Risk assessment and impact on technology decisions

Final report
25.09.2018

Index

Mandate

Determine to which extent the current use of risk evaluation methodologies, assumptions and decision criteria, as well as the contemporary mind set and risk perceptions in the petroleum industry, lead to technological decisions on the NCS that optimize value creation from a business as well as a societal perspective

Project process secured high involvement of relevant stakeholders in the industry

TTAs nominate high risk / high value technologies

- *Technology groups (TTAs*) in OG21 nominates example technologies that have high risk and high value*

Perceived risk		
	No-brainer (no)	**SCOPE**
	Not scope	No-brainer (yes)
	Potential value	

Selection and verification of <u>example</u> technologies

- *Based on nominated technologies Rystad Energy selected eight high risk/high value technologies*
- *These technologies are used as <u>examples</u> to understand the more general barriers*
- *Risk characteristics and value have been analyzed in detail for each technology (see Appendix)*

Interviews and research

- *+25 in-depth interviews with executives in E&Ps and oil service companies.*
- *Example technologies used as outset when conducting interviews to understand.*
- *How risk is viewed and treated in the different organizations where discussed, in addition to other barriers*

Identification and analysis of barriers

- *Identified barriers from example technologies and interviews placed and analyzed in a four-perspective framework, where risk and value perception are likely to be different:*
    - *Sub-supplier & supplier*
    - *Supplier & operator*
    - *Operator internal*
    - *Operator & license*

Cross-industry workshop

- *Workshop with 55 participants from research institutions, suppliers, operators and regulators (more technical background than interview objects)*
- *Verification of barriers presented in draft report and suggestion of new barriers*
- *Suggestions of measures to overcome identified barriers*

Recommendations

Six main recommendations that address identified challenges across the four perspectives:

- *Technology champion forums*
- *Interoperability between data platforms*
- *Regulator enforcement of the use of value adding technologies*
- *Build front-end capabilities with Petoro*
- *Full lifecycle standardized integrated contracts*
- *Change technology qualification standards to allow continuous uptake of new technology*

*TTA = Technology Target Area – four technology groups under OG21 umbrella

Stakeholders from a wide range of companies and institutions have provided input

Lloyd's Register

TechnipFMC

Aker Solutions

fishbones

PETROLEUMSTILSYNET

Schlumberger

IFE

IRIS

Lundin Petroleum

NOV

25+

in-depth interviews

55

workshop participants

AkerBP

subsea 7

The Research Council of Norway

VNG Norge

HYDRA WELL INTERVENTION

petoro

BAKER HUGHES a GE company

HALLIBURTON

SIEMENS

Sekal

WeST Group

ConocoPhillips

SINTEF

equinor

Universitetet i Stavanger

NORWEGIAN PETROLEUM DIRECTORATE

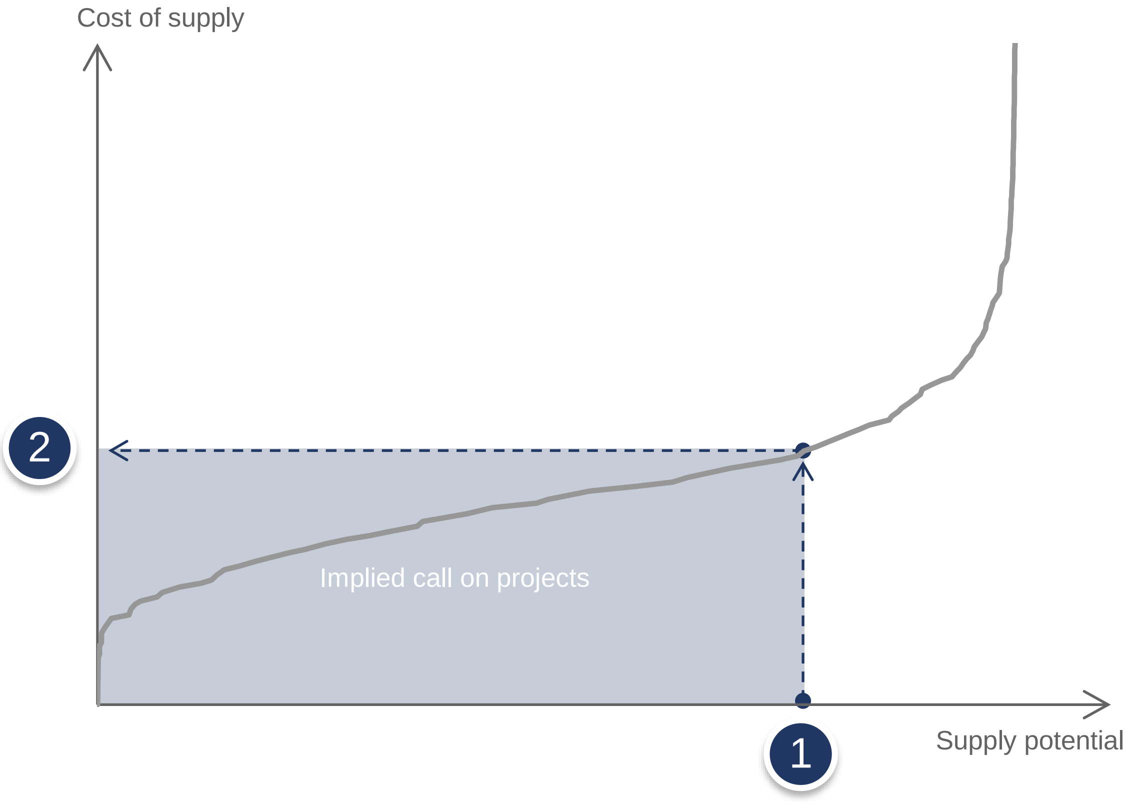
ABB

Source: OG21; Rystad Energy

Index

How we assess the competitiveness of offshore (non-OPEC) vs. shale

Cost-of-supply: Offshore & Unconventionals



Curve composition

Distribution of projects on a cost-of-supply line.

We quantify and discuss competitiveness between unconventionals and offshore. We analyze this through a cost-of-supply lens, but also through a lens of E&P companies as investors.

Implied marginal cost

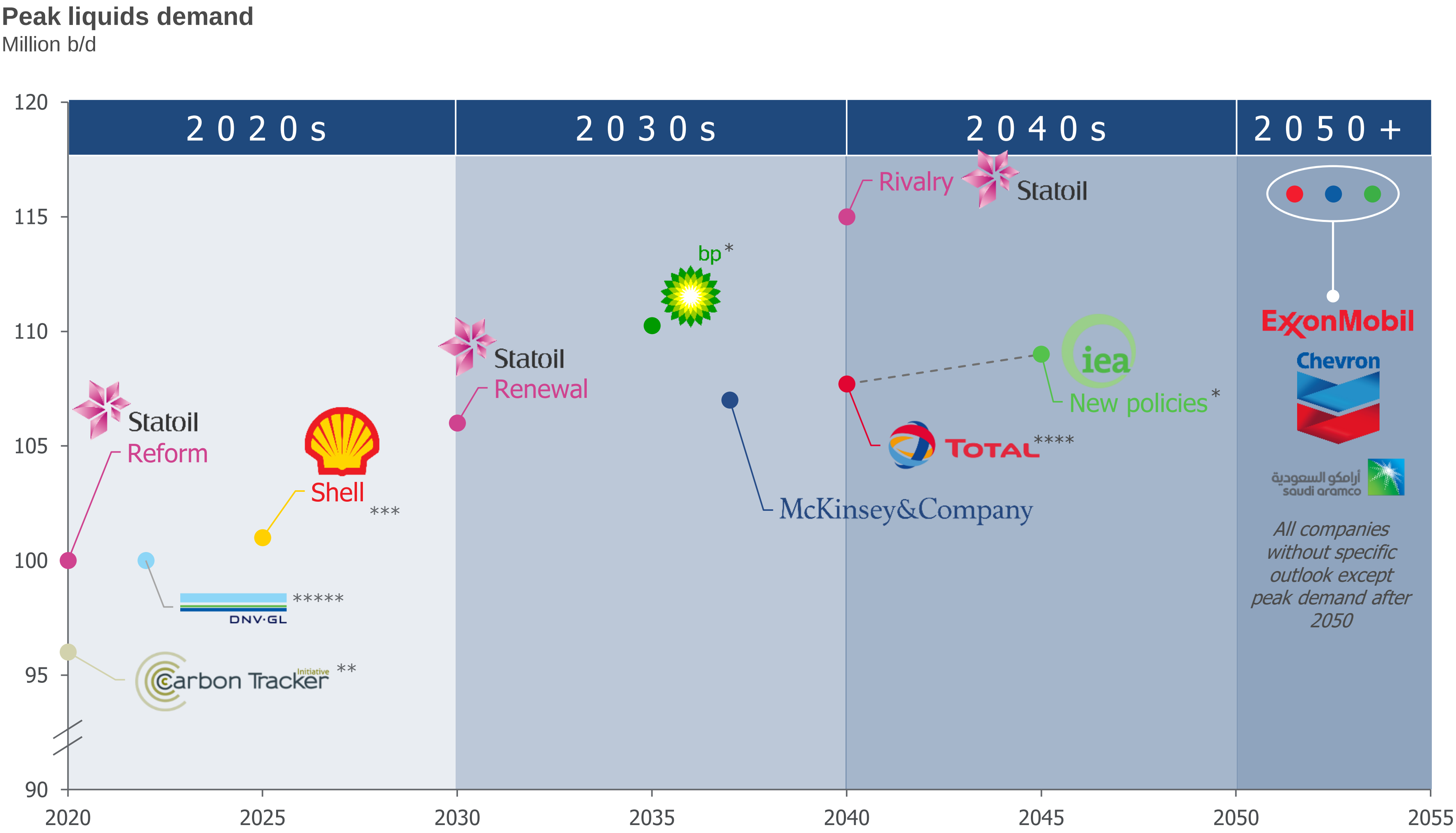
Realizing that exploration activities are driven by cash-flows, which in turn are driven by oil prices, we identify marginal cost of supply as a means of estimating likely range in oil price in each scenario. This forms the basis for our view of capital allocated to exploration in each scenario.

Call on supply

We quantify the call on offshore and unconventionals by evaluating likely outcomes of (A) global oil demand, (B) OPEC supply, (C) other supply and (D) decline rates. We then create three scenarios based on likely outcomes for these four independent variables.

Source: Rystad Energy research and analysis

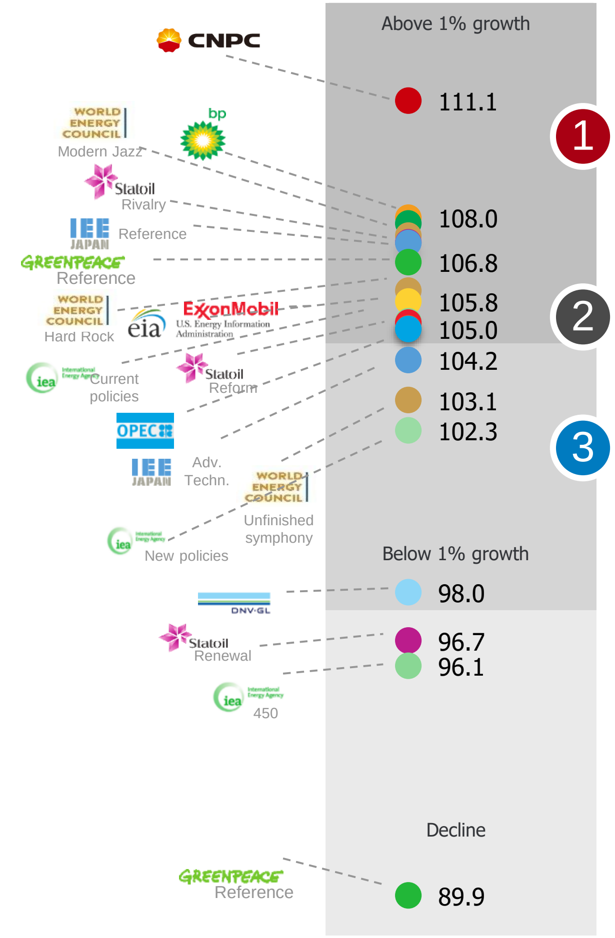
Large spread in peak demand views



*BP Energy Outlook 2018, peak between 2035 and 2040 **Peak in 2020, but with uncertain demand
***Shell not explicit on timing and demand level "sometime in mid to late 2020s" ****Follows IEA assumptions *****Uncertain peak level
Source: Rystad Energy research and analysis

Three scenarios for oil demand spanning the fan from 0.5 -1.4 mmbbl/d in annual growth

Benchmarks	Demand 2025* (mmbbl/d)	Demand Scenarios



High: "Continued Growth" (108.6 MMbbl/d)

This scenario implies an annual demand growth of **1.4 mmbbl/d** towards 2025, which is equal to the average demand growth from 2011 to 2017. In comparison, 2017 saw a demand growth of ~1.6 mmbbl/d, while the 10-year trend has been annual demand growth of 1.1 mmbbl/d. As such, this scenario implies a continued business-as-usual environment.

Medium: "Change of Pace" (105.0 mmbbl/d)

This scenario takes into account IEA's demand growth trajectories, growing on average by **~1.0 mmbbl/d** (**1.0%** annual growth rate). From 2018 through 2023, IEA's Medium Term Oil Market Report is used, reflecting a Current Policy/business-as-usual demand growth.

As climate change policies take time to implement, it is assumed that these have not manifested in the market by 2023, thus having a limited impact on demand. From 2020 onwards, climate change policies are assumed to gain a stronger foothold, and a delayed IEA New Policies scenario serves as the main trajectory.

Low: "Accelerated Peak Demand" (101.5 mmbbl/d)

This scenario calls for an average demand growth of **0.5 mmbbl/d or 0.5%.** The scenario name stems from a description of a reality that might pan out to underpin this scenario: Peak oil demand is brought forward in time (to 2025) due to a more rapid than expected penetration of electric vehicles or an accelerated policy program around climate change.

As such, the trajectory towards 2025 will likely be one where demand sees a base case growth in the near years, but then slows down significantly in the early 2020s, possibly due to the abovementioned drivers. Future growth half of IEA's projections until 2023, then no growth towards 2025.

*Demand is interpolated if not stated explicitly
Source: Rystad Energy research and analysis.

Call on offshore and unconventional between 30.7 and 39.9 mmbbl/d in 2025

Demand and supply scenarios (liquids mmbbl/d)

Global demand

−

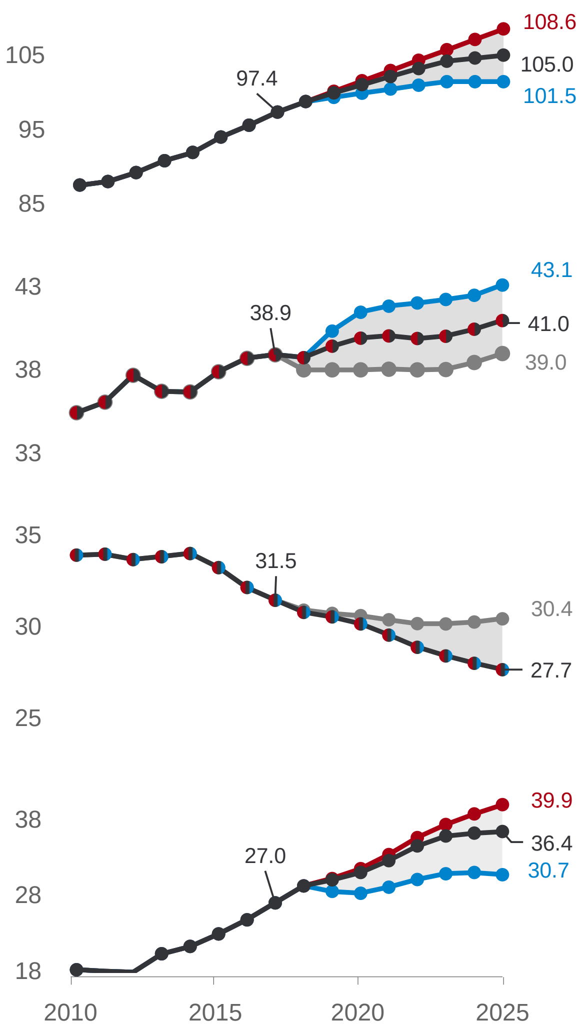
OPEC
supply

−

Other Onshore
supply

=

Call on Offshore
(non-OPEC) &
Unconventionals
supply



High = Continued growth

Base = IEA MTOMR*/
New policies

Low = Peak demand 2025

High = Defends market share

Base = Rystad Energy

Low = Supply disruptions

High = No decline in existing onshore production in Russia and China

Base = Rystad Energy

1. Continued Growth: High demand, base OPEC, base other onshore

2. Change of Pace: Base demand, OPEC, and other onshore

3. Accelerated Peak Demand:
Low demand, high OPEC, base other onshore

Scenario comments

- **High scenario:** Annual growth of 1.4 mmbbl/d from 2017-2025
- **Base scenario**: IEA's Medium Term Oil Market Report until 2023, then growth assumed in IEA's New Policies scenario.
- **Low scenario**: Future growth half of IEA's projections until 2023, then flat demand to 2025.

- **High scenario**: Assumes production is ramped up in Saudi Arabia, Iraq and Iran.
- **Base scenario**: Assumes continuous OPEC growth to meet demand.
- **Low scenario**: Assumes production disruptions due to military aggressions starting 2018.

- **High scenario**: Assumes that Russia and China, strongly influenced by their respective governments, decide to invest in completely offsetting decline in currently producing fields.
- **Base scenario**: Continuous decline in global conventional onshore production, new volumes not sufficient to offset sinking output.

- **Continued Growth**: Demand grows to reflect a business-as-usual situation, OPEC meets demand, onshore continues decline.
- **Change of Pace**: Demand gradually transitions to a New Policies trajectory in 2020, OPEC meets demand, onshore continues decline.
- **Accelerated Peak Demand**: Demand peaks in 2023-2025, OPEC pushes volumes to maximize profit, other onshore unable to respond and continues to decline.

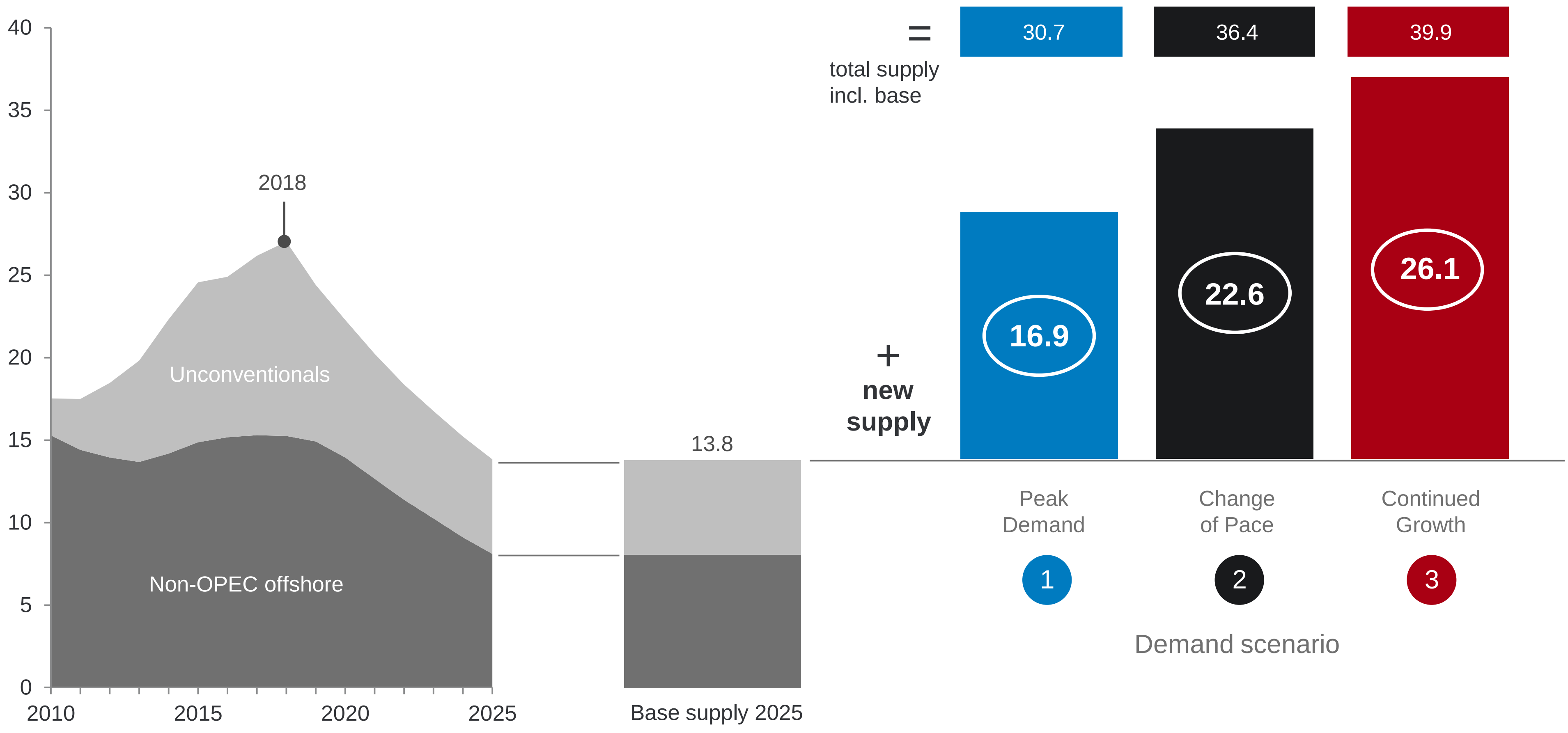
* MTOMR = Medium Term Oil Market Report
Source: Rystad Energy research and analysis.

