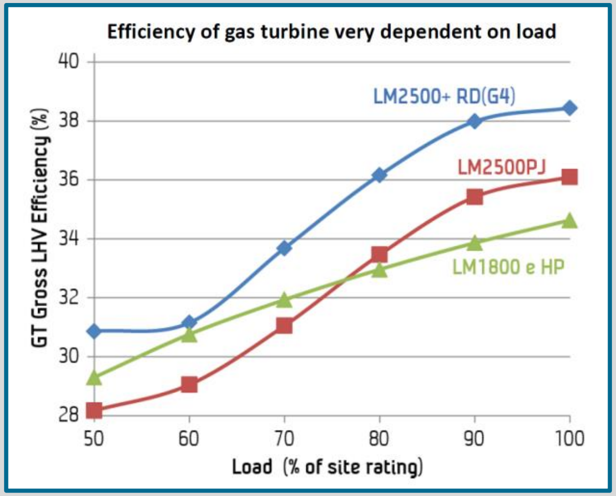
Optimized gas turbines: Assumptions and effects

Volume effects

- *There are no direct volume effects of this technology. However, during installation power supply might be disrupted from the turbines in question and may as such lead to production loss in the installation phase.*
- *However, if the optimization free-up an extra turbine, then rolling maintenance can be done on this equipment without shutting down production on the platform for prolonged periods of time and as such increase uptime. None of these two effects have been evaluated, but in net effect we expect the technology to have a neutral to positive effect on volumes.*

Cost effects

- *Based on SINTEF studies presented at amongst OTC, the turbine efficiency vary greatly dependent on the load. Example form the chart on the right, a LM2500+G4 turbine running at 90% load will have a average efficiency 37.9%, where a the same turbine at 60% load have an efficiency of 31%. This implies a reduction of 20% in fuel gas. For the same power demand should the turbine be possible to optimize the fuel gas consumption by introducing hybrid systems and frequency converters on selected equipment.*
- *Investments for the needed modifications and maintenance savings have not been evaluated. The modifications applied will likely be very different dependent on the platform in question and the processes run on that platform. As for all the other technologies the cost effect of emission reductions through reduced CO_2 tariffs are not included.*



Emission effects

- *Gas turbines are at its most energy efficient at full load. More than half of the turbines on the NCS run at 50-60%. Studies made by the EFFORT program on SINTEF has identified that the maximum potential of optimizing gas turbine usage for lower emissions is a 5% reduction. Their case was made in changing out existing gas turbines with smaller ones, but the same calculation will likely apply for other measures that enables the gas turbines to run at full load. As such 5% improvement potential on gas turbines are used.*

Time frame	Volume growth potential		Cost savings potential		Emission reduction potential	
	Total in period [Million boe]	*Daily* [Thousand boe/d]	*Total in period* [Billion USD real]	*Annually* [Million USD real]	*Total in period* [Million tn CO_2 eq.]	*Annually* [Million tn CO_2 eq.]
Short term (2020-2025)	Neutral	Neutral	-0.3	-50	-1.6	-0.3
Long term (2025-2050)	Neutral	Neutral	-1.1	-45	-6.0	-0.2

Lead time: 1-2 years

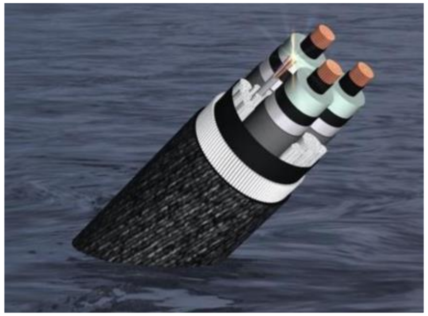
Cost of modifications and maintenance savings have not been evaluated. Reduction in CO_2 tariffs not included.

Sources: Interviews; TTA input; Marit Mazetti - OTC-24034-MS, SINTEF EFFORT presentations and research articles

Power from shore: Description and target volumes, costs and emissions

Power from shore: Description and target volumes, costs and emissions

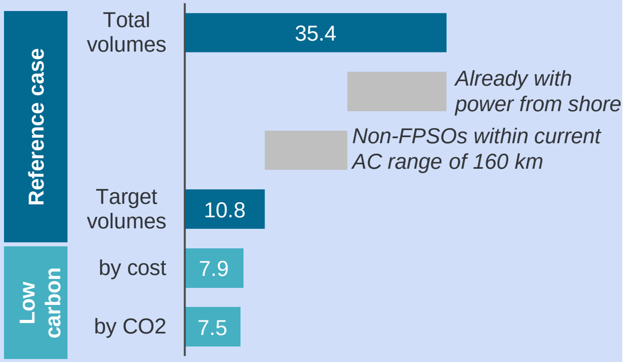
- *HVDC through turrets and long distance HVAC are identified as the current limitations of power from shore technologies.*
- *By enabling long distance AC cables, we can avoid expensive converter stations offshore which could be a hinder for brownfield electrification due to lack of deck space, and also ensure electrification of FPSOs that currently has HVDC turret limitations.*
- *The Barents Sea is especially prone for this technology with long distances to shore and FPSOs being the main benefactors of improvement in power from shore technologies*



Target volumes

- *Targets fields developed by FPSOs or that are further away from shore than 160 km.*
- *Fields that are electrified or planned electrified from shore are excluded.*

Target volumes – production 2020-2050
Billion boe

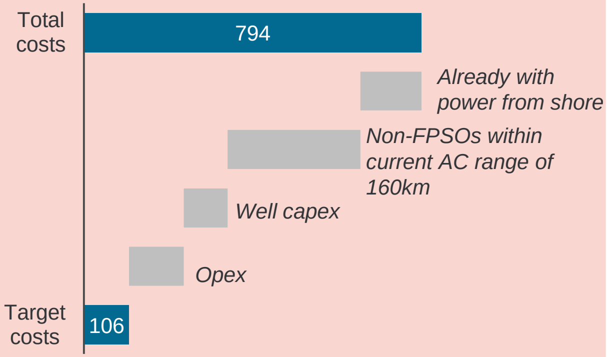


49%
of NCS reference volumes

Target costs

- *The main cost component of offshore electrification falls under facility capex.*
- *There are savings potential for opex, with reduced gas turbine maintenance and reduced fuel gas consumption*

Target costs – upstream spending 2020-2050
Billion USD

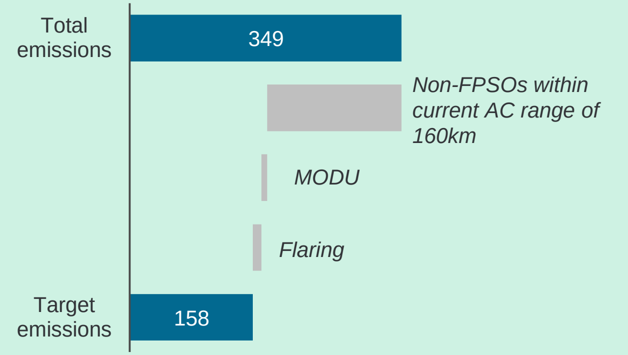


25%
of NCS costs

Target emissions

- *Emissions from gas turbines on the NCS*

Target emissions – upstream emissions 2020-2050
Million tonnes of CO_2 eq



45%
of NCS emissions targeted

Sources: Interviews; TTA input; NOWITECH; Hywind Tampen PUD; AKSO concept; Rystad Energy research and analysis

Power from shore: Assumptions and effects

Power from shore: Assumptions and effects

Volume effects

- *Increased regularity with electrification due to less downtime. Gas turbine maintenance typically involves shut-down of parts of the installation. Removing gas turbines could be an argument for increased regularity.*
- *However, there are examples (i.e. Goliat) where instability with the power from shore has been an issue and resulted in downtime. As such we do not attribute any volume effects to power from shore technologies*.

Cost effects

- *The chart to the right illustrate the DC vs AC boundary which is defined by the step-out and power needed. Most of the electrification on the NCS has due to large power requirements and step-out distance been completed with a DC and converter solution. Martin Linge (former name Hild used on the chart) is the worlds longest AC power from shore.*
- *In the Hywind PDO, previous estimates for the electrification of Snorre was disclosed. A full electrification including both Snorre A & B with 110 MVA HVAC cable from shore was at CO_2 abatement cost of* 1411 NOK17/tonnes CO_2*. This is viewed as fairly representative for HVAC electrification onshore.*
- *For Greenfields the cost should be lower as the cost of gas turbines and slimming of the topside can be incorporated. Equinor's evaluation of electrification of Johan Castberg with DC from shore had a stated abatement cost of between 3900-4600 NOK16/tn CO_2 (real 2016). This is not viewed as representative for the technology cases discussed here as this included separate DC to AC converter facility, and significant upgrades to the onshore grid. However, it underpins a central challenge for power from shore technologies – available capacity in the onshore grid.*

Emissions effect

- *Almost all of the power from shore projects on the NCS have been full electrification projects. This is also the assumption for future electrification projects, although there might be more economically viable solutions that only covers partial electrification. This is due to the complexity of switch direct drive turbines with electro motors where this is used and to keep the power demand within the limit of AC.*
- *We are looking at Scope 1 emissions (direct emissions), as such the implied effect of emissions assumes the electricity from shore comes from CO_2 neutral power production.*

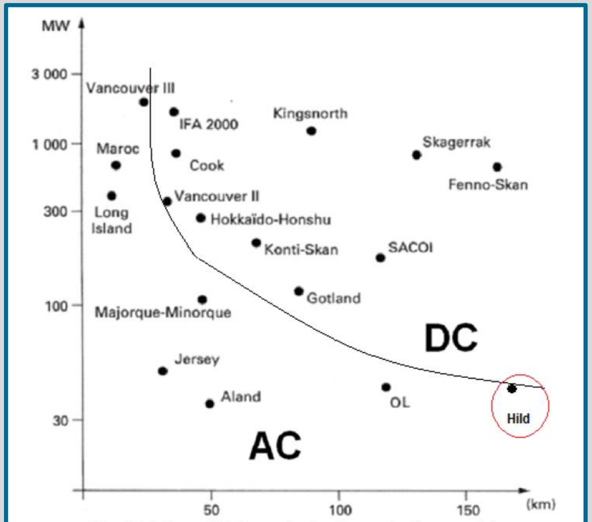


Fig. 5 AC and DC projects through the world

Time frame	Volume growth potential		Cost savings potential		Emission reduction potential	
	Total in period *[Million boe]*	***Daily*** *[Thousand boe/d]*	***Total in period*** *[Billion USD real]*	***Annually*** *[Million USD real]*	***Total in period*** *[Million tn CO_2 eq.]*	***Annually*** *[Million tn CO_2 eq.]*
Short term (2020-2025)	Neutral	Neutral	+1.3	+215	-7.2	-1.2
Long term (2025-2050)	Neutral	Neutral	+23.4	+940	-130	-5.2

Lead time: 2-3 years

CO_2 tariff savings are not included in these estimates

Full electrification assumed

Sources: Interviews; TTA input; Hywind Tampen PDO; Poyry Castberg electrification analysis; Martin Linge electrification study ("Selection of power from shore for an offshore oil and gas development");

Compact topside CCS: Description and target volumes, costs and emissions

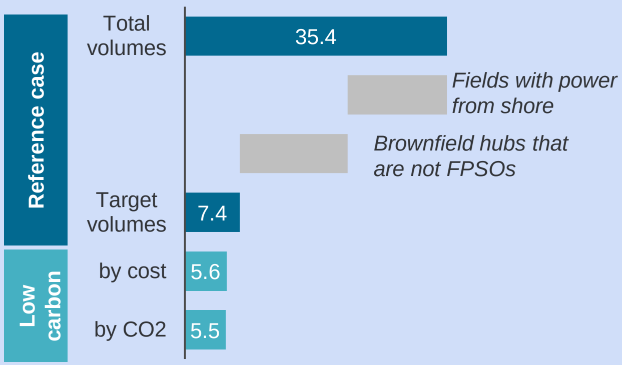
Compact topside CCS: Description and target volumes, costs and emissions

- *Compact topside CCS aims to use compact capture modules on a topside to capture CO_2 from the turbine exhaust*
- *Self contained power system: Secures green supply of power and heat without being dependent on other sources. Maintains independence of energy supply – no import from third party.*
- *The captured CO_2 can be disposed in the injected water. CO_2 levels are so small that it will have none/marginal effects on recovery rate.*
- *Dependent on easy access to exhaust gas and available deck space – pose challenges to brownfield retrofits*

Target volumes

- *Future standalones are the main target fields for the technology*
- *Brownfield FPSOs could be possible candidates as they are more flexible in terms of topside weight and space restrictions*

Target volumes – production 2020-2050
Billion boe

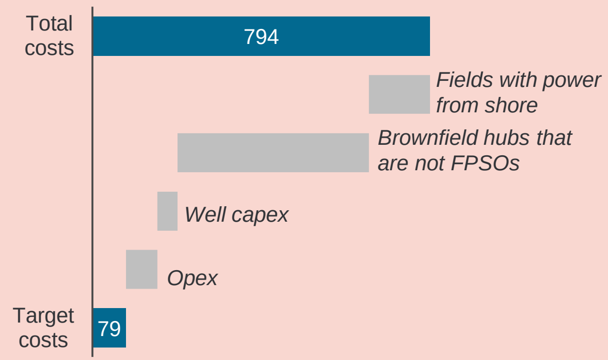


21%
of NCS reference volumes

Target costs

- *The main cost component of compact topside CCS falls under facility capex.*
- *Opex savings include reduced emission tariffs (not assessed as it is measured separately)*

Target costs – upstream spending 2020-2050
Billion USD

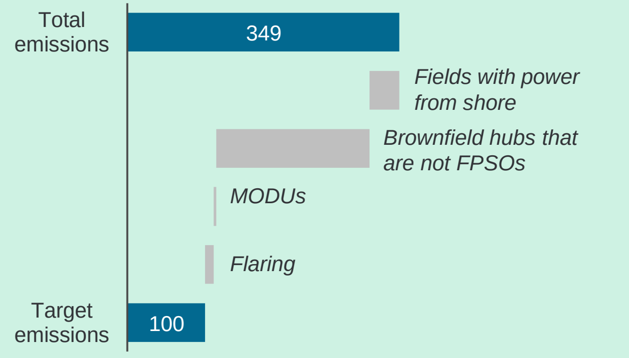


10%
of NCS costs

Target emissions

- *Emissions from gas turbines on greenfields and brownfield FPSO hubs.*

Target emissions – Upstream emissions 2020-2050
Million tonnes of CO_2 eq



29%
of NCS emissions targeted

Sources: Interviews; TTA input; AKSO Technology Day "Just Catch"; Compact Carbon Capture; Rystad Energy research and analysis

Compact topside CCS: Assumptions and effects

Compact topside CCS: Assumptions and effects

Volume effects

- *CO_2 is injected into the reservoir, but the amounts are far below the quantities needed in order to see any EOR effect of the injections.*
- *The technology requires significant topside capacity, both in terms of deck space and tonnage. For brownfield applications it will most likely only be FPSO facilities that are takers of retrofit solutions. For greenfield solutions it is assumed feasibly for all application areas.*
- *With few FPSOs on the NCS and not many future standalone facilities in the pipeline, the largest potential for this technology is most likely outside the NCS or in the FPSO leasing market.*
- *In terms of lead time, extensive modifications is needed on existing FPSOs, also will be subject to field development lead times for new standalone facilities.*

Cost effects

- *Cost levels dramatically reduced on capture technologies since 2012, but this technology does not get the benefit of reduced fuel gas use.*
- *Based on estimates from Aker Solutions the discounted abatement cost is competitive with the current NCS CO_2 tax which equates to approximately 500 NOK/CO_2 tonnes.*

Emissions effect

- *It is not viable to apply carbon capture technologies providing direct-drive of compressors, since these machines will be located in highly congested process areas where available footprint is not foreseeable in any circumstances. Hence, only applicable for turbines used for power generation, which are conventionally located in foreseeably less congested utility areas.*
- *Greenfield application: 80% emission reduction in emission from gas turbines, this assumes that the field will be fully electric with all gas turbines used to generate power for all applications on the topside. Initial studies indicate that capturing 80% of a turbine's CO_2 emission over a given duration is practicable.*
- *For brownfield application 41% emission reduction gas turbines. On existing fields it will likely only target gas turbines used for direct-drive, due to the previously stated restrictions. Gas turbines for indirect drive account for 53% of the emissions.*

Time frame	Volume growth potential		Cost savings potential		Emission reduction potential	
	Total in period *[Million boe]*	***Daily*** *[Thousand boe/d]*	***Total in period*** *[Billion USD real]*	***Annually*** *[Million USD real]*	***Total in period*** *[Million tn CO_2 eq.]*	***Annually*** *[Million tn CO_2 eq.]*
Short term (2020-2025)	Neutral	Neutral	+0.03	+4.4	-1.5	-0.3
Long term (2025-2050)	Neutral	Neutral	+1.9	+280	-59	-2.3

Lead time: 3-5 years

CO_2 tariff savings are not included in these estimates

Sources: Interviews; TTA input; Just Catch presentation - Aker Solutions Technology Day 2019; Rystad Energy research and analysis

17 focus technologies – many of the same technologies selected across the TTA groups

	Technology area	Description	TTA1	TTA2	TTA3	TTA4
TTA1 Energy efficiency and environment	Offshore wind for offshore facilities	*Clean supply source. Challenges with intermittence, will not replace gas turbines, but can reduce emissions.*				
	Optimized gas turbines	*Systems and equipment that allows for peak shaving and hybrid solutions that seek to optimize gas turbine load to improve efficiency and reduce emissions*				
	Power from shore technologies	*Large converters for long distance DC and issues with DC through turrets are identified as challenges. Long distance AC avoids costly topside modifications,*				
	Compact CCS for topsides	*Compact capture technologies for offshore applications. Applied on exhaust gas from turbines and disposed through water injection.*				
TTA2 Exploration and improved recovery	**Water diversion**	*Improvement of water sweep in oil reservoirs by injecting foam cement, gel and/or silicates. Reduces water produced and injected in addition to increased recovery*				
	CO_2 for EOR	*Increases recovery, but at a 2-3 year delay and with high cost. Delivery of point emission by ship and standalone subsea solutions on the horizon.*				
	Field model optimization	*Data systems and models to facilitate faster modelling, real time updates, machine learning and optimal well placement*				
	Big data exploration analytics	*Data systems and models to facilitate faster modelling, real time updates, machine learning and optimal well placement*				
TTA3 Drilling, completion and intervention	Wired pipe technologies	*Live monitoring while drilling for better well placement. Look around- look ahead. Enables the use of new tools and sensors*				
	Slot recovery technologies	*Existing and new wells are expected to be reused multiple times. More efficient slot recoveries will cut well capex and reduce rig days.*				
	Automated drilling control	*Increase adoption and widen scope (all aspects) - digitalization in drilling. Leads to reduction of NPT and PT.*				
	Smarter smart wells	*Monitor and control producers and injectors on oilfields to optimize production; eliminate unwanted products and maximize valuable products.*				
TTA4 Production, processing and transport	Predictive maintenance	*Interpretation of sensor data, modelling, digital twin software. Reduce down-time and man hours, increase life-time.*				
	Unmanned platforms	*Autonomous operations and automation. Robotics and drone technology for simpler platforms with reduced opex and less emissions.*				
	Standardized subsea satellites	*Develop standard concepts for small tie-back fields to minimize need for engineering, accelerate projects and reduce costs*				
	All electric subsea	*Umbilical-less solutions, subsea chemical storage, electric subsea actuators. Lower cost, better control, higher regularity and improved late-life flexibility*				
	Flow assurance	*Cold flow technologies, pipe-in pipe systems, heat tracing technologies. Technologies to deal with wax and hydrate formation over long distances.*				

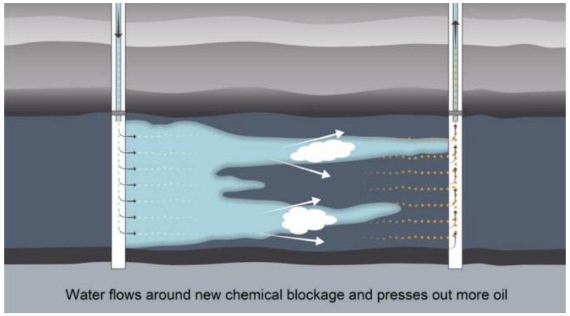
Selected *Suggested*

Source: Input from TTA workshops; Rystad Energy research and analysis

Water diversion: Description and targeted values

Water diversion: Description and target volumes, costs and emissions

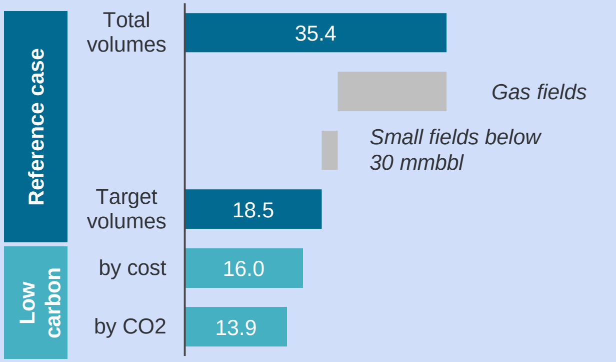
- *The main goal of the technology is to improve sweep in the reservoir, and increase recovery of mobile oil. This is achieved by diverting water flows through less permeable parts of the reservoir. Diversion can be completed by injecting foam cement, gel and silicate products.*
- *Enhancing technologies that gives higher recovery of mobile oil in the reservoir and reduces water breakthrough. Always applied in the brownfield phase and will by design not enable the development of a field.*
- *Further development of modelling and simulation techniques to accurately predict the effects of in-depth water diversion.*
- *At least two successful pilots on the NCS with foam cement on Ekofisk and sodium silicate on Snorre.*



Target volumes

- *Only applicable to oil fields that use water drive as (potential) recovery method.*
- *Small fields are excluded due to difficulty with economics and typically lack of sufficient wells and injectors.*

Target volumes – production 2020-2050
Billion boe

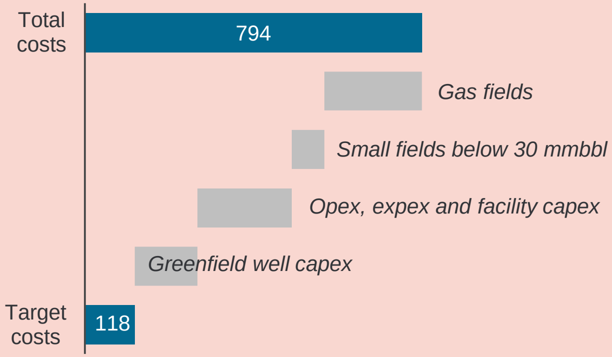


49%
of NCS reference volumes

Target costs

- *Same field selection as for volumes*
- *Only target brownfield well capex, as water break-through is an issue later in a fields life cycle*

Target costs – upstream spending 2020-2050
Billion USD

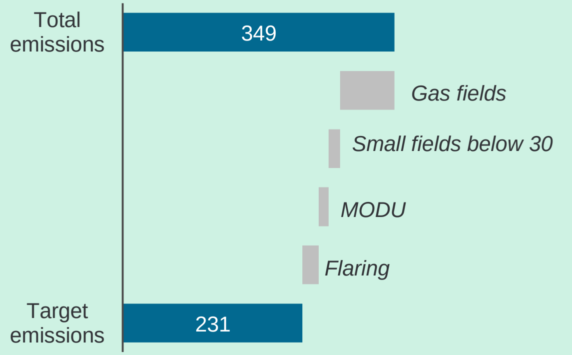


6%
of NCS costs

Target emissions

- *Emissions from gas turbines in larger oil fields*

Target emissions – upstream emissions 2020-2050
Million tonnes of CO_2 eq



64%
of NCS emissions targeted

Sources: Interviews; TTA input; NPD 2005 RR; OG21 strategy 2016; *Snorre in-depth water diversion* - Kjetil Skrettingland / Statoil (26.04.2016); OG21 workshop (23.05.2018); Rystad Energy research and analysis

RYSTAD ENERGY

Water diversion: Assumptions and effects

Water diversion: Assumptions and effects

Volume effects

- *The volume effects of water diversion pertains to improvement in the recovery of mobile oil by securing more optimal sweep. Onshore methodologies have proven that it is possible to achieve 5-30% incremental recovery rates due to increased mobility control. EOR potential offshore is likely lower due to larger well spacing, thus this analysis assumes incremental recovery rates of 2.5-15%. Impact given to all producing fields from 2020. The more complex the reservoir the better the improvement on recovery rate. Also, very uniform fields are excluded from the target fields as these will have little use of diversion techniques as current sweep patterns are sufficient. The measure used is the Resource Complexity Index (RCI) as defined by NPD, which is highly correlated to the recovery factor.*
- *For producing and sanctioned fields the recovery rates are estimated on a field-by-field basis. Fields with high geologic complexity will have less uniform sweep and better effect of water diversion methods. The technical potential for discoveries and estimated undiscovered volumes is estimated based on the average increased recovery rate for producing fields.*
- *After applying water diversion technologies you observe an immediate effect of producing more oil and less water, and a long term effect of having more water in the reservoir.*

Cost effects

- *Cost of application is expected to be between 6-14 USD per barrel of oil gained. This is based on case studies on the NCS, and has high uncertainty when looking to apply that figure for the NCS.*
- *However, producing less water should yield reduced opex, with less fuel use in the turbines to reinject water and less gas lift needed. Also, we expect that the need for interventions will be less as fewer wells will be in need of water shut-off.*

Emissions effect

Based on input from the TTAs we expect the emission saving due to less gas turbine use for gas lift and water injection. We scale this reduction directly with CO_2 emissions from to the share of the gas turbines supplying power to the same operations.

- *3-20% less water injection. Water injection accounts for roughly 40% of the turbine usage on an average oil field*
- *10-20% less gas lift compression. Gas lift compression accounts for around 5% of turbine usage on platforms*

Time frame	Volume growth potential		Cost savings potential		Emission reduction potential	
	Total in period *[Million boe]*	***Daily*** *[Thousand boe/d]*	***Total in period*** *[Billion USD]*	***Annually*** *[Million USD]*	***Total in period*** *[Million tn CO2 eq.]*	***Annually*** *[Million tn CO2 eq.]*
Short term (2020-2025)	+250	+120	+2.6	+425	-1.5	-0.25
Long term (2025-2050)	+1 600	+175	+16.0	+640	-9.6	-0.4

Lead time: 1-2 years

Effects on reduced opex due to less water processing and fewer interventions have not been analyzed, but expected to be minor

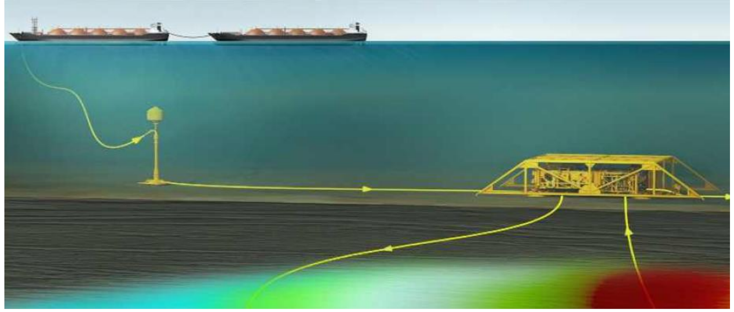
Sources: Interviews; TTA input; NPD 2005 RR; OG21 strategy 2016; *Snorre in-depth water diversion* - Kjetil Skrettingland / Statoil (26.04.2016); OG21 workshop (23.05.2018); Rystad Energy research and analysis

RYSTAD ENERGY

CO_2 for EOR: Description and target volumes, costs and emissions

CO_2 for EOR: Description and target volumes, costs and emissions

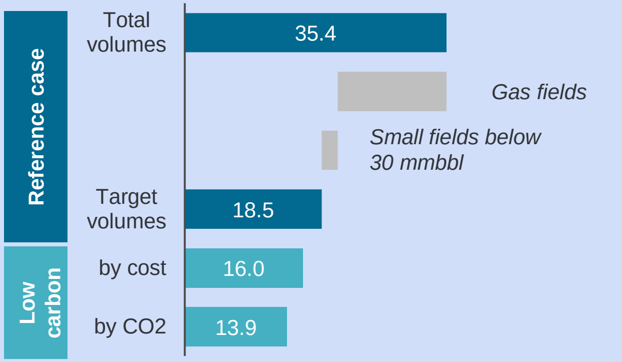
- *CO_2 is injected into already developed oil fields where it mixes with and "releases" the oil from the formation, thereby enabling it to move to production wells. Targets immobile oil .*
- *CO_2 that emerges with the oil is separated and re-injected into the formation. The technology requires large quantities of available CO_2 for injection. This needs to be gathered and transported to the field.*
- *Typically challenging to handle streams on the topside with as CO_2 is corrosive, developments within subsea CO_2 separation could reduce the need for large topside modifications.*
- *Effect on the reservoir is expected to be positive, and there is less technical risk with this method than other EOR methods. However, with longer well spacing effect in offshore reservoirs is expected to take 2-3 years before we can see any significant effect in increased volumes.*



Target volumes

- *These technologies are only applicable on oil fields that use water as the drive method.*
- *Small fields are excluded due to lack of sufficient wells and injectors.*

Target volumes – production 2020-2050
Billion boe

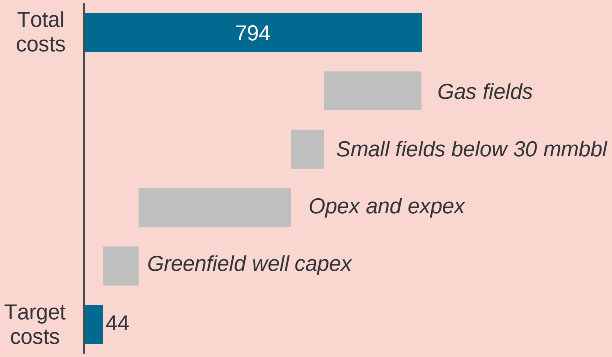


49%
of NCS reference volumes

Target costs

- *Same field selection as for volumes*
- *Requires significant facility investment and recompletions.*
- *Cost or payment to receive CO_2 at field is not assessed, but could be substantial dependent on the tariff regime.*

Target costs – upstream spending 2020-2050
Billion USD

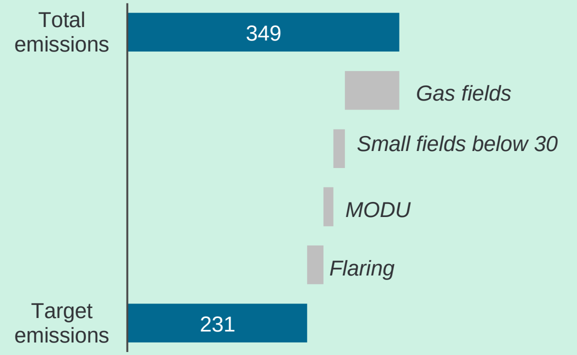


15%
of NCS costs

Target emissions

- *Emissions from gas turbines in oil fields*

Target emissions – upstream emissions 2020-2050
Million tonnes of CO_2 eq



64%
of NCS emissions targeted

Sources: Interviews; TTA input; NPD 2005 RR; OG21 strategy 2016; *Snorre in-depth water diversion* - Kjetil Skrettingland / Statoil (26.04.2016); OG21 workshop (23.05.2018); Rystad Energy research and analysis

CO_2 for EOR: Assumptions and effects

CO2 for EOR: Assumptions and effects

Volume effects

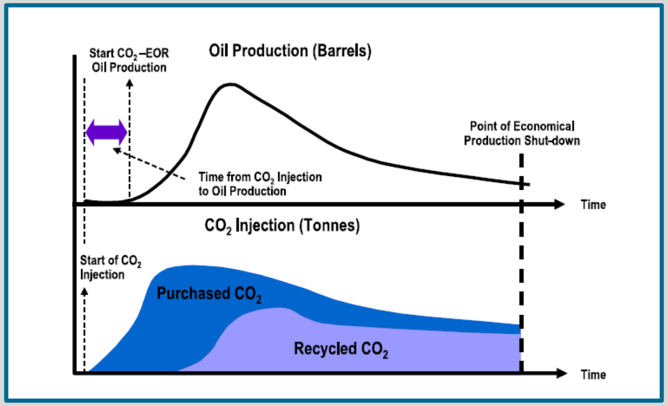
- *Onshore CO_2-EOR and ASP (Alkaline-Surfactant-Polymer) flooding have achieved an increased recovery rate of 4-15%. EOR potential offshore is likely lower than what is observed onshore due to lower well density, thus this analysis assumes incremental recovery rates of 3-9%. Impact is given to all producing fields from 2024 (assuming 3-4 years lead time from FID to start-up and 2-3 years to realize effect after application)*
- *For producing and sanctioned fields the recovery rates are estimated on a field-by-field basis. The lower RCI* the better the effect the EOR method is expected to have.*
- *The technical potential for discoveries and estimated undiscovered volumes is estimated based on the average increased recovery rate for producing fields. The total additional volume potential for EOR in the period evaluated is estimated at 825 million bbl. Åmutvalget (2010) estimated that this potential was ~1900 million bbl also considering the tail past 2050. However, in the last 10 years no EOR projects have been initiated and potential has been reduced.*

Cost effects

- *CO_2 for EOR is an expensive endeavor due to significant modifications needed on the topside to accommodate for the more corrosive streams and separation units. With a proposed subsea CO_2 separation solution this could be brought significantly down, possibly in the capex range of 20-25 USD per extra barrel produced. Whereas the topside facility solution is currently in the +30 USD/boe range.*

Emissions effect

- *The reservoir acts as a sink to store the CO_2, and after a while it starts to reproduce previously injected CO_2. This can be between 2-10 years dependent on the size of the reservoir and injection rate. Several studies have evaluated the EOR potential on the NCS with field specific evaluations. For these studies the CO_2 stored in reservoirs have been between 0.2-0.6 tonnes of CO_2 stored per additional barrel produced. A reduction in emissions of 13.2 million tonnes of CO_2 equivalents per year account for nearly all of NCS upstream emissions.*
- *The CO_2 reduction potential does also include storage potential in future fields. The potential from currently producing fields is estimated to be slightly above 1Gt of CO_2 in the period. This is inline with the BIGCCS report by SINTEF, stating storage potential of 1.5Gt in existing oil reservoirs 10 years ago.*



Time frame	Volume growth potential		Cost savings potential		Emission reduction potential	
	Total in period [Million boe]	*Daily* [Thousand boe/d]	*Total in period* [Billion USD]	*Annually* [Million USD]	*Total in period* [Million tn CO2 eq.]	*Annually* [Million tn CO2 eq.]
Short term (2020-2025)	None	None	None	None	None	None
Long term (2025-2050)	+825	+175	+20	+825	-330	-13.2

Lead time: 5-7 years

CO2 quota and purchase price are not part of the cost estimate

CO2 stored in nearby aquifers are not included in the EOR estimate.

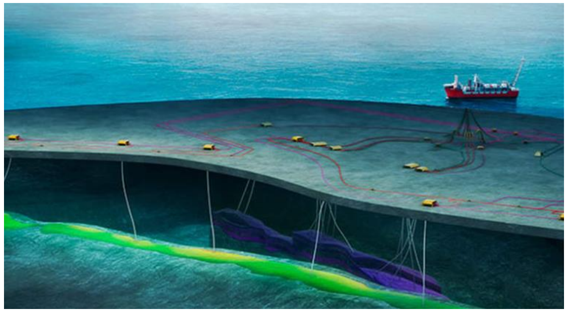
*Reservoir Complexity Index

Sources: Interviews; TTA input; SCCS; AKSO ONS 2016; NPD 2005 RR;OG21 strategy 2016; EOR and CO2 disposal – SINTEF/Holt et.al (2009)

Field model optimization: Description and targeted values

Field model optimization: Description and target volumes, costs and emissions

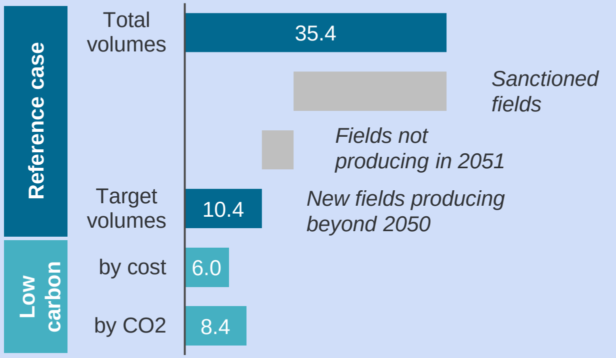
- *A data system able to reduce time required to do subsurface modelling and incorporate real time updates could increase volume potential and reduce cost through more efficient well placement.*
- *The key improvement required to realize the value of such a system is the ability to apply the learning from the construction of the initial wells onto the subsequent wells drilled.*
- *Improved well placement could improve recovery from oil fields through better sweep and access to additional pockets of oil.*
- *This improved sweep would also allow for fewer wells to be drilled, without sacrificing volume, which in turn would require less rig time to drill the wells, reducing the overall emissions.*



Target volumes

- *Over the life of the fields, no assumptions has been made as to the total volume produced.*
- *The volumes have, however been accelerated, resulting in increased volumes over the target timeframe.*

Target volumes – production 2020-2050
Billion boe

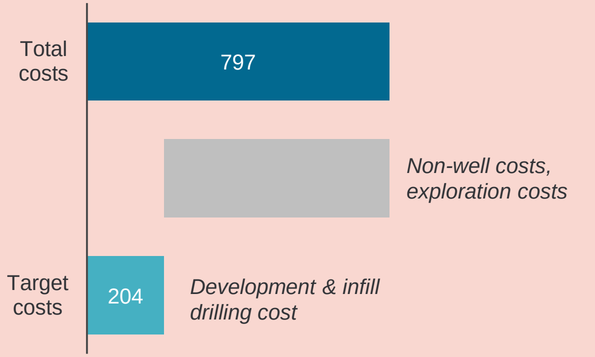


29%
of NCS reference volumes

Target costs

- *Improved well placement allows for fewer wells to be drilled with the same resource base.*
- *Well capex (excluding exploration) is consequently the key benefactor of such improvements.*

Target costs – upstream spending 2020-2050
Billion USD

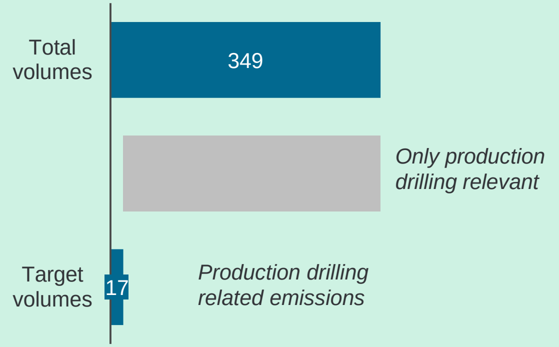


26%
of NCS costs

Target emissions

- *Emissions by drilling units are the target for such an improvement, driven by the lower number of wells needed.*

Target emissions – upstream emissions 2020-2050
Million tonnes of CO_2 eq



5%
of NCS emissions targeted

Sources: Interviews; TTA input; NPD 2005 RR; OG21 strategy 2016; OG21 workshop (23.05.2018); Rystad Energy research and analysis

Field model optimization: Breakdown and assumptions

Field model optimization: Assumptions and effects

Volume effects

- *The reduction in development time allows for faster extraction of volumes over the period. As such will the total volumes produced not increase, but the volumes produced within the time period will, specifically 2051 volumes are assumed to be produced in the 2020 to 2050 period. Similarly, certain volumes will move from the long term (2025 to 2050) to the short term (2020 to 2025).*
- *The net effect for these two periods are an additional 560 million barrels produced.*

Cost effects

- *Better placement of wells enable the extraction of the same volumes with fewer wells, reducing well capex.*
- *An estimated reduction of well investments of 20% would yield savings of 41 bn USD.*

Emissions effect

- *Reductions in emissions would be driven by the reduced requirement for wells. Emissions from mobile drilling units would decline in line with the lower number of wells drilled, i.e. 20%.*
- *In total this would reduce emissions by 3.3 million tonnes of CO_2 equivalents*

Time frame	Volume growth potential		Cost savings potential		Emission reduction potential	
	Total in period *[Million boe]*	***Daily*** *[Thousand boe/d]*	***Total in period*** *[Billion USD]*	***Annually*** *[Million USD]*	***Total in period*** *[Million tn CO_2 eq.]*	***Annually*** *[Million tn CO_2 eq.]*
Short term (2020-2025)	**+425**	+230	-7.3	-1460	-0.4	-<0.1
Long term (2025-2050)	**+135**	+70	-33.5	-1340	-2.9	-0.1

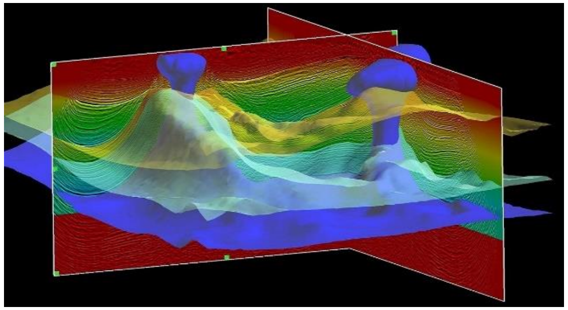
Lead time: 3-5 years

Sources: Interviews; TTA input; NPD 2005 RR; OG21 strategy 2016; OG21 workshop (23.05.2018); Rystad Energy research and analysis

Big data exploration analytics: Description and targeted values

Big data exploration analytics: Description and target volumes, costs and emissions

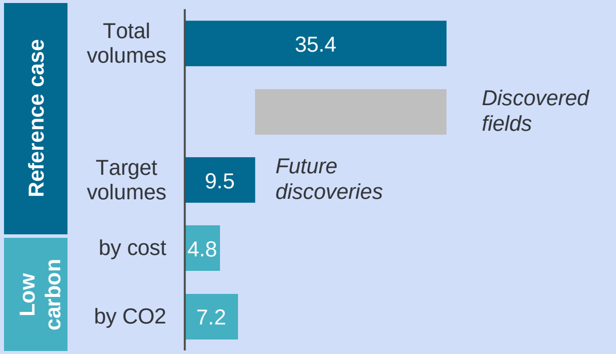
- *Exploration for petroleum has transitioned from targeting simpler structures to more complex structures and petroleum systems. As a consequence, it is more difficult to assess rate and rank of these systems, prioritizing only the best targets.*
- *Combining historical data gathered globally, to understand the future targets could support geologists in making better decisions, increasing the discovery rate.*



Target volumes

- *Improved use of data to increase exploration results could increase the chance of success, for gas fields as well as oil fields.*
- *The target volumes are consequently equal to the produced volumes from undiscovered fields over the period.*

Target volumes – production 2020-2050
Billion boe

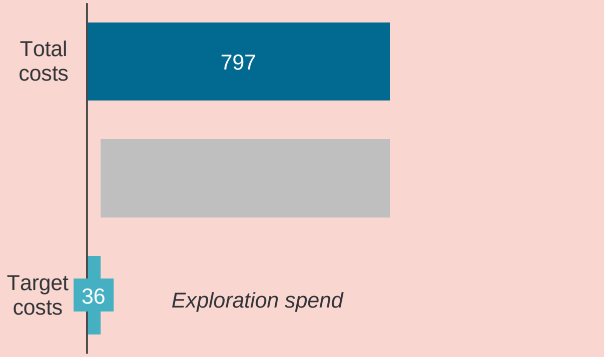


27%
of NCS reference volumes

Target costs

- *Efficiencies made through improved exploration is applicable across all types of exploration spend, as improved results drive down required spend.*

Target costs – upstream spending 2020-2050
Billion USD

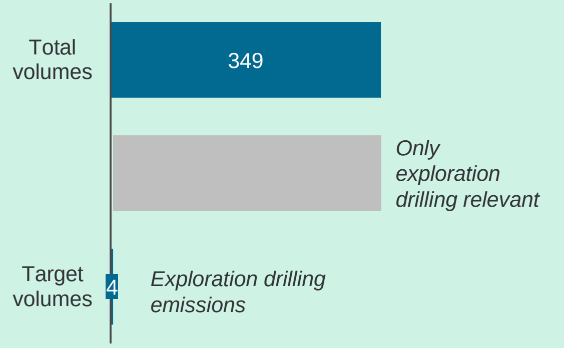


4%
of NCS costs

Target emissions

- *Emissions from exploration could be reduced in a similar fashion as the costs, consequently the emissions from exploration drilling is most relevant.*

Target emissions – upstream emissions 2020-2050
Million tonnes of CO_2 eq



1%
of NCS emissions targeted

Sources: Interviews; TTA input; NPD 2005 RR; OG21 strategy 2016; OG21 workshop (23.05.2018); Rystad Energy research and analysis

Big data exploration analytics: Assumptions and effects

Big data exploration analytics: Assumptions and effects

Volume effects

- *Improved exploration analytics can either be used to increase volumes or reduce costs (through reduced effort with equal output). Currently exploration yield economic discoveries in about one in three wells, or a success rate of 33%.*
- *A material improvement in analytics could push this towards 40% (1 in 2.5 wells are economic), increasing discovered volumes by 20%.*
- *With very long lead time from exploration (commonly around 15 years), the additional volumes are most significant during the second half of the second time period.*

Cost effects

- *As described above, improved analytics could reduce costs.*
- *By forsaking the increased volumes, realizing the cost savings instead, the cost could be reduced by the same 20%. This would be applicable to spending across all phases of exploration, including both seismic and drilling.*

Emissions effect

- *Corresponding to the cost reduction scenario, with lower exploration efforts, emissions from exploration drilling is reduced by 20%.*
- *Could also have impact on the need for seismic activity, both increased or less dependent on the situation. However, this is marine activity and not covered under the scope 1 definitions.*

Time frame	**Volume growth potential**		**Cost savings potential**		**Emission reduction potential**	
	Total in period *[Million boe]*	***Daily*** *[Thousand boe/d]*	***Total in period*** *[Billion USD]*	***Annually*** *[Million USD]*	***Total in period*** *[Million tn CO_2 eq.]*	***Annually*** *[Million tn CO_2 eq.]*
Short term (2020-2025)	-	-	-<0.1	-6	-<0.1	-<0.1
Long term (2025-2050)	+1900	+210	-5.9	-240	-0.6	-<0.1

Lead time: 7-15 years

Sources: Interviews; TTA input; NPD 2005 RR; OG21 strategy 2016; OG21 workshop (23.05.2018); Rystad Energy research and analysis

17 focus technologies – many of the same technologies selected across the TTA groups

	Technology area	Description	TTA1	TTA2	TTA3	TTA4
TTA1 Energy efficiency and environment	Offshore wind for offshore facilities	*Clean supply source. Challenges with intermittence, will not replace gas turbines, but can reduce emissions.*				
	Optimized gas turbines	*Systems and equipment that allows for peak shaving and hybrid solutions that seek to optimize gas turbine load to improve efficiency and reduce emissions*				
	Power from shore technologies	*Large converters for long distance DC and issues with DC through turrets are identified as challenges. Long distance AC avoids costly topside modifications,*				
	Compact CCS for topsides	*Compact capture technologies for offshore applications. Applied on exhaust gas from turbines and disposed through water injection.*				
TTA2 Exploration and improved recovery	Water diversion	*Improvement of water sweep in oil reservoirs by injecting foam cement, gel and/or silicates. Reduces water produced and injected in addition to increased recovery*				
	CO2 for EOR	*Increases recovery, but at a 2-3 year delay and with high cost. Delivery of point emission by ship and standalone subsea solutions on the horizon.*				
	Field model optimization	*Data systems and models to facilitate faster modelling, real time updates, machine learning and optimal well placement*				
	Big data exploration analytics	*Data systems and models to facilitate faster modelling, real time updates, machine learning and optimal well placement*				
TTA3 Drilling, completion and intervention	**Wired pipe technologies**	*Live monitoring while drilling for better well placement. Look around- look ahead. Enables the use of new tools and sensors*				
	Slot recovery technologies	*Existing and new wells are expected to be reused multiple times. More efficient slot recoveries will cut well capex and reduce rig days.*				
	Automated drilling control	*Increase adoption and widen scope (all aspects) - digitalization in drilling. Leads to reduction of NPT and PT.*				
	Smarter smart wells	*Monitor and control producers and injectors on oilfields to optimize production; eliminate unwanted products and maximize valuable products.*				
TTA4 Production, processing and transport	Predictive maintenance	*Interpretation of sensor data, modelling, digital twin software. Reduce down-time and man hours, increase life-time.*				
	Unmanned platforms	*Autonomous operations and automation. Robotics and drone technology for simpler platforms with reduced opex and less emissions.*				
	Standardized subsea satellites	*Develop standard concepts for small tie-back fields to minimize need for engineering, accelerate projects and reduce costs*				
	All electric subsea	*Umbilical-less solutions, subsea chemical storage, electric subsea actuators. Lower cost, better control, higher regularity and improved late-life flexibility*				
	Flow assurance	*Cold flow technologies, pipe-in pipe systems, heat tracing technologies. Technologies to deal with wax and hydrate formation over long distances.*				

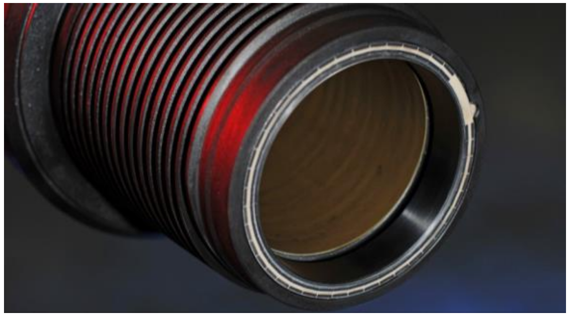
Selected *Suggested*

Source: Input from TTA workshops; Rystad Energy research and analysis

Wired pipe and sensor technology: Description and targeted values

Wired pipe and sensor technology: Description and target volumes, costs and emissions

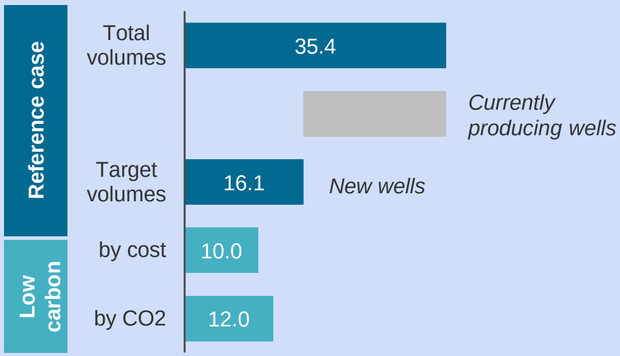
- A wired pipe enables the real time transfer of information from downhole up to the surface at a faster rate than the traditional method, through pressure pulses sent to the surface via the mud.
- The increased transfer speed enables the operator to assess the downhole conditions real time and adjust to challenges immediately.
- Wells with narrow pressure envelopes will particularly benefit from such information as volumes previously too challenging to access, would be accessible. Furthermore, drilling time would be reduced as problematic zones and time consuming mitigation efforts could be could be avoided.
- With increased access to data, well placement would also improve, allowing for increased recovery.