Demand implies 17 to 26 MMbbls/d of new offshore and unconventionals supply in 2025

Decline of current production

Current production in 2025

New supply required to meet 2025 demand



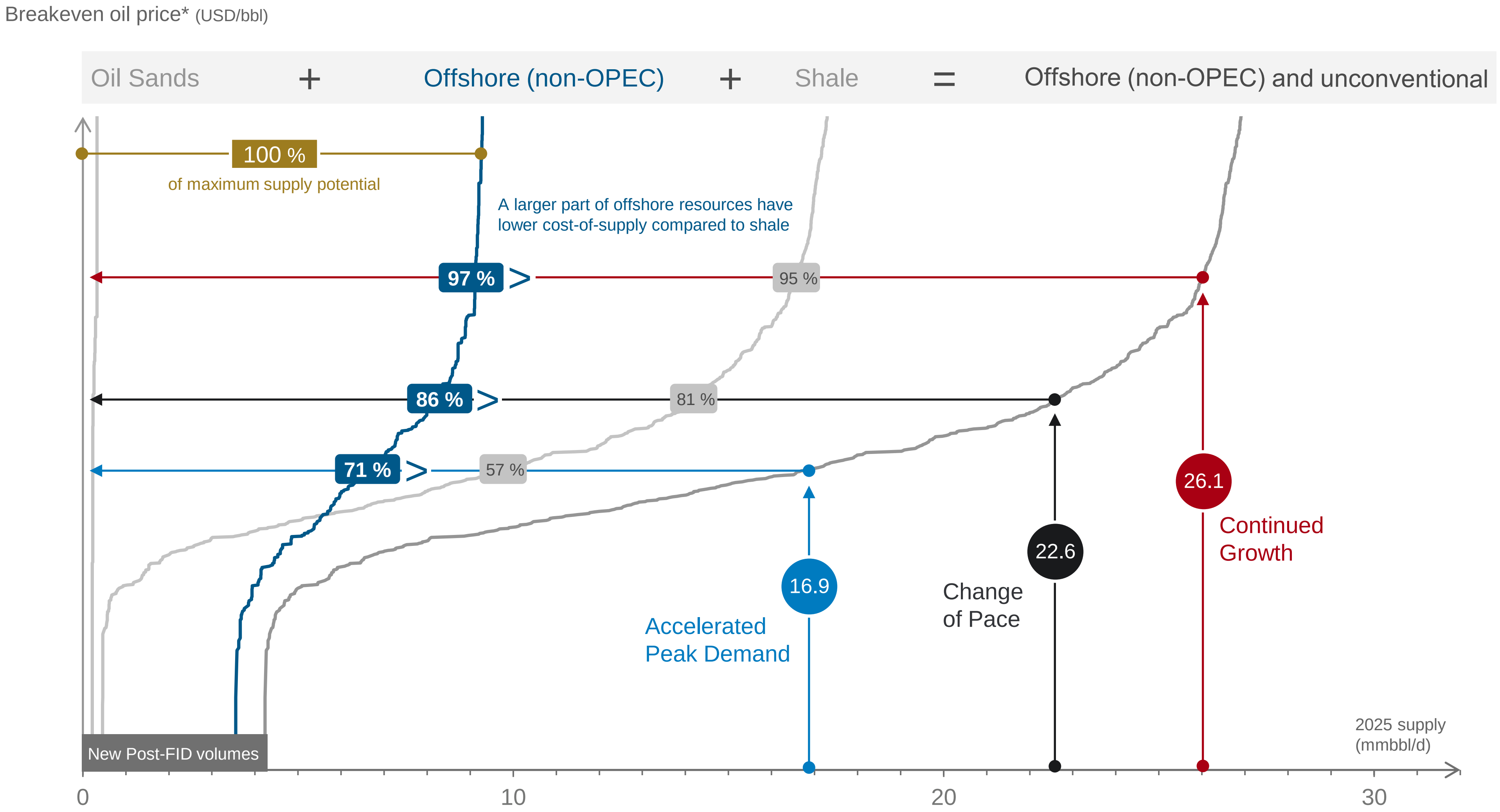
Production from currently producing fields*
mmbbl/d

Total and new supply from offshore and unconventionals*
mmbbl/d

*Non-OPEC offshore and unconventionals
Source: Rystad Energy research and analysis

Significant share of offshore resources are competitive from a pure cost-of-supply analysis

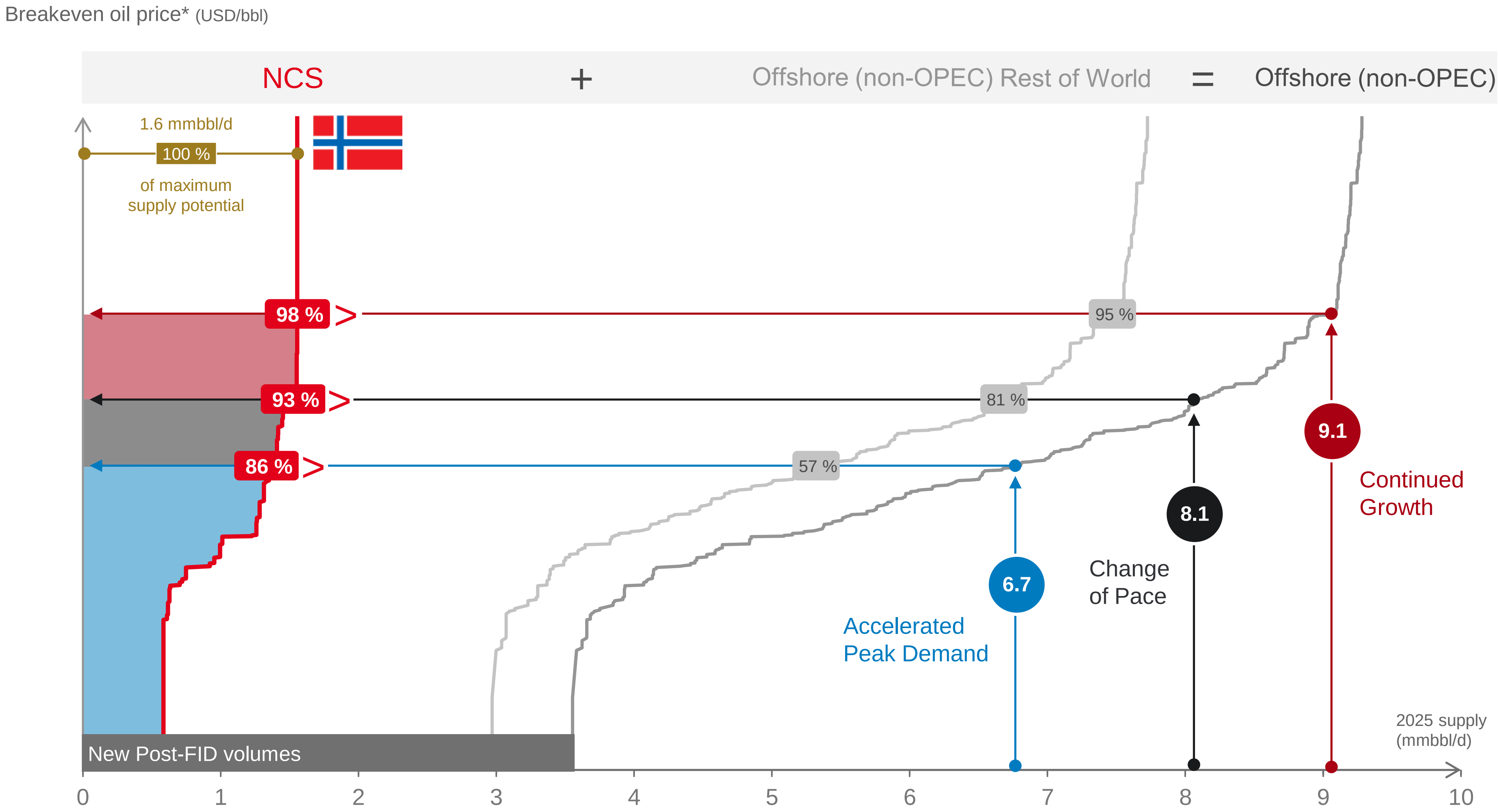
Cost of supply for non-producing fields (non-OPEC offshore and unconventionals)



*Based on 7.5% real discount rate and full tax position where relevant. Premium on offshore (non-OPEC) and oil sands in Change of Pace and Accelerated Peak Demand scenarios.
Source: Rystad Energy UCube; Rystad Energy research and analysis

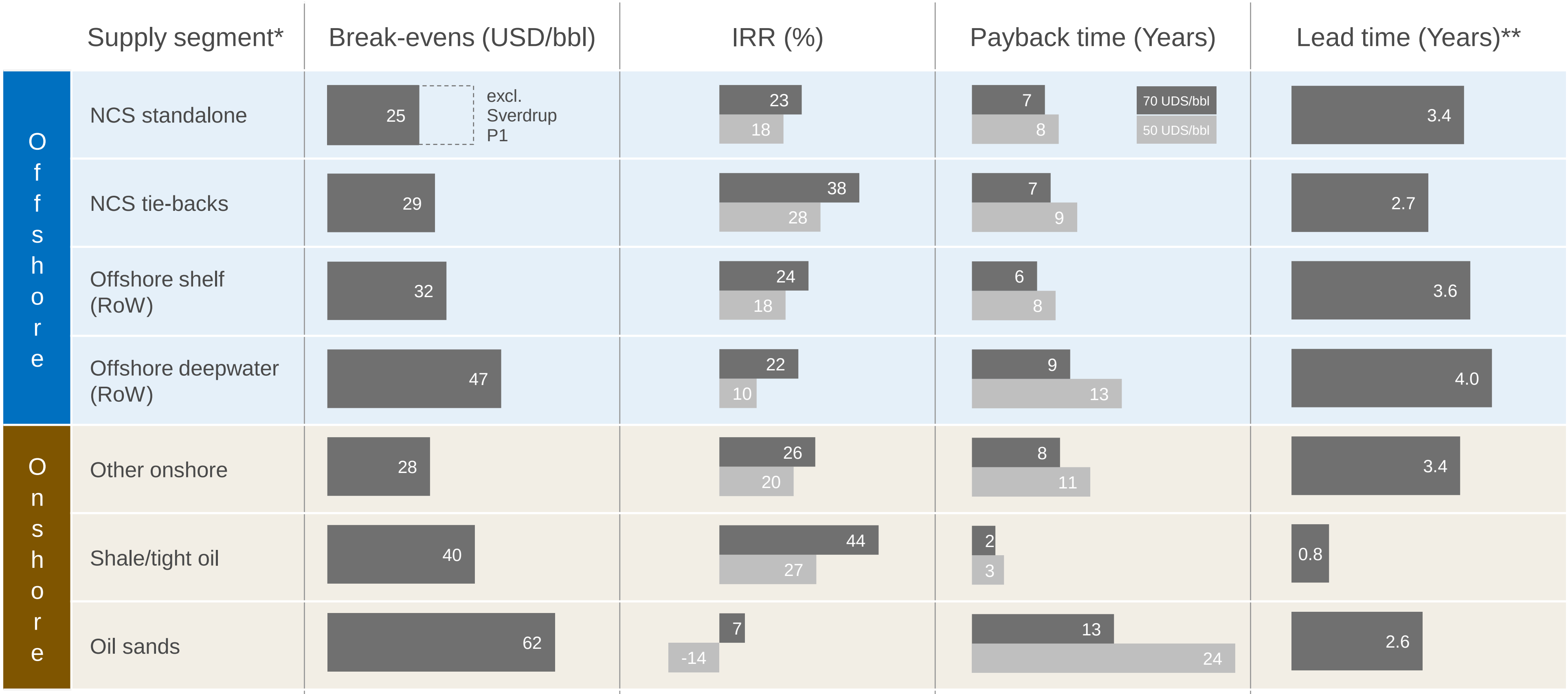
NCS resources very competitive compared to offshore resources in the rest of the world (RoW)

Cost of supply for **new offshore supply** split on region



*Based on 7.5% real discount rate and full tax position where relevant. Premium on offshore (non-OPEC) and oil sands in Change of Pace and Accelerated Peak Demand scenarios.
Source: Rystad Energy UCube; Rystad Energy research and analysis

NCS resources and shale oil the most attractive resources among supply segments



	Supply segment*	Break-evens (USD/bbl)	IRR (%)	Payback time (Years)	Lead time (Years)**
Offshore	NCS standalone	25 (excl. Sverdrup P1)	23 18	7 8	3.4
	NCS tie-backs	29	38 28	7 9	2.7
	Offshore shelf (RoW)	32	24 18	6 8	3.6
	Offshore deepwater (RoW)	47	22 10	9 13	4.0
Onshore	Other onshore	28	26 20	8 11	3.4
	Shale/tight oil	40	44 27	2 3	0.8
	Oil sands	62	7 -14	13 24	2.6

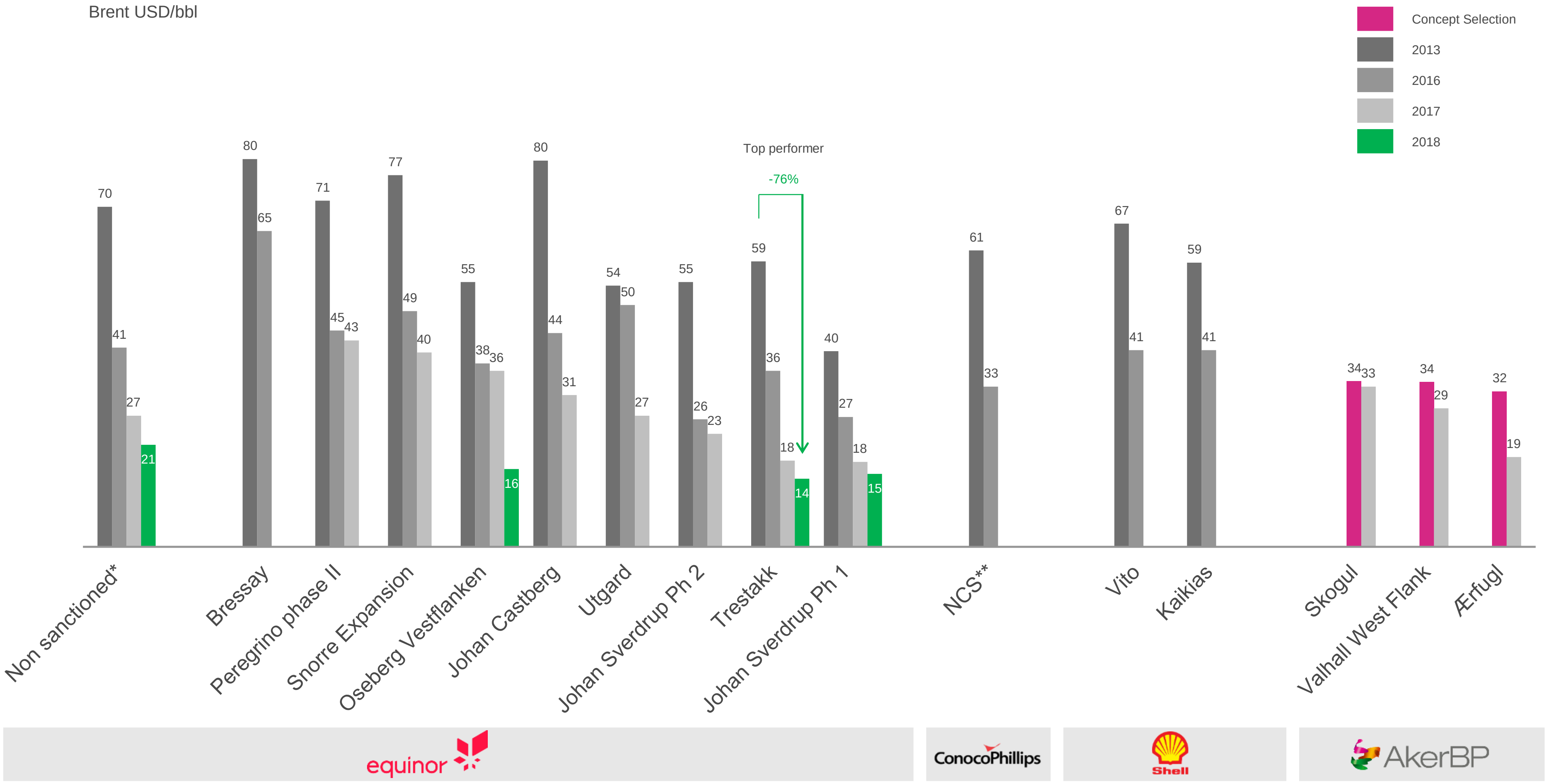
	Break-evens (USD/bbl)	IRR (%)	Payback time (Years)	Lead time (Years)**
Technology contribution	Positive	Positive	Negative	Negative
Description	• By definition, the business case for a given technology application should be positive and thus positively affect the breakeven of the project	• Increased project value from technology application should increase return on investment and project economics	• Increased project lead time and higher initial capital investments related to new technology will increase the total payback time of the project	• Development and/or application of new technology in a greenfield setting will likely increase lead time as new elements are introduced

*Top 30 projects in terms of resources within each supply segment, with FID between 2015 and 2020 **Time from Approval Year to Production Start Year

Sources: Rystad Energy research and analysis; Rystad Energy UCube

Offshore break-evens down 40-60% since 2013, some projects achieving up to 70% reduction

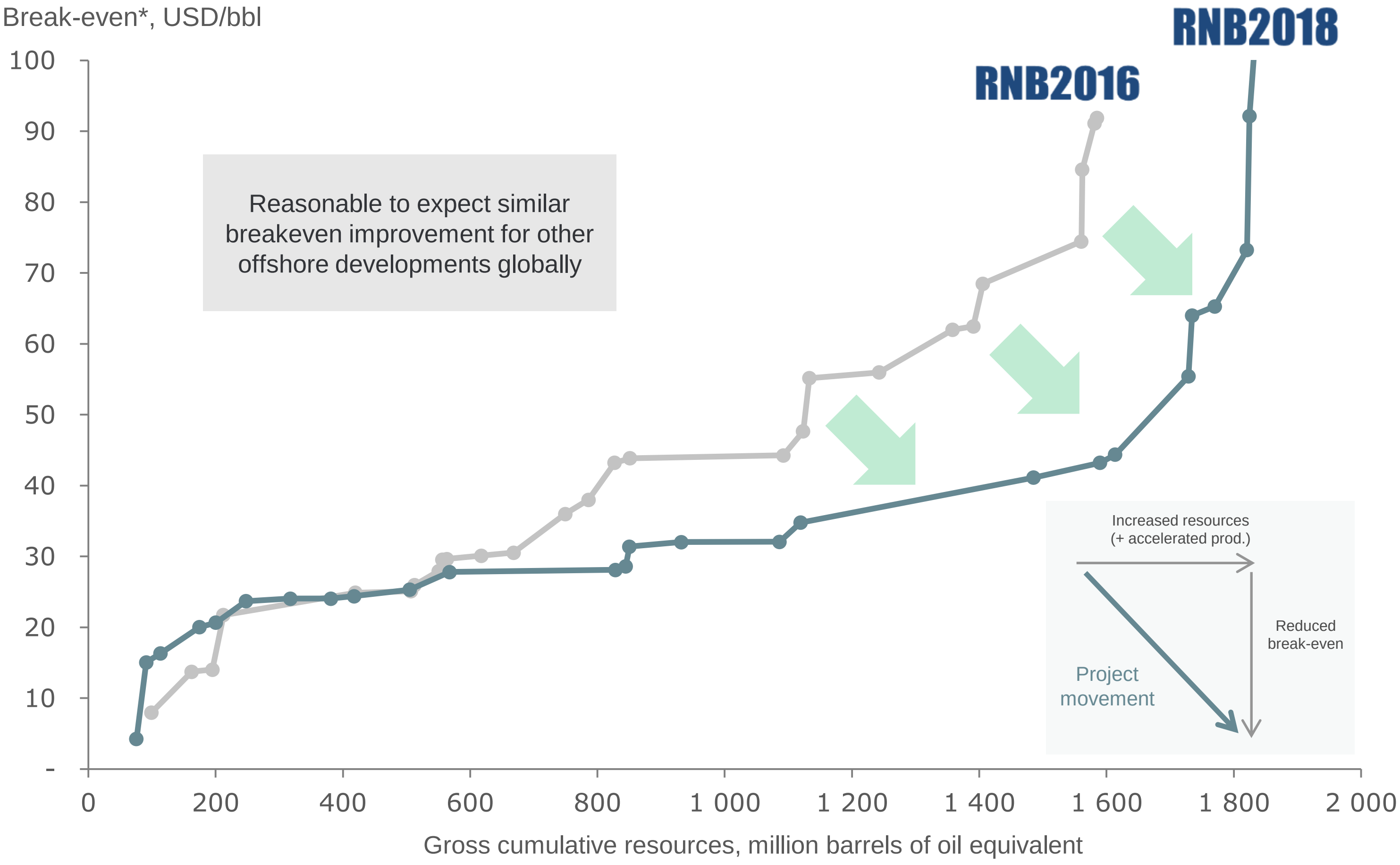
Break-even reductions for selected offshore projects



2013 and 2016: Equinor operated projects, planned for sanction within 2022. Volume weighted. 2017 and 2018: Equinor- 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: Equinor (Statoil) Capital Markets Day 2016, 2017 and 2018, Shell, ConocoPhillips, AkerBP

Petoro has communicated substantial improvements in pre-FID project economics

Cost of supply for “like-for-like” contingent projects in the SDFI portfolio



Reasonable to expect similar breakeven improvement for other offshore developments globally

RNB2016

- Operator data on production and cost submitted to Norwegian authorities in **October 2015**
- Submission timing was at the early stage 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 significantly improved SDFI portfolio cost competitiveness

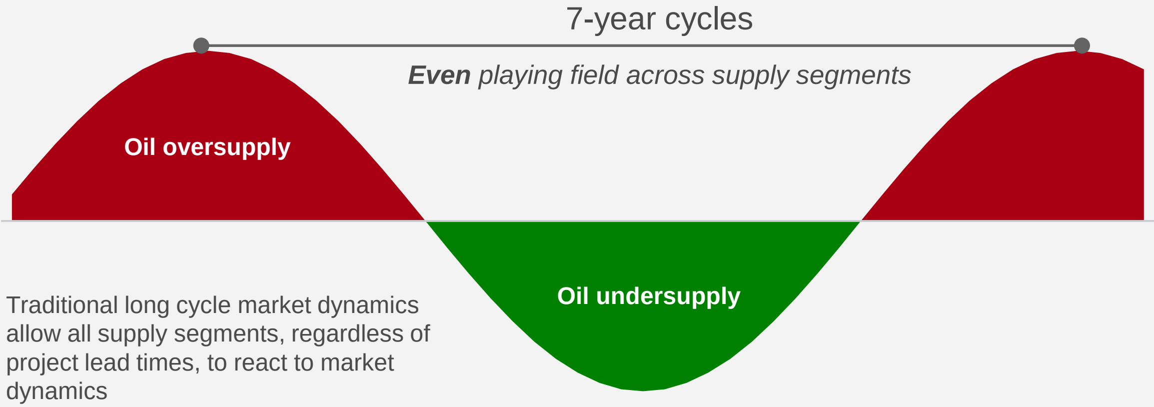
Petoro’s mission is to oversee the Norwegian State’s Direct Financial Interest (SDFI) in Norwegian oil and gas fields. The project portfolio represents interest in about 75% of the remaining NCS discovered resources. As such the improved project economics provide a very good indication of general offshore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

*Breakeven assumes 7.5% real discount rate and full tax position
Source: Petoro

Structural shift in oil market dynamics to shorter cycles set to hurt offshore?

Traditional oil market

Oil market supply/demand dynamics



***Even** playing field across supply segments*

Traditional long cycle market dynamics allow all supply segments, regardless of project lead times, to react to market dynamics

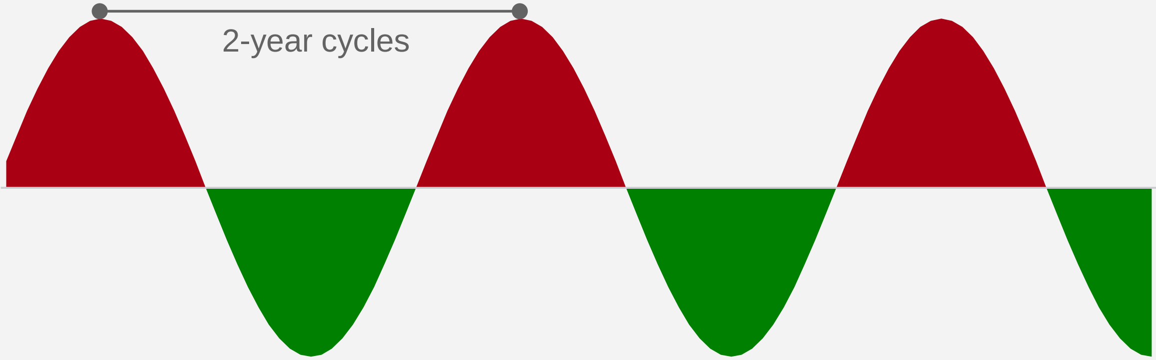
Competitiveness through:

Project break-even prices

- Classic model applicable: **Competition can be measured in break-evens**
- Offshore supply competitive when reaching cost parity with tight oil
- Capital influx from an array of players that can bear the long payback profile of an offshore project

New reality?

***Uneven** playing field across supply segments*



Tight oil responds by adding capacity, while offshore does not have the time to respond.

Short cycled tight oil volumes being part of the marginal producer stack → expect shorter cycles

Competitiveness through:

Project lead time

- Classic model not applicable: **Focus on rapid paybacks**
- **Offshore too slow to compete** - price signal gone before able to sanction?
- Capital influx from investors who can see through multiple cycles

Source: Rystad Energy research and analysis

Lead time has become an important decision metric – critical for adoption of new technology

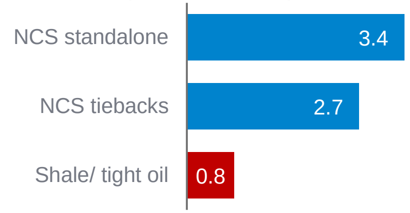
Why the focus on lead time?

Key characteristics

Agile competitor

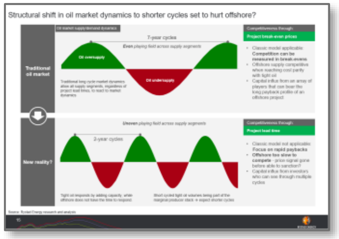
- Shale has established itself as the marginal source of oil production
- Shale producers are more agile and able to respond to oil price and cost-of-supply parity of their resources much faster than other producers, especially offshore developers

Lead time (FID to first oil)



Shorter cycles

- Shale producers may cause a structural shift in oil market dynamics, from long cycles to shorter cycles caused by the short cycle nature of shale resources
- The playing field becomes uneven as resources with longer lead times cannot respond quickly enough to cope with the new short cycle oil market environment



Structural shift in oil market dynamics to shorter cycles set to hurt offshore?

Traditional oil market

7-year cycles

Even playing field across supply segments

Oil oversupply

Oil undersupply

Competitiveness through

Project break-even prices

New reality?

Uneven playing field across supply segments

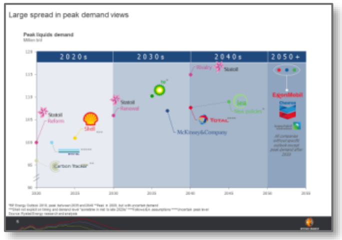
2-year cycles

Competitiveness through

Project lead time

Peak demand?

- Energy diversification and peak oil scenarios create uncertain outlook for oil and gas prices
- Times of uncertainty draw capital from investors looking for quicker payback on their investment, which (again) favors the short cycle shale producers



Large spread in peak demand views

Peak liquids demand

Offshore players trying to short-cycle typically long-cycle projects

- Large reserves, high value offshore projects are built as phased developments with smaller initial investments to establish production, creating cash flow to support their own expansion through several phases.
- Lean development concepts with conventional technology are used to reduce lead time. Examples include:
    - Zohr in Egypt (Eni) – 3 phases – 2.5 years from discovery to first oil
    - Liza offshore Guyana (ExxonMobil) – 2 phases, uses converted VLCC in first phase – 5 years from discovery to first oil (2020)

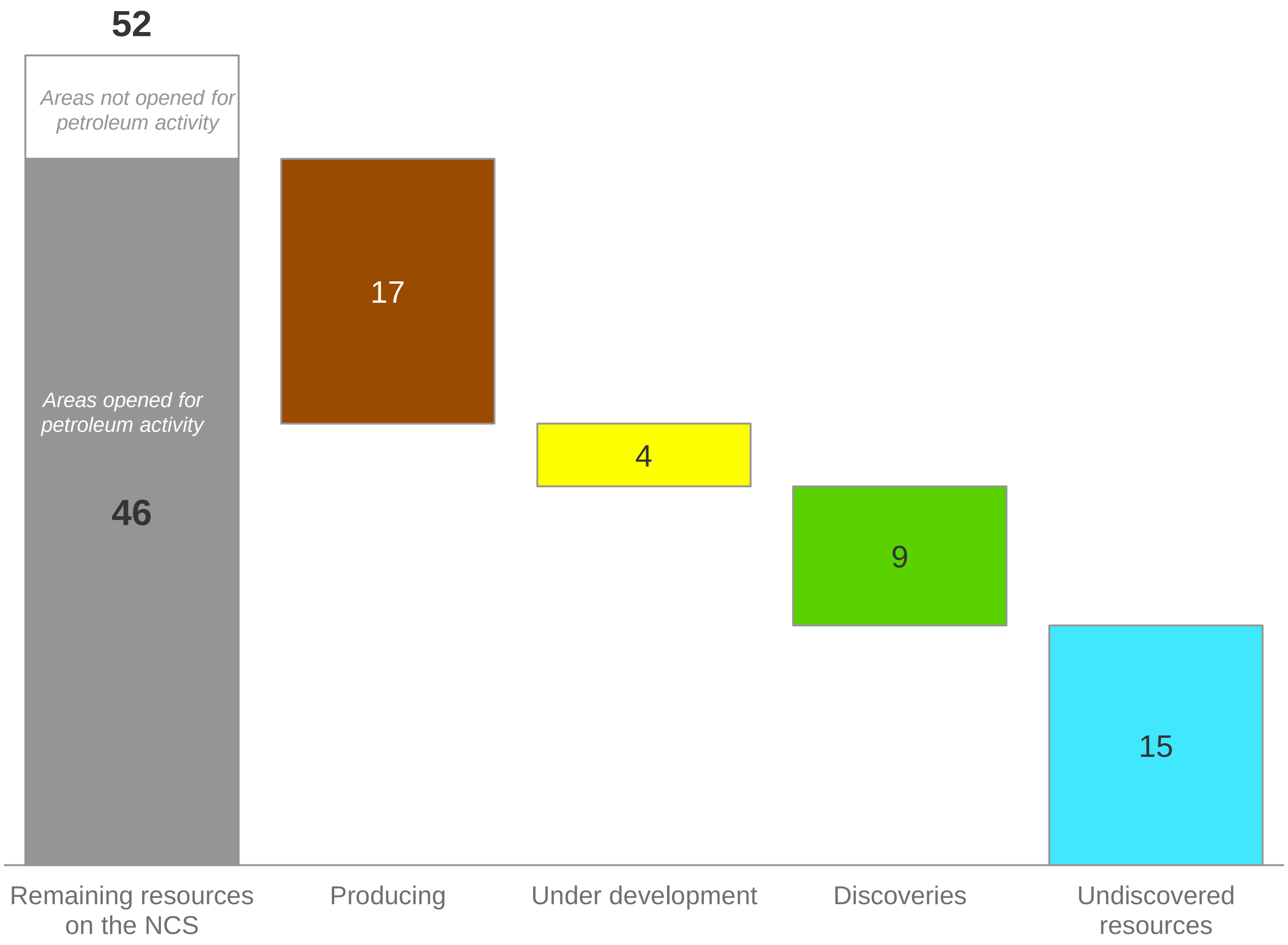
Source: Rystad Energy research and analysis

Index

NCS resources

52 billion boe left on the NCS – 67% of which is not currently in production

Remaining resources on the NCS split by life cycle
Billion barrels of oil equivalent



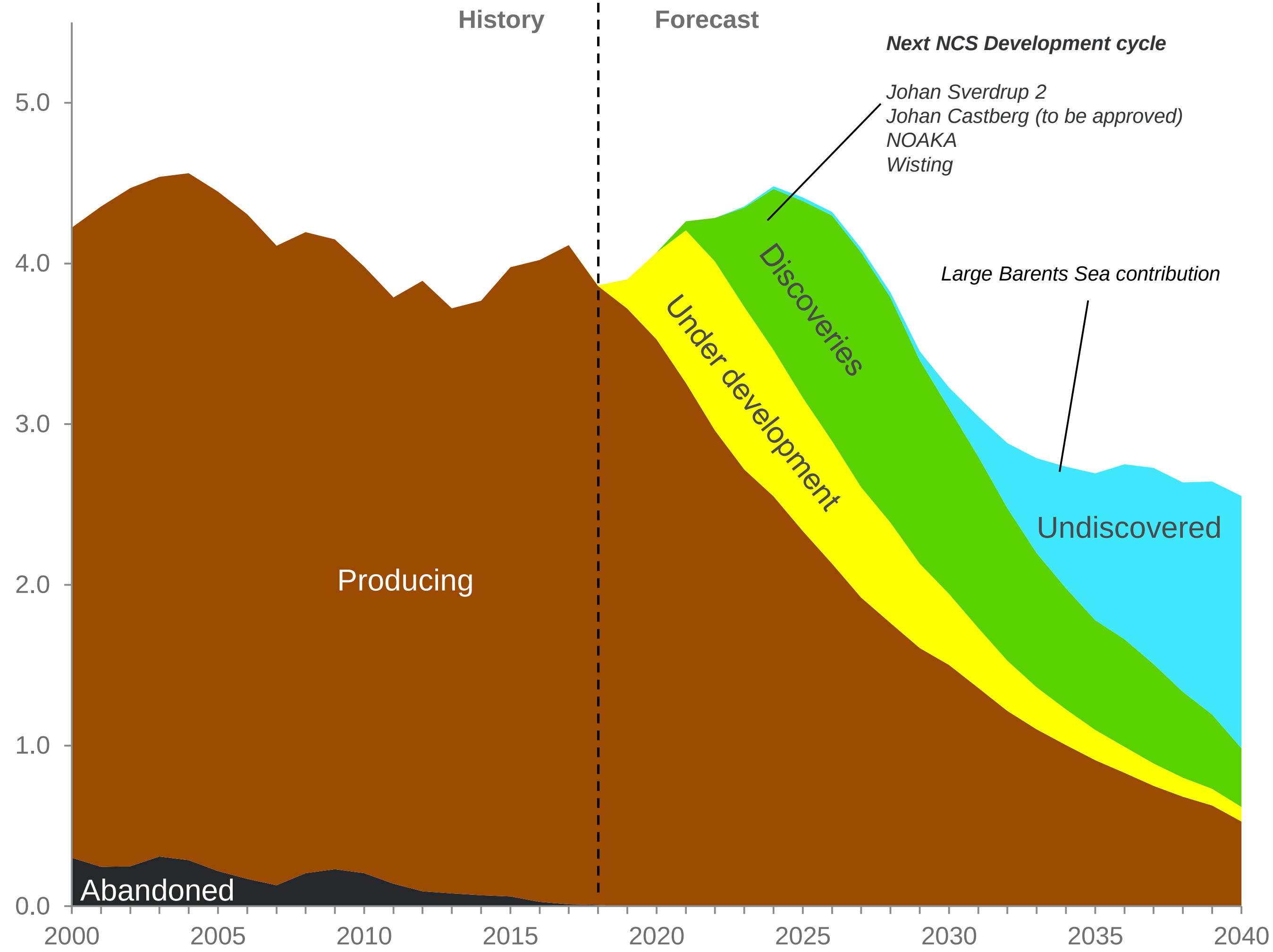
- The chart shows estimated remaining resources on the NCS split by field life cycle as of May 2018.
- Remaining resources on the NCS are estimated to 52 billion boe, with ~90% located in areas opened for petroleum activity.
- Producing fields are estimated to hold the largest share of remaining resources (17 billion boe, 33% of remaining). It is further estimated that opened areas contain undiscovered resources almost amounting to what is currently producing fields – 15 billion boe
- 4 billion boe is located in fields that are currently under development, with the largest being the giant Johan Sverdrup field. In total, 9 billion boe have been discovered, but are not (yet) sanctioned. Many of these are smaller discoveries.

Source: NPD; Interviews; Rystad Energy research and analysis

NCS baseline production

Production peak of ~4.5 million boe/day towards 2024 with rapid decline towards 2030

Production on the NCS split by life cycle
Million boe per day

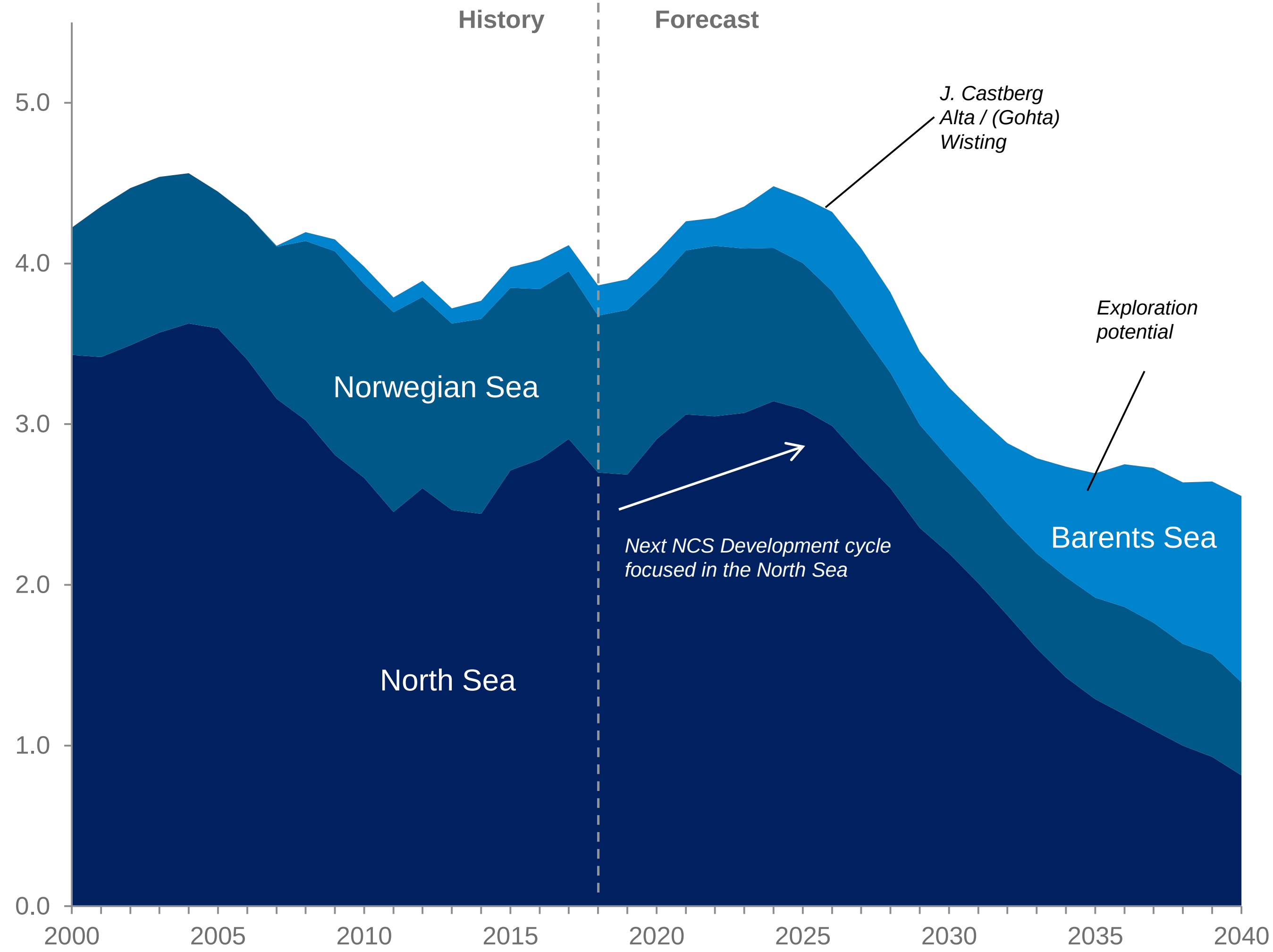


- Oil and gas production on the NCS reached 4.0 million boe/d for the first time in 1997. From peak production of 4.5 million boe/d in 2003, the production dropped to a local low of 3.7 million boe/d in 2013. In 2017 the production increased once more to a level of 4.1 million boe/d.
- Future production on the NCS is expected to increase to 4.5 million boe/d in 2024 as new production from projects like Johan Sverdrup phase 2 and Johan Castberg is expected to come on stream.
- From the chart, we observe that discoveries must be sanctioned to maintain production from 2021 towards 2030. After 2027, new discoveries are needed to maintain production at around 4 million boe/d and prevent rapid decline.
- In 2040 production is forecasted to be a little more than half of current production, and around 60% is likely to come from fields not yet discovered.

Source: NPD; Interviews; Rystad Energy research and analysis

North Sea represents 70% of current NCS production – Barents Sea majority producer in 2040

Production on the NCS split on province
Billion barrels of oil equivalents

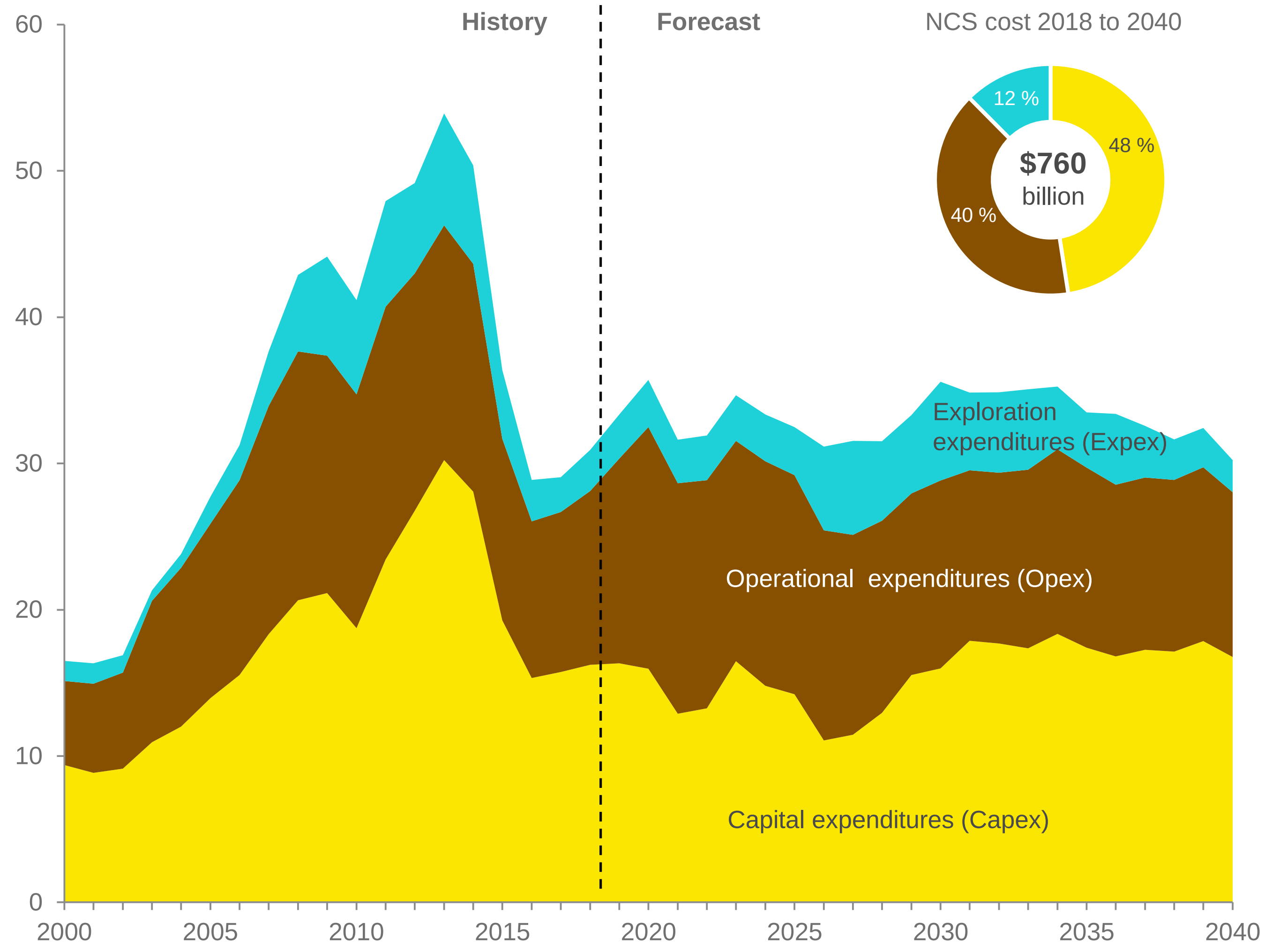


- Oil and gas production on the NCS is currently dominated by the North Sea, which produced 71% of total NCS output in 2017.
- North Sea's share of NCS production is expected to remain stable at ~70% towards 2025, then gradually decrease to 32% in 2030.
- In 2017 Barents Sea production constituted 4% of total NCS production. However, the Barents province holds the majority of the undiscovered resources on the NCS, which is reflected in future production. By 2040, production from Barents Sea is estimated to make up 45% of NCS production.
- The Norwegian Sea currently represents 25% of NCS production, which is expected to decrease to 20% in 2030, eventually increasing to 25% again by 2040.

Source: NPD; Interviews; Rystad Energy research and analysis

Historic high of over $50 billion in 2013 will not return – costs expected to be flat towards 2040

Expenditures on the NCS split on category
Billion USD (real 2018)



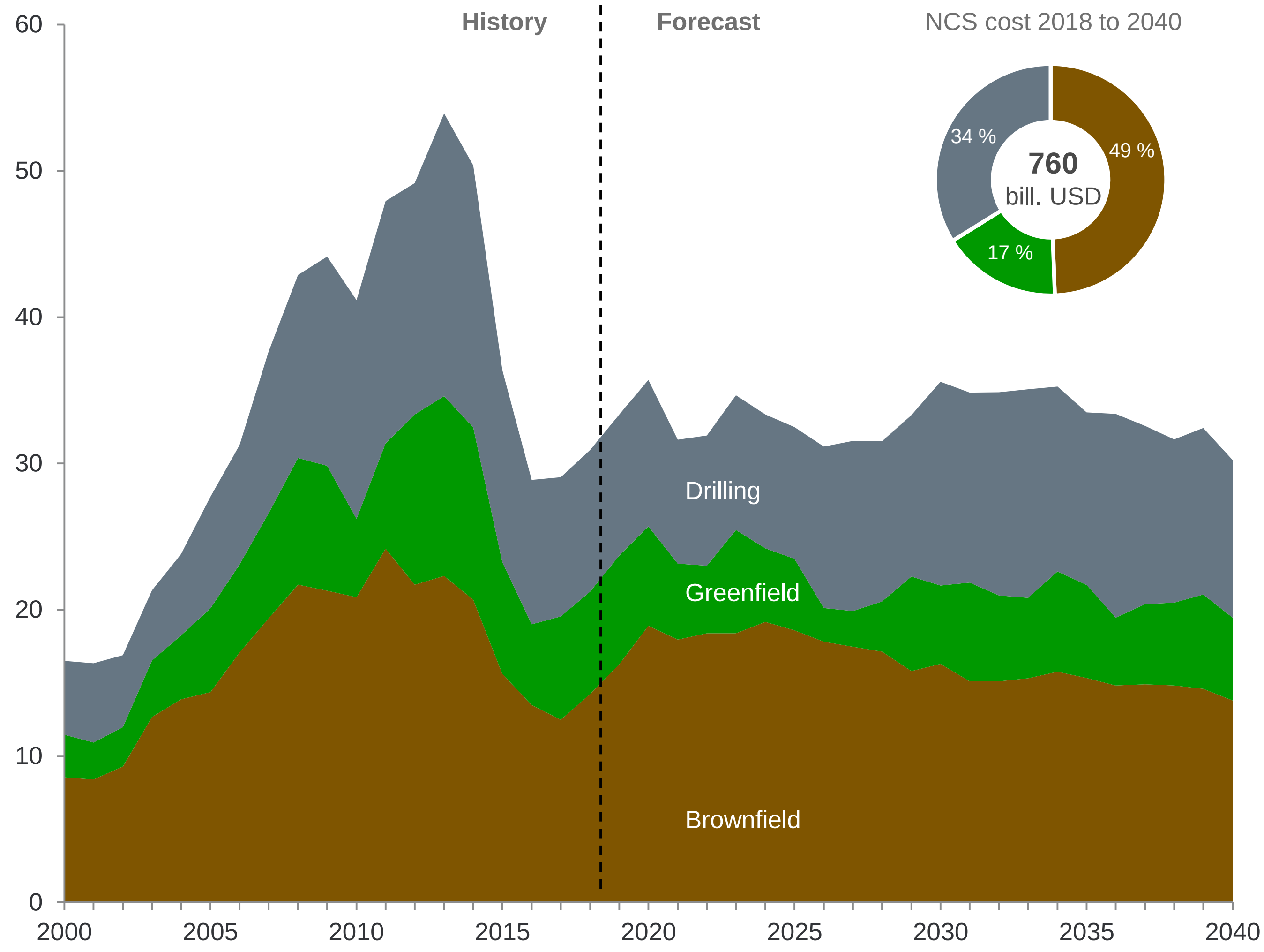
- Expenditures on the NCS reached $54 billion (real 2018) in 2013. Triggered by the oil price collapse, expenditures on the NCS fell to $29 billion in 2016, a 46% decrease in just three years
- After reaching a bottom in 2016, expenditures have stabilized and are expected to increase towards 2020.
- Expenditures are expected to remain fairly flat from 2020 towards 2040. Opex is expected, for a limited period, to exceed capital costs in the mid-2020s. This can be explained by the wave of current development projects coming to an end, switching mode from capex to opex.
- Exploration costs on the NCS, which currently make up 10% of costs, are expected to increase to 20% post 2025 as operators get improved operational cash flow. Also, more resources need be discovered to mitigate production decline on the NCS and globally.