Target volumes

- *Improved placement of wells would allow for higher recovery from new wells.*
- *This would be applicable for both oil and gas fields, though currently producing gas and gas condensate fields are unlikely to see significant gains.*

Target volumes – production 2020-2050
Billion boe

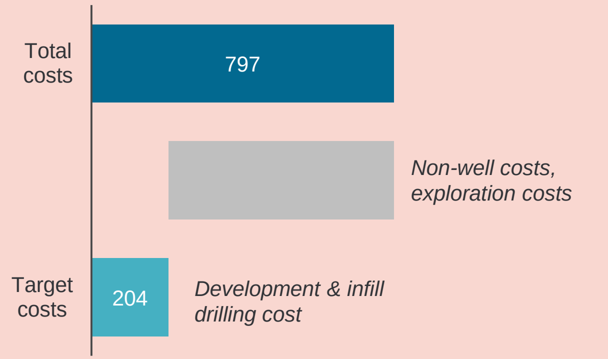


45%
of NCS reference volumes

Target costs

- *All new production wells could benefit from such a technology.*
- *Limited value for exploration wells (being vertical) not exposed to the same level of uncertainty with regards to placement.*

Target costs – upstream spending 2020-2050
Billion USD

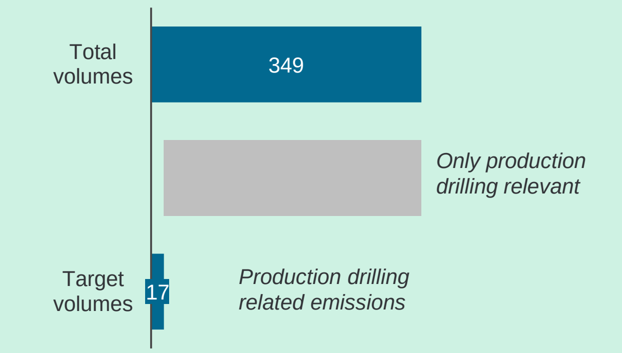


26%
of NCS costs

Target emissions

- *The reduced emissions stemming from the lower number of production wells is the driver of reduced emissions.*

Target emissions – upstream emissions 2020-2050
Million tonnes of CO_2 eq



5%
of NCS emissions targeted

Sources: Interviews; TTA input; NPD 2005 RR; OG21 strategy 2016; OG21 workshop (23.05.2018); Rystad Energy research and analysis

Wired pipe and sensor technology: Breakdown and assumptions

Wired pipe and sensor technology: Assumptions and effects

Volume effects

- *Improvement placement of wells could drive volumes higher by accessing otherwise inaccessible pockets of oil. Implemented from the project development phase, wired pipe could also increase recovery in gas fields, but producing gas field see very limited drilling and are as such not likely to see gains. With a typical recovery factor of around 50% for oil fields, an increase in recovery factor of 10%-points would represent a 20% increase in total recovery.*
- *In total this would represent an increase in recovery of 3220 MMboe over the full time period.*

Cost effects

- *The improved stream of information to the surface also enables the drillers to make better decisions, reducing downtime and increasing efficiency. With NPT making up around 15% of well cost (Oil and Gas Authority UK), a reduction in NPT of 2%-points should be achievable. Furthermore, the same information stream should allow for faster drilling as the drillers' understanding of the formation improves. A 5% improvement has been applied in this study to capture such effects.*
- *In terms of cost, all non-exploration wells should be key targets for such technology. With a combined gain in efficiency of 7%, this adds up to savings of 14 billion USD.*
- *Note that wired pipe technologies could generate additional efficiencies when combined with other technologies, such as automated drilling. These gains have not been included here.*

Emissions effect

- *Reduced use of drilling rigs would lower emissions. Consequently, wired pipe could reduce emissions from development drilling by 7%, constituting a reduction in emissions of 1.2 million tons CO_2 equivalents.*

Time frame	Volume growth potential		Cost savings potential		Emission reduction potential	
	Total in period *[Million boe]*	***Daily*** *[Thousand boe/d]*	***Total in period*** *[Billion USD]*	***Annually*** *[Million USD]*	***Total in period*** *[Million tn CO_2 eq.]*	***Annually*** *[Million tn CO_2 eq.]*
Short term (2020-2025)	+540	+300	-2.6	-510	-0.1	-<0.1
Long term (2025-2050)	+2680	+300	-11.7	-470	-1.0	-<0.1

Lead time: 6-12 months

Sources: Interviews; TTA input; NPD 2005 RR; OG21 strategy 2016; OG21 workshop (23.05.2018); Rystad Energy research and analysis, OGA (UK)

Slot recovery technology: Description and targeted values

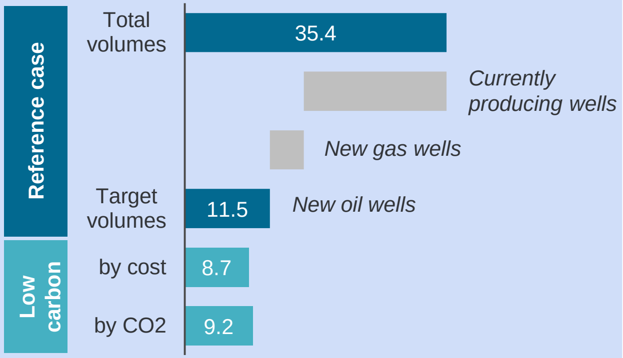
Slot recovery technology: Description and target volumes, costs and emissions

- The reuse of well slots allow operators to access new part of the reservoir without adding new infrastructure, either on the platform or subsea.
- As the drilling of the top is not a large part of the well construction, time savings of performing a slot recovery, compared to the drilling of a new well, is limited. Slot recoveries entail exiting the well, which is a complicated operation.
- Systems and technologies are able to reduce the complexity of reusing slots could generate value through reduced rig time, and such lowering of costs would also allow for marginally higher economic volumes, as additional wells would be profitable.

Target volumes

- *Any potential improvements in recovery from lower cost slot recoveries would stem from new well targets in oil fields, as the reuse of well slots is rarely relevant for gas fields.*

Target volumes – production 2020-2050
Billion boe

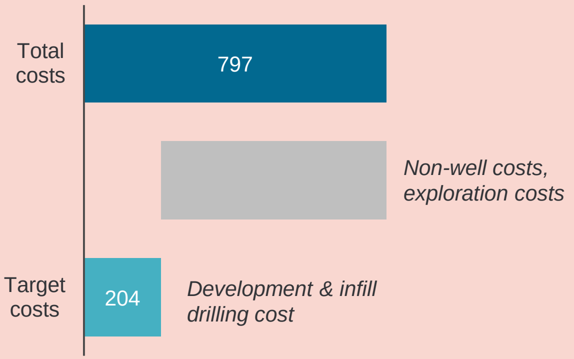


33%
of NCS reference volumes

Target costs

- *Only drilling and wells costs are relevant for improvements in slot recovery technologies.*

Target costs – upstream spending 2020-2050
Billion USD

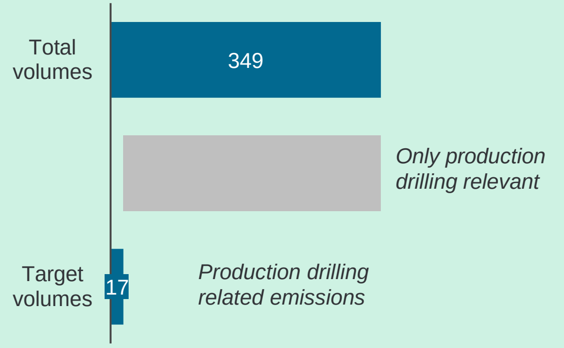


26%
of NCS costs

Target emissions

- *Slot recovery technologies could reduce the impact from drilling production wells, making up about 5% of NCS emissions.*

Target emissions – upstream emissions 2020-2050
Million tonnes of CO_2 eq



5%
of NCS emissions targeted

Sources: Interviews; TTA input; NPD 2005 RR; OG21 strategy 2016; OG21 workshop (23.05.2018); Rystad Energy research and analysis. *2010 to 2018 average

Slot recovery technology: breakdown and assumptions

Slot recovery technology: Assumptions and effects

Volume effects

- *Lower cost of slot recoveries may in theory make certain marginal well targets economical, and as such enable the license to target such additional volumes. In practice these volumes are, however expected to be very small.*

Cost effects

- *Slot recoveries are common on the NCS, making up 46% of development drilling. It is most common on large oilfields, between 2010 and 2018, 321 of the 443 slot recoveries preformed on the NCS were performed on fields with more than 1 bnBoe of original resources (Troll, Statfjord and Ekofisk being the largest contributors).*
- *A number of these fields are however expected to halt drilling over the next couple of years, indicating that 46% is likely too high of a share for slot recoveries going forward. Using the share of well capex in large fields (above 1 bnBoe) as a proxy, the share of slot recoveries of total well capex is set to halve in the short term, and be reduced to 25% over the long term. This would imply that 23% of well capex is relevant between 2020 and 2025, with 12% relevant between 2026 and 2050.*
- *A major challenge in slot recoveries is the time consumed by the process before the whipstock enters the hole. Casings are often rusty and filled with debris, which in many cases creates considerable problems. Examples from Statfjord, where one operation required 65 runs to retrieve the casing, illustrates the challenges in slot recoveries and the potential of new slot recovery technologies. Industry best practice indicates that major cost saving can be gained from combining runs (cutting and pulling simultaneously) and introducing better technology for logging.*
- *Improved slot recovery technologies could potentially reduce drilling time by 10 days on a 50 day well (equal to 20%). With 36 billion USD of target cost short term, and another 167 billion target cost long term the net savings are estimated at 1.7 bn USD and 3.9 bn USD, respectively.*

Emissions effect

- *The reductions in emissions would be driven by the same logic as the cost effects, but only the mobile drilling units emissions would be relevant.*
- *With a small share of NCS emissions being targeted, the net emissions savings are minimal.*

Time frame	**Volume growth potential**		**Cost savings potential**		**Emission reduction potential**	
	Total in period *[Million boe]*	***Daily*** *[Thousand boe/d]*	***Total in period*** *[Billion USD]*	***Annually*** *[Million USD]*	***Total in period*** *[Million tn CO_2 eq.]*	***Annually*** *[Million tn CO_2 eq.]*
Short term (2020-2025)	Limited	Limited	-1.7	-340	-0.1	-<0.1
Long term (2025-2050)	Limited	Limited	-3.9	-150	-0.3	-<0.1

Lead time: 6-12 months

Certain emissions savings effect could also be gained from fixed facilities, but these are smaller and complicated to estimate' accurately.

Sources: Interviews; TTA input; NPD 2005 RR; OG21 strategy 2016; OG21 workshop (23.05.2018); Rystad Energy research and analysis

Automated drilling control: Description and targeted values

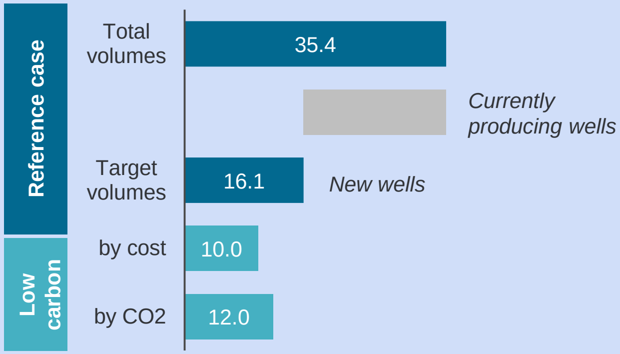
Automated drilling control: Description and target volumes, costs and emissions

- The management of the drilling process is currently very dependent on the drillers ability to absorb, analyze and react to information gathered on the surface and downhole. The human limitations of this process means that efficiencies can be captured by automating more of the process.
- An automated system would be able to avoid issues by correctly reading complex situations. This system is correcting in real time, resulting in increased efficiency and reduced downtime.
- Lessons learned from previous wells could also be implemented more consistently using an automated system, further reduce risk and increase efficiency through pre-modelling of the drill trajectory.

Target volumes

- *Improved placement of wells would allow for higher recovery from new wells.*
- *This would be applicable for both oil and gas fields, though currently producing gas and gas condensate fields are unlikely to see significant gains.*

Target volumes – production 2020-2050
Billion boe

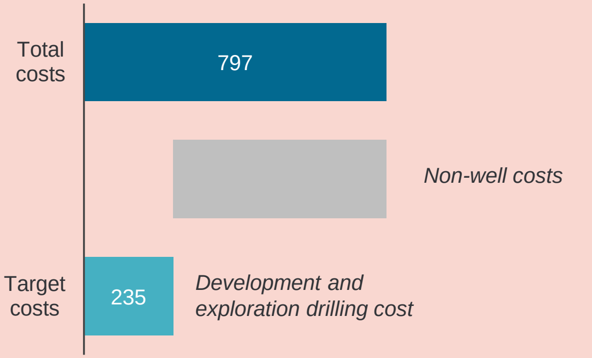


45%
of NCS reference volumes

Target costs

- *Automated drilling would target all types of drilling, both production and exploration.*

Target costs – upstream spending 2020-2050
Billion USD

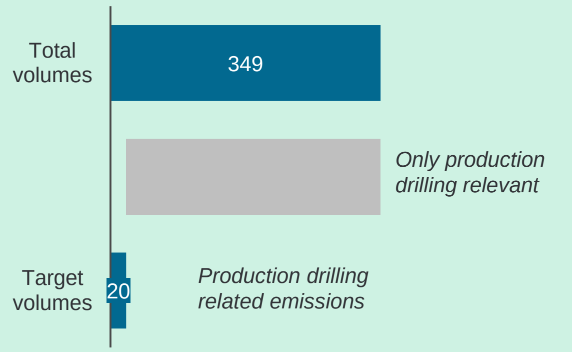


30%
of NCS costs

Target emissions

- *An automated system has the potential to reduce emissions from drilling in both the exploration and development phase.*

Target emissions – upstream emissions 2020-2050
Million tonnes of CO_2 eq



6%
of NCS emissions targeted

Sources: Interviews; TTA input; NPD 2005 RR; OG21 strategy 2016; OG21 workshop (23.05.2018); Rystad Energy research and analysis

Automated drilling control: Breakdown and assumptions

Automated drilling control: Assumptions and effects

Volume effects

- *In theory, improved control over the drilling process would allow operators to drill more complex targets. However, operators would almost certainly require that the well is drillable without the system, as it is possible to temporarily lose the system*
- *The result being that the no additional volumes would be accessible through the use of this system.*

Cost effects

- *One avenue through which automated drilling control could save costs is through the reduction of NPT. The OGA (UK) reports that NPT makes up 15% of overall well cost. An automated drilling system could help avoid some of the issues driving NPT, notably by eliminating the performance differences between individual drill operators and reducing the number of operational errors. Automating the drilling process would assure drill performance comparable or better than the best human operators, thereby reducing drilling time and cost. Furthermore, it could increase drilling speed during normal operations, optimizing the drilling. A 10% increase in drilling speed should be achievable through such an optimization.*
- *Reducing NPT by 5%-points and increasing drilling speed by 10%, adds up to a net reduction in drilling time of 15%. Time variable cost elements in drilling make up around 60% of the total well cost. As it takes time to implement such technology, the short term potential is believed to be limited. Between 2025 and 2050, however, operators should be able to realize this potential. Rystad Energy expects well investments to total 235 bn USD in this period, a 15% reduction of time consequently adds up to a 21 bn USD saving.*
- *Additional benefits include the elimination of costly training programs for new drillers, and the possibility for better pre-modeling of new wells.*

Emissions effect

- *The reduction in emissions from automated drilling would largely be driven by the reduction in the drilling time by mobile drilling units.*
- *With 6% of NCS emissions coming from drilling rigs, a reduction in drilling time of 15% would yield an overall reduction of NCS emissions of 1%, or 3.0 million tons.*

Time frame	Volume growth potential		Cost savings potential		Emission reduction potential	
	Total in period *[Million boe]*	***Daily*** *[Thousand boe/d]*	***Total in period*** *[Billion USD]*	***Annually*** *[Million USD]*	***Total in period*** *[Million tn CO_2 eq.]*	***Annually*** *[Million tn CO_2 eq.]*
Short term (2020-2025)	Limited	Limited	-3.3	-660	-0.4	-<0.1
Long term (2025-2050)	Limited	Limited	-17.9	-720	-2.7	-0.1

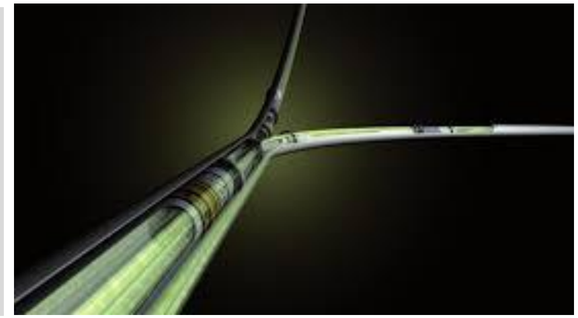
Lead time: 6-12 months

Sources: Interviews; TTA input; NPD 2005 RR; OG21 strategy 2016; OG21 workshop (23.05.2018); Rystad Energy research and analysis

Smarter smart wells: Monitor and control for more of the wanted volumes

Smarter smart wells: Description and target volumes, costs and emissions

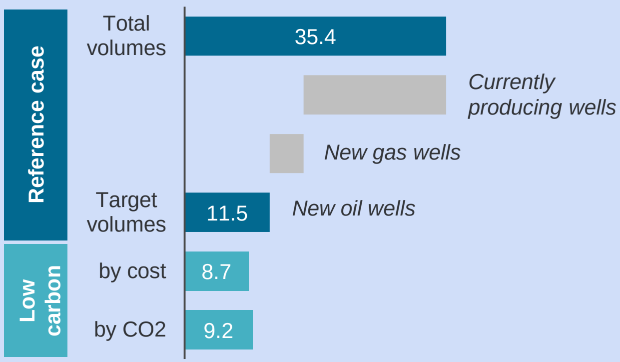
- Improvements in well design and the availability of real time data on temperature and pressure allow operators to better understand the downhole conditions, and adjust accordingly.
- The elimination of unwanted production fluids (water and, in some cases, gas), would enable improved production rates and overall recovery. Lower volumes of water also means that the processing system can be downsized, reducing facility costs. Furthermore, certain cost reductions can be made through better understanding on the well, by reducing the need for interventions.



Target volumes

- *New wells equipped with smart well technology would likely enable increased recovery, as water production could be limited, improving the reservoir sweep.*
- *Gas fields would likely not benefit as much as oil fields from such technologies.*

Target volumes – production 2020-2050
Billion boe

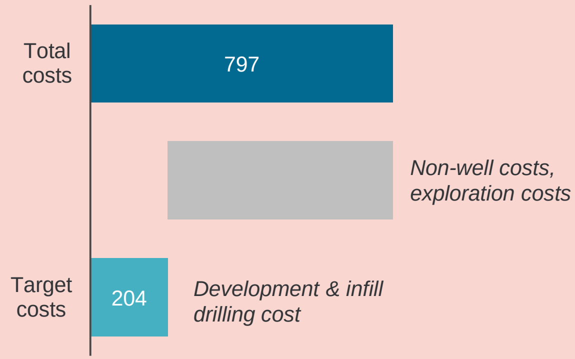


33%
of NCS reference volumes

Target costs

- *Only drilling and wells costs are relevant for improvements in smarter smart well technologies.*

Target costs – upstream spending 2020-2050
Billion USD

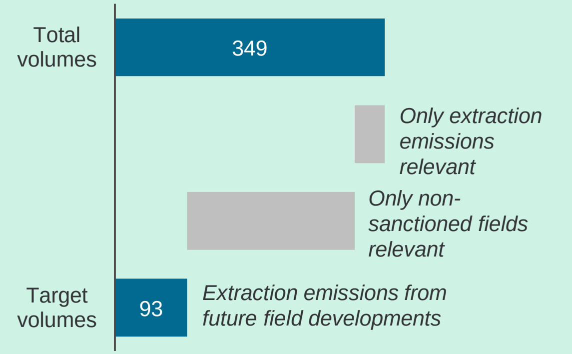


26%
of NCS costs

Target emissions

- *Optimizing fluid production would enable operators to produce the same amount of hydrocarbons, but with a smaller volume of water injected.*
- *Emissions from extraction from non-sanctioned fields are consequently the target in terms of emissions.*

Target emissions – upstream emissions 2020-2050
Million tonnes of CO_2 eq



27%
of NCS emissions targeted

Sources: Interviews; TTA input; NPD 2005 RR; OG21 strategy 2016; OG21 workshop (23.05.2018); Rystad Energy research and analysis

Smarter smart wells: Breakdown and assumptions

Smarter smart wells: Assumptions and effects

Volume effects

- *Smarter smart wells could generate increased recovery through improved sweep of the reservoir, reduced problems with coning and better management of production from different zones in the same well.*
- *A major issue lies in incorporating new reservoir data in real time in order to enable better recovery and optimizing operations. Incorporating fiber systems to feed real time data into the reservoir model, in addition to improving organizational routines for data management, enables better operations and efficiency.*
- *As downhole hardware is needed, only new wells would be relevant for such technology, furthermore, as gas wells generally show very high recovery rates, the potential is deemed to be relevant for oil wells only.*
- *This still makes up a target volume of 11.5 bn Boe, and with an increased recovery of 5% (implying an increased recovery factor of around 2.5%-points), generates an additional 580 million boe of resources.*

Cost effects

- *With the reduced water flow to surface and reduction in interventions, smart well equipment will likely be able to generate reduced costs at a similar level to the cost of the equipment. Consequently, the net effect from a cost perspective is neutral for the operator.*

Emissions effect

- *Emission reductions will likely be driven by improved fluid composition (less water), meaning that the need for water injection is reduced, as less water is produced. Water injection accounts for about 40% of turbine usage on the average oilfield.*
- *With a reduction in water injection of 5%, this technology has the potential to reduce emission by 2% or 1.9 million tonnes in the short term*

Time frame	Volume growth potential		Cost savings potential		Emission reduction potential	
	Total in period *[Million boe]*	***Daily*** *[Thousand boe/d]*	***Total in period*** *[Billion USD]*	***Annually*** *[Million USD]*	***Total in period*** *[Million tn CO_2 eq.]*	***Annually*** *[Million tn CO_2 eq.]*
Short term (2020-2025)	+100	+50	Neutral	Neutral	-1.9	-0.32
Long term (2025-2050)	+480	+50	Neutral	Neutral	-11.5	-0.38

Lead time: 6-18 months

Sources: Interviews; TTA input; NPD 2005 RR; OG21 strategy 2016; OG21 workshop (23.05.2018); Rystad Energy research and analysis

17 focus technologies – many of the same technologies selected across the TTA groups

	Technology area	Description	TTA1	TTA2	TTA3	TTA4
TTA1 Energy efficiency and environment	Offshore wind for offshore facilities	*Clean supply source. Challenges with intermittence, will not replace gas turbines, but can reduce emissions.*				
	Optimized gas turbines	*Systems and equipment that allows for peak shaving and hybrid solutions that seek to optimize gas turbine load to improve efficiency and reduce emissions*				
	Power from shore technologies	*Large converters for long distance DC and issues with DC through turrets are identified as challenges. Long distance AC avoids costly topside modifications,*				
	Compact CCS for topsides	*Compact capture technologies for offshore applications. Applied on exhaust gas from turbines and disposed through water injection.*				
TTA2 Exploration and improved recovery	Water diversion	*Improvement of water sweep in oil reservoirs by injecting foam cement, gel and/or silicates. Reduces water produced and injected in addition to increased recovery*				
	CO_2 for EOR	*Increases recovery, but at a 2-3 year delay and with high cost. Delivery of point emission by ship and standalone subsea solutions on the horizon.*				
	Field model optimization	*Data systems and models to facilitate faster modelling, real time updates, machine learning and optimal well placement*				
	Big data exploration analytics	*Data systems and models to facilitate faster modelling, real time updates, machine learning and optimal well placement*				
TTA3 Drilling, completion and intervention	Wired pipe technologies	*Live monitoring while drilling for better well placement. Look around- look ahead. Enables the use of new tools and sensors*				
	Slot recovery technologies	*Existing and new wells are expected to be reused multiple times. More efficient slot recoveries will cut well capex and reduce rig days.*				
	Automated drilling control	*Increase adoption and widen scope (all aspects) - digitalization in drilling. Leads to reduction of NPT and PT.*				
	Smarter smart wells	*Monitor and control producers and injectors on oilfields to optimize production; eliminate unwanted products and maximize valuable products.*				
TTA4 Production, processing and transport	**Predictive maintenance**	*Interpretation of sensor data, modelling, digital twin software. Reduce down-time and man hours, increase life-time.*				
	Unmanned platforms	*Autonomous operations and automation. Robotics and drone technology for simpler platforms with reduced opex and less emissions.*				
	Standardized subsea satellites	*Develop standard concepts for small tie-back fields to minimize need for engineering, accelerate projects and reduce costs*				
	All electric subsea	*Umbilical-less solutions, subsea chemical storage, electric subsea actuators. Lower cost, better control, higher regularity and improved late-life flexibility*				
	Flow assurance	*Cold flow technologies, pipe-in pipe systems, heat tracing technologies. Technologies to deal with wax and hydrate formation over long distances.*				

Selected *Suggested*

Source: Input from TTA workshops; Rystad Energy research and analysis

Predictive maintenance: Description and target volumes, costs and emissions

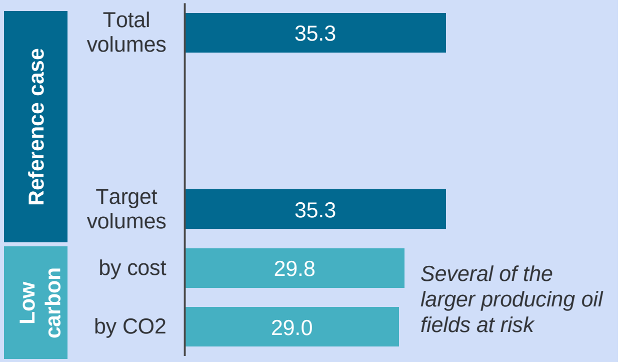
Predictive maintenance: Description and target volumes, costs and emissions

- *Predictive maintenance applies machine learning techniques to big data generated from offshore installations in order to reduce planned and unplanned downtime related to equipment failure and maintenance. The technology uses meta-data and real time sensor data on offshore installations in order to provide continuous assessment of equipment integrity and predict equipment failure.*
- *The ability of advanced algorithms to identify and learn equipment failure patterns allows maintenance to be based on the actual condition of the equipment instead of run-time or age. This reduces unnecessary maintenance of functioning equipment while ensuring timely replacement of failing equipment.*
- *The effect is increased production regularity and decreased maintenance costs from reduced downtime; optimization of planned maintenance; and extensions to equipment and installation lifetime.*

Target volumes

- *Applicable to all offshore fields and installations.*

Target volumes – production 2019-2050
Billion boe

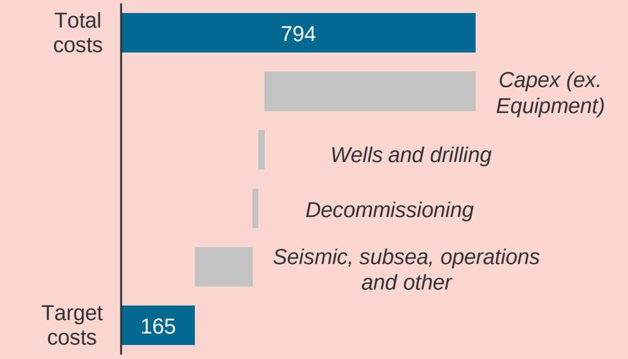


100%
of NCS reference volumes

Target costs

- *Same field selection as for volumes.*
- *Targets only costs related to maintenance activities, parts and equipment, and offshore manning.*

Target costs – expenditure 2019-2050
Billion USD

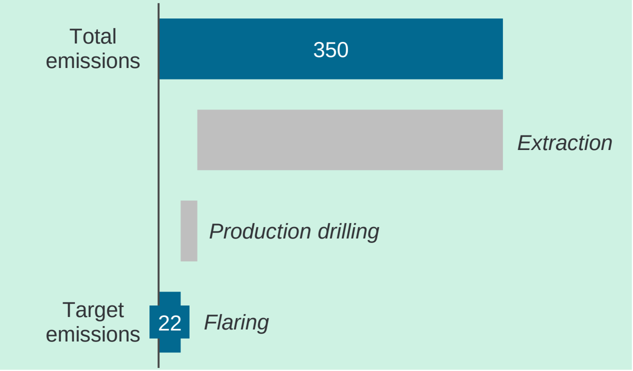


21%
of NCS costs

Target emissions

- *Same field selection as for volumes.*
- *Targets emissions from flaring, specifically from flaring related to planned and unplanned downtime.*

Target emissions – GHG emissions 2019-2050
Million tonnes of CO_2 eq



6%
of NCS emissions targeted

Sources: Interviews; TTA input; Assessment of flare strategies (Miljødirektoratet, 2015); TTA4 workshop (14.05.2018); Rystad Energy research and analysis

Predictive maintenance: Assumptions and effects

Predictive maintenance: Assumptions and effects

Volume effects

- *Predictive maintenance technologies' impact on volumes relates to the increases gained from improved regularity and less downtime. Established methodologies indicate that a 2-5% improvement in regularity can be gained by implementing the technology. This study therefore assumes incremental regularity improvements of 3.5% on the current NCS average of 83% regularity. Variations are likely to materialize across different fields due to differences in life-cycles and significant installation specific variations from the average regularity rate. Further improvements from extended installation platform are also likely to appear, but these effects have not been analyzed. Impact is given to all producing fields from 2020.*
- *For producing and sanctioned fields the recovery rates are estimated on a field-by-field basis. The technical potential for discoveries and estimated undiscovered volumes is estimated based on the average increased recovery rate for producing fields.*

Cost effects

- *The cost effects from predictive maintenance concern gains made due to reduced maintenance requirements and longer equipment lifecycles. Offshore manning can be reduced by 20-40% due to reduced maintenance requirements stemming from better optimization of maintenance routines and increased prevention of unexpected equipment failures. This will reduce labor costs, transportation and logistics costs. Furthermore, better monitoring of equipment condition will likely lead to a 5-10% reduction in expenditures on replacement parts and equipment. This study assumes a 30% reduction in offshore manning requirements and a 7.5% reduction in expenditure on parts and equipment.*

Emissions effect

- *Impact on emissions will largely stem from reduced planned and unplanned downtime. Currently, 40% of flaring on the NCS can be directly attributed to downtime. Gaining an additional 3.5%-points in production regularity from predictive maintenance technologies represents a reduction in downtime of 21% and consequently a reduction in directly attributable flaring emissions by the same amount. Further reductions in emissions can be expected from lower energy consumption for life support and decreased helicopter traffic, as well as indirectly through lower parts and equipment consumption.*

Time frame	Volume growth potential		Cost savings potential		Emission reduction potential	
	Total in period *[Million boe]*	***Daily*** *[Thousand boe/d]*	***Total in period*** *[Billion USD]*	***Annually*** *[Billion USD]*	***Total in period*** *[Million tn CO_2 eq.]*	***Annually*** *[Million tn CO_2 eq.]*
Short term (2020-2025)	+420	+190	-9.9	-1.6	-0.5	-0.09
Long term (2025-2050)	+1070	+120	-33	-1.3	-1.25	-0.05

Lead time: 1-2 years

Effects on increased equipment and installation lifetime (pushed decom) have not been analyzed.

Effects on decreased transportation and logistics requirements not included in estimate

Sources: Interviews; TTA input; Assessment of flare strategies (Miljødirektoratet, 2015); TTA4 workshop (14.05.2018); Rystad Energy research and analysis

Standardized subsea satellites: Cut costs, accelerate volumes and enable small tie-backs

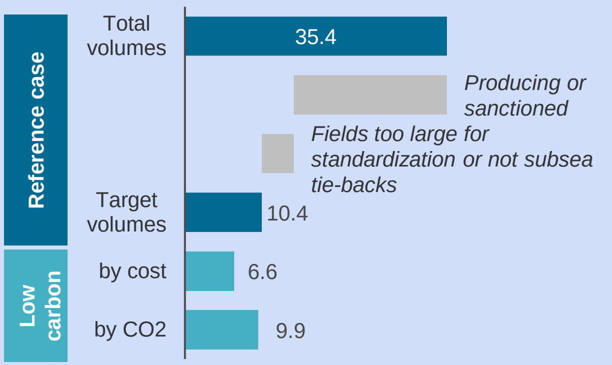
Standardized subsea satellites: Description and target volumes, costs and emissions

- *Develop standardized subsea solutions for small satellites to decrease cost and lead time of development*
- *As discovery sizes are decreasing, current costs and lead times on new subsea fields may be prohibitive to development*
- *Standardization may require operators to accept for instance lower recovery rates as less field-specific adjustments are made; cost/benefit considerations may still favor standardization*
- *Savings are expected in the engineering and installation phase due to fewer interfaces between SPS and SURF*
- *Procurement cost might also decrease if standardization leads to "less steel"*
- *As engineering- and installation time is reduced, first oil is accelerated with corresponding large value creation*

Target volumes

- *Future developments*
- *Only fields likely to be developed as subsea tie-backs*
- *Only smaller fields (<300 mmboe) candidates for standardization*

Target volumes – production 2020-2050
Billion boe

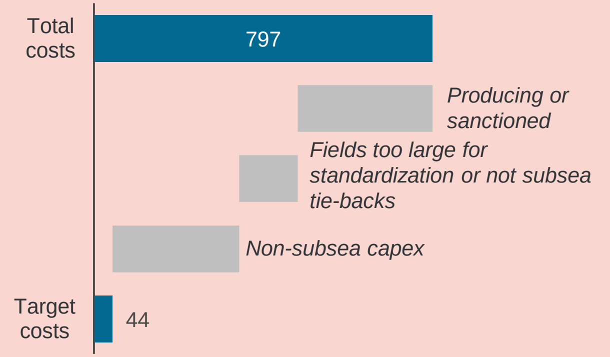


29%
of NCS reference volumes

Target costs

- *Same field selection as for volumes*
- *Only subsea-related expenditure targeted*
- *Both brownfield and greenfield expenditures relevant*

Target costs – upstream spending 2020-2050
Billion USD

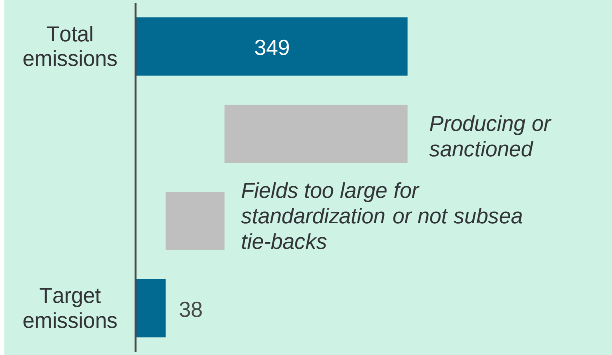


6%
of NCS costs

Target emissions

- *Same field selection as for volumes*
- *No emission effects*

Target emissions – upstream emissions 2020-2050
Million tonnes of CO_2 eq



11%
of NCS emissions targeted

Sources: Interviews; Rystad Energy research and analysis

Standardized subsea satellites: Assumptions and effects

Standardized subsea satellites: Assumptions and effects

Volume effects

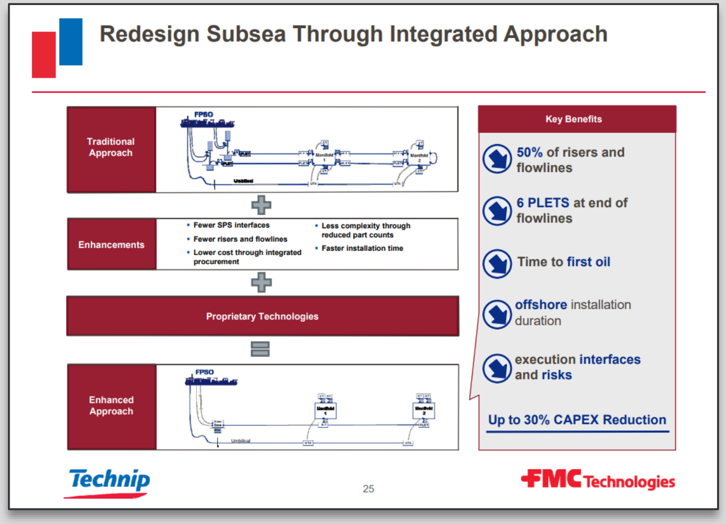
- *Interviews suggest that lead time may be reduced from around 2.7 years to 1 year as engineering and planning is minimized*
- *Standardized solution may also enable some discoveries too small to warrant current development costs. This effect is not assessed.*

Cost effects

- *Cost effects are related to cutting costs across engineering, planning, installation and procurement*
- *Engineering time is reduced both by having solutions ready and by reduced complexity (for instance fewer interfaces between SPS and SURF requiring less adaption)*
- *Installation cost is reduced by reducing number of parts, interfaces and project specific actions*
- *Procurement cost may go down if integration leads to fewer parts*
- *Value proposition of integrated and standardized subsea solutions from TechnipFMC suggest up to 30% capex reduction*
- *No opex effects are considered*

Emissions effect

- *No emission effects identified.*



TechnipFMC presentation October 2016

Time frame	**Volume growth potential**		**Cost savings potential**		**Emission reduction potential**	
	Total in period *[Million boe]*	***Daily*** *[Thousand boe/d]*	***Total in period*** *[Billion USD real]*	***Annually*** *[Million USD real]*	***Total in period*** *[Million tn CO_2 eq.]*	***Annually*** *[Million tn CO_2 eq.]*
Short term (2020-2025)	+632	+289	-5	-772	Neutral	Neutral
Long term (2025-2050)	+869	+95	-9	-348	Neutral	Neutral

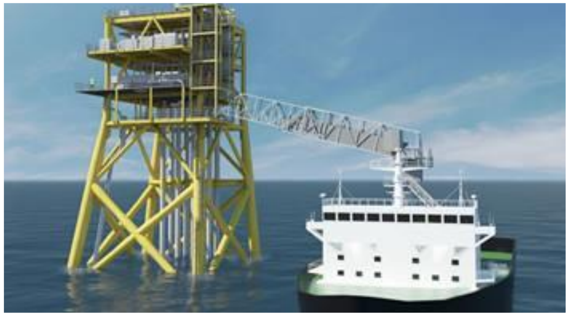
Lead time: 1 year

Sources: Interviews; TechnipFMC roadshow presentation; Rystad Energy research and analysis

Unmanned platforms: Creates opportunities with on-site processing and reduced costs

Unmanned platforms: Description and target volumes, costs and emissions

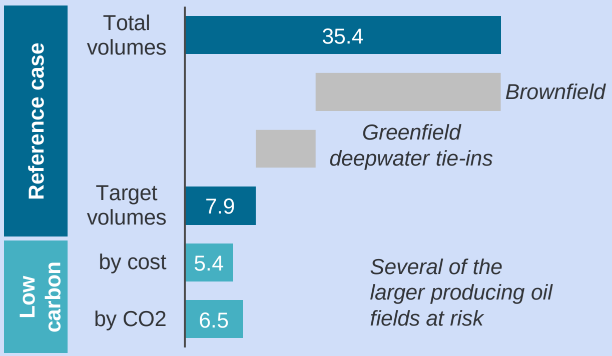
- *Unmanned platforms take advantage of developments in automation, robotics, drone technology, analytics and communication technology to provide fully unmanned platforms that go beyond the existing unmanned wellhead platforms by incorporating production and processing facilities on-site.*
- *These installations can be operated at low cost with or without a host facility, thus facilitating the development of several currently unviable and marginal fields. In many cases unmanned platforms will serve as an alternative to long subsea tie-backs.*
- *The effect is reduced opex and capex related to life support, wages and logistics; increased volumes and reduced emissions from improved regularity; as well as reduced emissions from reductions in utility power consumption.*



Target volumes

- *Applicable to greenfield projects and yet-to-find volumes.*
- *Small deepwater fields under 100 mmboe are excluded as these will likely remain dependent on a manned host.*
- *Brownfield projects are excluded due to larger uncertainty with regards to operational viability.*

Target volumes – production 2020-2050
Billion boe

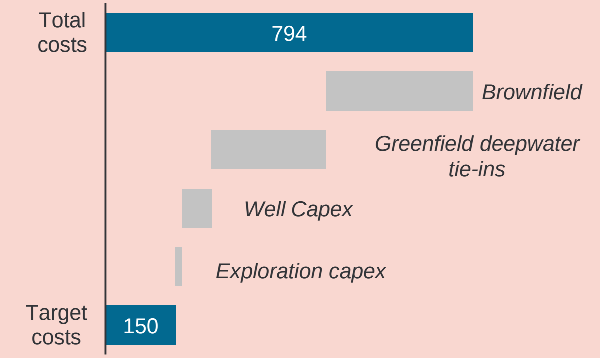


22%
of NCS reference volumes

Target costs

- *Same field selection as for volumes.*
- *Targets only costs related to opex and facility capex.*

Target costs – upstream spending 2020-2050
Billion USD

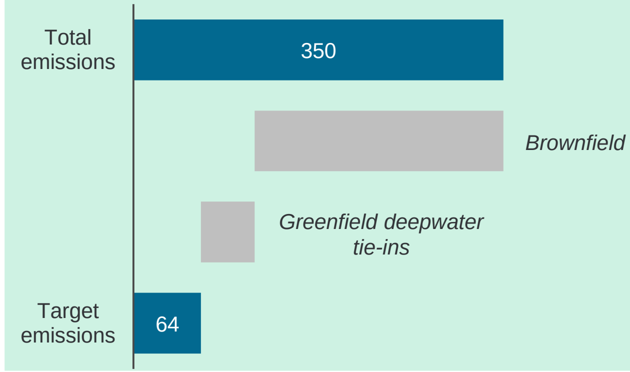


20%
of NCS costs

Target emissions

- *Same field selection as for volumes.*

Target emissions – upstream emissions 2020-2050
Million tonnes of CO_2 eq



18%
of NCS emissions targeted

Sources: Interviews; TTA input; TTA4 workshop (14.05.2018); Rystad Energy research and analysis

Unmanned platforms: Leaner, cleaner, greener, and with significant decreases in cost

Unmanned platforms: Assumptions and effects

Volume effects

- *The volume effects from introducing unmanned platforms relate to the same effects found in advanced predictive maintenance. Automation of offshore installations implies extensive introduction and implementation of advanced monitoring systems, with subsequent benefits of increased regularity from less downtime. Established methodologies indicate an increase in regularity of 2-5% can be expected on the existing NCS regularity of 83%. This study assumes an increase in regularity of 3.5%, closely resembling results from Equinor's Krafla case study.*

Cost effects

- *The technology's impact on costs revolves around gains achieved by reducing manning offshore, which decreases opex and facility capex. Lower offshore staffing requirements translates directly into lower opex through decreases in wage costs, accommodation expenses, transportation and other costs associated with sustaining offshore workforces. Current estimates point to a 50% reduction in opex from decreased worker intensity. Similarly, an estimated 30% reduction in facility capex can be expected due to accommodation and life support systems being waved from unmanned platform designs. This estimate is in-line with Equinor's expected gains from the Krafla unmanned platform project, and points to automation resulting in a leaner, cleaner and altogether greener platform with lighter topside weight and lower development costs.*

Emissions effect

- *Reducing offshore manning through unmanned platforms has a direct impact on emissions due to the removal of utility power generation required for sustaining offshore workforces. Utility power generation accounts for 15% of offshore greenhouse gas emissions. Implementing unmanned platforms is estimated to reduce utility power demand by 50%, resulting in an overall emissions reduction estimate of 7.5% when compared to conventional platforms. Further emission reductions will likely materialize directly, through decreased flaring from improved regularity, and indirectly, through less helicopter transportation and leaner platform construction.*

Time frame	Volume growth potential		Cost savings potential		Emission reduction potential	
	Total in period *[Million boe]*	***Daily*** *[Thousand boe/d]*	***Total in period*** *[Billion USD]*	***Annually*** *[Billion USD]*	***Total in period*** *[Million tn CO_2 eq.]*	***Annually*** *[Million tn CO_2 eq.]*
Short term (2020-2025)	+19	+8.5	-8.5	-1.4	-0.06	-0.01
Long term (2025-2050)	+315	+34.5	-50	-2.0	-4.7	-0.2

Lead time: 2-4 years

Effects on increased equipment lifetime from improved maintenance have not been analyzed..

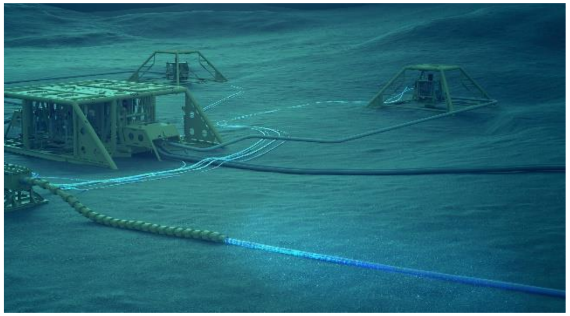
Effects from improved regularity and reduced transportation and logistics are not included in estimate.

Sources: Interviews; TTA input; TTA4 workshop (14.05.2018); Rystad Energy research and analysis

All-electric subsea: Reduces costs and improves reliability of subsea systems

All-electric subsea: Description and target volumes, costs and emissions

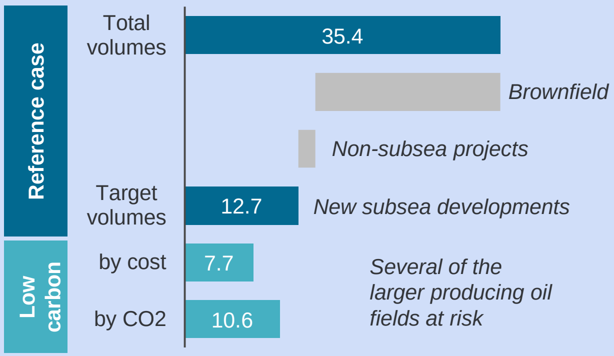
- *All-electric subsea relates to technologies that replace current electro-hydraulic control systems with electric infrastructure to control and power subsea production systems. This eliminates the need for hydraulic fluids and thereby reduces the number and extent of umbilicals needed for each subsea project, while improving regularity and improving the viability of long tie-backs.*
- *Current complex systems relying on hydraulic actuators can be replaced with simpler, more efficient and reliable electric systems and actuators, which also allow for better monitoring and data collection.*
- *The effect is increased regularity and improved reliability in production; lower capex related to installation of subsea production systems; lower opex related to maintenance; and reduced emissions due to decreased downtime. Furthermore, the elimination of hydraulic fluids reduces the risks to safety and the environment.*



Target volumes

- *Applicable to all fields with new subsea tie-back projects.*
- *Existing subsea production systems are excluded due to uncertainty with regards to viability, but provide an upside potential for additional volumes.*

Target volumes – production 2020-2050
Billion boe

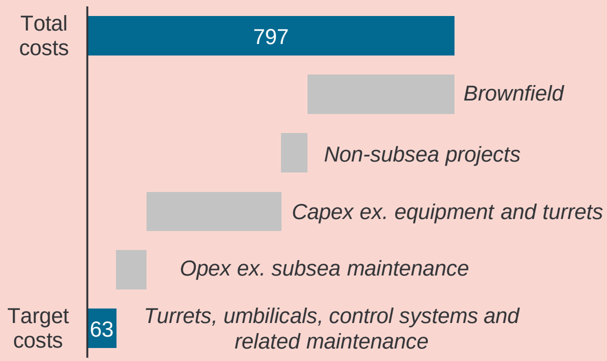


36%
of NCS reference volumes

Target costs

- *Applicable to new subsea tie-back fields.*
- *Includes costs associated subsea capex and opex, including umbilicals, control systems, subsea maintenance costs and topside turrets.*

Target costs – upstream spending 2020-2050
Billion USD

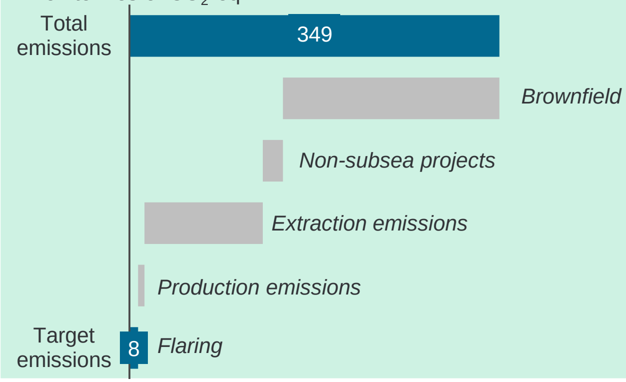


8%
of NCS costs

Target emissions

- *Same field selection as for volumes.*
- *Targets only emissions related to downtime flaring from production by subsea projects, hence other emissions such as power generation for extraction and production are excluded.*

Target emissions – upstream emissions 2020-2050
Million tonnes of CO_2 eq



2%
of NCS emissions targeted

Sources: Interviews; TTA input; TTA4 workshop (14.05.2018); Rystad Energy research and analysis

All-electric subsea: Provides significant cost savings for subsea systems and boosts volumes

All-electric subsea: Assumptions and effects

Volume effects

- *All-electric subsea impacts volumes by increasing the production system's regularity in a similar fashion to that of predictive maintenance technologies. Electrification entails the implementation of digital control systems that provide better data and monitoring than what is currently available from hydraulic systems. This allows system operators to have a more comprehensive view of the system's health and the condition of individual elements such as manifolds, x-mas trees and wellheads. This improved oversight of real-time system health, in addition to the accompanying advances in data collection, allow for better maintenance regimes and production optimization. An estimated 2-5% increase in regularity for subsea systems can be expected on top of today's 83% regularity rate. This study assumes an increase in regularity of 3.5% for all new subsea production systems.*
- *The technology also improves the viability of long tie-backs by removing operational issues relating to the transportation of hydraulic fluids over long distances. This may enable production from fields that otherwise would have been uneconomical or technically challenging, thereby adding a potential upside to the presented estimates.*
- *Numerous existing subsea production systems have the potential to replace existing electro-hydraulic systems with all-electric ones while conducting major overhauls. This counts towards a further increase to upside potential in the presented estimates below.*

Cost effects

- *Switching from complex electro-hydraulic systems to simpler and more efficient all-electric systems enables considerable costs savings. Umbilical costs are estimated to drop by 85% due to the elimination of hydraulic fluids, while subsea control system costs are expected to fall by 25%. Furthermore, turret costs are expected to decrease by 15-20% as a consequence of fewer umbilicals needed for each subsea production system due to the elimination of hydraulic fluids. This study assumes a 17% reduction in turret costs. Finally, improved data collection and monitoring are estimated to shave further 30% off maintenance costs and 7.5% off equipment and parts costs, in accordance with the effects of predictive maintenance.*

Emissions effect

- *Direct impacts on emissions from all-electric subsea stem from improvements in production regularity. This reduces the amount of flaring from downtime, which currently represents 40% of all flaring on the NCS. An increase in regularity of 3.5% represents a 21% reduction in downtime and associated flaring.*

Time frame	Volume growth potential		Cost savings potential		Emission reduction potential	
	Total in period [Million boe]	*Daily* [Thousand boe/d]	*Total in period* [Billion USD]	*Annually* [Million USD]	*Total in period* [Million tn CO_2 eq.]	*Annually* [Million tn CO_2 eq.]
Short term (2020-2025)	**+30**	+13.5	**-1.3**	-220	-0.14	-0.02
Long term (2025-2050)	**+506**	+55.5	**-12.3**	-491	-0.49	-0.02

Lead time: 1-2 years

Effects of reduced hydraulic fluid consumption have not been analyzed..

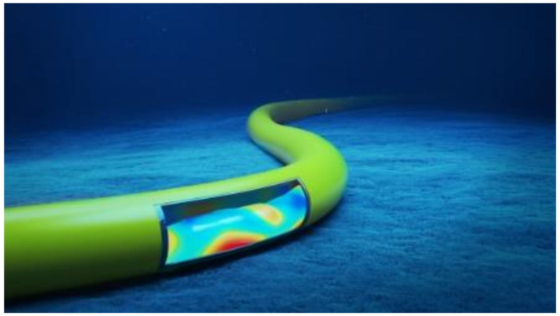
Effects from reduced material consumption not included in estimate.