Source: NPD; Interviews; Rystad Energy research and analysis

NCS expenditures

Mature NCS drives brownfield and drilling

Expenditures on the NCS split on category
Billion USD (real 2018)



In the chart, costs have been grouped into three parts:

- Drilling: all costs related to wildcats, appraisals, development drilling and infill drilling
- Greenfield: development costs (primarily capex) on new fields excl. drilling.
- Brownfield: opex and capex on producing fields excl. drilling.

- Costs related to brownfield are, and will remain until 2040, the biggest expenditure due to the maturity of the NCS. In 2017, brownfield related costs made up 43% of total costs.

- In 2017, greenfield costs made up 24% of total costs. However, this number is for a few years expected to decrease to below 10% in the mid-2020s, as the portfolio of new development projects on the NCS decreases, subsequently rebounding to ~20% in the late 2020s until 2040.

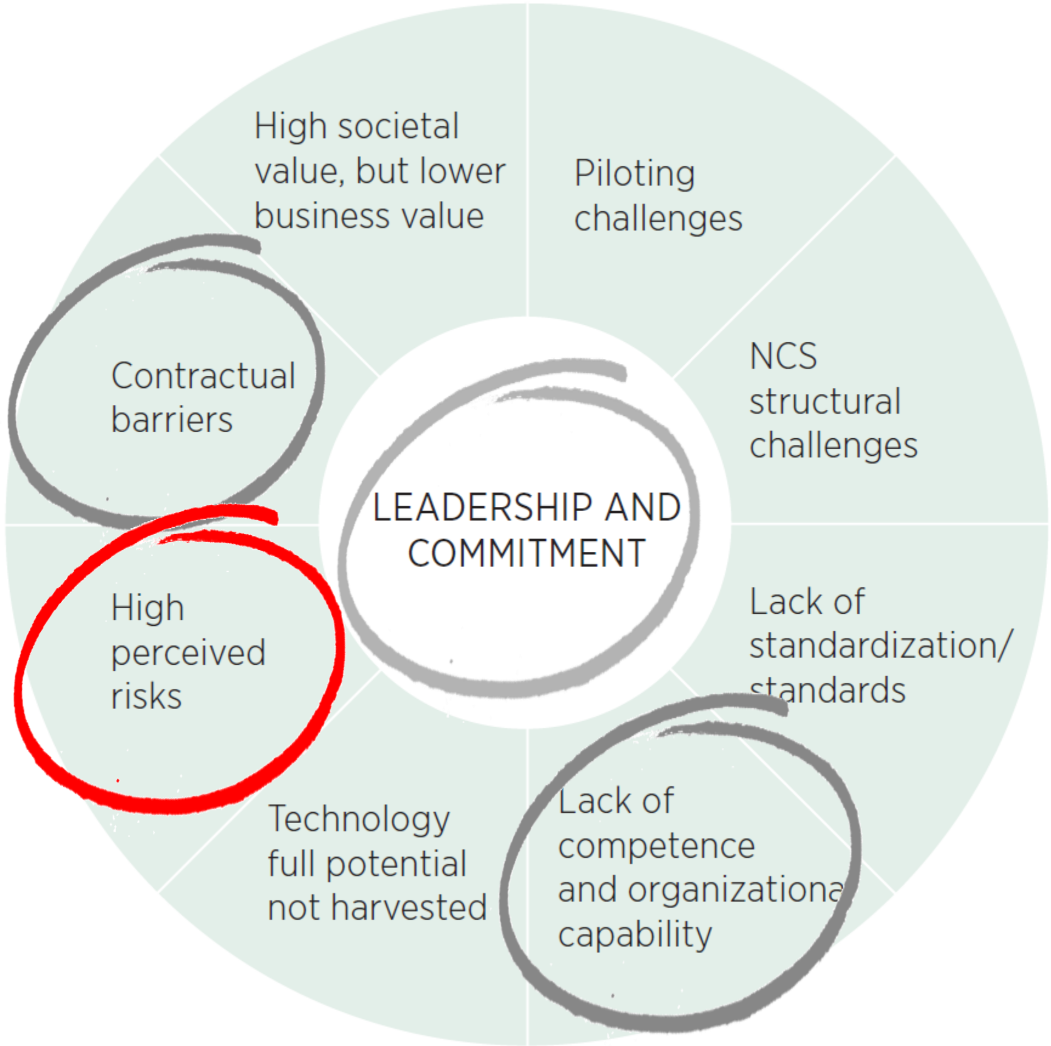
- Drilling costs make up a large part of greenfield projects and from 2018 to 2040 constitute $100 billion in greenfield drilling, $100 billion in exploration drilling, and $50 billion in infill drilling (brownfield).

Source: NPD; Interviews; Rystad Energy research and analysis

Index

OG21 has identified perceived risk as one of the key barriers for technology adoption

Main barriers for technology development and adoption as identified by OG21

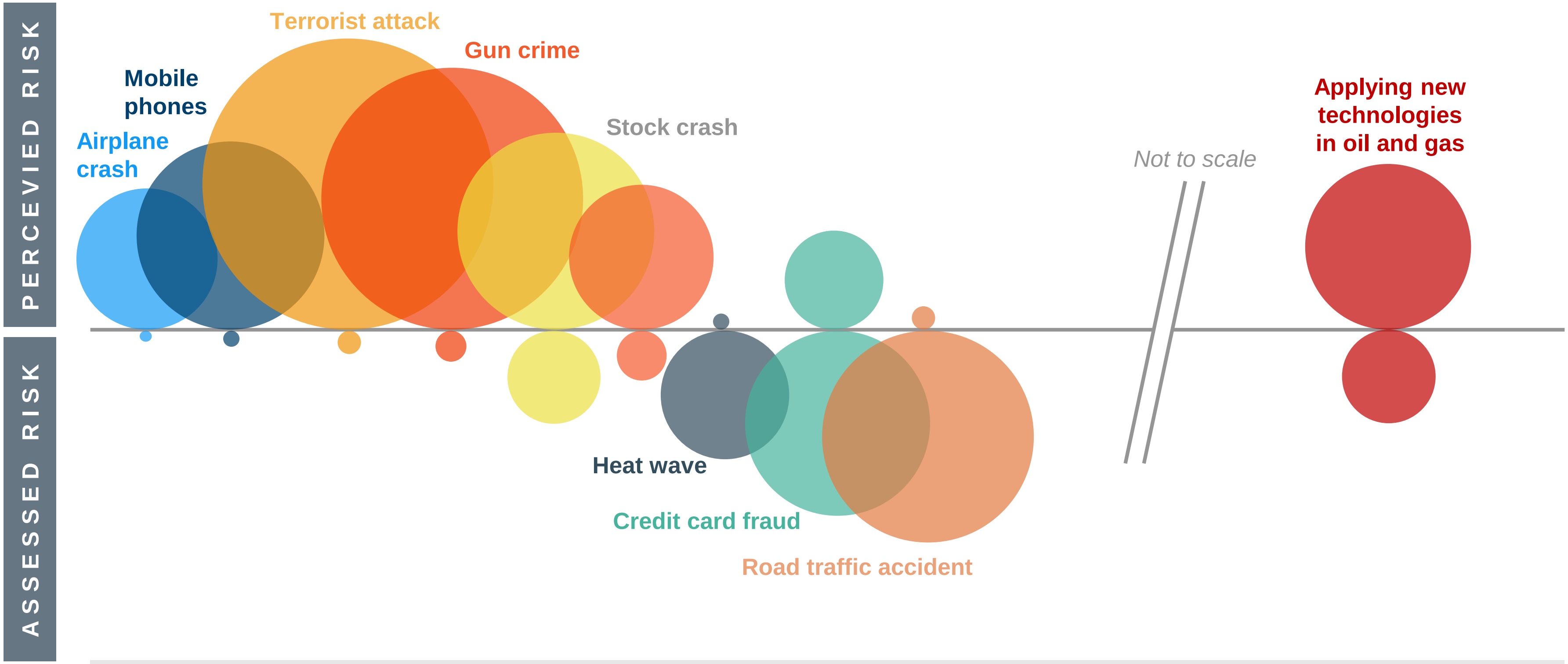


- OG21 in its latest strategy revision identifies high perceived risk as one of the main barriers in implementing new technologies. Lack of competence / organizational capability is also identified as a main barrier.
- These two tie together, as high perceived risk often occurs with limited risk assessment systems in place or limited technology competence.
- Also, contractual barriers tie with the risk term. This is especially true for integrated contract modes, where sharing of risk and return between operator and supplier is one of the driving forces.
- Under *High perceived risk* the document details three sub themes:
  - Some technologies are intrusive – affect cash flow if problems
  - Risk perception, aversion and conservatism
  - Perceived or real HSE risks

Source: OG21 strategy; Rystad Energy research and analysis

Perceived risk seldom aligns with assessed risk – oil and gas technologies are no exception

Risk perception vs assessed risk



- Studies reveal that there is a large discrepancy between the scenarios that the population fears and those that are actually harmful (see chart above). I.e., the public's perceived risk of flying is far higher than that of driving a car. Assessed risk of flying is actually very low, and driving a car is objectively one of the more dangerous things to undertake.
- In the OG21 strategy, **perceived risk is identified as one of the barriers of technology adoption.** That is, an additional premium on the assessed risk, explaining the conservatism and risk aversion that characterizes the industry in adopting new technologies.
- For the purpose of this study, we always assume that the perceived risk is higher than the assessed risk, driven by the detailed procedures on HSE and qualification underlying risk assessment procedures.

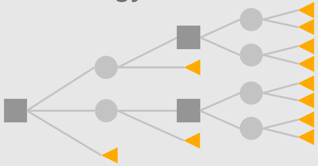
Source: Susanna Hertrich, 2008: «Reality Checking Device»; OG21 2016 strategy; Rystad Energy research and analysis

Traits of assessed and perceived risk – the concept of perceived risk premium

ASSESSED RISK

Quantitative or qualitative risk assessment that evaluates the likelihood and magnitude of impact in applying a new technology

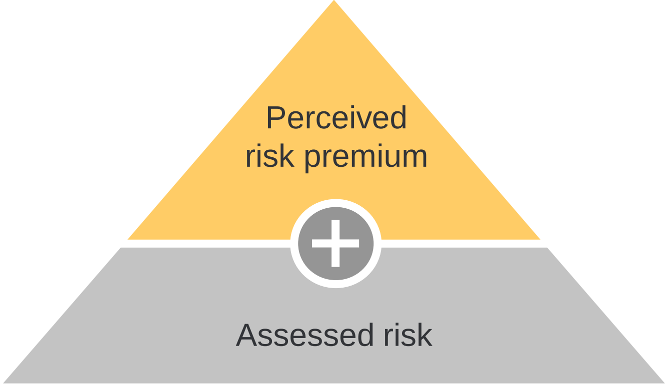
- Analytical and rational
- High degree of knowledge about the technology
- Systematic and common approach for technology evaluation



PERCEIVED RISK

<u>Feelings</u> of uncertainty about the consequences of a applying a new technology

- Feelings based
- Lack of knowledge about the technology
- Lack of trust in the presented assessed risk or in the people that conducted it
- Non-systematic



Perceived risk premium

Assessed risk

Total risk perception

- Assessed risk is related to <u>rational decision making</u> which makes use of systemized risk assessment methods with a set of defined inputs. Although these inputs may vary from company to company, the approach is similar.
- Perceived risk involves gut-feeling and instinct-based decision making. Past experience , company culture and reward systems are important «inputs» into these types of decisions.
- It is the total risk perception that is decisive for a technology decision. In the world of oil and gas, the assessed risk is always the foundation, while a perceived risk premium also applies.

Source: Rystad Energy research and analysis

… but also assessed risk methods include subjective considerations and assumptions

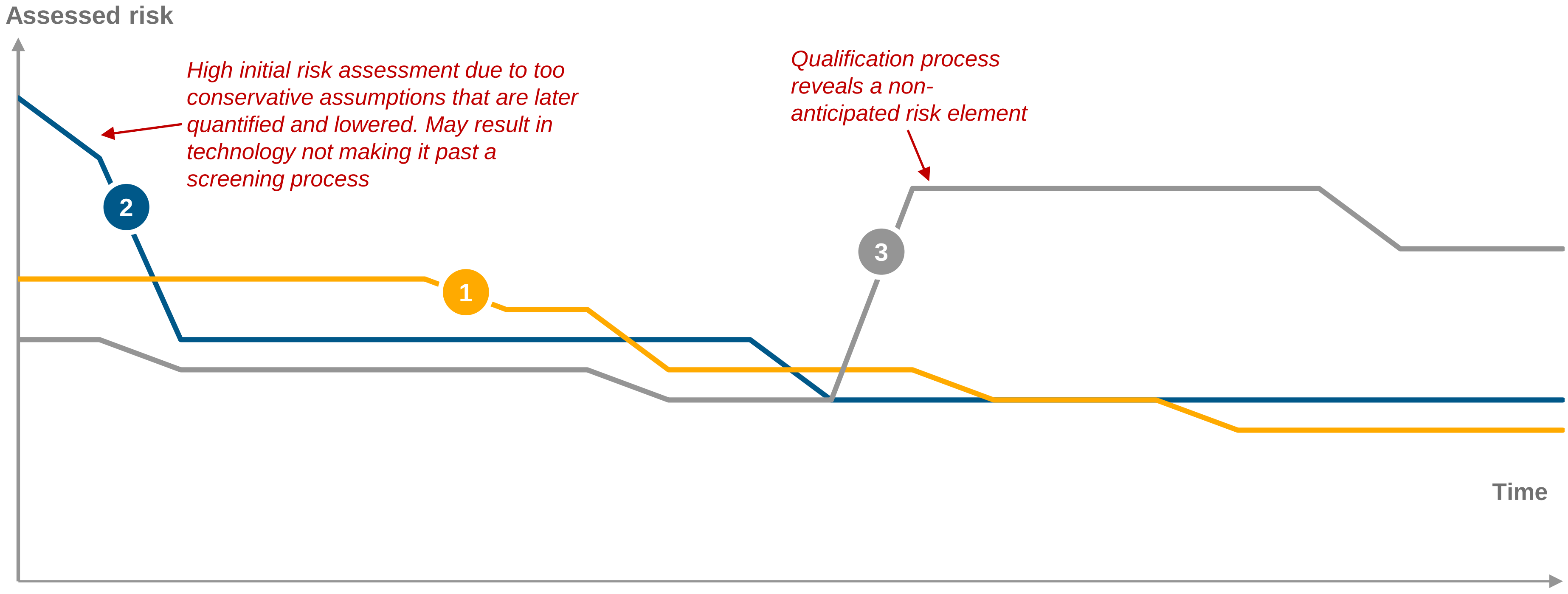
	Common methods*	Description of method	Subjective inputs	Importance for technology decisions
Qualitative	Hazard analyses	HAZOP (Hazard and Operability study) and HAZID are table based methods that aim to identify and describe hazards by looking at possible operational deviations or incidents to a component. • Method is qualitative, does not quantify effects or likelihoods. • Output: A list of problem areas that lead to potential hazards and suggested changes to mitigate consequences.	• Brainstorming of deviations and possible incidents	• Part of standard “due-diligence” when qualifying technology • Seldom forms a part of the basis for the final technology decision, but key hazards may be brought forward from this exercise • HAZID may serve as a preparatory method to FMECA and Tree Analyses • Important tool in the development of a technology
	Failure Mode analyses	• FMEA or FMECA (Failure Mode, Effect [and Criticality] Analysis) is a rigorous and systematic component by component approach to evaluate single point failures in a system. • Can be qualitative or quantitative. In a quantitative setup, frequency, effect and (frequency/probability) and effect may be qualitative or quantitative. • Output: the result is a prioritized list of component and failure modes with high criticality (high likelihood/frequency and severe consequences) which works as a priority list in the design process of a technology	• Failure frequencies / probabilities • Effect	• Part of standard “due-diligence” when qualifying technology • Seldom forms a part of the basis for the final technology decision, but key failure modes with effects may be included in the final basis. • Can be used as a tool to screening technologies to take out the ones with the highest risk early in the process
Quantitative	Tree analyses	FTA (Fault Tree Analyses), ETA (Event Tree Analyses) gives a visual representation of interdependencies of events. FTA is top-down, where ETA is bottom-up. When probabilities are added to the branches one can calculate the total risk of the system evaluated. BTA (Bow Tie Assessment) combines both sides of the equation through a visual representation. • Output: Decision metrics, most typically a risk neutral NPV, with evaluated upsides and downside cases	• Events/Hazards • Likelihood • Effects	• Primary use of method is for decision making and often a part of the basis for final decision. • Decision metrics from method form key decision criteria for decision holder. • Quantifies all paths on tree giving a overview of the effect of up- and downsides.
	Simulations in existing models	• Using existing simulation models to carry out risk analysis. Often in the form of Monte Carlo simulations where multiple input parameters are varied across a set range. • The reservoir model is a common tool to conduct such analyses when analyzing the full range of effects a new technology can have on the reservoir. • Output: Decision metrics, most typically NPV	• Input parameters and ranges	• Used for decision making, gives good overview of upside and downsides, especially in cases with multiple uncertainties and outcomes.

In the early stages of qualification several of the parameters could be based on gut-feel and result in too conservative assessments

*A wide range of risk assessment methods are used in the oil and gas industry, some very domain specific, the list of methods in the table is far from exhaustive.

Source: Interviews; Research articles; Rystad Energy research and analysis

In the process of qualifying a technology the assessed risk is subject to change over time



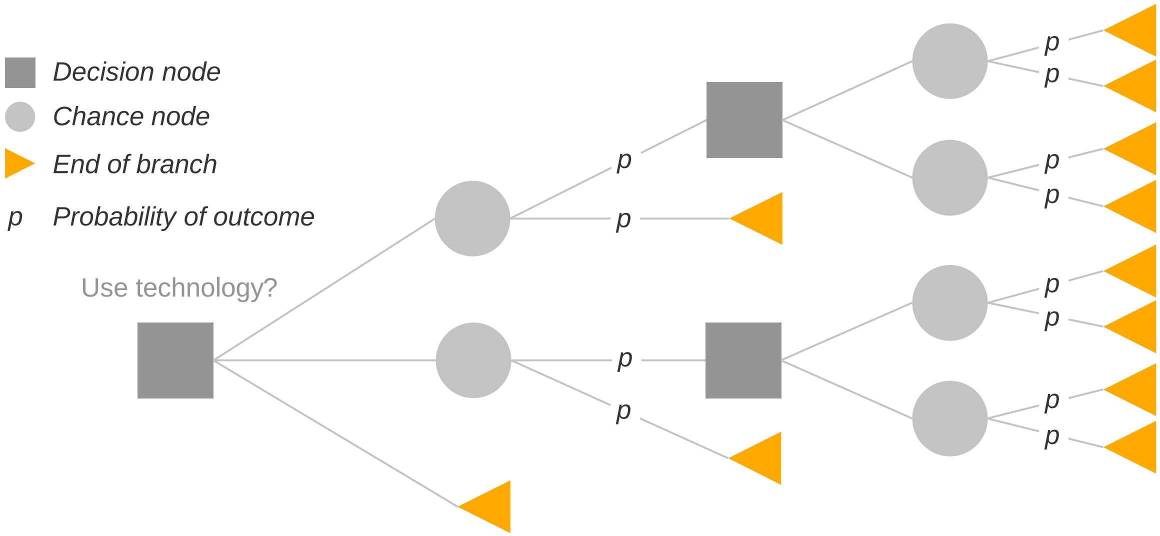
Assessed risk is not static over time. The process of qualifying a technology provides new information, improvements to technology and new mitigating actions to the most severe of outcomes.

1. **Typical technology path** – as a technology is matured towards first application, testing and mitigating actions will reduce the assessed risk compared to the initial assessment. Risk is at an acceptable level when decision to implement technology is taken.
2. **Early conservative assumptions** – Early risk assumptions can be set too high due to limited information or personal bias against technology. Can result in a technology being scrapped at an early/screening stage.
3. **Risk surprise** – common for most risk assessment methods is that the events and hazards identified is largely a result of a group's collective ideas. Unforeseen events and hazards, or complex interdependencies, may result in a risk surprise during the qualification period that stops

Source: Interviews; Rystad Energy research and analysis

Assessed risk method still allows for companies to arrive at different conclusions

Tree Analyses – common risk assessment method



Risk neutral NPV = SUM (◀)

Input

Decisions	Probabilities	Outcomes	NPV / other decision metric
• Cost • Purchasing power	• Experience / data	• Oil and gas price assumptions • Field selection that technology is applied to	• Discount rate

Assessed risk still leaves room for different decisions between operators. Key differentiators:

Probabilities (risk):

- – prior experience / in-house data vs. supplier provided failure data / no data
- – Shared risk with suppliers?

- Field / case selection: Type of field determines effect and value. Multiple field cases of application may increase value
- Macro assumptions: Oil and gas prices and service cost inflation are key inputs to estimate value.
- Cost: Purchasing power of the different operators may be different. Also, access to capital may be different from company to company.
- Discount rate: Based on given companies' investment opportunities, important decision criteria for positive technology decision.

Source: Rystad Energy research and analysis

Additional value metrics to NPV are also used when valuating technology application

IRR (Internal rate of return)

The discount rate at which NPV becomes 0

Used to prioritize between projects, as it gives the return on investment for each project. E&P companies could have IRR cut-off that depends on the competitiveness of their project portfolio or their shareholders' return criteria.

DPI (Discounted profitability index)

DPI = NPV / discounted capex

Measure of value (NPV) generated per unit of capex invested in a project or technology. E&P companies will typically have a DPI cut-off value at which they will not be willing to sanction a project below a certain threshold. Useful tool to rank investments. Problematic metric on the NCS due to high tax percentage, as pre-tax capex is used in the denominator.

Break-even oil/gas prices

The commodity price at which NPV = 0

Used as sanctioning criteria and commodity price sensitivity metric on projects, depends on discount rate chosen (typically 10% nominal). Projects with low break-evens will be robust even with lower prices.