Sources: Interviews; TTA input; TTA4 workshop (14.05.2018); Rystad Energy research and analysis

New flow assurance tech likely to impact development solution of remote discoveries

Flow assurance for long tie-ins: Description and target volumes, costs and emissions

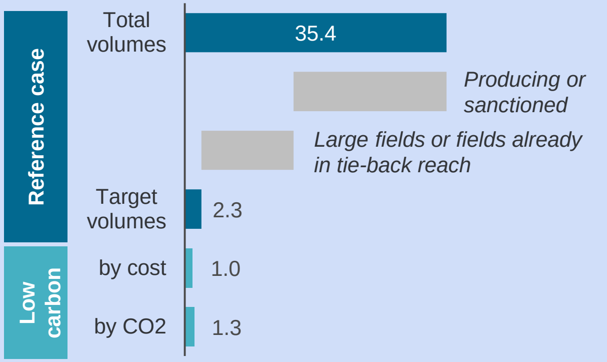
- *Technologies to prevent or remediate flow issues to enable tie-backs over distances not currently possible*
- *Pushing the boundary for technically possible tie-back distances may reduce the cost of developing smaller discoveries located far from existing infrastructure as e.g. topside processing facilities are avoided*
- *Longer possible tie-back distances can potentially enable smaller discoveries that currently do not support standalone development*
- *Currently, tie-backs are typically limited to a host proximity of 40 km for liquids and 150 km for wet gas, which imply that many small discoveries in the North Sea and the Barents Sea require new hosts to be developed*
- *Examples include electrical trace heated pipe-in-pipe, cold flow technologies, and new modelling software combined with sensors*



Target volumes

- *Future developments*
- *Large fields (>300 mmboe) excluded as these fields warrant standalone development*
- *Only fields out of current tie-back reach (>40 km liquids, >150km wet gas)*

Target volumes – production 2020-2050
Billion boe

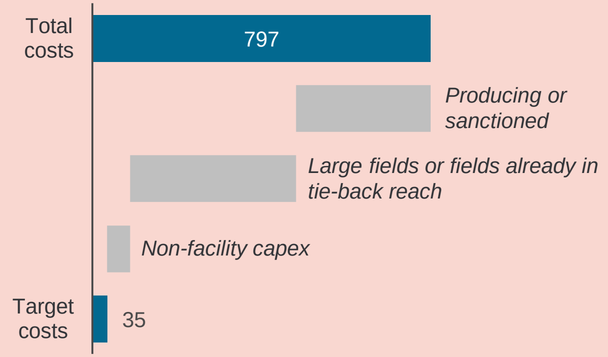


6%
of NCS reference volumes

Target costs

- *Same field selection as for volumes*
- *Only target facility capex*
- *Both greenfield and brownfield capex relevant*

Target costs – upstream spending 2020-2050
Billion USD

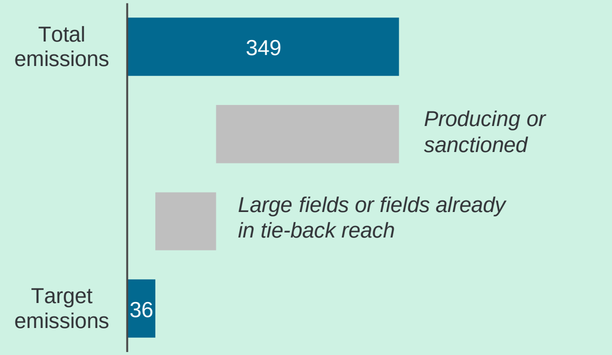


4%
of NCS costs

Target emissions

- *Same field selection as for volumes*
- *Technology may have implications on flaring, power demand etc., but this is not assessed*

Target emissions – upstream emissions 2020-2050
Million tonnes of CO_2 eq



10%
of NCS emissions targeted

Sources: Interviews; Rystad Energy research and analysis

Increasing tie-back distances may save facility cost related to remote discoveries

Flow assurance for long tie-ins: Assumptions and effects

Volume effects
- *No volume effects considered*
- *Longer tie-back distances may enable or accelerate production from small discoveries and as such have a volume effect*

Cost effects
- *Cost effects pertain to the lower capital expenditure needed for tie-back developments compared with standalone facilities for a given resource base*
- *Facility costs are highly field specific, but historical facility costs for smaller standalone and tie-back developments on the NCS and the UKCS point to roughly 40 % lower facility cost per boe for tie-back developments*
- *Some savings related to the cost of existing flow assurance techniques may apply (such as fewer pigging operations and reduced chemicals need), but new technologies also likely to be energy demanding (such as electricity for electrically trace heated pipe-in-pipe). These effects are not assessed.*

Emissions effect
- *Some flaring may be omitted due to fewer shut-ins, but power needed for heating, pumping etc. will counteract this reduction. Net effect depend on the source of the additional energy needed to support technology.*
- *No emission effects are assessed.*

Time frame	Volume growth potential		Cost savings potential		Emission reduction potential	
	Total in period *[Million boe]*	***Daily*** *[Thousand boe/d]*	***Total in period*** *[Billion USD real]*	***Annually*** *[Million USD real]*	***Total in period*** *[Million tn CO_2 eq.]*	***Annually*** *[Million tn CO_2 eq.]*
Short term (2020-2025)	Neutral	Neutral	0.1	16	Neutral	Neutral
Long term (2025-2050)	Neutral	Neutral	14	556	Neutral	Neutral

Lead time: 2-3 years

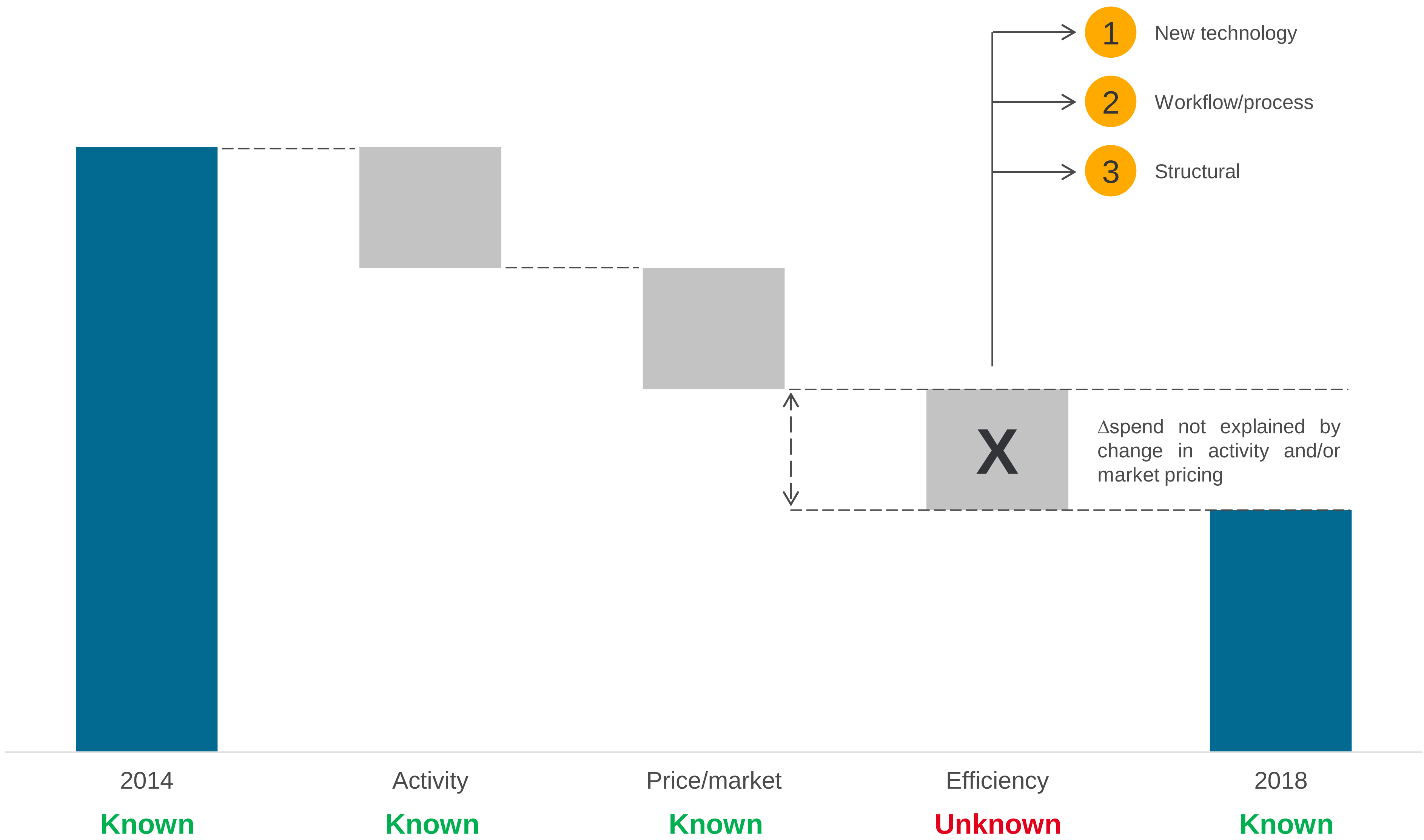
Reduction in opex not assessed, but expected neutral as new flow assurance technologies also incur opex

Emission effects not assessed as any reduction is likely to be counteracted by increased power demand

Sources: Interviews; Rystad Energy research and analysis

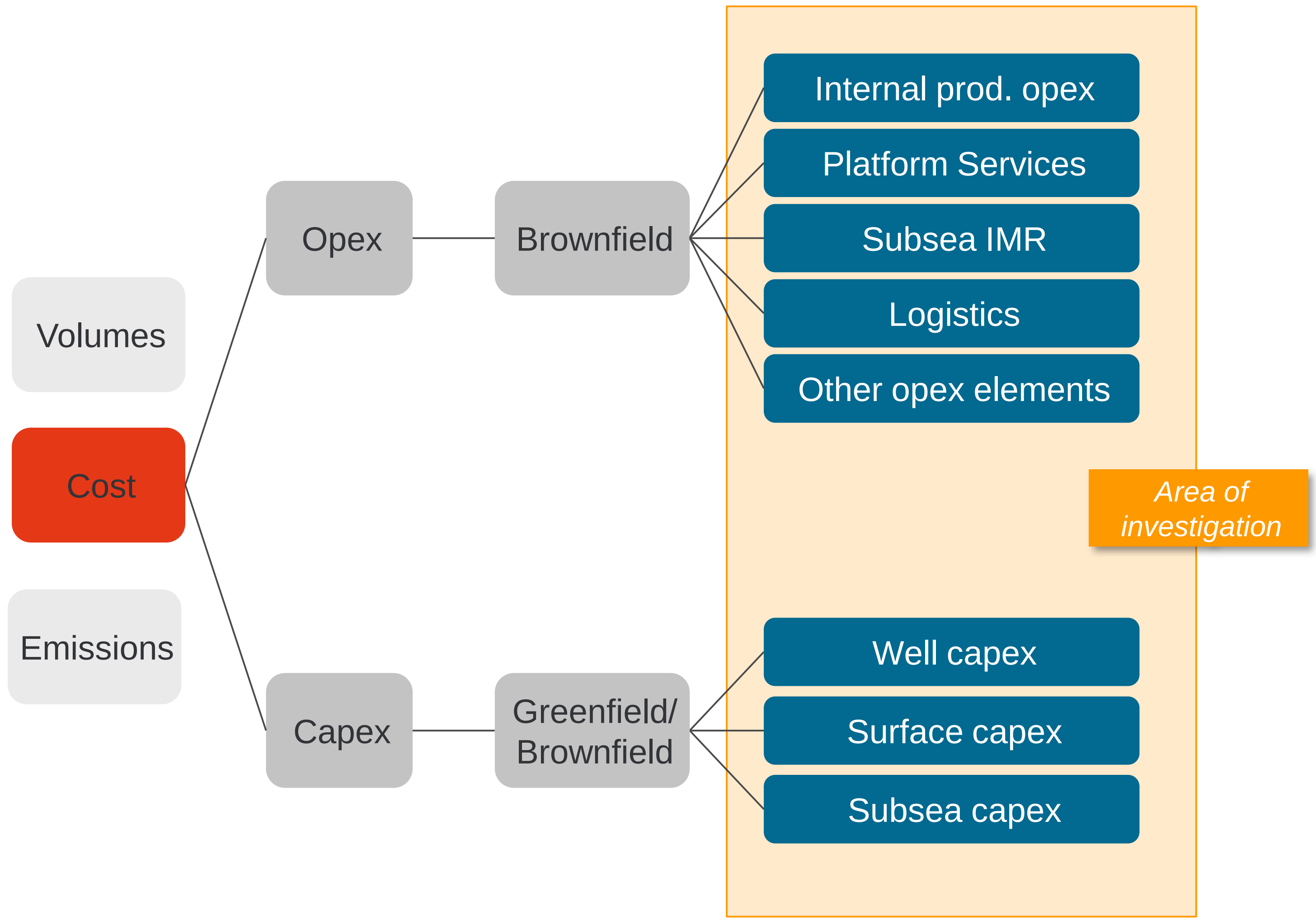
Index

Conceptual: Implying efficiency gains as the only unknown in the equation



Source: Rystad Energy research and analysis

Defining granularity of cost-reduction analysis from 2014 to 2018



Installed base of topside tons on the NCS at the same level in 2018, as in 2014

Segment	Cost element:	Activity	Efficiency	Price

Platform services

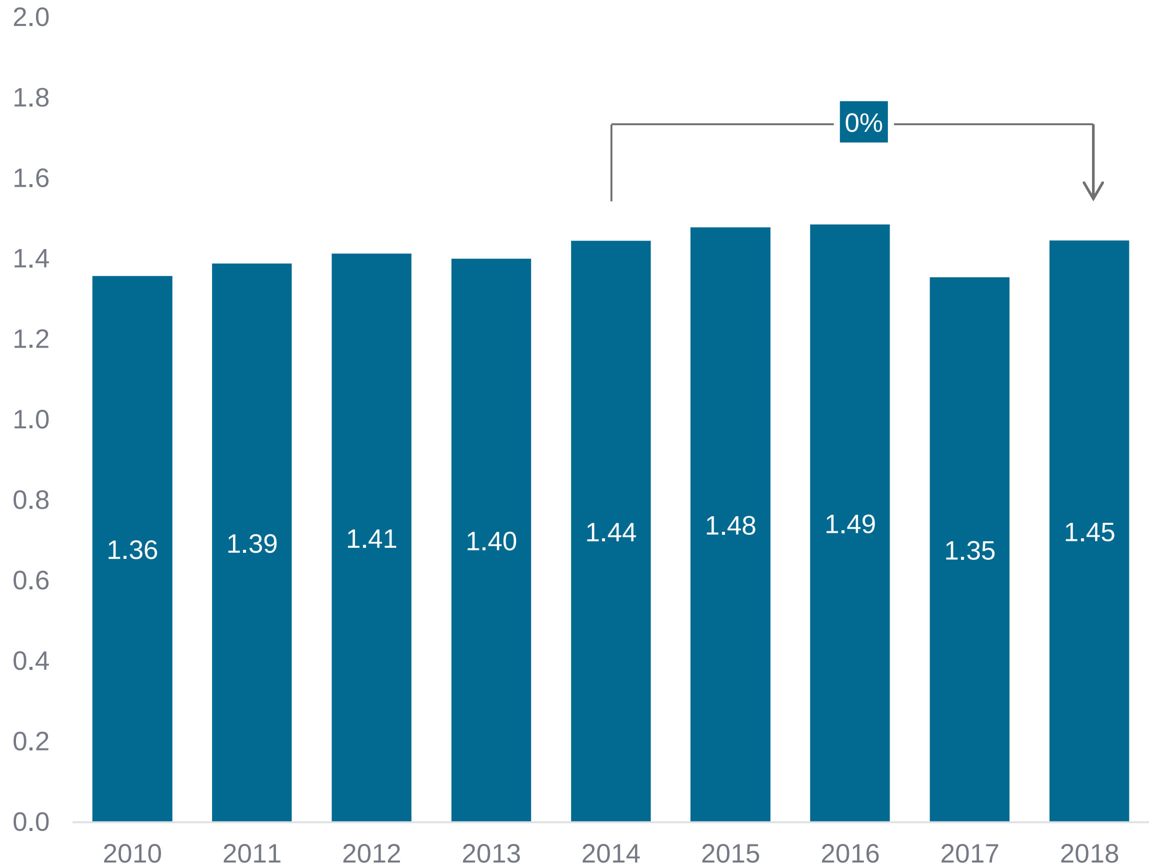
Subsea IMR

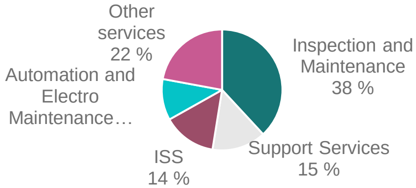
Logistics

Other opex elements

Internal production opex

Installed base of topside on the NCS
Million tons installed





- The graph is showing the base of installed topside tons on the NCS from 2010 to 2018
- Although topsides has come and gone in the period, the amount of topside tons installed on the NCS in 2018 is for all practical purposes the same as in 2014, at around 1.45 million tons
- Notable changes in the inventory of topsides from 2014 to 2018 includes Varg, Volve, and Jotun topsides removed in 2016, while Aasta Hansteen, parts of Johan Sverdrup P1, and Martin Linge was installed in 2018

Source: Rystad Energy research and analysis;

25% reduction in contractor offshore hours from 2014 to 2018

Segment	Cost element:	Activity	Efficiency	Price

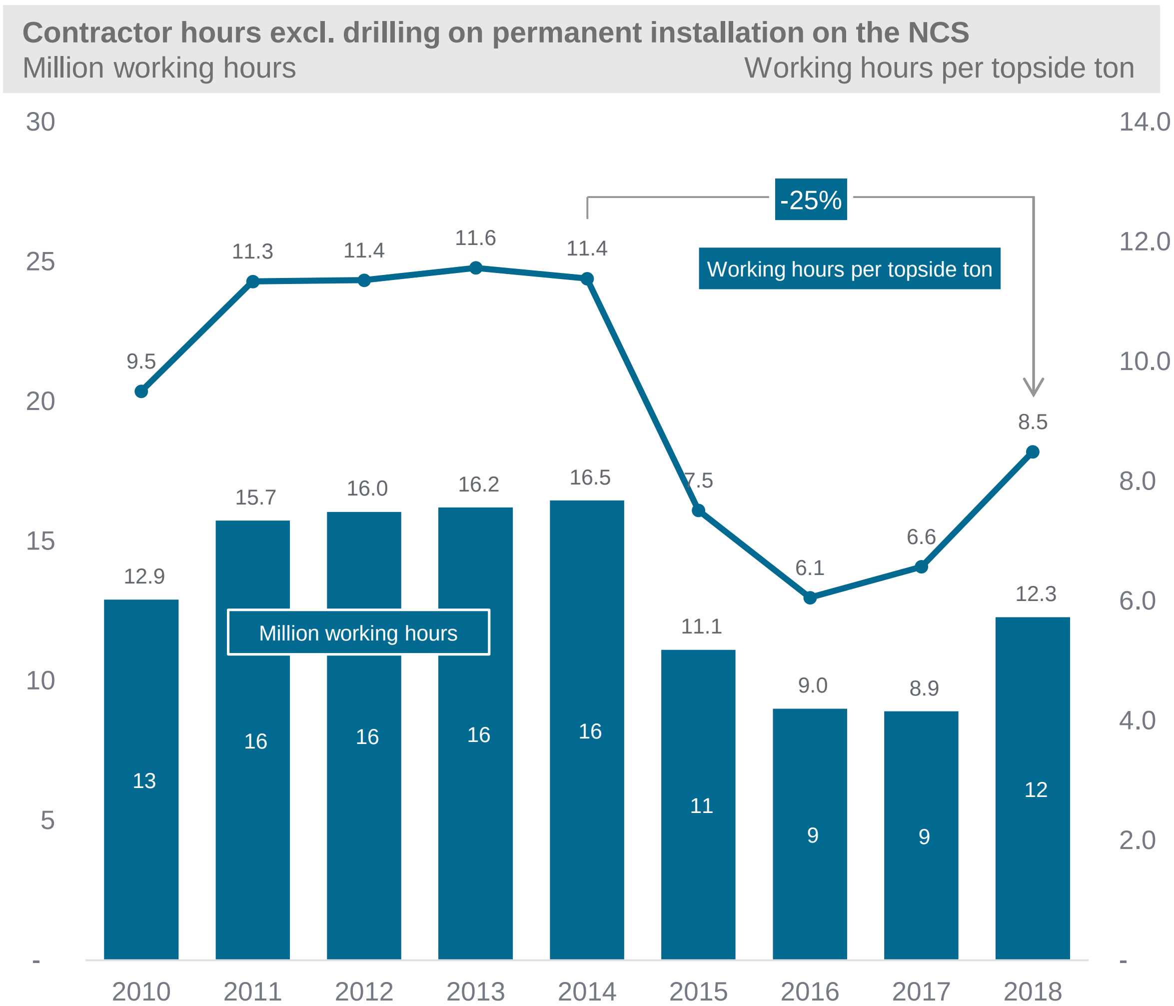
Platform services

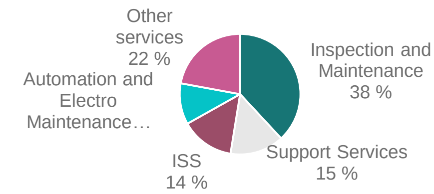
Subsea IMR

Logistics

Other opex elements

Internal production opex





- The majority of platform services are labor intensive and is per definition run by contracted workers
- The graph is showing the number of hours logged by contract-workers on permanent installations on the NCS from 2010 to 2018
- As the there is ~0% change in the amount of topside tons installed on the NCS from 2014 to 2018, the absolute number of contractor working hours, and working hours per topside tons, is down ~25% in the period

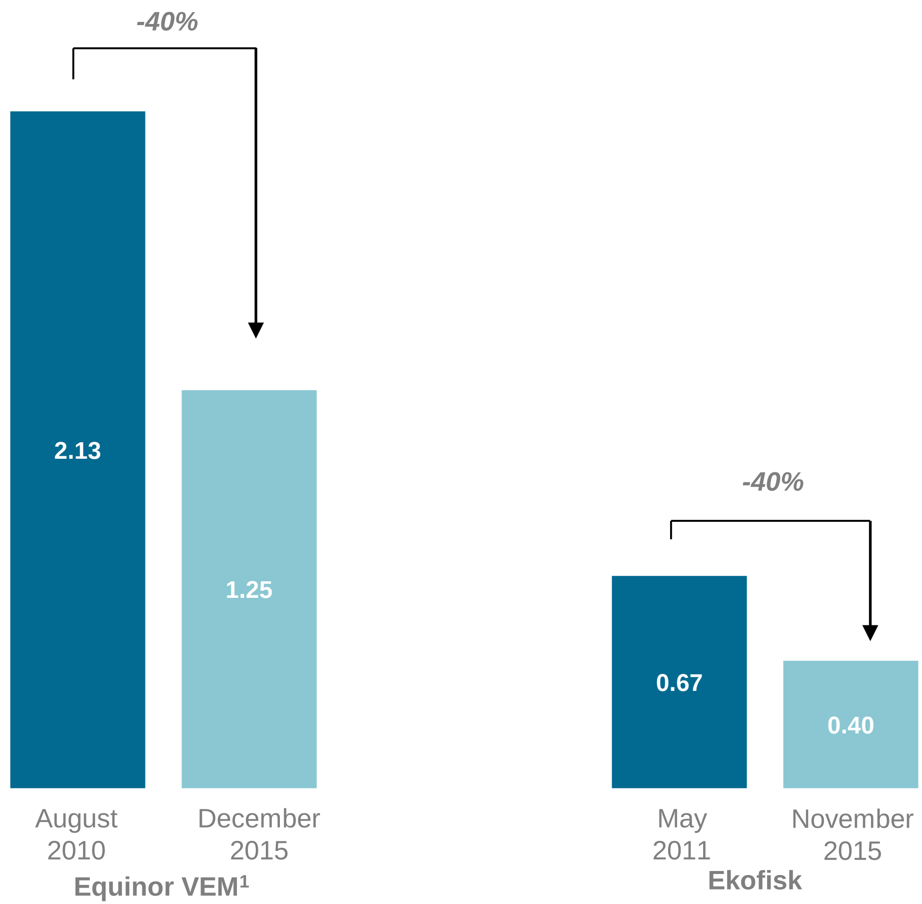
Source: Rystad Energy research and analysis ; Petroleumstilsynet (PTIL)

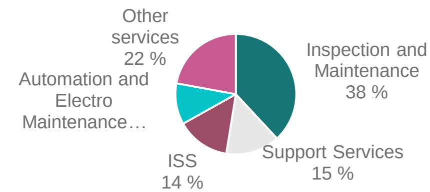
25% reduction in contractor offshore hours from 2014 to 2018

Segment	Cost element:	Activity	Efficiency	Price

- **Platform services**
- Subsea IMR
- Logistics
- Other opex elements
- Internal production opex

Selected MMO contract awards before and after the 2014 downturn
Billion NOK





- A clear cost cut is observed between pre- and post-downturn contracts, with reductions indicating an average 40% fall in like for like contract values.
- Equinor's VEM portfolio, awarded to Aibel in 2010 for 6 years at 2.125 bn NOK per year, was re-awarded to the same MMO contractor after the downturn at 1.25 bn NOK per year. This constitutes a 40% reduction.
- Likewise, ConocoPhillips awarded Ekofisk to Aibel in 2011 for 670 million NOK per year, and re-awarded the same asset to Aker Solutions in 2015 for 400 million NOK per year.

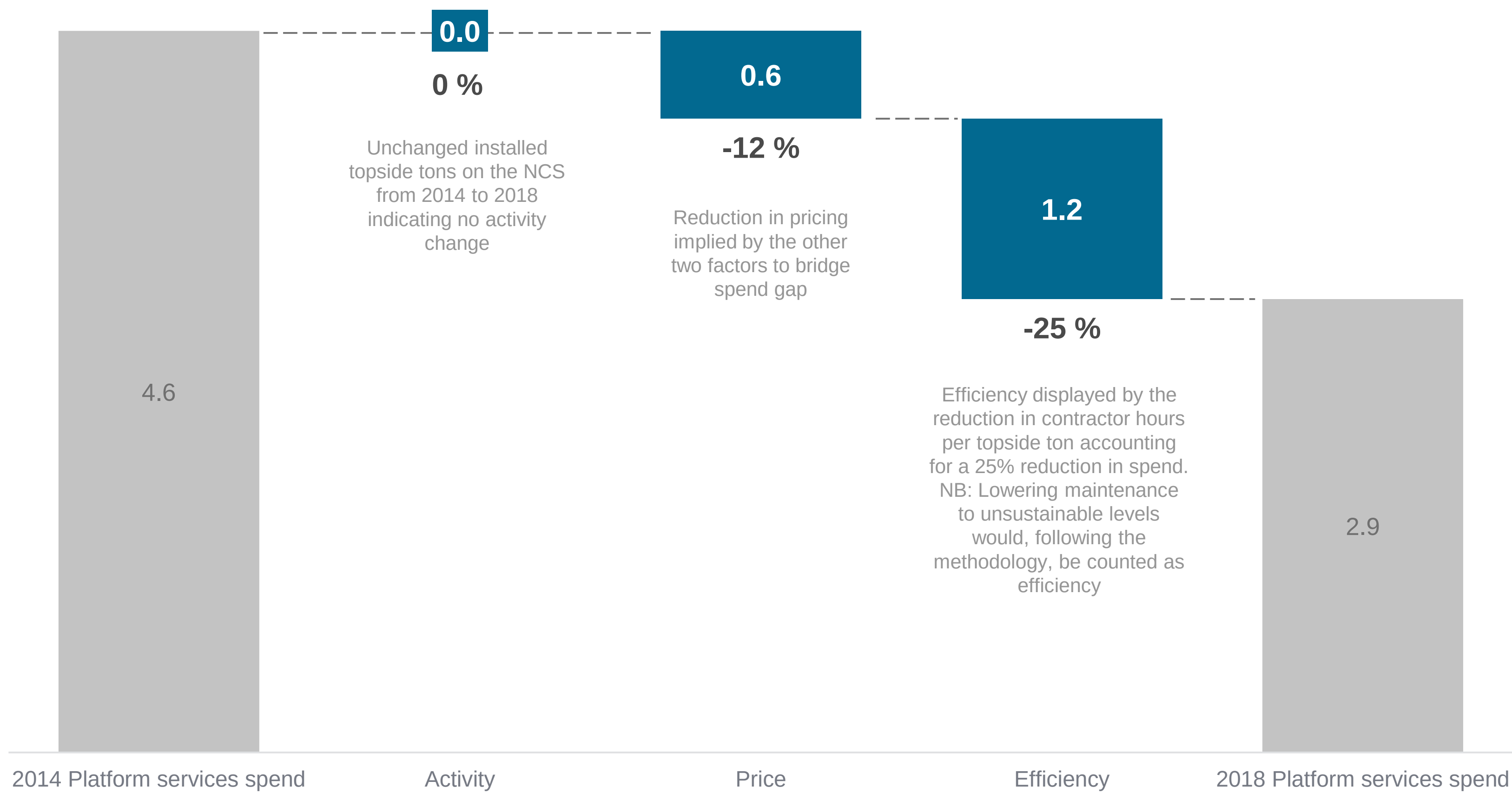
1) Includes Oseberg, Huldra, Veslefrikk, Njord, Kristin, Norne, Snøhvit, Kollsnes, Kårstø and Sture. The 2015 contract also includes Aasta Hansteen
Source: Rystad Energy research and analysis

Large efficiency gains manifested through reduced contractor working hours offshore

Segment	Cost element:	Activity	Efficiency	Price

Segment: **Platform services** | Subsea IMR | Logistics | Other opex elements | Internal production opex

Activity and price implications on platform services
Billion USD (real 2019)

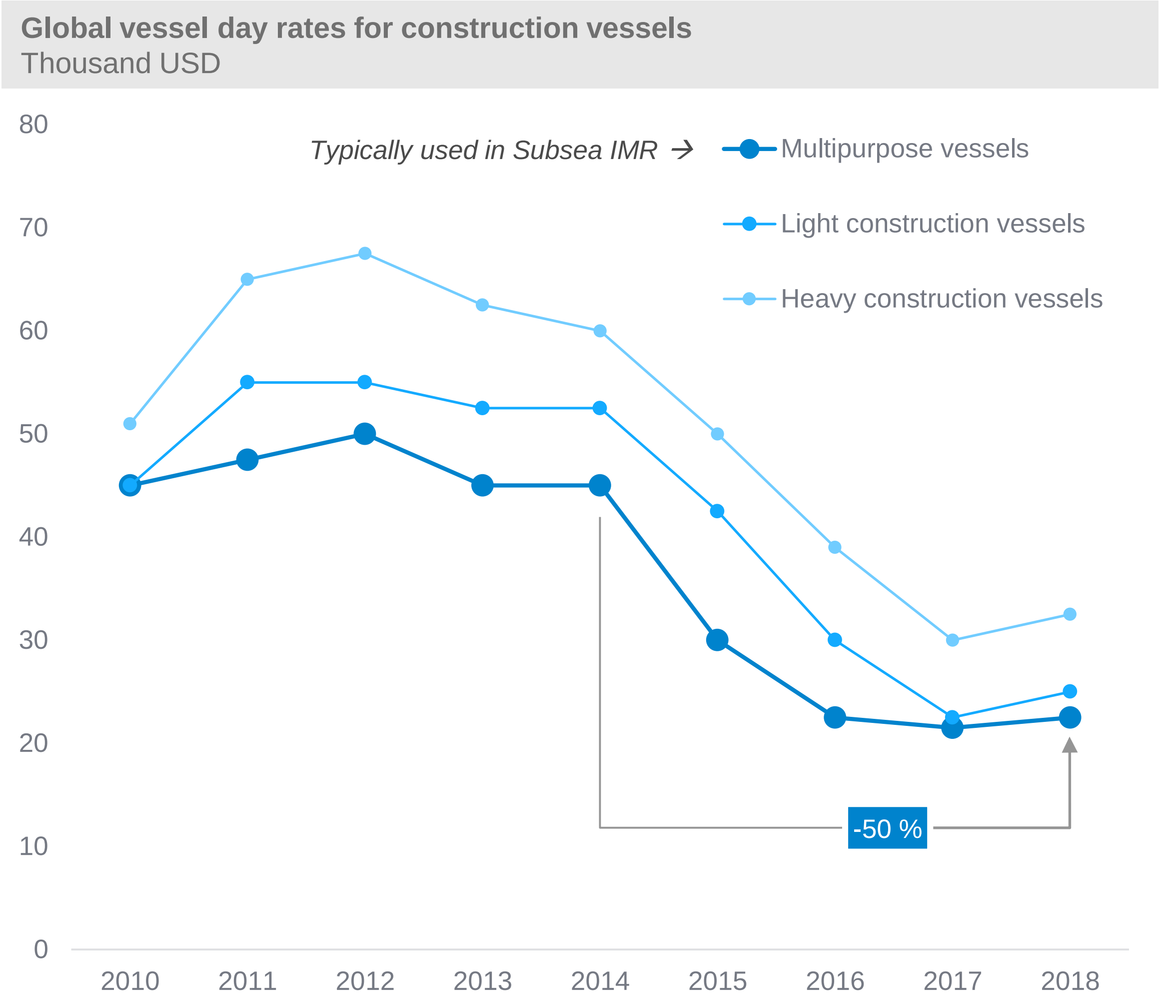


Source: Rystad Energy research and analysis;

IMR vessel day rates down by 50% between 2014 and 2018

Segment	Cost element:	Price	Activity	Efficiency

- Platform services
- **Subsea IMR**
- Logistics
- Other opex elements
- Internal production opex



- The chart shows the global development of day rates for construction vessels, split between heavy construction vessels, meaning vessels with crane capacity above 250 tonnes, light construction vessels with crane capacity less than 250 tonnes, and multipurpose vessels. The latter is the one that is typically used for IMR work
- Day rates for multipurpose vessel contracts decreased by 50% between 2014 and 2018. However, the "running rate" of vessels in 2018 is higher due to contracts negotiated pre-2018.

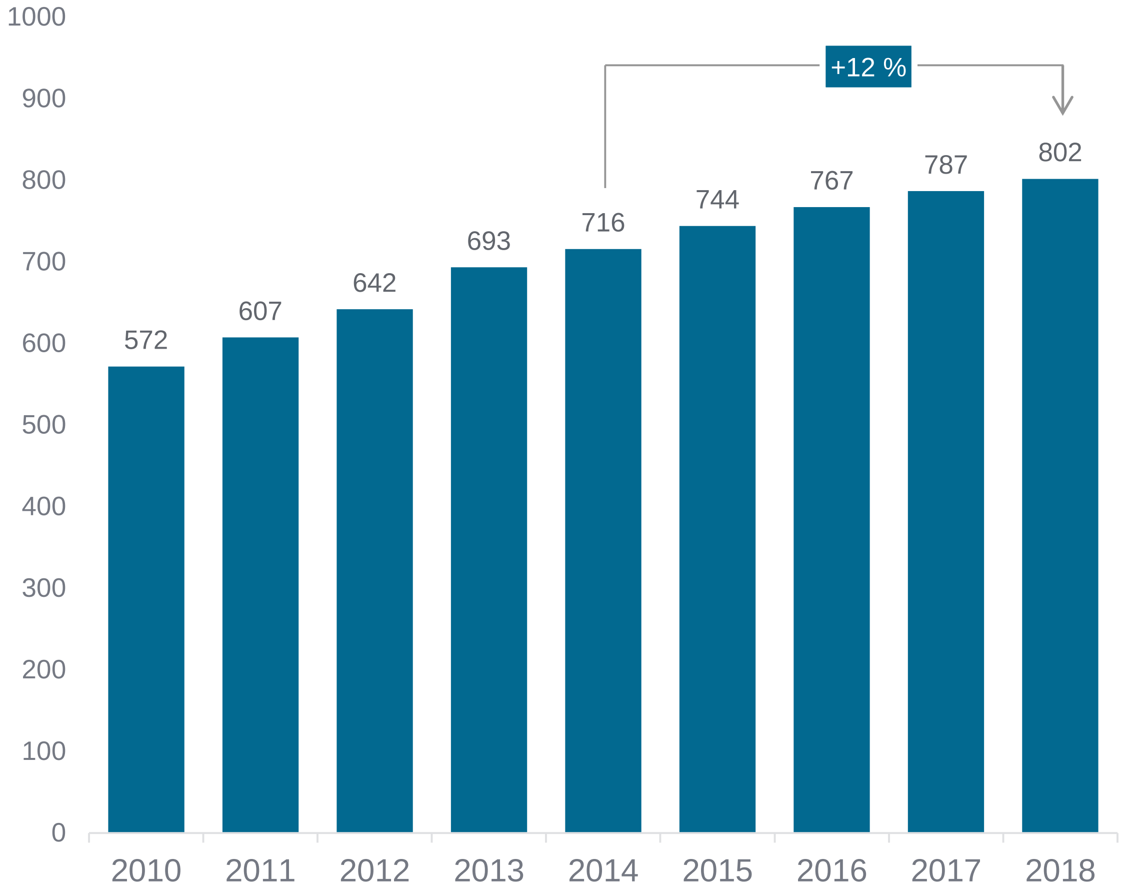
Source: Rystad Energy research and analysis; Fearnley Offshore Supply

NCS subsea XMTs installed base increased by 12% from 2014 to 2018

Segment	Cost element:	Price	Activity	Efficiency

- Platform services
- **Subsea IMR**
- Logistics
- Other opex elements
- Internal production opex

NCS active* subsea Xmas trees
# of XMTs



- The chart shows the base of installed, and "active" XMTs on the NCS from 2010 to 2018
- The number of installed XMTs is the driver of subsea IMR and hence a good proxy for activity
- As can be seen from the chart the active base of "active" subsea XMTs on the NCS rose by 12% from 2014 to 2018

*Subsea producers/injectors with status as Injecting, Online/Operational, Producing, Closed, Suspended at the date of the snapshot
Source: Rystad Energy research and analysis;

Subsea IMR sees large day rates and efficiency reducing 2014 to 2018 spend

Segment

Platform services

Subsea IMR

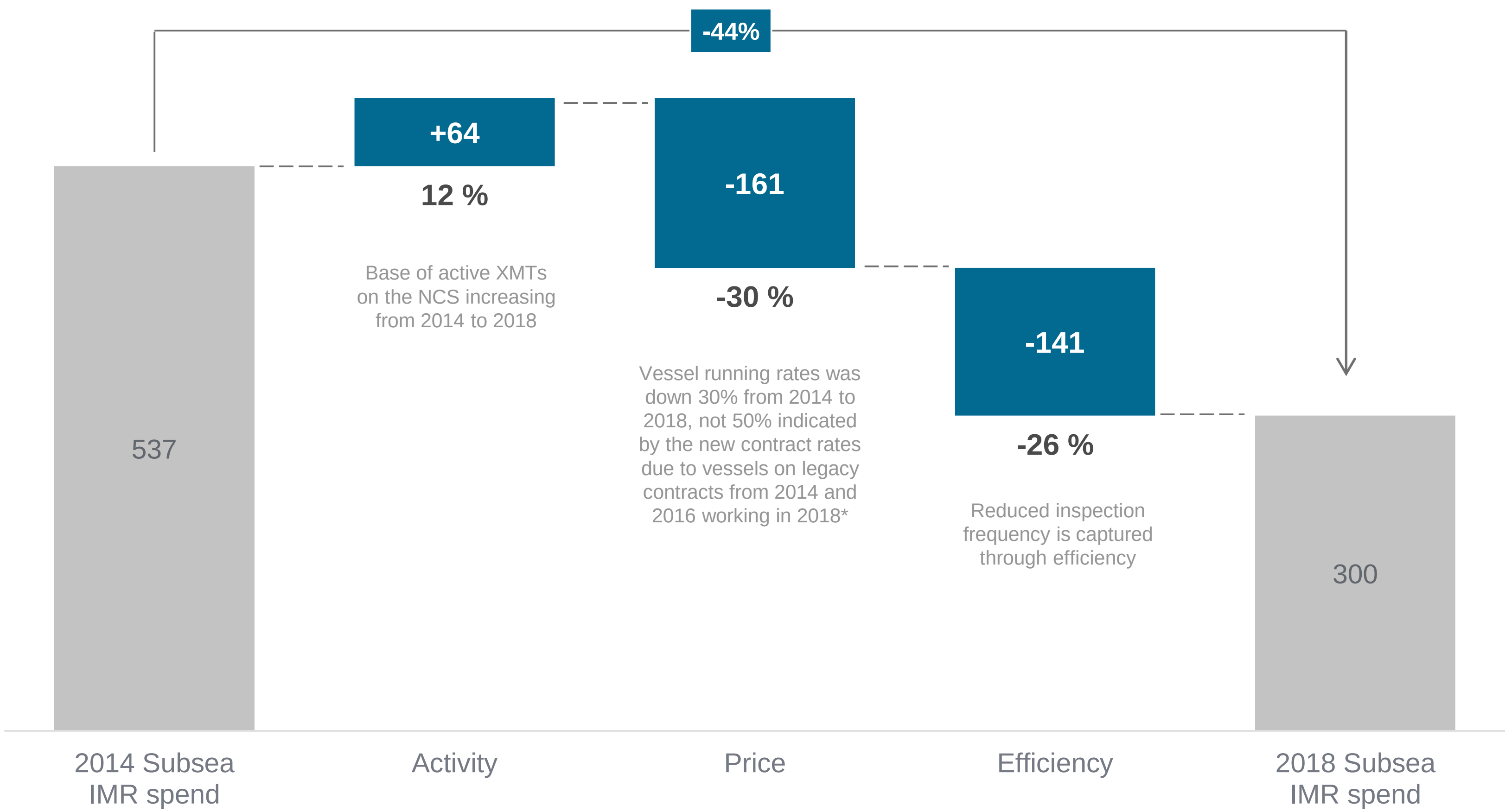
Logistics

Other opex elements

Internal production opex

Cost element: Price | Activity | Efficiency

Activity, price efficiency implications on Subsea IMR
Million USD (real 2019)



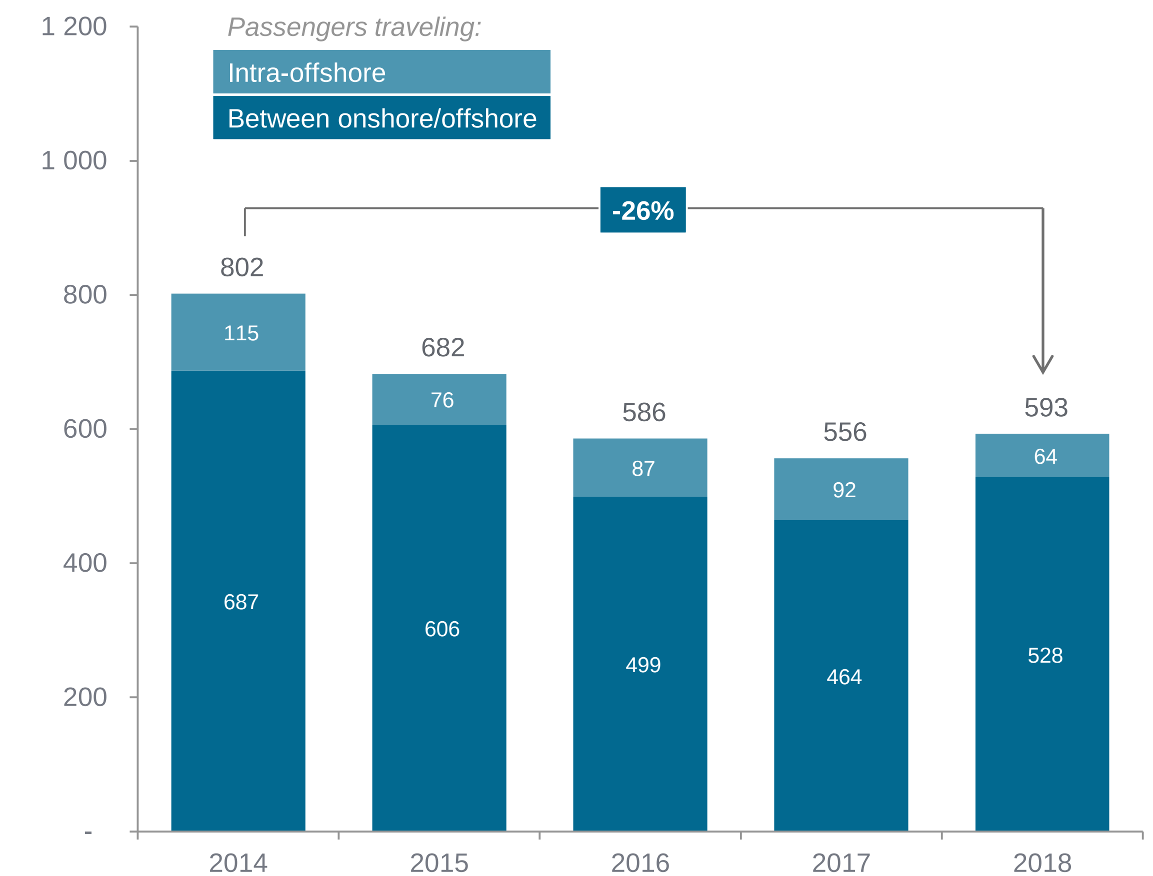
*Equinor: One 2014-contract extending through 2018, and two 2016-contracts extending through May 2018, Shell: One 2016-contract extending through 2018

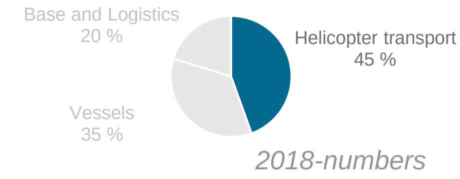
Source: Rystad Energy research and analysis;

Helicopter activity in terms of passengers down -26% from 2014 to 2018

Segment	Cost element:	Activity	Efficiency	Price

- Platform services
- Subsea IMR
- **Logistics**
- Other opex elements
- Internal production opex





- The graph is showing the total number of passengers transported either between installations offshore («intra-offshore»), or trips between onshore and offshore
- The number of helicopter passengers defines the work the helicopters has to undertake and is thus a measure of activity
- Helicopter passenger count declined by 26% in the 2014 to 2018 period

*Between onshore/offshore and intra-offshore shuttle traffic
Source: Rystad Energy research and analysis; Avinor; PTIL

Helicopter passenger transport efficiency up

Segment	Cost element:	Activity	Efficiency	Price

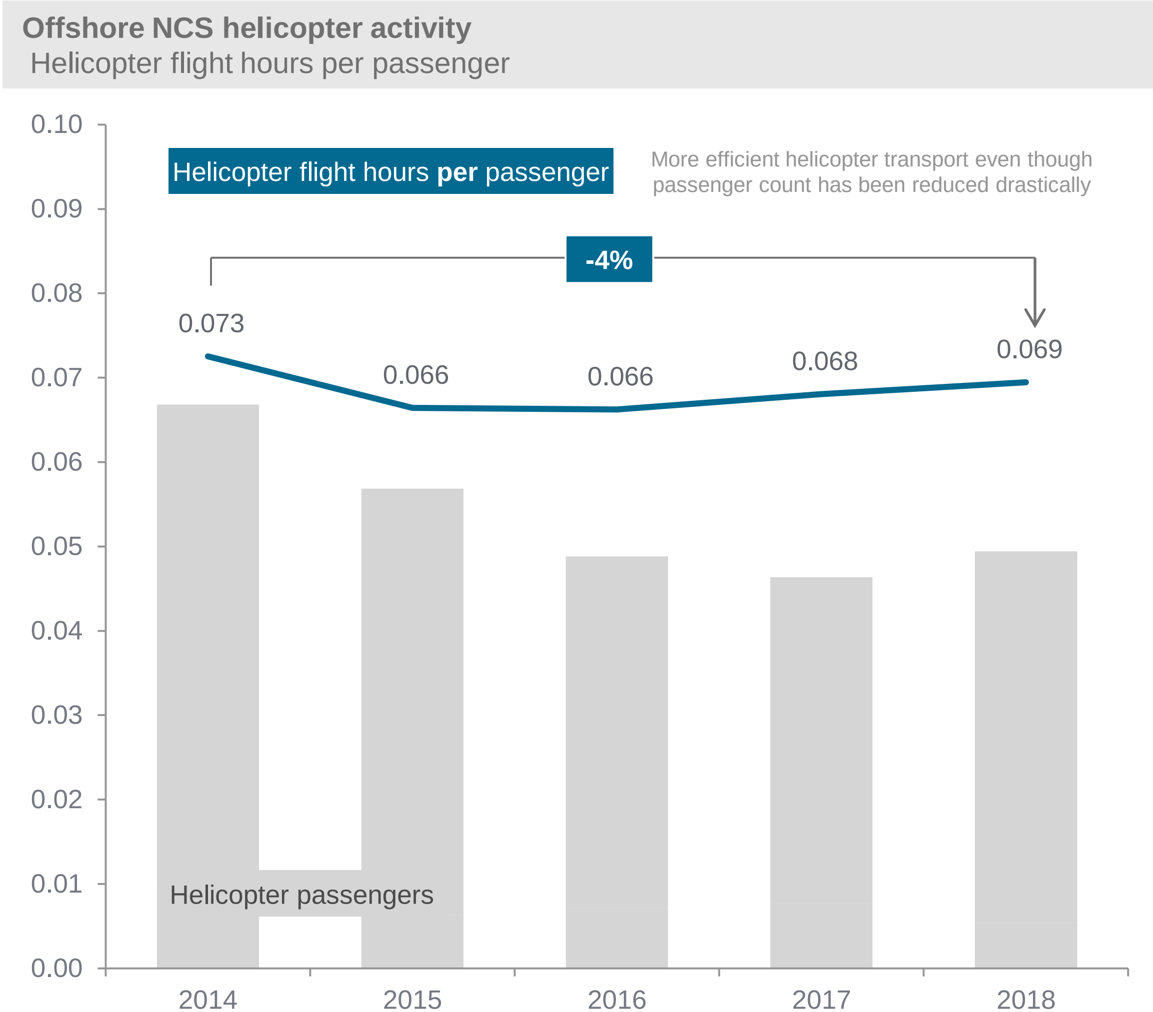
Platform services

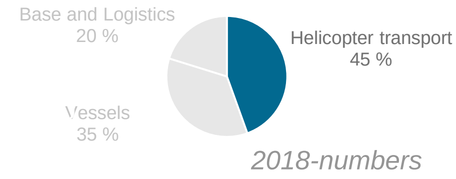
Subsea IMR

Logistics

Other opex elements

Internal production opex





- The graph shows the helicopter flight hours normalized for activity (per passengers) as a metric for the development of efficiency in the period
- While helicopter passengers has decreased significantly throughout the period, helicopter flight hours has decreased even more, meaning helicopter flight hours **per** passenger is down 4%, indicating efficiency gains

Source: Rystad Energy research and analysis;

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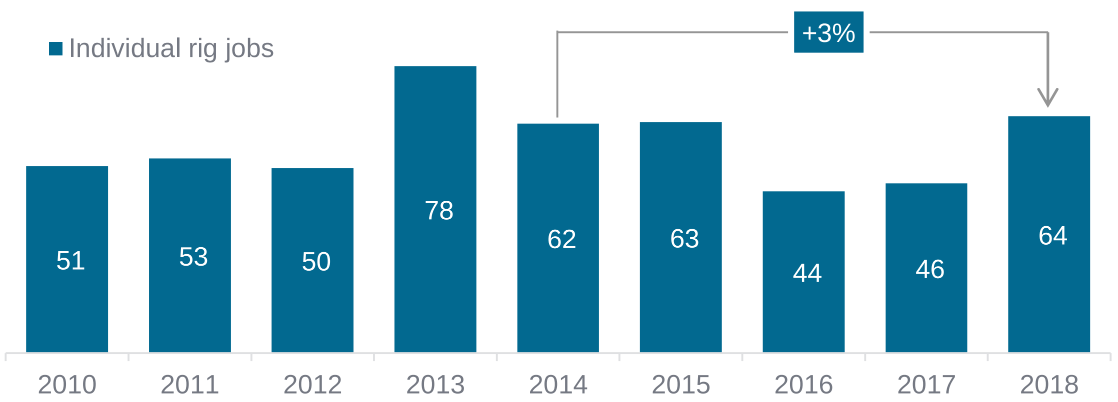
Modest AHTS vessel activity increase, but it has been seen positive efficiency gains

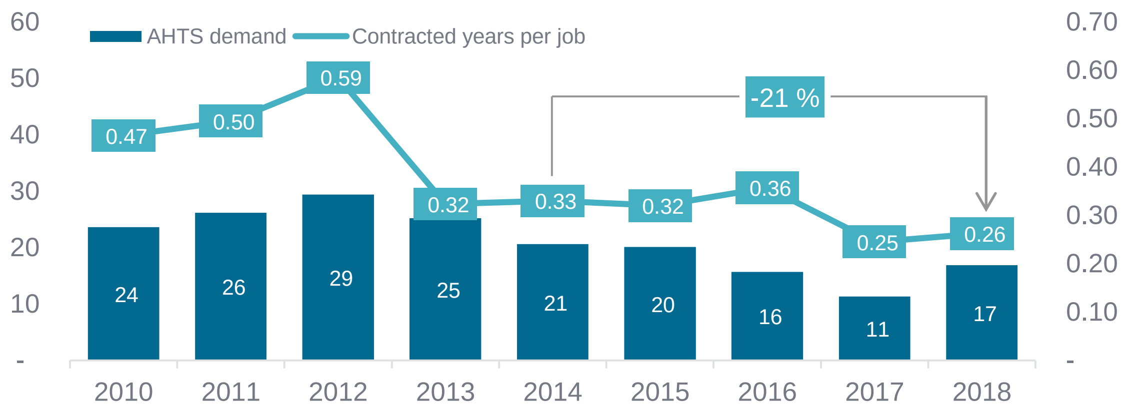
Segment	Cost element:	Activity	Efficiency	Price

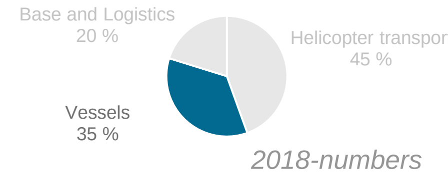
- Platform services
- Subsea IMR
- **Logistics**
- Other opex elements
- Internal production opex

NCS rig demand, jack-up and floaters
Individual rig jobs



NCS AHTS vessel efficiency
Demand years/individual rig job





- The second largest segment in Logistics is Vessels covering PSVs and AHTS vessels.
- AHTS vessel activity is driven by rig moves meaning the number of individual rig jobs will be an indicator of ATHS activity, which is up 3% from ‘14 to ‘18
- Contracted supply years in the same period declined 18%, implying a 21% improvement in contracted vessels years per rig job

Source: Rystad Energy research and analysis; Rystad Energy OSVCube; Rystad Energy RigCube

PSV vessel sees limited efficiency gains, but activity driver is down 20% in period

Segment	Cost element:	Activity	Efficiency	Price

Platform services

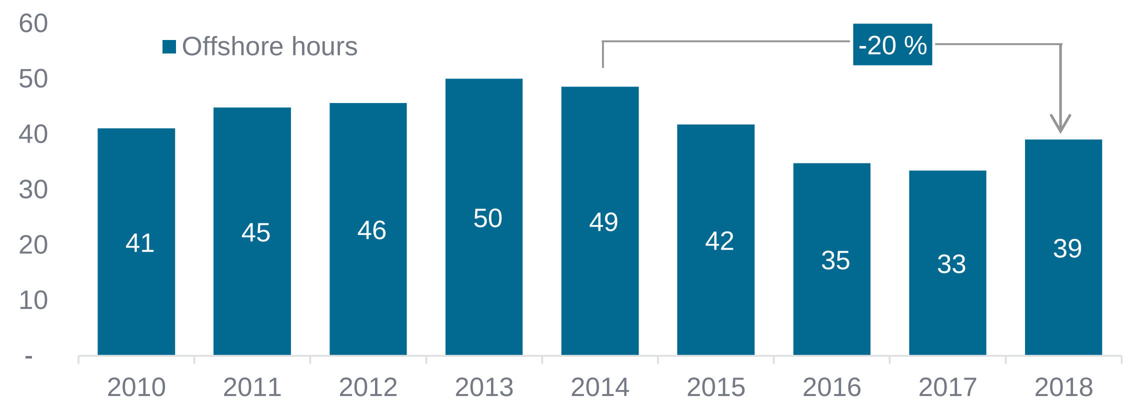
Subsea IMR

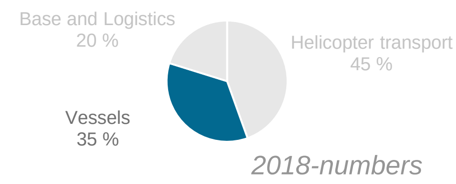
Logistics

Other opex elements

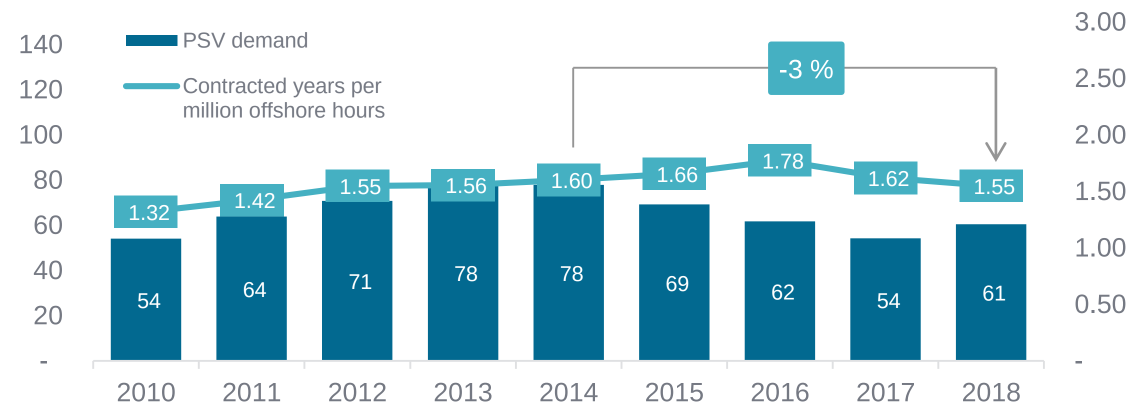
Internal production opex

Operator and contractor NCS offshore hours
Million offshore working hours, both permanent and moveable units