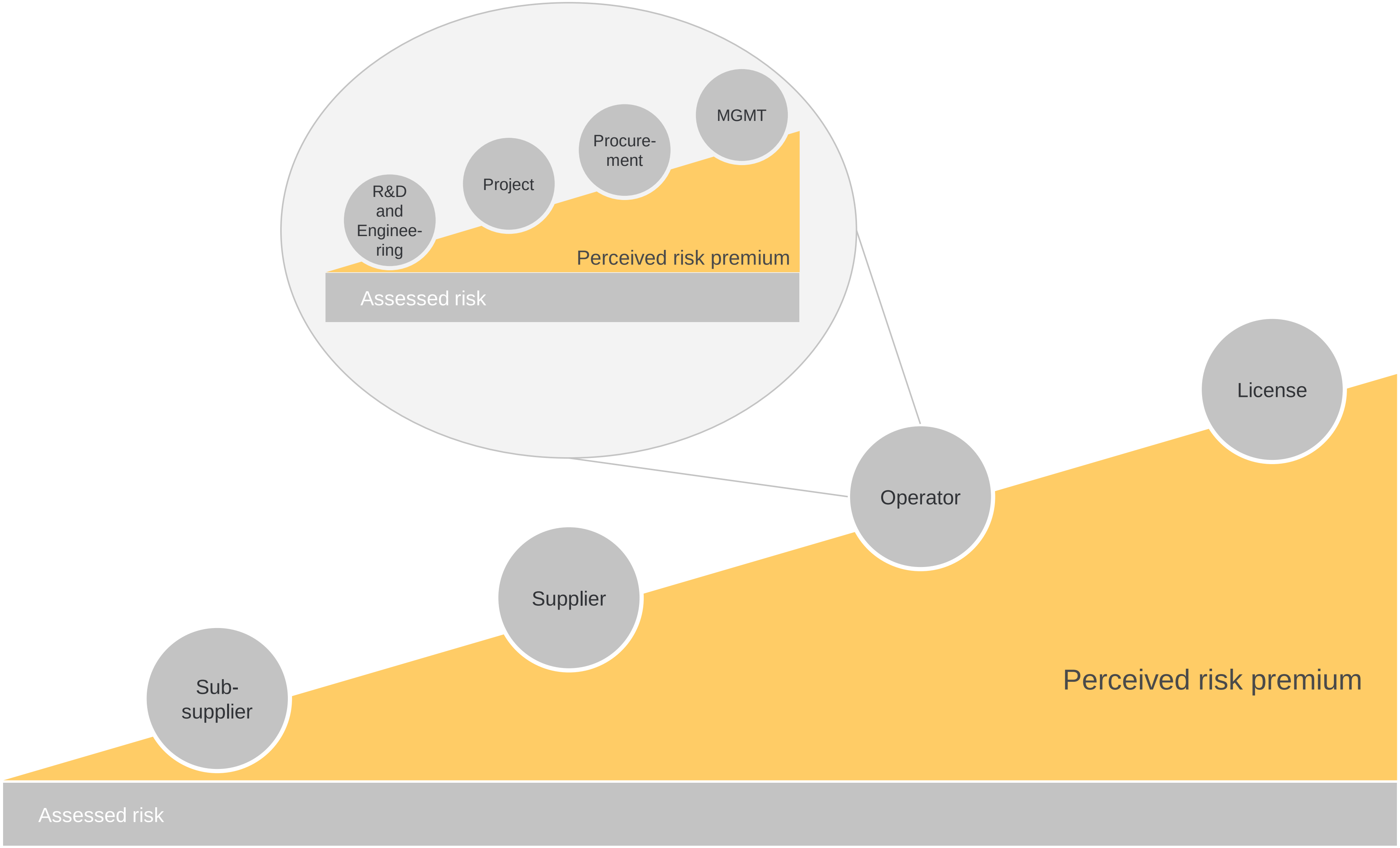
Payback time

The length of time needed to recover the cost of investment (nominal, real or discounted terms)

The longer time the higher uncertainty of external factors (i.e. oil price). It is also indicative of effect on the E&P company's cash flow situation. Could be evaluated in nominal, real or discounted terms, depending on the whether one wants to include the time-value of money.

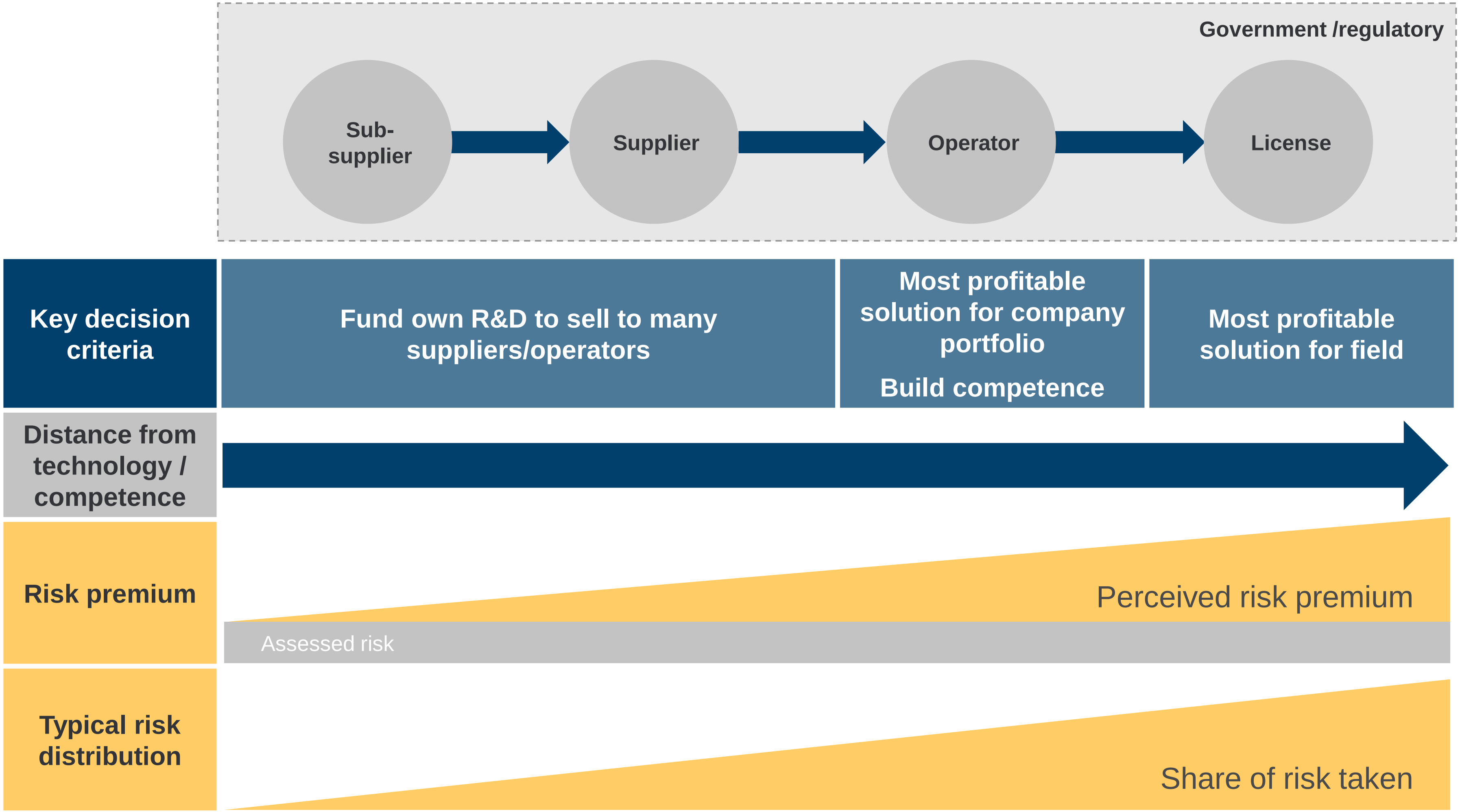
Source: Rystad Energy research and analysis

Distance from technology affects the perceived risk of the technology, also within the operator



Source: Rystad Energy research and analysis

Perception of risk and value likely to be different in the various “decision locations”



Government /regulatory

Sub-supplier → Supplier → Operator → License

Key decision criteria

Fund own R&D to sell to many suppliers/operators

Most profitable solution for company portfolio

Build competence

Most profitable solution for field

Distance from technology / competence

Risk premium

Perceived risk premium

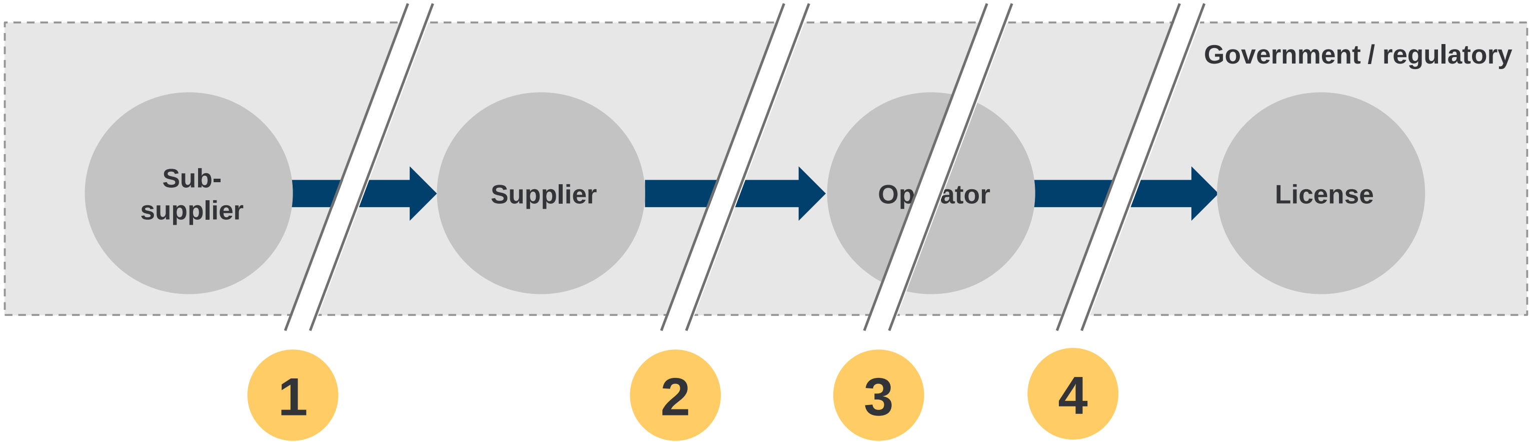
Assessed risk

Typical risk distribution

Share of risk taken

Source: Rystad Energy research and analysis

Four interfaces to evaluate risk and other decision criteria's impact on technology decisions



1. **Sub-supplier vs. supplier**
2. **Supplier vs. operator**
3. **Operator internal**
4. **Operator vs. license**

Source: Rystad Energy research and analysis

Index

Four perspectives on risk assessment and impact on technology decisions

Supplier vs. operator

Changed service landscape

Early involvement and effects of integration

Technology qualification
- Qualification vs. lead time
- Sharing of data

Sub-supplier vs. supplier

Value chain inefficiencies as obstacle for technology adoption

Effect of integration on smaller sub-suppliers

Risk assessment and impact on technology decisions

Operator internal

Decision criteria in greenfield, brownfield and drilling applications

Enabling vs enhancing technologies – pull vs. push

Organizational barriers
- KPIs and cross discipline challenges
- Procurement («Terms and conditions»)
- Changed work processes

Operator vs. license

Changed player landscape on the NCS over the last three years

License dynamics
- Field vs. portfolio value
- Partner investment opportunities
- Partner technology evaluation and risk appetite

Source: Rystad Energy research and analysis

Key take-aways from the four perspectives

Risk assessment and impact on technology decisions

Supplier vs. operator

- Early involvement has positive impact on the use of new technologies and innovative concepts, but could limit the set of potential technologies for application.
- Technology must find a license for last qualification steps, but the license may not have sufficient time for qualification without affecting lead time.
- Technology pipeline management challenging for suppliers with respect to field use cases and timing
- Limited data sharing results in requalification and negative technology decisions

Sub-supplier vs. supplier

- Sub-suppliers are a key contributor to technology development on the NCS and globally
- Value chain inefficiencies, like day-rate models, hinder adoption of new technologies from smaller sub-suppliers
- Although integrated set-ups create one more gatekeeper for the sub-suppliers, it may resolve some but not all value chain inefficiencies

Operator internal

- Decision holders are not incentivized to be first movers on new technologies, particularly for enhancing technologies
- Technologies that are cross discipline tend to amplify *“first mover disadvantage”*
- Procurement is cost-optimized rather than value-optimized – terms and conditions do not favor suppliers to take on technology risk
- Change of work process needed to fully realize value from new technologies

Operator vs. license

- Technology adoption may stop in licenses due to differences in perceived value and risk
- License partners do not get the same portfolio effect as operators in applying the technology for the first time, partly due to inefficient sharing of data
- The operator is often late in bringing technology decisions to the license – can result in conservative decisions
- Mostly benefits from the changed NCS player landscape

Source: Rystad Energy research and analysis

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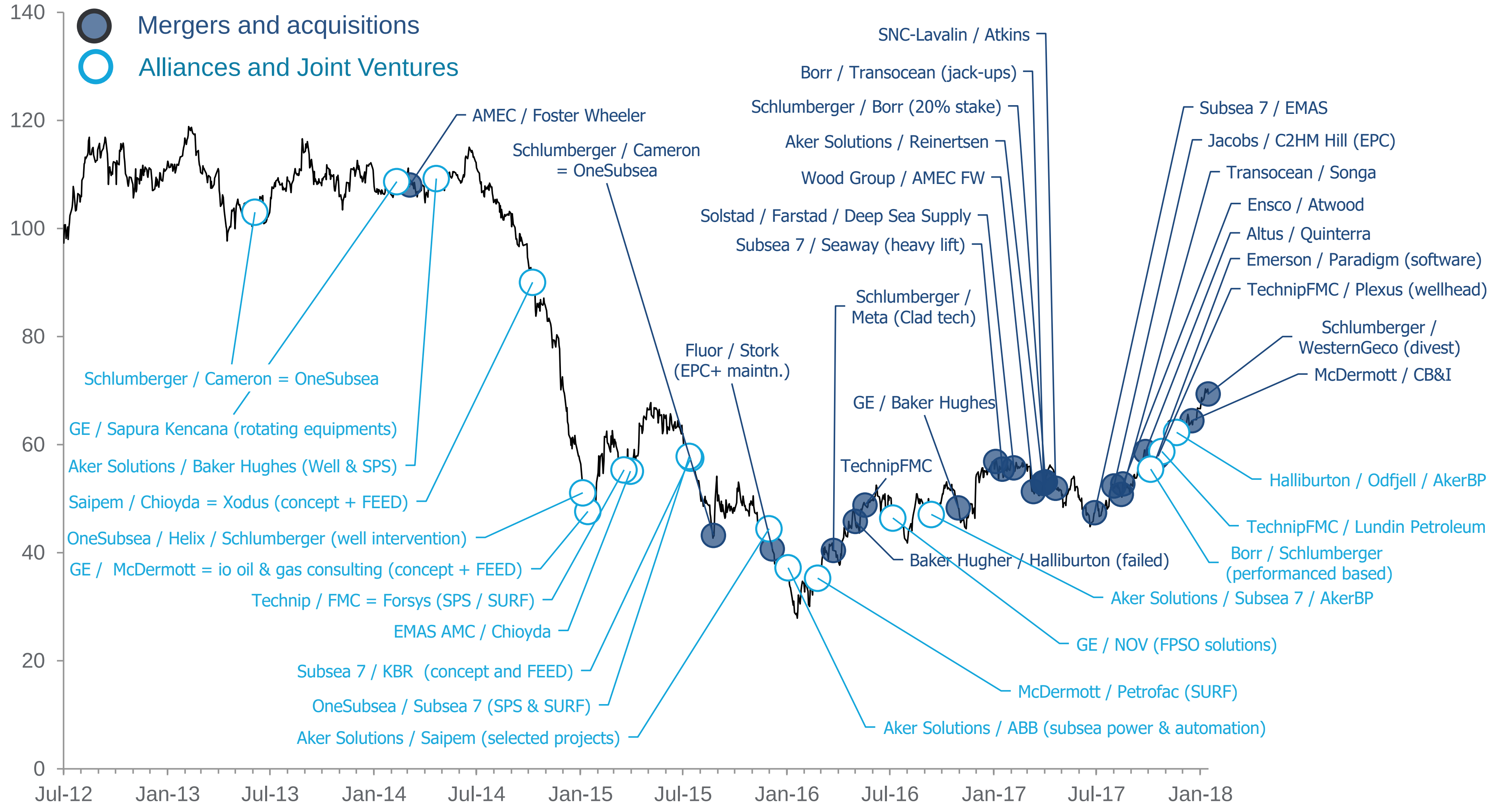
Source: Rystad Energy research and analysis

Alliances and JVs followed by M&A in the downturn

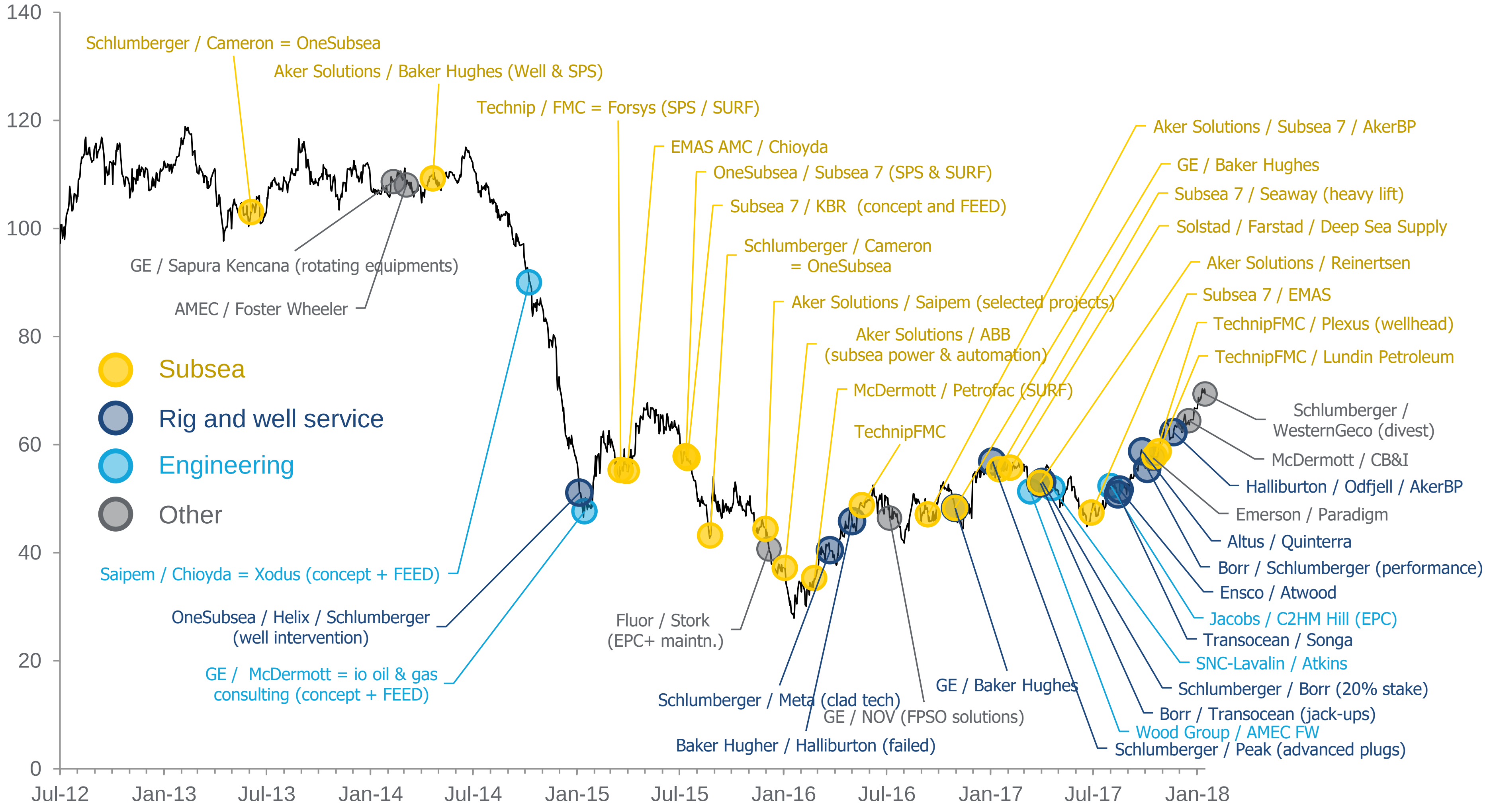
Alliance, joint venture and merger & acquisition in Offshore OFS, July 2012 - Jan 2018



Source: Rystad Energy research and analysis

Subsea players have been most active, but significant activity in rig and well service

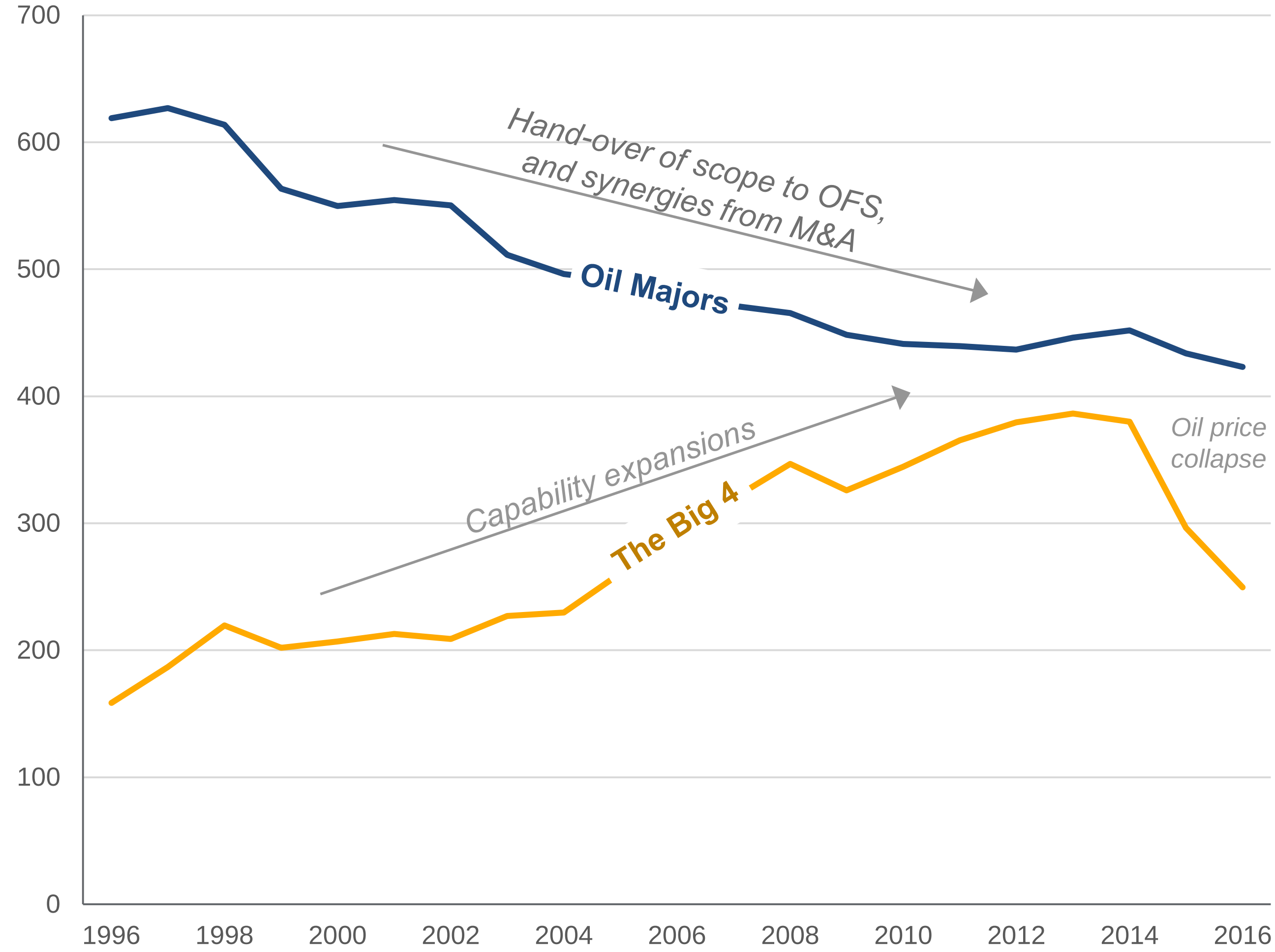
Alliance, joint venture and merger & acquisition in Offshore OFS, July 2012 - Jan 2018



Source: Rystad Energy research and analysis

Long term trend: OFS companies taking over E&P scope is not new

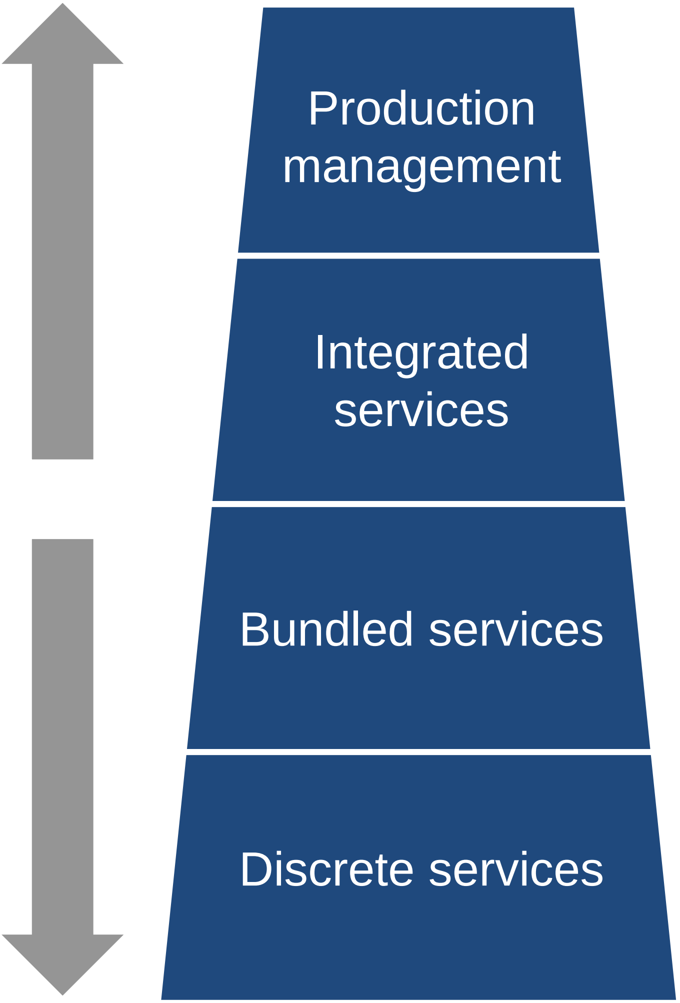
Number of employees for Oil Majors (excl. Eni) and the Big 4 OFS companies*
Thousand of employees



- **Majors** have reduced their employee numbers steadily, falling by an average **2% annually** over the last 20 years.
- The Big 4 contractors have taken over larger parts of the value chain from E&Ps, offering services that were typically handled by the E&Ps in the past.
- From 1996 to 2014 the number of employees in **the Big 4** has more than doubled, growing at about **5% annually.**
- But since the oil price crash, the employee count has been reduced by almost 20% annually.

*Adjusted for larger acquisitions (included history of acquired companies) and divestitures (included future of divested companies)
Big 4: Schlumberger (Smith, Cameron), Haliburton (KBR), Baker Hughes (BJ Services), Weatherford
Majors: ExxonMobil (Exxon, Mobil), Shell (Enterprise, BG), Total (Fina, Elf), BP (Amoco, Burmah Castrol and ARCO), Chevron (Texaco), ConocoPhillips (Conoco, Phillips, Phillips66, Tosco)
Source: SEC filings, annual reports, Rystad Energy research and analysis

Part of a consolidation rationale for OFS companies is to take on operational risk and capture more value



More operational risk, and higher value capture
Integration gives control over value chain and creates value for OFS companies through synergies

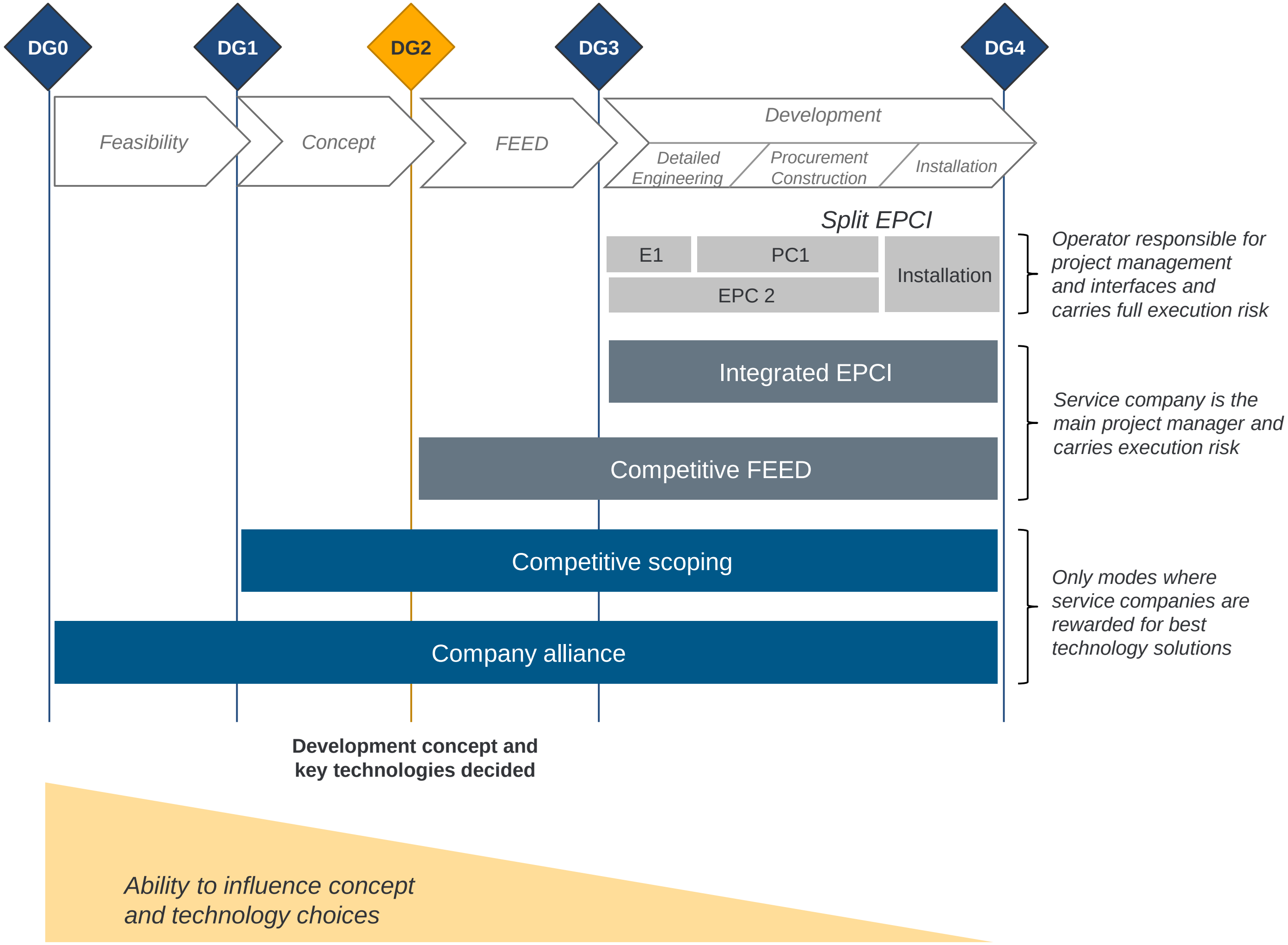
Less operational risk, and less value capture
Limited need to integrate and control risk in the value chain, and limited upside for OFS in creating efficiency gains

	Pricing mechanism	Description
Production management	$ / boe	One service contractor takes on full responsibility for the full development and relieves the operator for risk. However, service contractor also shares some of the field upside from e.g. payments in incremental barrels.
Integrated services	$ / project	One service contractor takes on full responsibility and provides services and/or sub-contract services. Low cost risk for the operator, while all upside in the field is retained. The contractor risks losing total project profitability if a single service fails, but is rewarded for good project execution.
Bundled services	$ / day $ / product + bundle discount	Bundling of some services, i.e. one or more service companies can perform multiple services and/or take on the responsibility of sub-contracting. Still, the individual service lines are only responsible for their respective deliveries.
Discrete services	$ / day	Standard service offerings from various service companies. E&Ps handle the procurement of each service. This puts greater demand on the operator to achieve efficient results and risk is thus placed mainly with the operator.

Source: Rystad Energy research and analysis

Integrated contract modes' effect on risk and technology decisions

Project development process and integrated contract modes



- **Contract modes have changed to more incentive-based structures to align supplier and operator interests**. Integration is not a prerequisite for shared incentives, and this can be detailed in conventional contract modes as well.
- A large part of the motivation from both suppliers and E&Ps has been to **share project execution risk and reward.** All the four integrated set-ups illustrated to the left accomplish this.
- The use of new technologies is typically decided at DG2. This means that the **only two contract modes that reward and incentivize oil service companies for innovative concepts are company alliances and competitive scoping.**
- Also, for **post DG2 contract modes**, it is the operator (or the engineering firm contracted) that is responsible for evaluating the portfolio of technologies that can form the development concept for a field. This **demands high technology competence inside the operator to successfully evaluate the full portfolio of opportunities.**
- **Similarly, early lock-in of suppliers** (i.e. through company alliances) **will limit the technology options to the suppliers' portfolio of products and services.**

Source: NPD; Interviews; Rystad Energy research and analysis

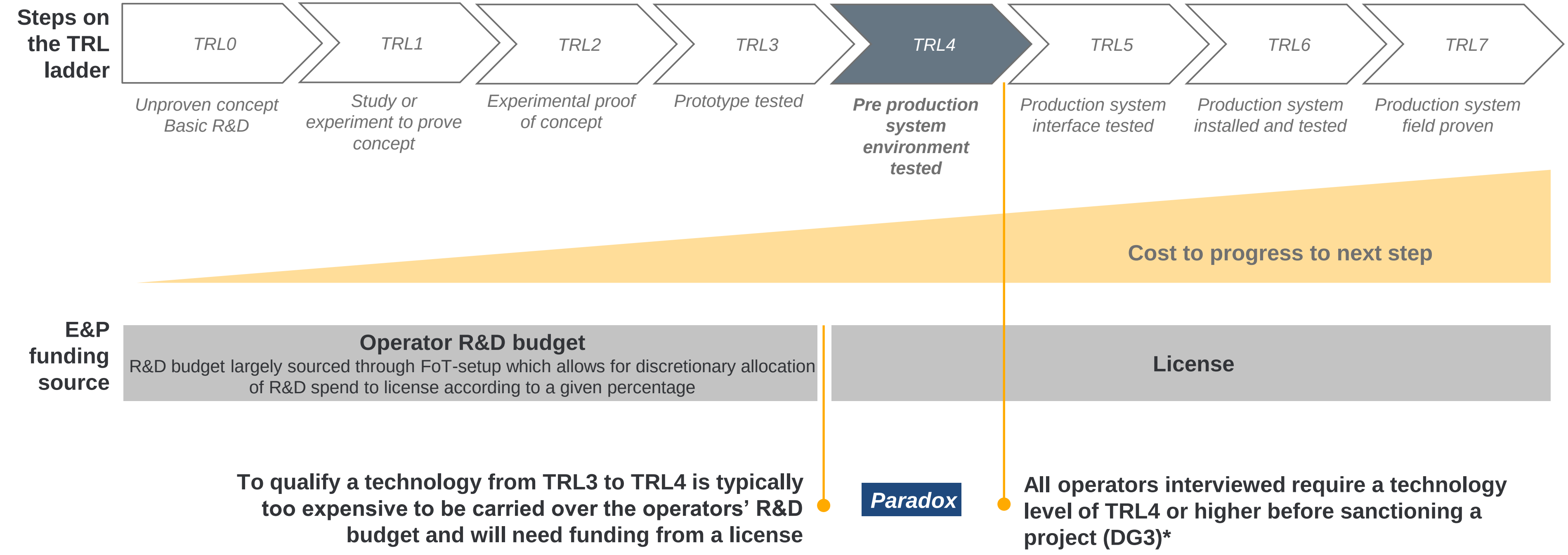
Shared incentives not only reason for integration, not all options are open for everyone

Example company	Observed contract types	Likely other company specific rationales
equinor	• **Split EPCI** (Several) • Integrated EPCI (Trestakk only)	• Not same organizational need as seen in other companies ○ High in-house technology competence ○ Excellent project management capabilities ○ Large future portfolio to keep project organization busy, also outside NCS. • Due to dominating role as procurer on the NCS, it cannot forge alliances with specific suppliers without altering the competitive supplier landscape • More integrated setups could result in service price inflation long term
AkerBP Lundin Petroleum	**Company alliances** within following domains **Aker BP:** • Subsea EPCI • Platform EPC • Rig & well service • Maintenance / integrity **Lundin:** • Subsea EPCI • Well service	• Secure high degree of capabilities and competence for future needs, while maintaining a smaller operator workforce • Limited portfolio of discoveries, need for future project organization more uncertain • Need for lean organization to meet changes in oil price environment
(Ormen Lange)	**Competitive scoping** on Ormen Lange • 4-5 suppliers working separate concepts for Ormen Lange compression	• Spawn new development concepts for complex application • Outsource concept work in light reduced technology capacity in Norway?
VNG Norge	**Competitive FEED** for full subsea scope on Fenja development	• Smaller operator, more limited technology and project management capabilities in organization • Dependent on supplier to run qualification of EH PiP technology and project management of interfaces.

Source: Interviews; Company presentations; Rystad Energy research and analysis

The technology maturity paradox – need license to fund, but license doesn't have time

Maturing technologies
Technology Readiness Level (TRL) – API17N



Steps on the TRL ladder

TRL0	TRL1	TRL2	TRL3	TRL4	TRL5	TRL6	TRL7
Unproven concept Basic R&D	*Study or experiment to prove concept*	*Experimental proof of concept*	*Prototype tested*	***Pre production system environment tested***	*Production system interface tested*	*Production system installed and tested*	*Production system field proven*

E&P funding source

Operator R&D budget
R&D budget largely sourced through FoT-setup which allows for discretionary allocation of R&D spend to license according to a given percentage

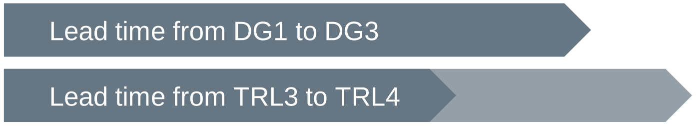
License

To qualify a technology from TRL3 to TRL4 is typically too expensive to be carried over the operators' R&D budget and will need funding from a license

Paradox

All operators interviewed require a technology level of TRL4 or higher before sanctioning a project (DG3)*

***Paradox:** Technology qualification does not match time sensitive nature of the development project, yet is dependent on the project for further maturation*



Key implications:

- **For suppliers the TRL4 paradox is a «valley of death»** especially when focus on lead time becomes more important
- If technology is not enabling the field, **it is less likely that the license will risk delays by qualifying a technology as a part of the development**
- Even if the qualification lead time is shorter, it leaves a very narrow window for the supplier to approach the right field for application. **Timing management becomes very critical and transparency into the asset portfolio key**

*Exceptions exist, but using less mature technologies increases risk of project delay significantly

Source: Interviews; OG21 2016 strategy; Rystad Energy research and analysis

Limited data sharing results in re-qualifications and negative technology decisions

A **Limited data sharing between operators and between operator and supplier leads to unnecessary re-qualifications**

- *Several examples of technologies that have been used multiple times by multiple operators but are then requalified by a new operator. Much has to do with lack of sharing of data.*
- *Demand for proven track-record seems to apply more to track-record within the same operator than on similar previous applications.*
- *Some oil service companies are not given access to data showing the effect of their own technology after application. This makes it very difficult to prove business cases for their technology to other operators*

B **Anonymized data leads to higher perceived risk and loss of meta data increases assessed risk**

- *Of the data that is shared, a lot of time is spent on anonymization so that it can be distributed without any trace-backs to the field where it was collected. This is especially common with failure data.*
- *Anonymizing data has two main negative consequences:*
  - *It disables the possibility to analyze whether the field being considered for application of a technology will be less or more likely to have failure than the average failure data point.*
  - *Creates distance to the experience data and makes it less easy to trust, hence increasing the perceived risk premium*
- *Lack of metadata may be the cause of requalification need as it creates uncertainty as to whether the same type of field (i.e. infrastructure, reservoir, water depth) has utilized this technology previously*

Data sharing reservation #1

Some data is stock price-sensitive and can't be shared, in particular subsurface and production data

Data sharing reservation #2

Data is the competitive advantage of each oilco; sharing it would be like giving away trade secrets

> *"In practice it should be possible to share all data in a license after the license has been awarded"*
>
> CEO of Norwegian Independent

Source: Interviews; Rystad Energy research and analysis

Key observations within the supplier-operator perspective

	Key observations	Rationale
1	**Early involvement has positive impact on the use of new technologies and innovative concepts, but could limit the set of potential technologies for application**	• *The OFS supplier landscape has consolidated in the downturn with integration being held as a key consolidation rational. Subsea, rig and well service are among the segments that have seen the most consolidation.* • *New business models, integrated set-ups, have been built to allow suppliers & operators to share project execution risk & reward.* • *Some contract modes like competitive scoping and company alliances involve the supplier before DG2 (choice of concept). These set-ups reward and incentivize oil service companies to utilize new technologies and innovative concepts.* • *But early lock-in of suppliers (i.e. through company alliances) may limit the technology options to the portfolio of the supplier.* • *Shared incentives are not the only reason for integration; the operator's organizational capabilities are important for the choice of set-up. Not all options are open to all operators.*
2	**Technology must find a license for final qualification, but the license may not have sufficient time for qualification without affecting lead time**	• *To qualify a technology from TRL3 to TRL4 is typically too expensive to be carried over the operator's R&D budget and will need funding from a license.* • *Operators require a technology maturity of TRL4 or higher before sanctioning a project, but the license that could use the technology may not have sufficient time for qualification without affecting project lead time.* • *For suppliers the TRL4 paradox is a «valley of death» especially when focus on lead time becomes more important.* • *If technology is not enabling the field, it is not likely that the license will risk delays by qualifying a technology as a part of the development.* • *Even if the qualification lead time is shorter, it leaves a very narrow window for the supplier to approach the right field at the right time. Timing management becomes very critical and transparency into the asset portfolio is key.*
3	**Technology pipeline management is challenging for suppliers with respect to field use cases and timing**	• *Difficult for suppliers to ensure that they develop technologies that will meet traction with operators and ultimately find a license.* • *Challenging for suppliers to maintain overview of potential use cases for the technology and when to approach. Narrow time window to approach the right field with the best technology solution.* • *Case of subsea boosting: Large difference between the application potential (use cases on the NCS) from a supplier viewpoint and as seen from the operators.*
4	**Limited data sharing results in requalification and negative technology decisions**	• *Limited data sharing between operators and between operator and supplier lead to unnecessary re-qualifications with new operators* • *Anonymized data leads to higher perceived risk and loss of important meta data increases assessed risk.*

Source: Interviews; Rystad Energy research and analysis

Four perspectives on risk assessment and impact on technology decisions

Sub-supplier
vs. supplier

Supplier vs. operator

Changed service landscape

Early involvement and effects of integration

Technology qualification

- Qualification vs. leadtime
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Changed player landscape on the NCS over the last three years

License dynamics

- Field vs. portfolio value
- Partner investment opportunities
- Partner technology evaluation and risk appetite

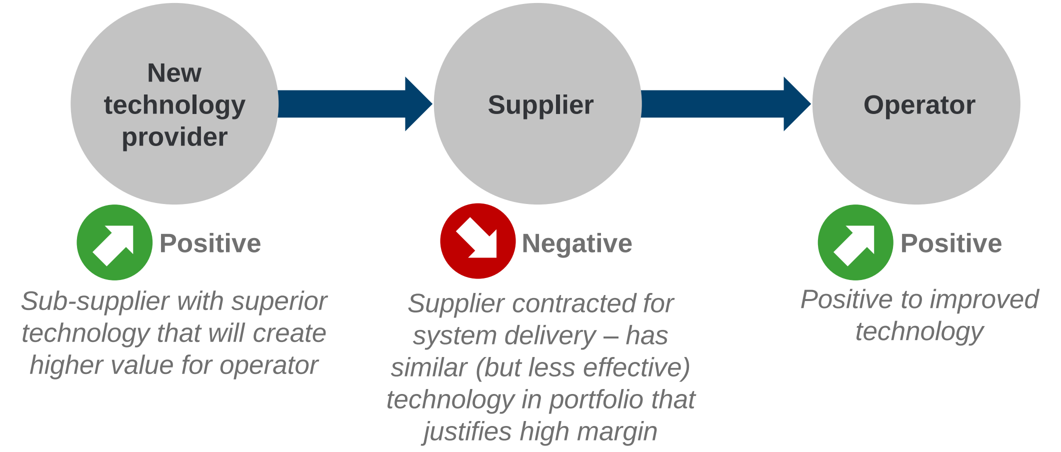
Source: Rystad Energy research and analysis

Two types of inefficiencies observed: margin protection and contract structures

Type of value chain inefficiency

Illustration

Margin protection



New technology provider → **Supplier** → **Operator**

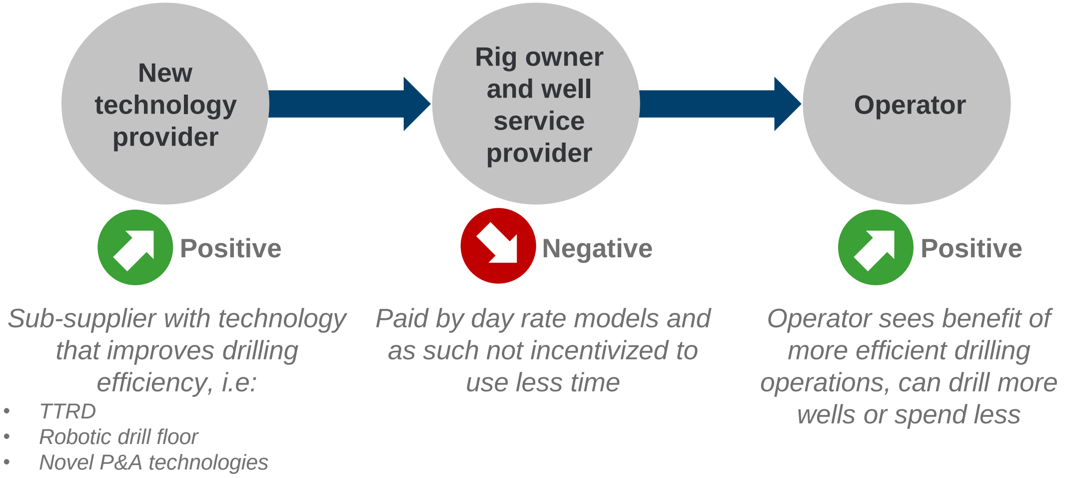
Positive – *Sub-supplier with superior technology that will create higher value for operator*

Negative – *Supplier contracted for system delivery – has similar (but less effective) technology in portfolio that justifies high margin*

Positive – *Positive to improved technology*

- Smaller sub-suppliers that can't provide full system deliveries will meet value chain resistance when trying to replace a product or service within the main suppliers product portfolio.
- In addition to removing revenue for main supplier, the technology replaced is typically high margin and part of the supplier's competitive offering.