NCS PSV vessel demand
Demand years



- The upper graph shows the number of offshore working hours on the NCS, while the bottom shows the contracted supply of PSVs in the same period
- While offshore hours (a proxy for offshore activity) declined by 20%, contracted PSVs years fell by 22%, resulting in a decline of 3% in PSV demand years per million offshore hours, implying a modest 3% efficiency gain

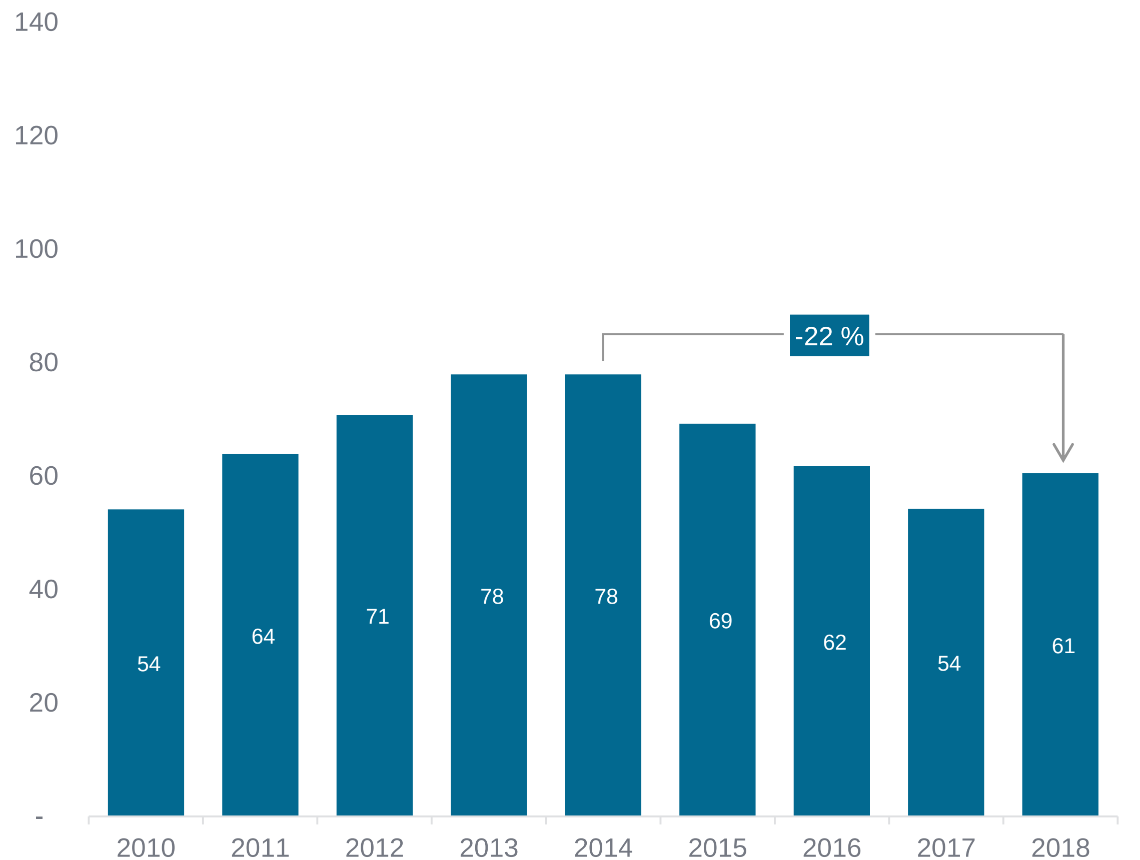
Source: Rystad Energy research and analysis; Rystad Energy OSVCube; PTIL

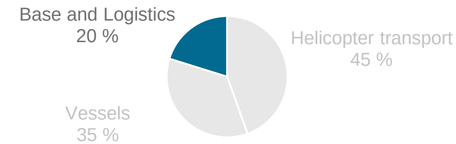
Supply base activity driven by PSVs activity, which is down 22% from 2014 to 2018

Segment | Cost element: | **Activity** | Efficiency | Price

- Platform services
- Subsea IMR
- **Logistics**
- Other opex elements
- Internal production opex

NCS PSV vessel demand
Demand years





2018-numbers

- The graph shows the contracted supply of PSVs from 2010 to 2018
- From 2014 to 2018, the number of PSV vessel years contracted on the NCS fell by 22%
- PSV traffic makes up the majority of activity on the supply bases, hence this metric is applied as the activity indicator

Source: Rystad Energy research and analysis;

Logistics

Segment	Cost element:	Activity	Efficiency	Price

Platform services

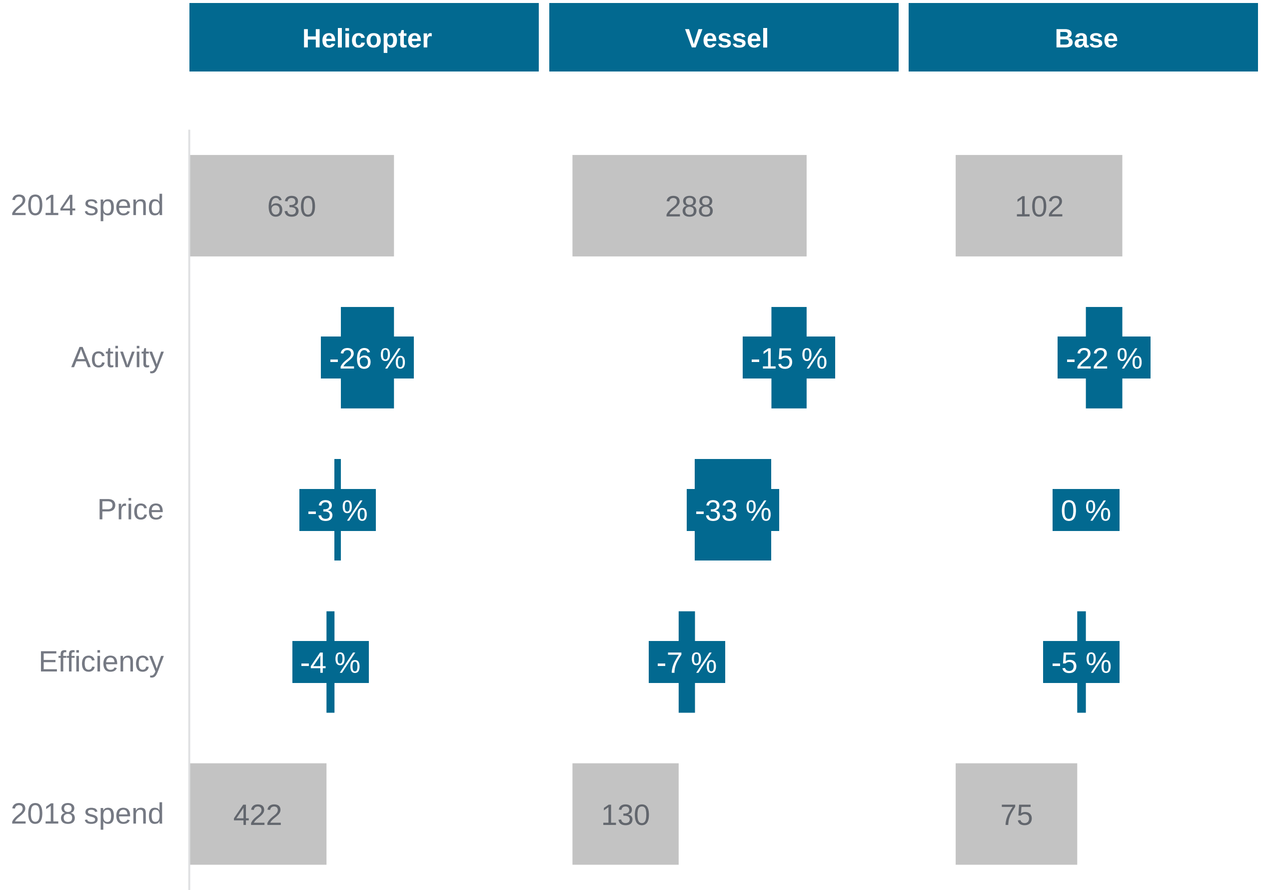
Subsea IMR

Logistics

Other opex elements

Internal production opex

Activity and price implications on Logistics
Million USD (real 2019)



- **Helicopter**
  Heli-passengers down 26%, efficiency up 4% considering flight hours per passenger, leaving price down 3%
- **Vessels**
  AHTS and PSV weighted demand down 15%, while weighted efficiency is down 7%, leaving price down 33%
- **Base**
  PSV activity driving bases down 22%, prices assumed to see limited (0%) movement due to longer contracts, leaving efficiency up 5%

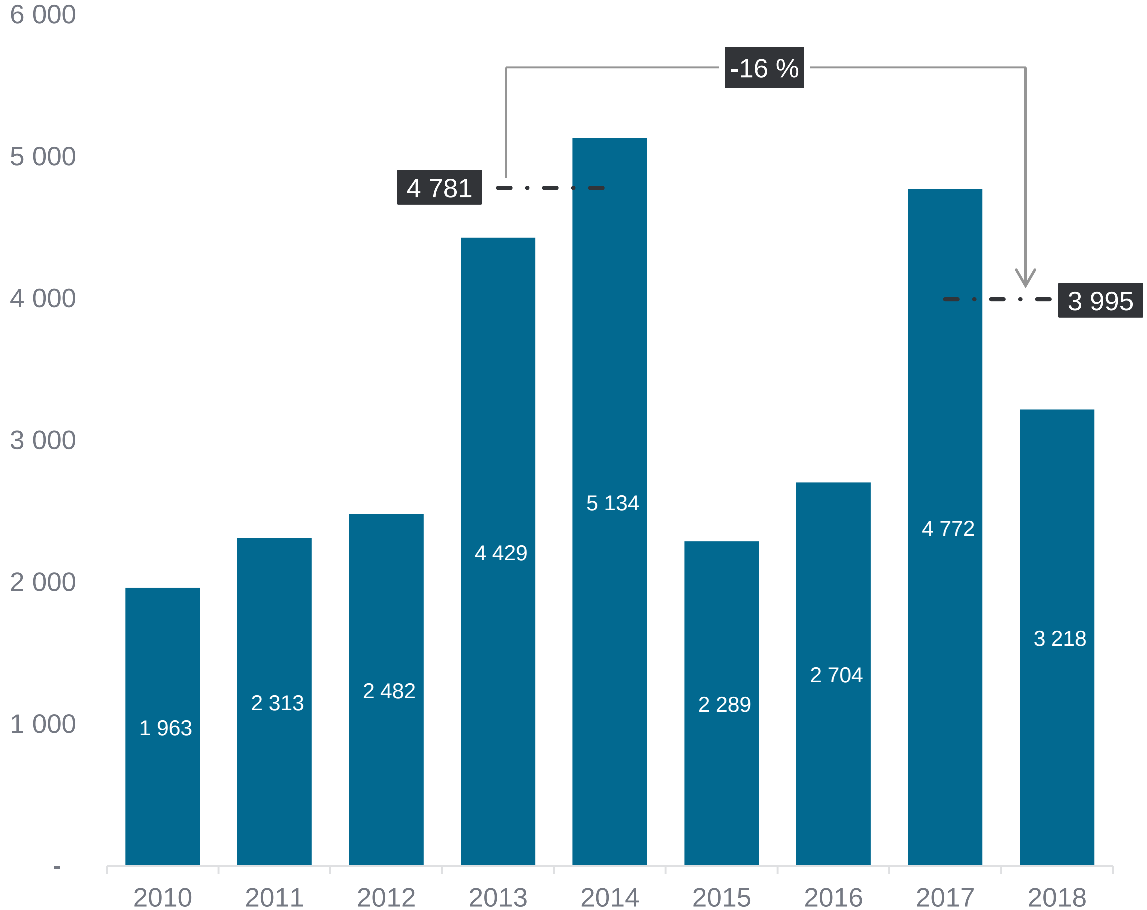
Source: Rystad Energy research and analysis;

Contract seismic: 4D seismic activity declining 16% from ‘13/’14 to ‘17/’18

Segment | Cost element: | **Activity** | Efficiency | Price

Platform services
Subsea IMR
Logistics
Other opex elements
Internal production opex

4D seismic shot on the NCS from 2010 to 2018
Net area (km²)



- The graph shows the net area shot during 4D seismic surveys per year
- 4D seismic is routinely shot over producing fields in order to get more information about reservoir dynamics in terms of drainage and sweep
- To account for timing of payment and seismic shooting, an average has been applied
- From 2014/13 avg. to 2018/17 avg., the net area shot for the purpose of 4D seismic declined 16%

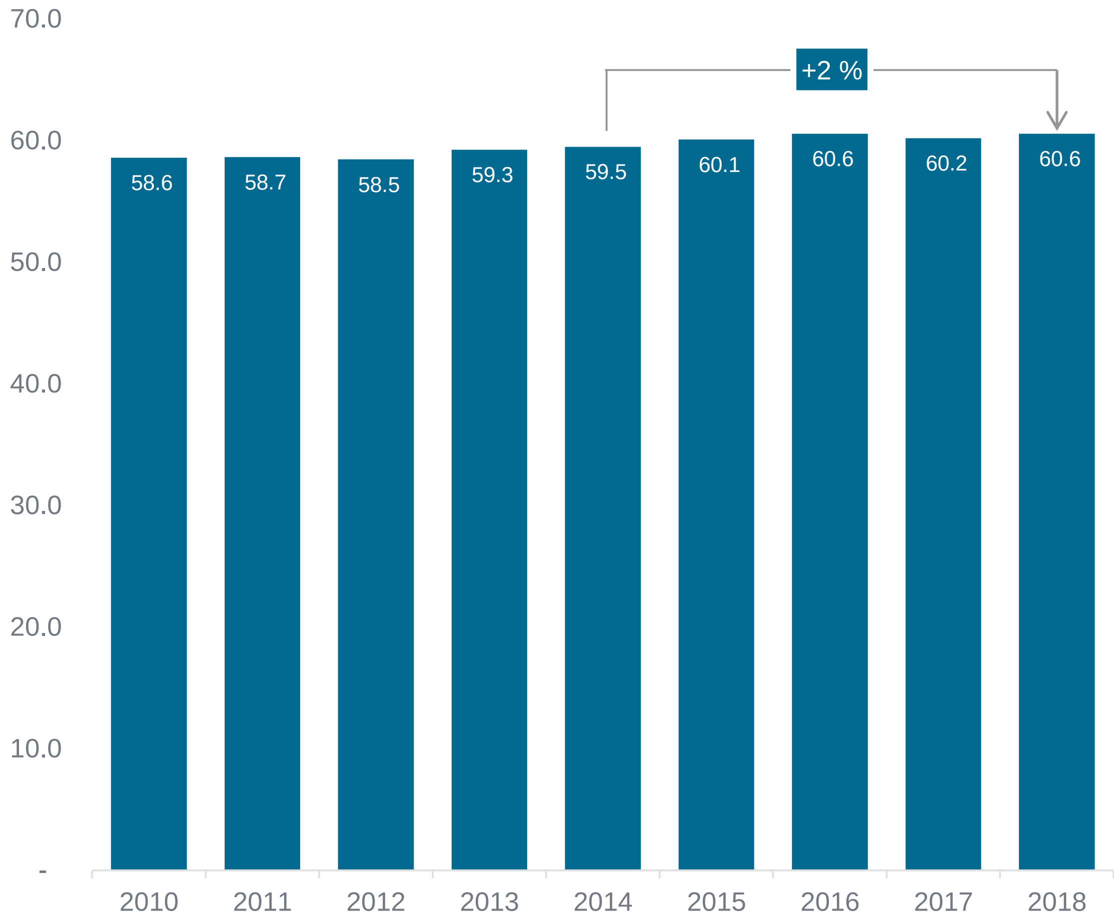
Source: Rystad Energy research and analysis;

G&G: Original resources in production on the NCS increasing by 2% in the '14 to '18 period

Segment	Cost element:	Activity	Efficiency	Price

- Platform services
- Subsea IMR
- Logistics
- **Other opex elements**
- Internal production opex

Original resources in production on the NCS from 2010 to 2018
Billion barrels



- The graph shows the amount of original resources in production from 2010 to 2018
- The resource count is adjusted for original resources entering and leaving the count, as fields are starting up or shutting down
- Original resources in production has remained relatively steady as all the major fields on the NCS is still was still producing as of 2018
- From 2014 to 2018 the inventory of original resources producing rose 2%

Source: Rystad Energy research and analysis;

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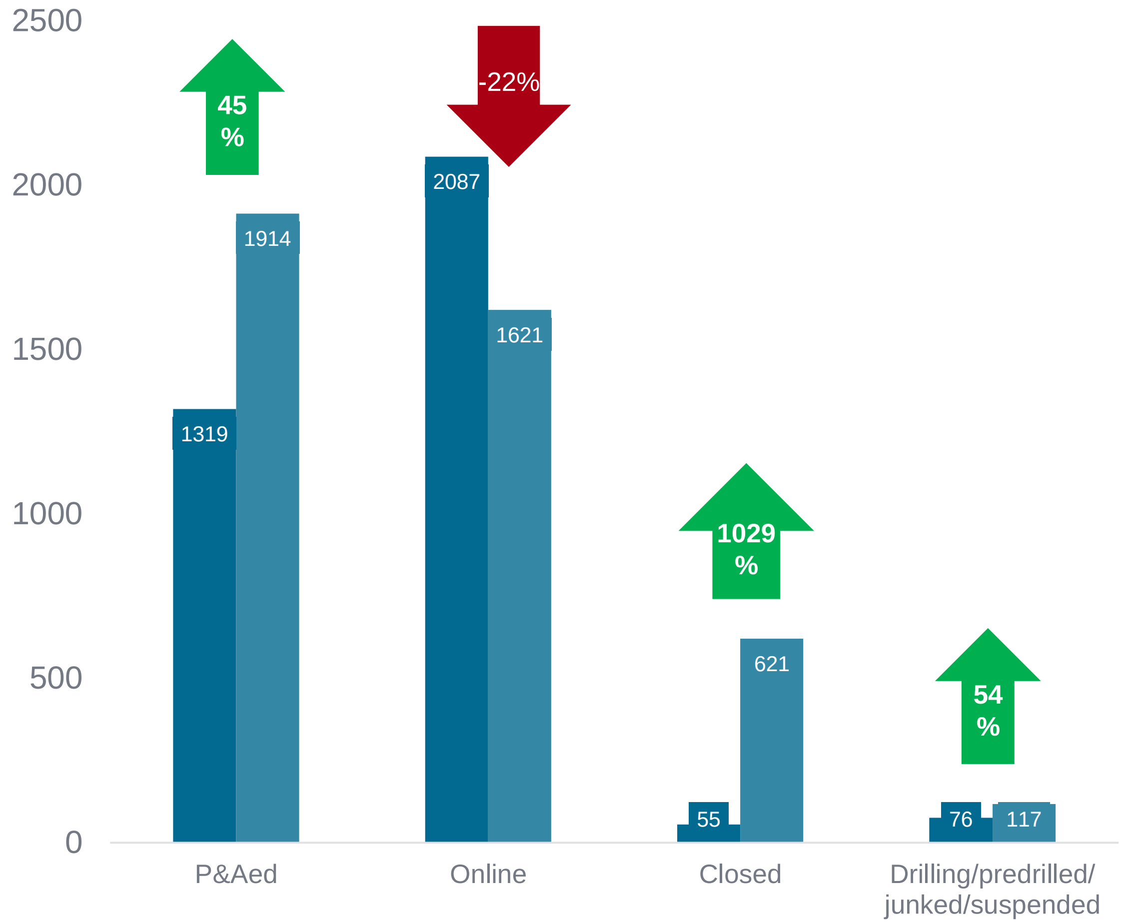
Well services: Active wellbores on the NCS declining 22% from 2014 to 2018

Segment	Cost element:	Activity	Efficiency	Price

- Platform services
- Subsea IMR
- Logistics
- **Other opex elements**
- Internal production opex

Active wellbore on the NCS in 2014 and 2018
# of wellbores



- The graph shows the distribution of wells in 2014 and 2018, across four categories of well status
- Since 2014, a wave of wells have been P&Aed, reducing the inventory of «active» wells producing on the NCS
- The number of wells online declined by 22% from 2014 to 2018

Source: Rystad Energy research and analysis; NPD

Segment

Platform services

Subsea IMR

Logistics

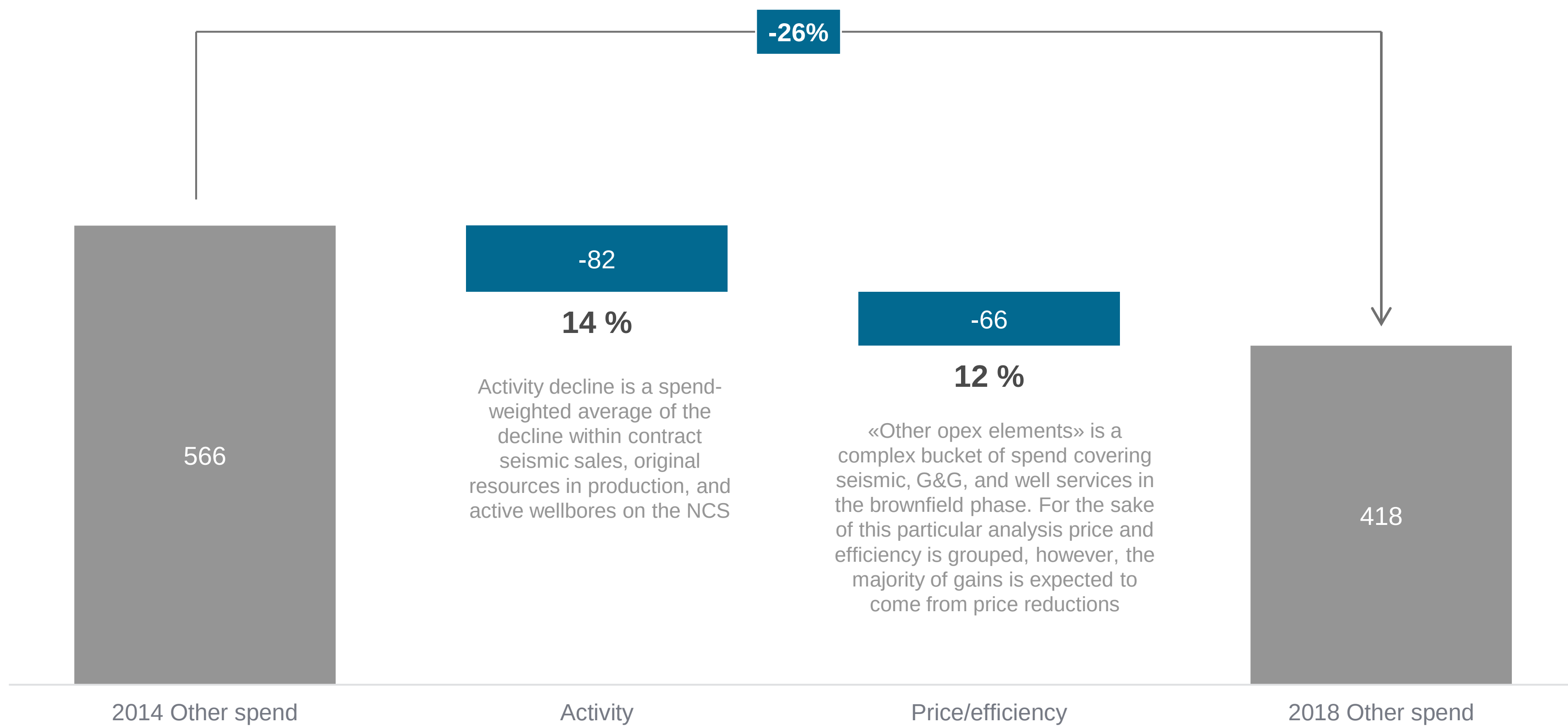
Other opex elements

Internal production opex

Cost element: **Activity** | Efficiency | Price

Activity and price implications on other opex elements

Million USD (real 2019)



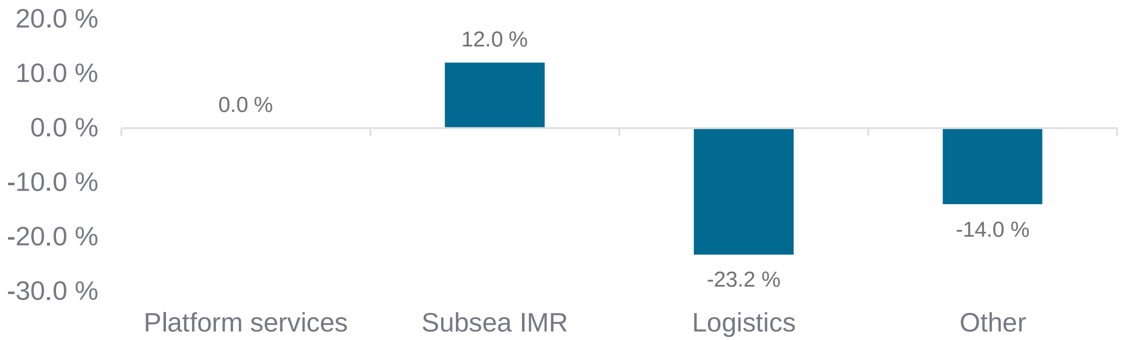
Source: Rystad Energy research and analysis;

Spend-weighted activity indicator down 4% for internal production opex

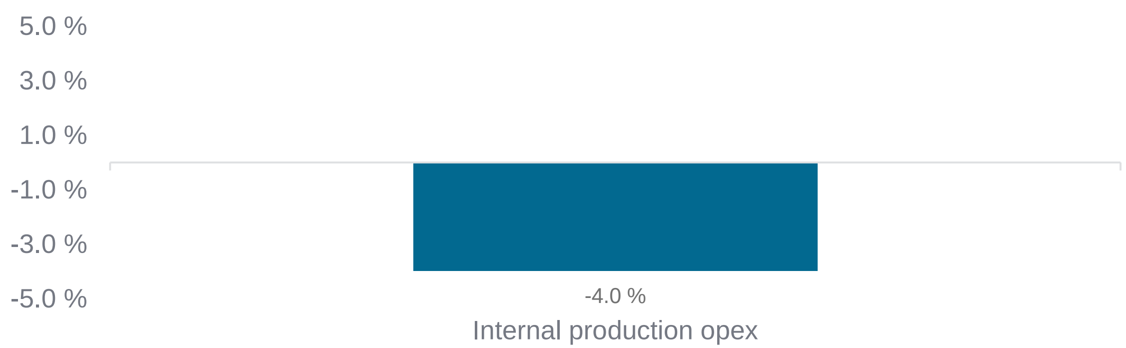
Segment	Cost element:	Activity	Efficiency	Price