Contract structure
-
Rig example



New technology provider → **Rig owner and well service provider** → **Operator**

Positive – *Sub-supplier with technology that improves drilling efficiency, i.e:*

- *TTRD*
- *Robotic drill floor*
- *Novel P&A technologies*

Negative – *Paid by day rate models and as such not incentivized to use less time*

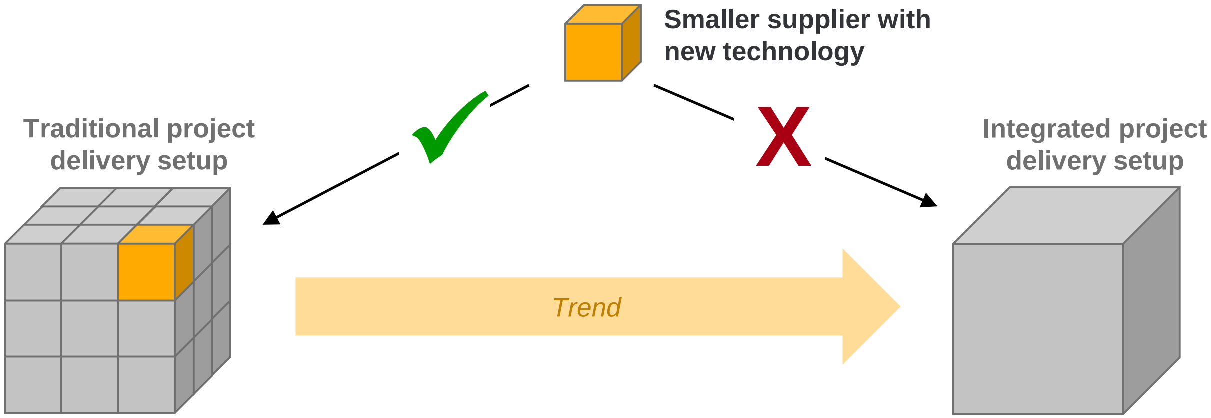
Positive – *Operator sees benefit of more efficient drilling operations, can drill more wells or spend less*

- Day-rate models are a classic example of contract set-ups that don't incentivize use of new technologies.
- For sub-suppliers this represents a clear obstacle for technology adoption and is especially visible in the drilling and well domain.

Source: Interviews; Rystad Energy research and analysis

Operators are playing with bigger blocks; integrated suppliers are the new gatekeepers

1 Operators are playing with bigger building blocks; smaller suppliers can't deliver directly to operator and must go through the integrated service company



- Split contracts, smaller building blocks purchased at a time.
- **Possible for smaller supplier with independent delivery to operator**

- Integrated contracts, bigger building blocks
- **Sub-supplier cannot deliver directly to operator**

2 Integrated setups can remove some value chain inefficiencies…

- With more integrated set-ups the suppliers are more aligned with operators' incentives.
- Moving from $/day to $/project will incentivize the use of efficiency and cost improving technologies (i.e. drilling technologies).
- Volume improving technologies will not have the same effect.

3 …but with increased execution risk for the integrated player, using new third party tech is risky

- With execution risk on cost and time placed at the integrated player, using new third party technologies may stand at risk of losing return.
- Especially integration set-ups that only look to execution (i.e. integrated EPCI and competitive FEED contracts), will likely not want to take on production-improving or opex-reducing technologies that can cause delays or overruns in execution.

Source: Interviews; Rystad Energy research and analysis

Key observations within the sub-supplier – supplier perspective

Key observations	*Rationale*
1 **Sub-suppliers are a key contributor to technology development on the NCS**	*Smaller suppliers are pivotal for technology development for the NCS, current examples include:* inflow control magseis Sekal fishbones Cognite reelwell HYDRAWELL INTERVENTION CUBILITY SOLUTION SEEKER eDrilling RESMAN® WIRELESS RESERVOIR SURVEILLANCE wellcem Robotic DRILLING SYSTEMS aptomar safety at your fingertips
2 **Value chain inefficiencies hinder adoption of new technologies from smaller sub-suppliers**	*Two types of value chain inefficiencies identified:* - *Margin protection: Smaller sub-suppliers that can't provide full system deliveries will meet value chain resistance when trying to replace a product or service within the main suppliers portfolio. The technology replaced is typically high margin and part of the suppliers competitive offering.* - *Contract structures: Day-rate models are classic examples of contract setups that don't incentivize use of new technologies that attempts reduce the revenue multiplier (days)*
3 **Integrated setups create one more gatekeeper for the sub-suppliers, but may resolve some value chain inefficiencies**	- *With integrated contracts, operators are playing with bigger building blocks. Smaller suppliers will to a lesser degree deliver directly to operator, and must go through the integrated service company.* - *With more integrated setups the supplier is now more aligned with operator incentives, but not for all elements. Technologies that lower cost on execution will likely see the same drive, but technologies that see effects post-project delivery (i.e. volume improving technologies or opex reducing technologies) will likely not be favored.* - *The integrated supplier now holds the same execution risk that the operator previously had. Using new technology from sub-suppliers will now potentially be viewed as a disadvantage*

Source: Interviews; Rystad Energy research and analysis

Four perspectives on risk assessment and impact on technology decisions

Operator internal

Supplier vs. operator

Changed service landscape

Early involvement and effects of integration

Technology qualification
- Qualification vs. leadtime
- Sharing of data

Sub-supplier vs. supplier

Value chain inefficiencies as obstacle for technology adoption

Effect of integration on smaller sub-suppliers

Risk assessment and impact on technology decisions

Decision criterias in greenfield, brownfield and drilling applications

Enabling vs enhancing technologies – pull vs. push

Organizational barriers
- KPIs and cross discipline challenges
- Procurement («Terms and conditions»)
- Changed work processes

Operator internal

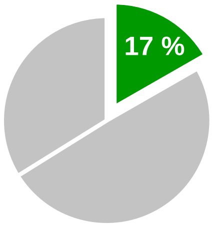
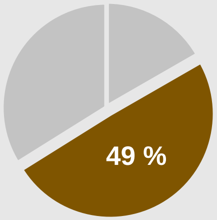
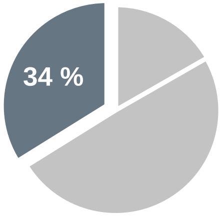
Changed player landscape on the NCS over the last three years

License dynamics
- Field vs. portfolio value
- Partner investment opportunities
- Partner technology evaluation and risk appetite

Operator vs. license

Source: Rystad Energy research and analysis

Application areas for the different technologies have different decision criteria

	Greenfield	Brownfield	Drilling
*Share of costs 2018-2040 (real 2018)**			
NCS use cases	**Some** *Limited portfolio of discoveries: ~10 standalone facilities and ~80 tieback / wellhead plfs + exploration upside*	**Several** *~200 assets in production by 2040 in addition to exploration upside*	**Many** *~100 wells per year, includes exploration, infill (brownfield) and development (greenfield) drilling*
Assessment lead time	**Crucial**	**Less important**	**Important**
Decision holder	**Project manager**	**Asset manager**	**Drilling / reservoir lead**
Key KPIs for decision holder	• **Cost overruns** • **Lead time** • **HSE**	• **Uptime / regularity** • **Opex** • **HSE**	• **Well cost** • **Drilling efficiency** • **Target / well integrity** • **HSE**
High risk / high value technologies	All electric subsea Electrification from onshore grid Unmanned facilities / Automation	Subsea boosting Radical new EOR solutions CO2 IOR Water diversion	Robotic drill floor PWC P&A

Application area for a given technology is key to understand decision criteria for adoption.

Greenfield technologies

- Greenfield applications are more sensitive to project lead time than brownfield. Timeline management of technology application is therefore important for the supplier
- Delays and cost overruns as KPIs for decision holder are not an advantage for new technology adoption.
- Fewer greenfield use cases compared to brownfield and drilling affects repeatability of technology (on the NCS).

Brownfield technologies

- Brownfield applications not as sensitive to lead time, technology qualification can be allowed to take time.
- Mostly intrusive technologies that, if fails, negatively affect the most important KPIs: uptime and production regularity
- Several assets to experiment with on the NCS, some are very large and can singlehandedly carry large technology qualifications.

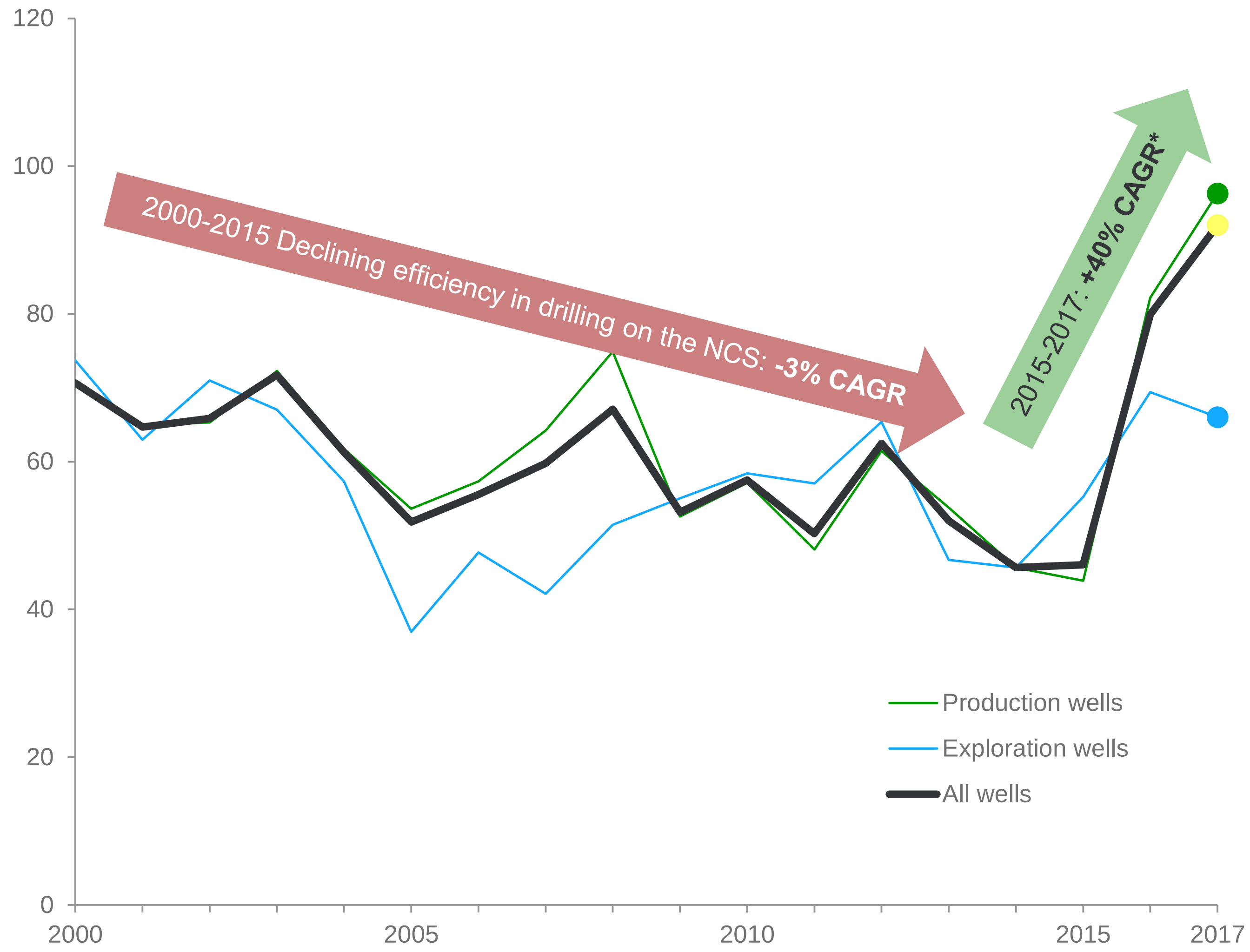
Drilling technologies

- Multiple use cases which should allow for repeatability and rapid technology adoption

Source: Rystad Energy research and analysis

Drilling efficiencies improved massively during downturn – technology improvements or changed incentives?

Meters drilled per active drilling day* at NCS, by well type
Meters per day



- **Drilling efficiency** as measured by meters drilled per active drilling day has fallen steadily towards 2015 at a rate of almost **-3% per year.** From 2015 to 2017 we saw massive improvements in drilling performance.
- Massive **oversupply in the rig market led to performance incentives** for rig owners in order to secure new contracts, despite being on day rate contracts.
- **Influx of newer rigs and several changed/upgraded derricks** on fixed installations are also an important part of the equation – the industry simply started to fully utilize new technology.
- **Fast adoption made possible by large number of applications** which is typical for drilling technologies

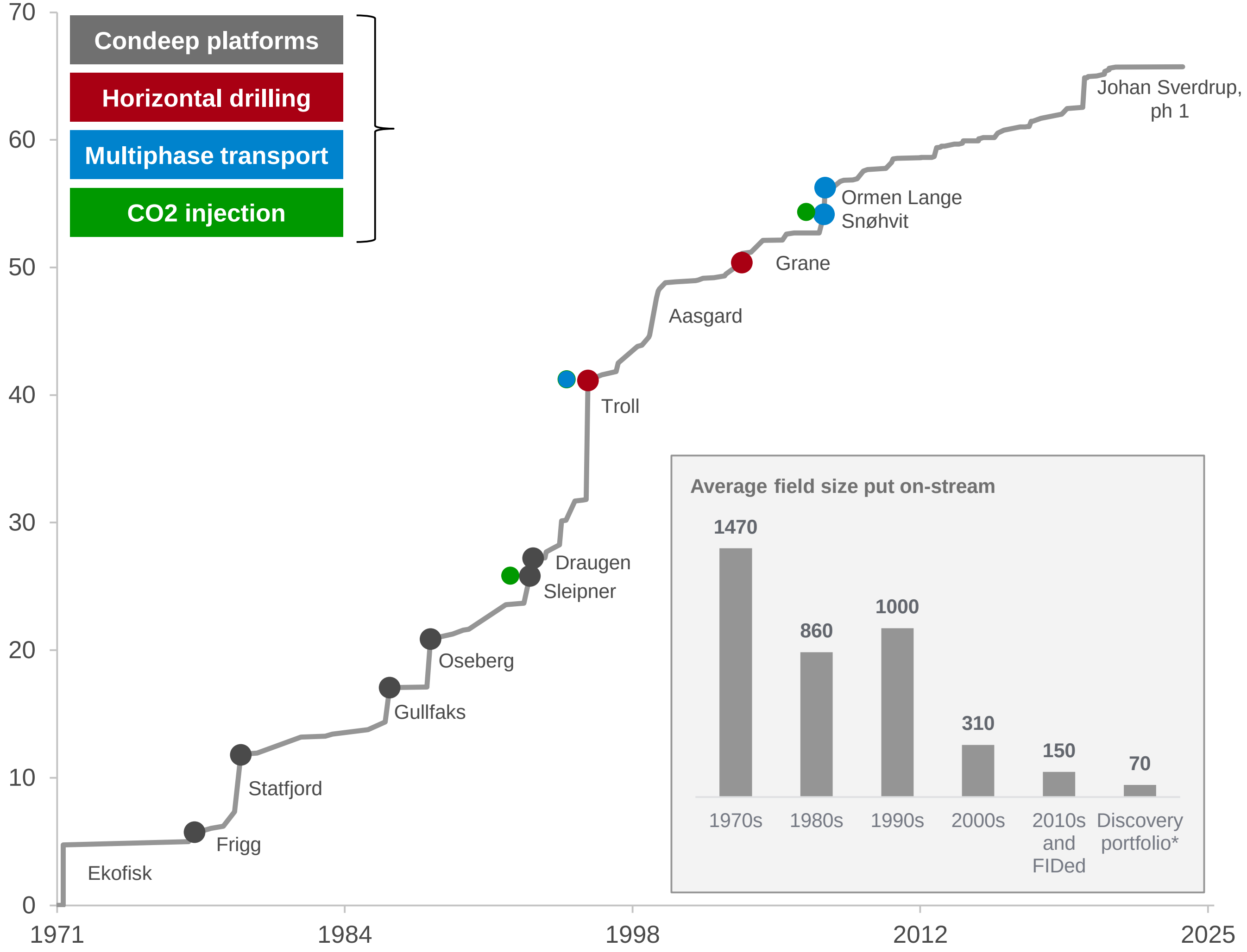
Note: Meters drilled = Measured Max Well depth - Water depth – Kelly Bushing. For sidesteps, we have estimated starting point of the side step based on an assumption that drilling speed is the same as the drilling speed in the main wellbore. *Includes all offshore activities, and is not a to be considered as meters drilled (ROP) when actual drilling. Sources: NPD; Rystad Energy research and analysis

Enabling vs. enhancing technologies

New tech pivotal for the largest fields – current avg. NCS development too small?

Operator internal

Cumulative resource development on the NCS by start-up year and field
Billion barrels of oil equivalents



The curve is typical for most mature offshore basins, with the largest structures being discovered and developed first. After the production start on Troll, the average size of fields put on stream has gradually decreased, with the exceptions being fields such as Aasgard, Ormen Lange, Snøhvit, and Johan Sverdrup (under development).

By enabling production from many of these fields, several novel technologies have been instrumental with first application on the NCS:

- Condeep platforms, enabling oil production on water depths outside the range of fixed steel platforms
- Horizontal drilling, enabling drilling in the thin oil zones at Troll and later Grane
- Multiphase flow analysis, enabling long tie-backs such as Ormen Lange and Snøhvit. Also enabled wet gas transport from Troll to Kollsnes
- CO2 injection offshore enabling the development Sleipner

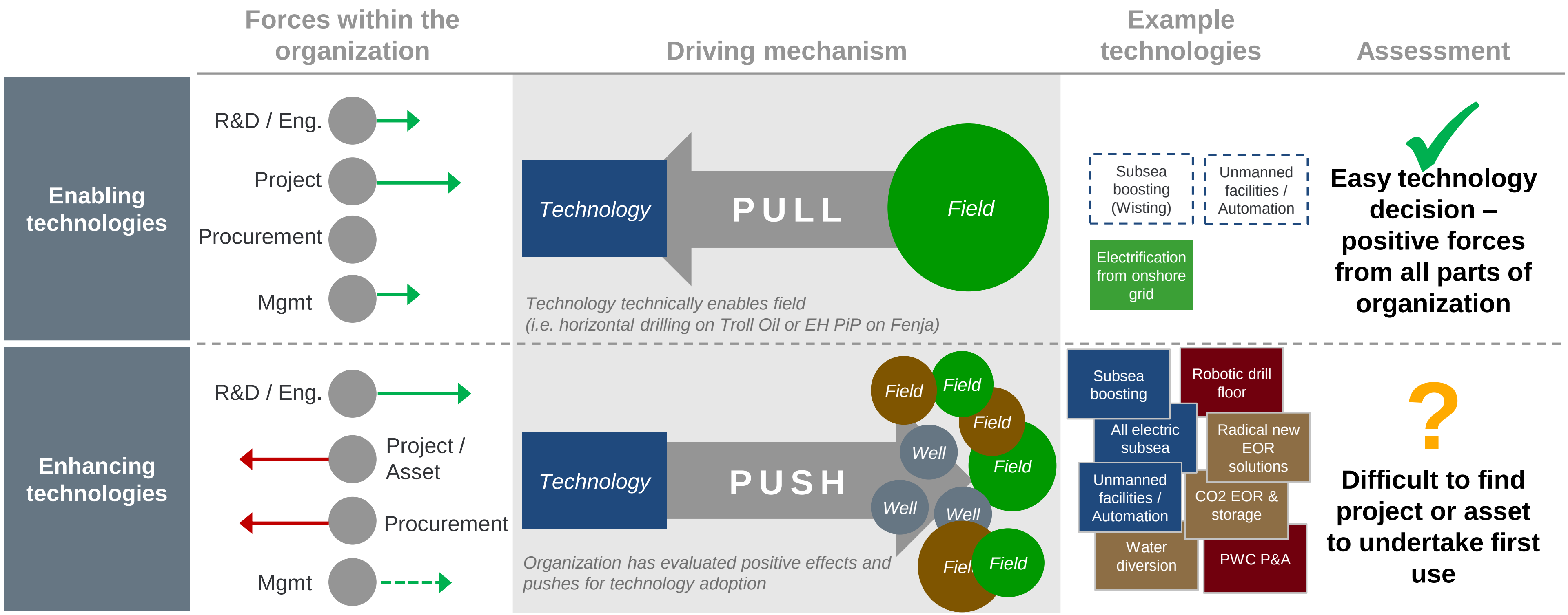
Average on-stream field size has gone significantly down, and there are **not many discoveries in the NCS portfolio that can enable large technology developments like the ones seen historically.**

Sources: Rystad Energy research analysis; Rystad Energy UCube

Enabling vs. enhancing technologies

Most example technologies are enhancing – need to be pushed through the system

Operator internal



Forces within the organization | Driving mechanism | Example technologies | Assessment

Enabling technologies

R&D / Eng.

Project

Procurement

Mgmt

Technology

PULL

Field

Technology technically enables field (i.e. horizontal drilling on Troll Oil or EH PiP on Fenja)

Subsea boosting (Wisting)

Unmanned facilities / Automation

Electrification from onshore grid

✓

Easy technology decision – positive forces from all parts of organization

Enhancing technologies

R&D / Eng.

Project / Asset

Procurement

Mgmt

Technology

PUSH

Field

Field

Field

Well

Field

Well

Well

Fiel

Field

Organization has evaluated positive effects and pushes for technology adoption

Subsea boosting

Robotic drill floor

All electric subsea

Radical new EOR solutions

Unmanned facilities / Automation

CO2 EOR & storage

Water diversion

PWC P&A

?