- Platform services
- Subsea IMR
- Logistics
- Other opex elements
- **Internal production opex**

Activity indicator
[%]



Spend-weighted activity metric

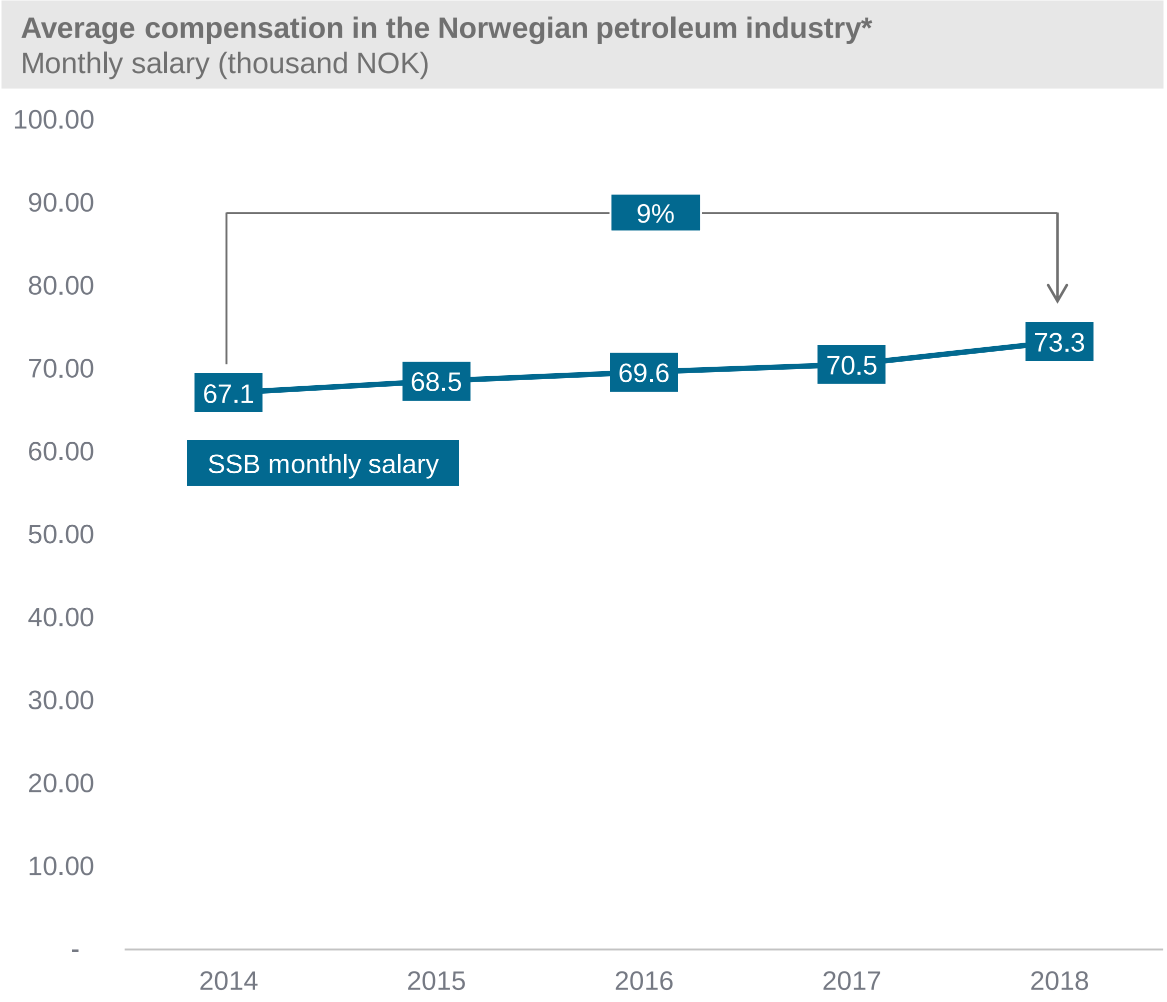


- Internal production opex covers mainly compensation of employees working on asset-level, following up suppliers and coordinating day-to-day activity on NCS fields
- The activity measure for this segment is a spend-weighted metric incorporating the change in activity seen across the other four opex-elements in this analysis
- Following this methodology the activity, or volume of work, assumed to be seen by employees of E&Ps is down 4%

Source: Rystad Energy research and analysis;

Average compensation in the NCS petroleum industry is up 9% from ‘14 to ‘18

Segment	Cost element:	Activity	Efficiency	Price
Platform services				
Subsea IMR				
Logistics				
Other opex elements				
Internal production opex				



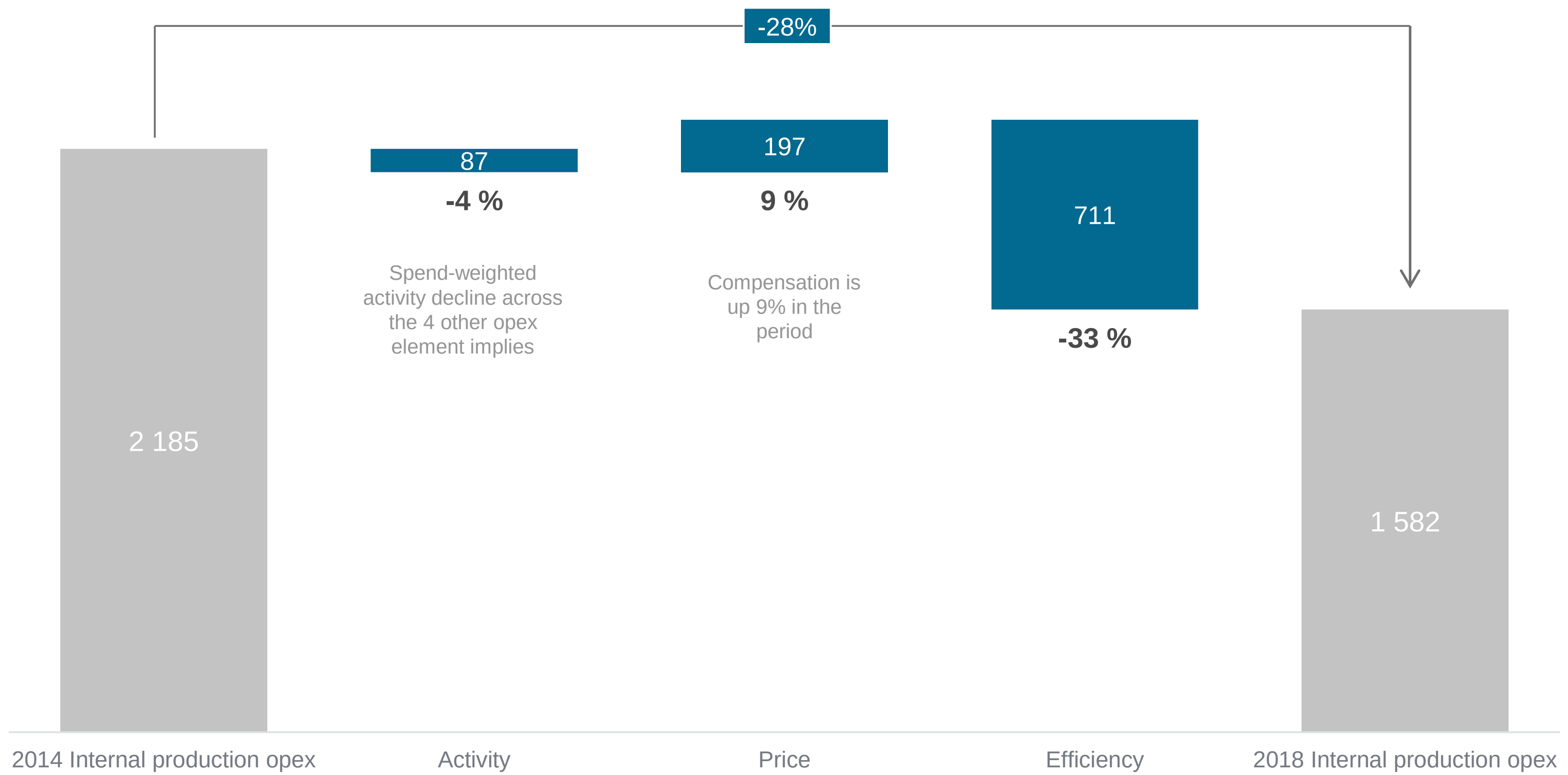
- Since 2014, the average monthly compensation in the petroleum industry has risen to 73.3 kNOK, an increase of 9% from 2014-levels
- Similar increase in compensation is seen in statistics from Tekna where the sample is limited to employees with a Master’s Degree and is a member of Tekna
- Internal production opex is dominated the salary of employees working for the oil companies

*SSB statistics of monthly salary for full-time workers in the mining & oil/gas extraction sector
Source: Rystad Energy research and analysis;

Segment	Cost element:	Activity	Efficiency	Price
Platform services				
Subsea IMR				
Logistics				
Other opex elements				
Internal production opex				

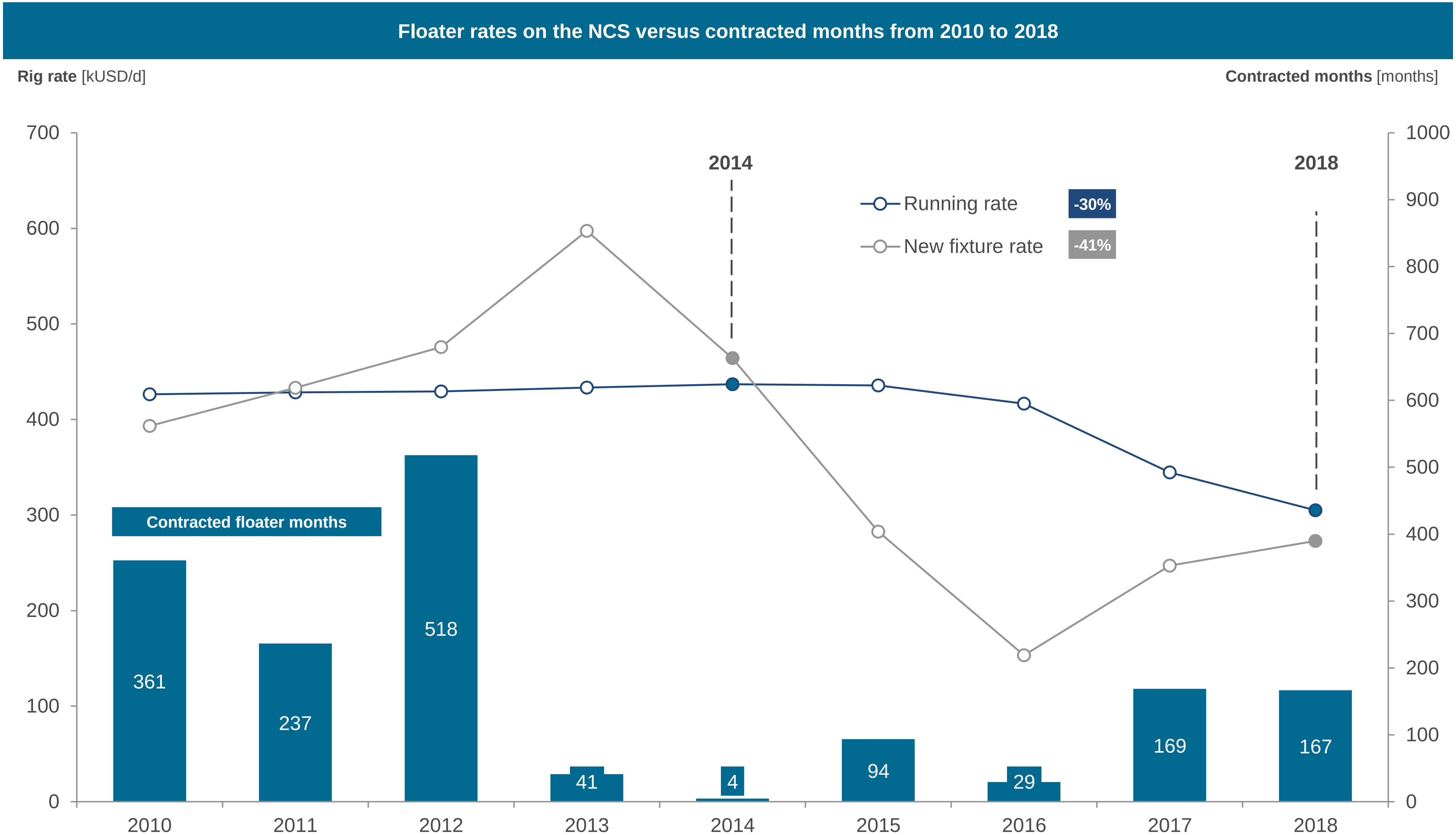
Activity and price implications on internal production opex

Million USD (real 2019)



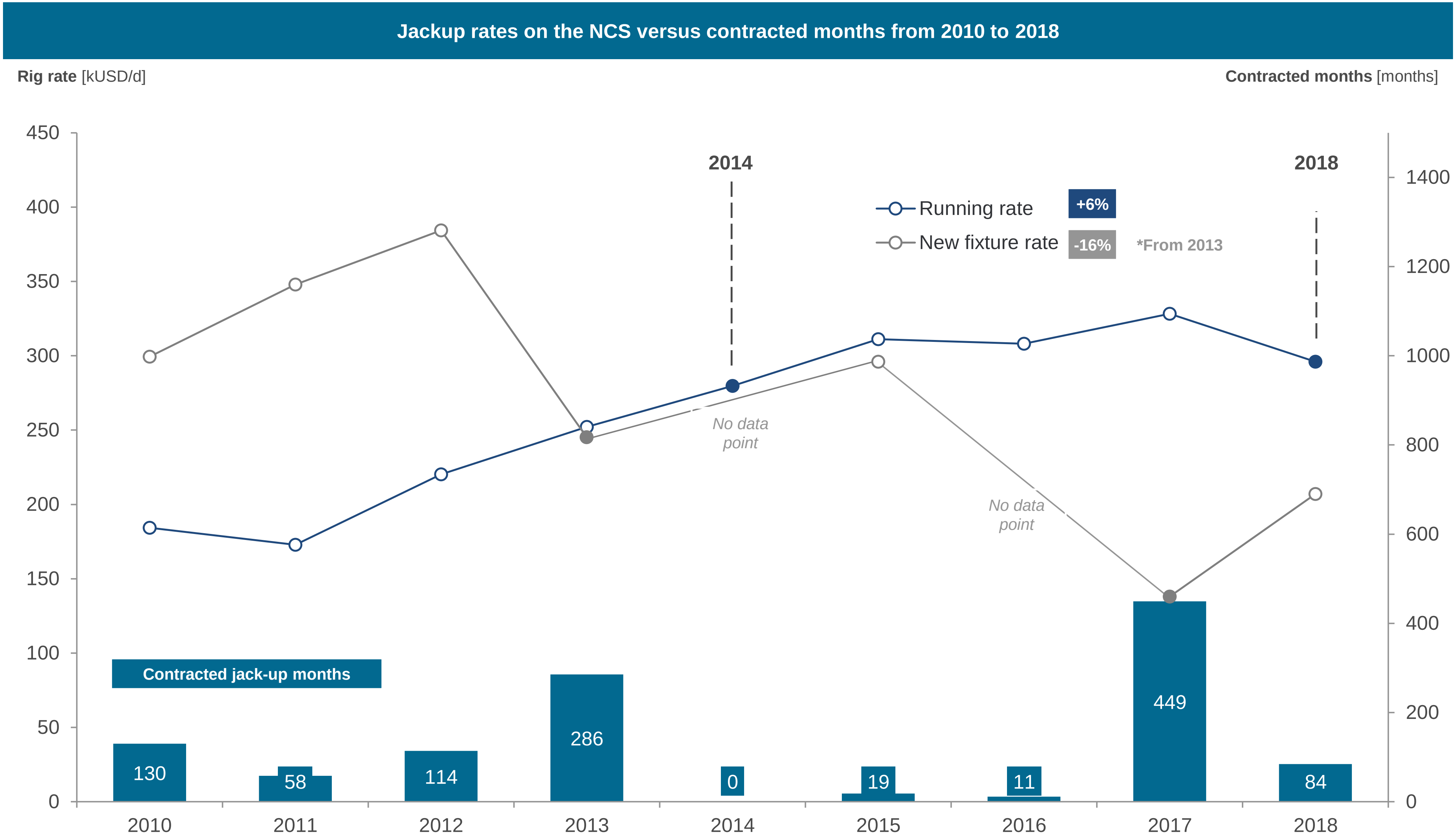
Source: Rystad Energy research and analysis;

Floater running rate declining due to lower-priced new fixture contracts seen in downcycle



Rystad Energy research and analysis; Rystad Energy RigCube;

Jackup running rate increasing by 6% from 2014 to 2018



Rystad Energy research and analysis; Rystad Energy RigCube;

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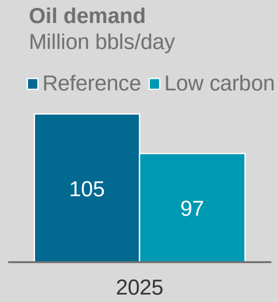
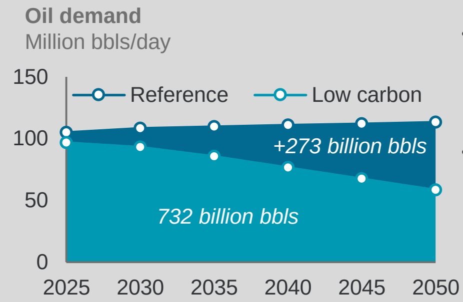
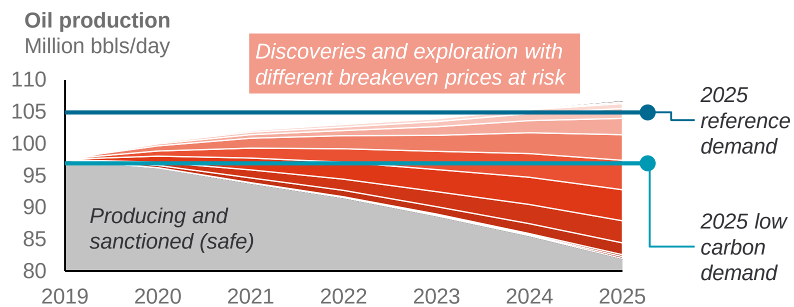
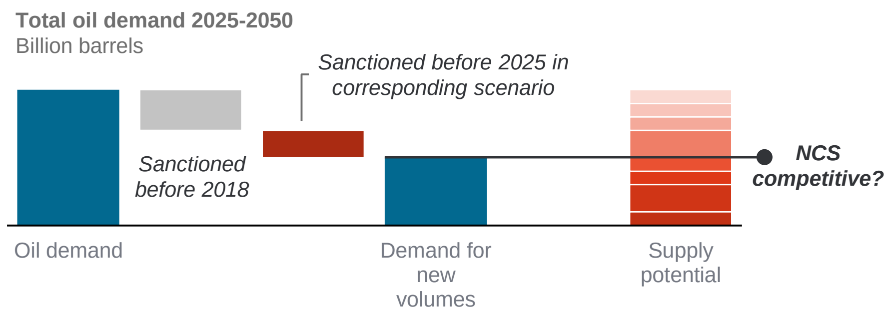
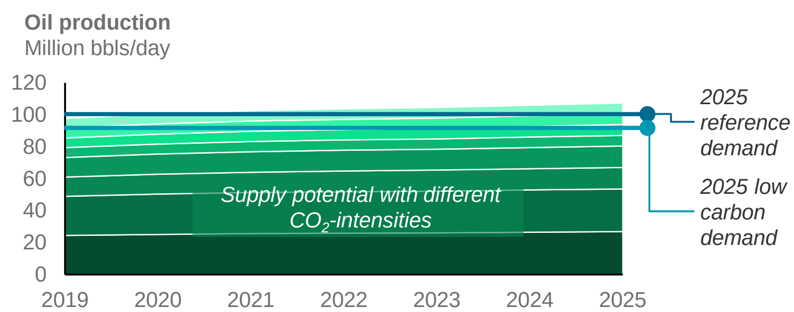
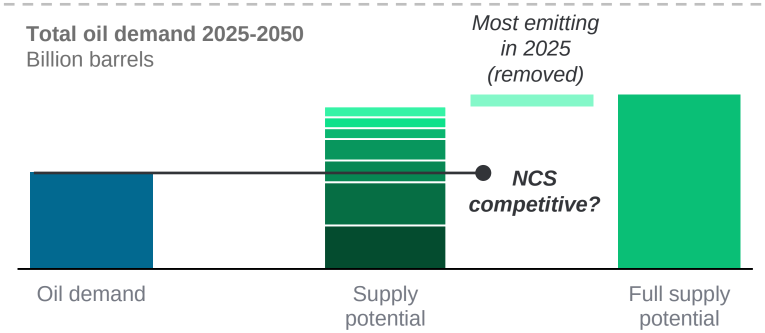
Index

Competitiveness in light of future demand – what NCS volumes will be called for?

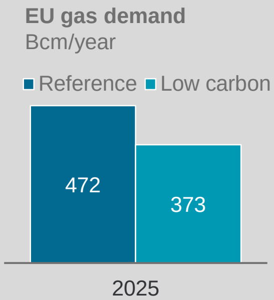
	Short term (2025)	Long term (2025-2050)
Demand view	 • Competitiveness is assessed by ability to deliver 2025 production levels. • Timing and lead time of projects come into play	 • In the long run competitiveness is assessed by ability to deliver sum of 2025 to 2050-volumes • Timing is less relevant, as a field's full lifecycle fits within the timeframe evaluated. Total volumes contributed is therefore evaluated
Cost discrimination		
CO_2 Discrimination		

Source: Rystad Energy research and analysis

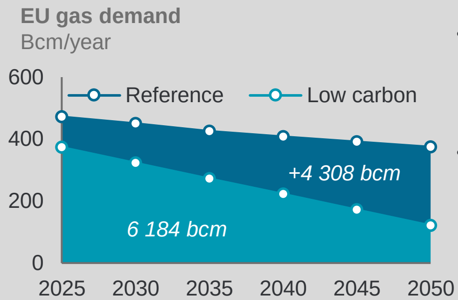
Competitiveness in light of future demand – what NCS volumes will be called for?

	Short term (2025)	Long term (2025-2050)

Demand view

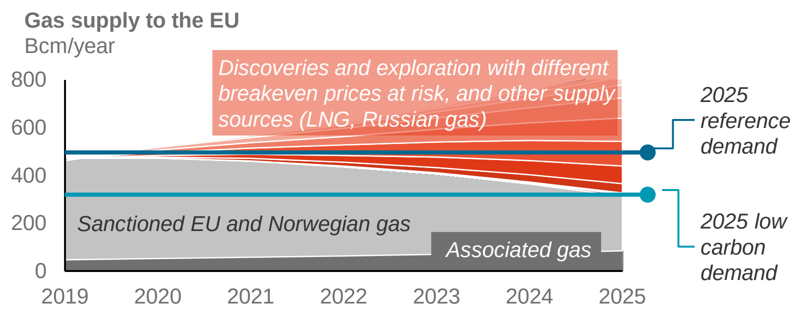


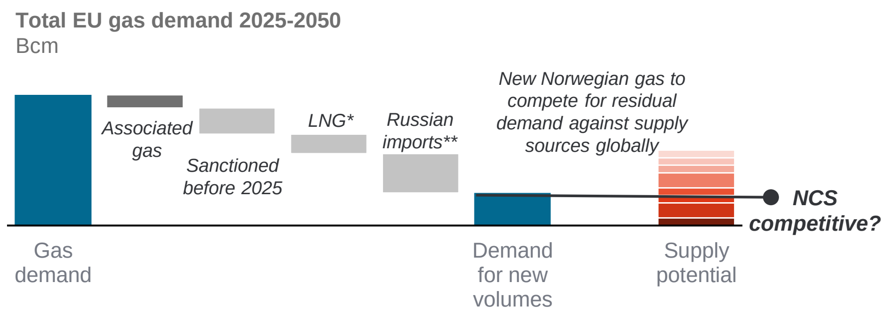
- Competitiveness is assessed by ability to deliver 2025 production levels.
- Timing and lead time of projects come into play



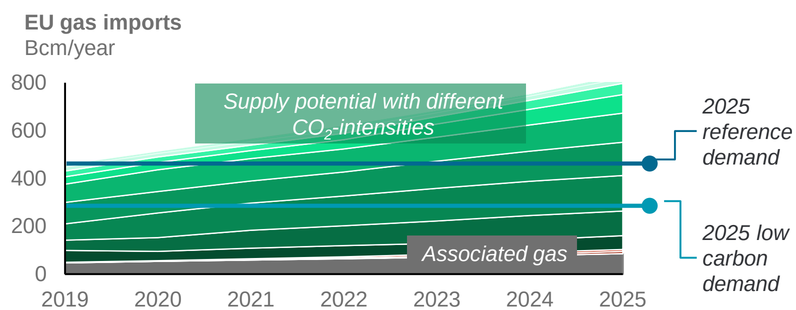
- In the long run competitiveness is assessed by ability to deliver sum of 2025 to 2050-volumes
- Timing is less relevant, as a field's full lifecycle fits within the timeframe evaluated. Total volumes contributed is therefore evaluated

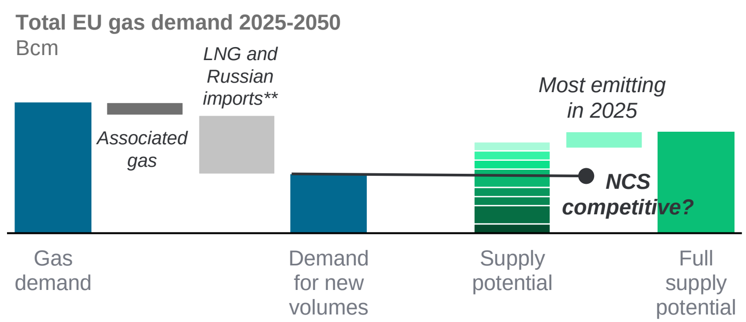
Cost discrimination





CO_2 Discrimination





* LNG market share assumed at 15%, acting marginal supplier. ** Russian share assumed to make up 30% of imports to the EU (currently around 40%). Geopolitics curb further market share growth.
Source: Rystad Energy research and analysis