Difficult to find project or asset to undertake first use

Enabling technologies: These technologies see few barriers in the organization. Technology is needed for field viability and is therefore endorsed by all elements of the operator organization

Enhancing technologies:

- Most E&Ps describe their technology development process as problem-oriented, they seek to find solutions to identified problems. This can be viewed as pull based. However, in most cases technologies represent an improvement to the original case and do not enable the project. Brownfield technologies are by definition enhancing.
- Negative forces within the projects as “no-one wants to be the first to apply the technology”. The decision holder does not have the incentive to be the first one to apply the technology, and in particular, the **decision holders’ KPIs do not support first-time adoption of new technology**. Procurement is often cost-optimized and will not necessarily support the use of an enhancing technology.
- Management push for the application of enhancing technologies is vital in order to overcome internal barriers. This applies especially for technologies that create system value, e.g. digitalization and automation. In order to overcome the possibility of high perceived risk among management, management competence and the way the technology is presented is important.
- Several suppliers state that in order to find application for their technology they must find a **technology champion that will fight for their technology within the operator organization. Relational skills are considered equally important to actual risk and value assessment**

Source: Rystad Energy research and analysis

Organizational obstacles within the operator

Operator internal

	Key observations	Rationale

1	**Decision holders are not incentivized to be first movers on adoption of new technologies**	• *No clear incentives among decision holders to be the first to utilize technology. For technologies seeking application on multiple cases it is primarily downside for a decision holder to be the first test case. As a result, enhancing technologies are struggling to find their first application within each operator.*
		• *KPIs are not set up to incentivize adoption of new technologies, although some operators have changed this.*
		  • *Greenfield applications: Delays and cost-overruns are primary concerns*
		  • *Brownfield: Securing uptime and protecting production stream primary concern, all example technologies with brownfield applications are intrusive.*
		  • *Drilling: Drilling efficiency, utilizing new technologies typically involves risk of delays which have high cost consequences in a drilling operation*

2	**Technologies that are cross discipline tend to amplify first mover disadvantage**	• *The "first mover disadvantage" is amplified when technologies involve multiple disciplines within the operator. Each discipline will experience risk of application, whereas the value may only pertain to one of the disciplines:*
		  • *All electric subsea is an example where the value of the technology lies within the subsea domain, but drilling and well discipline experience significant risk due to the necessity of a electric downhole safety valve, a critical element in the well.*
		  • *EOR technologies is another example, where application typically requires topside modifications to handle changes in the production stream, either chemical treatment or corrosion resistance (CO2). The value, however, pertains to the reservoir discipline.*
		• *Most of the TTA4 technologies are cross-discipline.*

3	**Procurement is cost-optimized rather than value-optimized – terms and conditions do not favor suppliers to take technology risk**	• *Current procurement setups are cost-optimizing rather than value-optimizing. Reduction in cost and delivery time are key measurable KPIs that do not always align with the project organization's technology needs.* • *"Terms and conditions" in the contracts do not favor new technologies, suppliers are hesitant to risk their own returns by applying new technology*
4	**Change of work process needed to fully realize value of new technologies**	• *In order to maximize the effect of new technology, work processes and procedures must be changed. This is time consuming and requires changes in multiple layers of the operator organization.* • *New technologies may "fail" in utilization and not in application.* • *Technologies that result in reduction of work force or reallocation of employees will likely meet resistance, both from individual employees and unions.*

Source: Interviews; Rystad Energy research and analysis

Four perspectives on risk assessment and impact on technology decisions

Supplier vs. operator

Changed service landscape

Early involvement and effects of integration

Technology qualification
- Qualification vs. leadtime
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Organizational barriers
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- Changed work processes

Operator vs. license

Changed player landscape on the NCS over the last three years

License dynamics
- Field vs. portfolio value
- Partner investment opportunities
- Partner technology evaluation and risk appetite

Source: Rystad Energy research and analysis

Changed player landscape

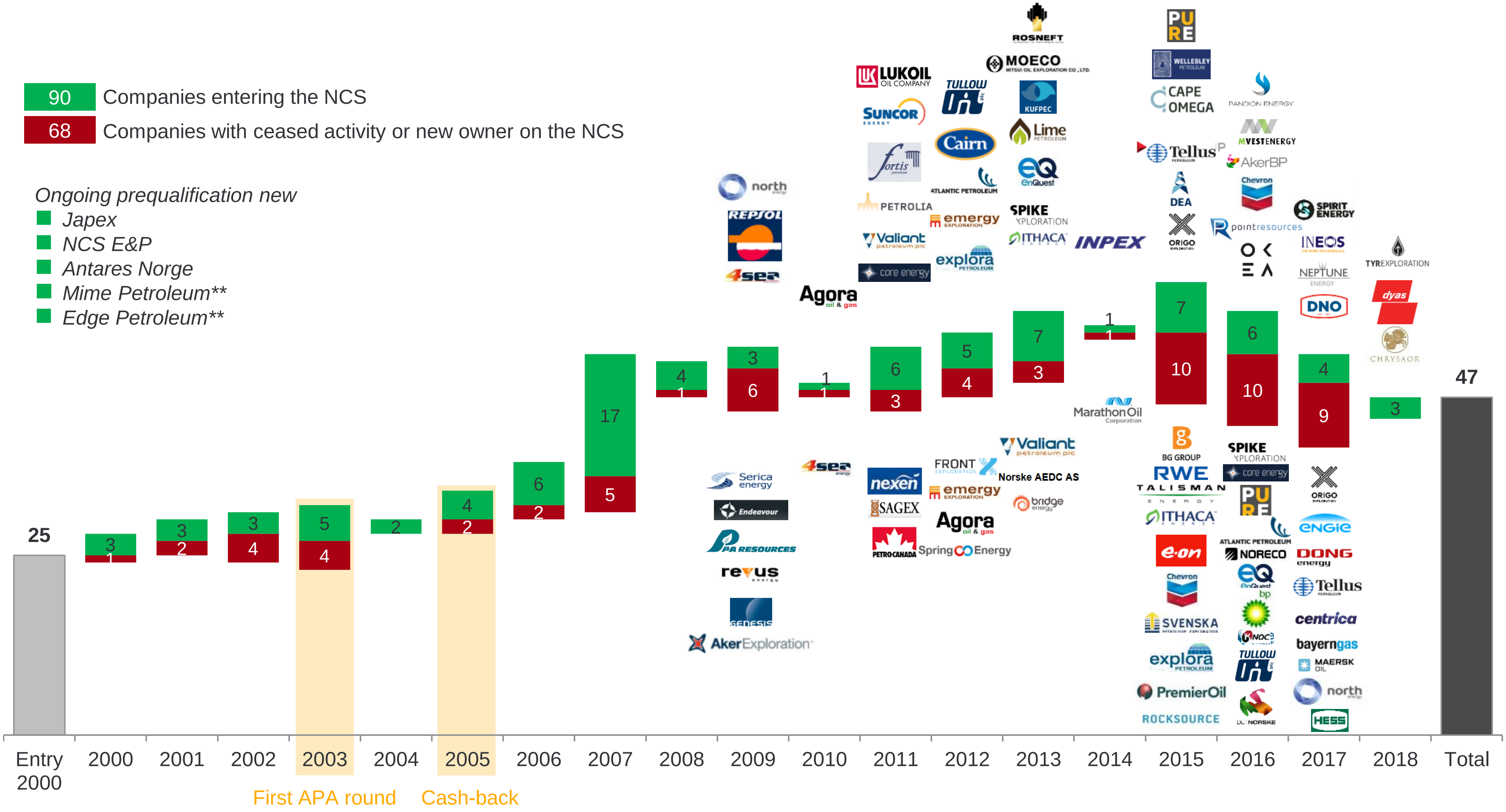
NCS with high M&A activity and consolidation over the last 3 years

Operator vs. license

Number of active companies on NCS (prequalified incl. companies without any active license) - new and ceased activity since 2000*

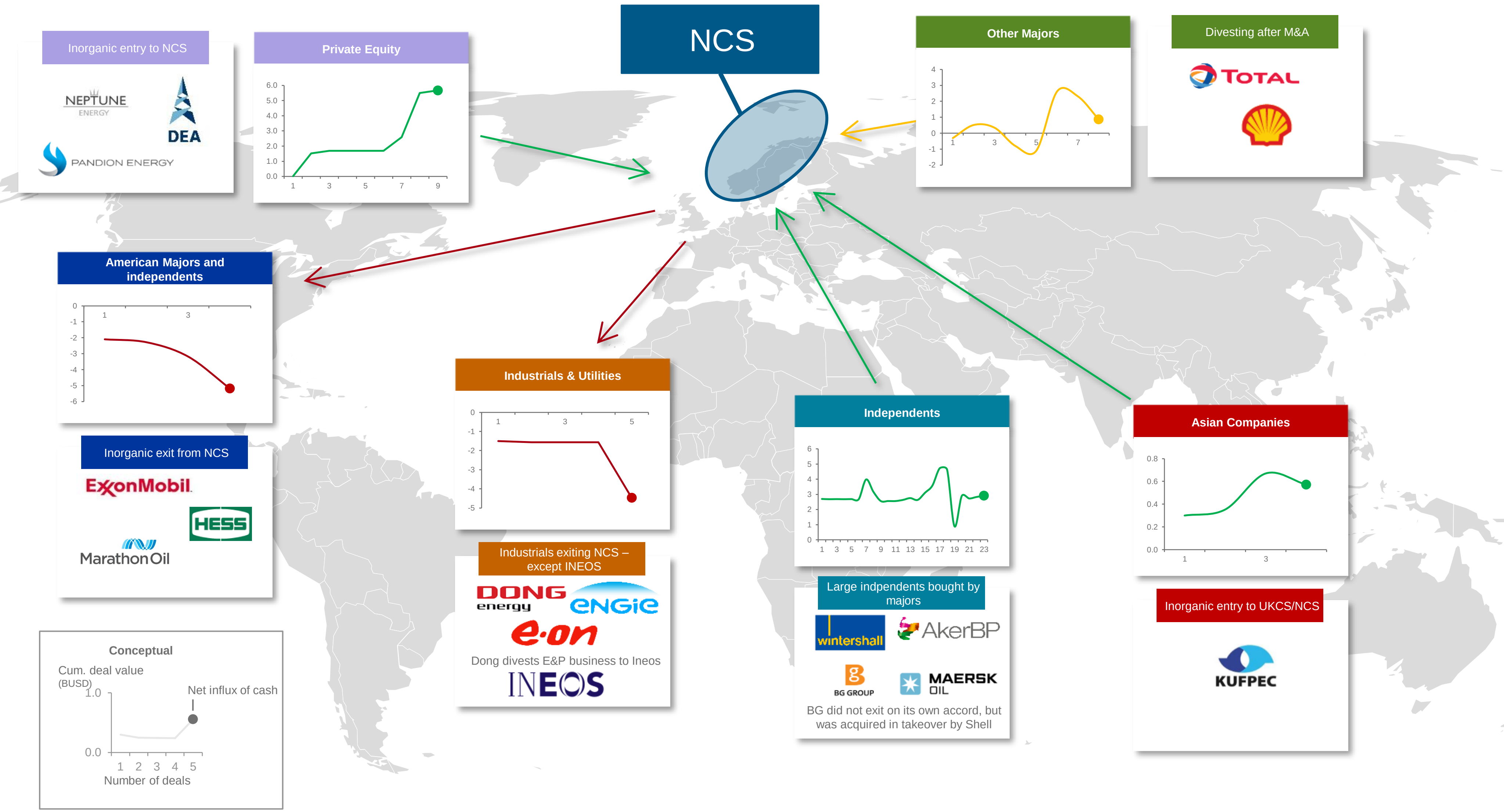
🟩 90 Companies entering the NCS
🟥 68 Companies with ceased activity or new owner on the NCS

Ongoing prequalification new
- 🟩 *Japex*
- 🟩 *NCS E&P*
- 🟩 *Antares Norge*
- 🟩 *Mime Petroleum***
- 🟩 *Edge Petroleum***



* Transactions also includes announced but not completed, Chrysaor and Dyas **Announced will seek prequalification. Mime backed by BlueWaterEnergy and Edge Petroleum by Elliot Management.
Source: NPD; Rystad Energy research and analysis

Americans moving home to shale, PE and independents with biggest net increase



*Number of deals conducted at the UKCS and NCS since 2015 and size in terms of BUSD spent (transaction value) per company segment. Sale counts as negative deal value, buy as positive. Large deals NCS relevance: Shell/BG: 1%, Total/Maersk: 50%, Neptune/Engie: 50%

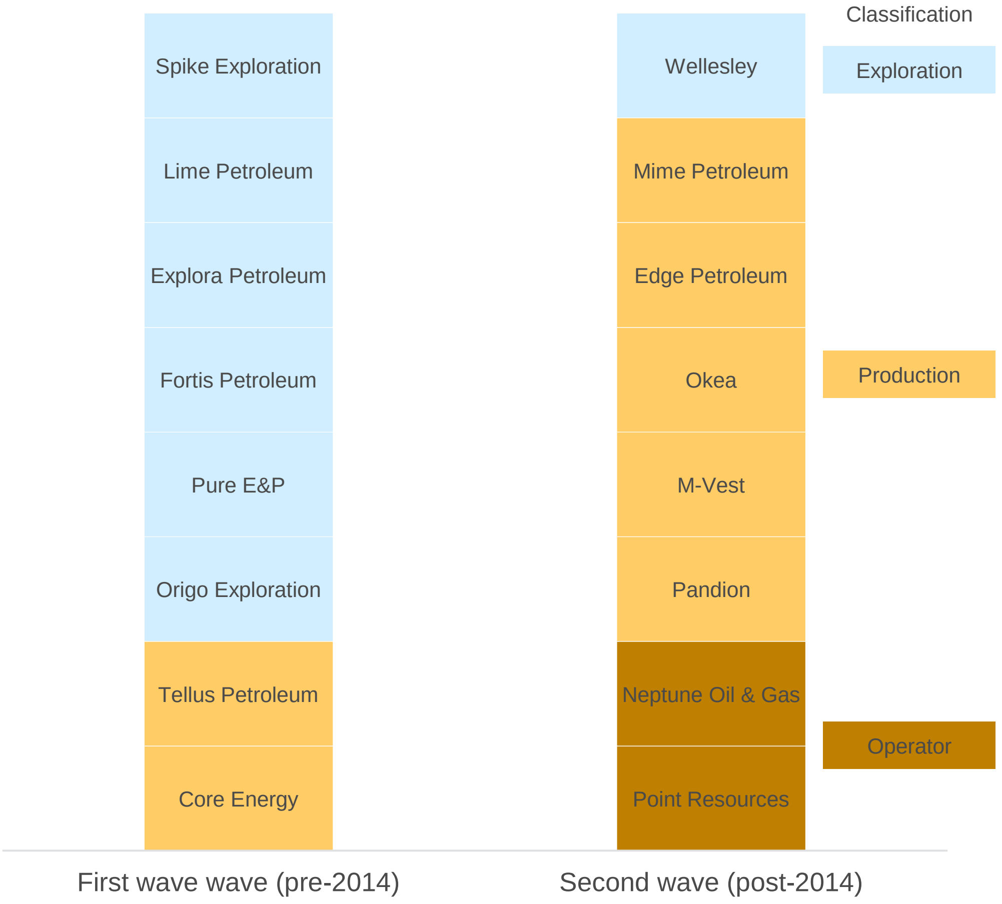
Source: Rystad Energy UCube M&A Module

New trend - PE-backed companies to buy production and develop discoveries

Two waves of PE-backed companies to the NCS

High oil price environment pre-2014
Discovery to sell

Low oil price environment post-2014
Discovery to production



Why have PE-backed companies changed strategy?

Prior to the oil price fall starting in 2014, specialized and lean PE-backed exploration companies focused on making discoveries and selling to operators capable of developing the discovery to production. **Post 2014, discoveries have been priced low due to uncertainty in the future oil price.** In some cases, discoveries were priced with a negative value since there were liabilities attached to owning the discovery, but there was no chance it would be developed under the oil price environment at that time.

However, at a certain point PE-backed companies started speculating and started buying production at a what they believed was a low point with regards to oil price. In addition, the increasing oil price has increased the value of discoveries to a point where exploring and developing the discovery yourself makes economic sense. **Due to tax optimization it is important to own production** creating revenue which the developer can write off against capital expenditures relating to development.

This trend can be observed among **PE-backed companies on the NCS which have shifted from purely exploration focused to buying production and operating as a complete E&P entity.**

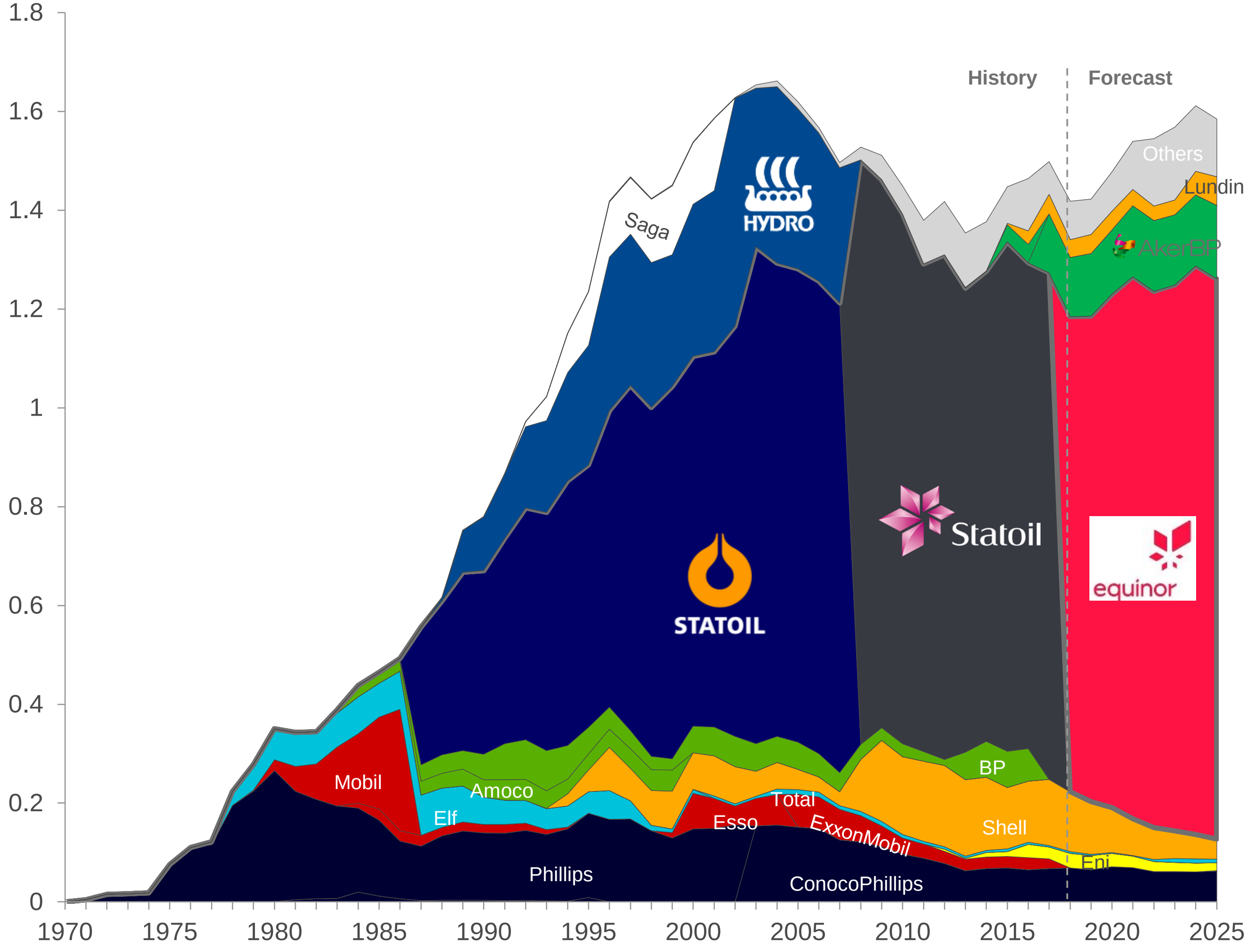
Source: Companies, Rystad Energy research and analysis

Changed player landscape

Operator: AkerBP and Lundin larger than Majors, Equinor with dominant position

Operator vs. license

Operator landscape on the NCS – production by historic operator
Billion boe per year



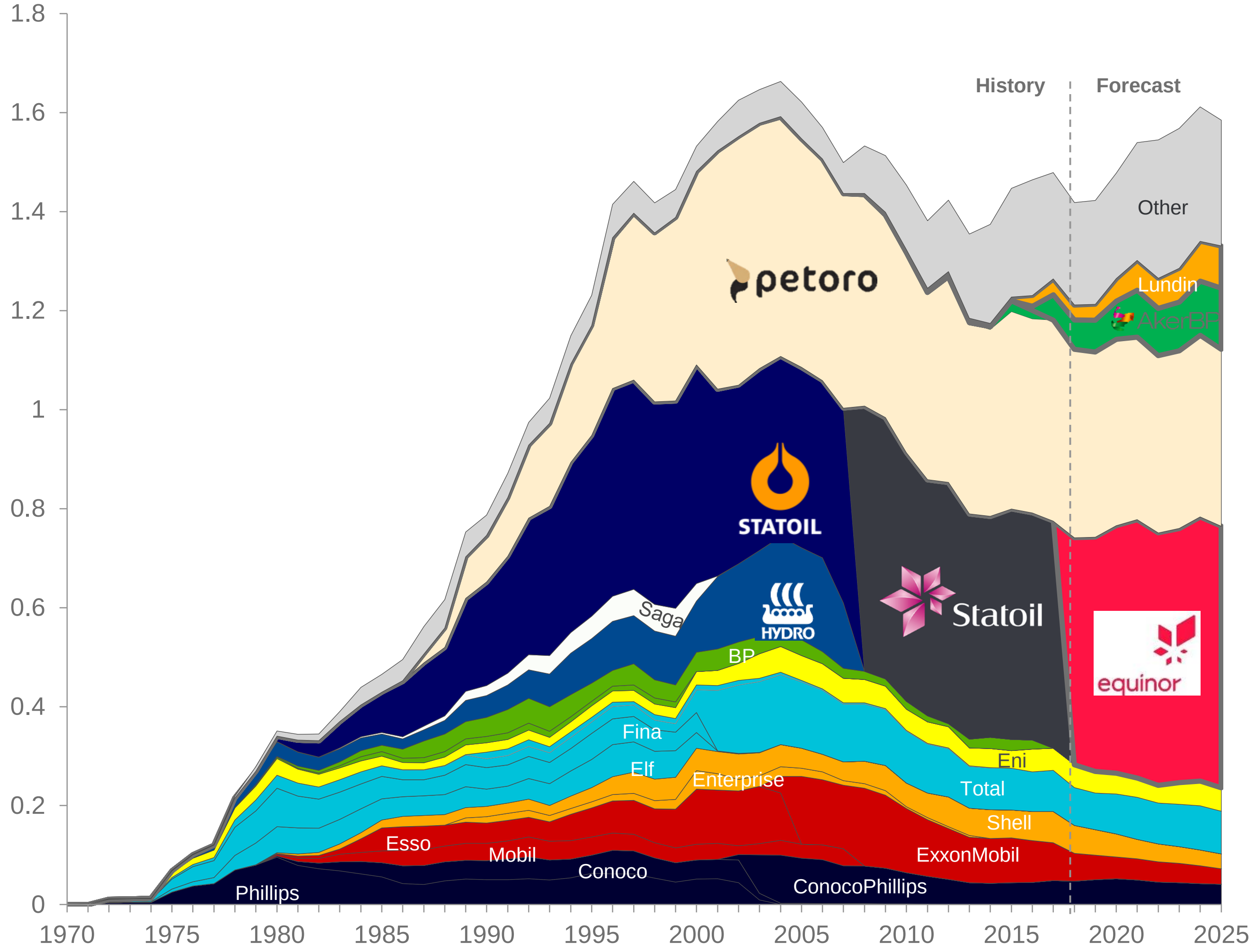
- The number of large operators with production have been reduced on the NCS since 1990:
  - 1990: 9 large operators (3 Norwegians)
  - 2000: 8 large operators (3 Norwegians)
  - 2010: 6 large operators (1 Norwegians)
  - 2018: 6 large operators (3 Norwegians)
- There are now only three Majors left with operated production on the NCS: Shell, ConocoPhillips and Eni.
- The merger between Statoil and Hydro and the loss of two competing technical environments have been described as a loss for technology development and adoption on the NCS by several interviewees.
- However, in recent years through Lundins organic growth and AkerBPs inorganic acquisitions we are seeing two forward leaning Norwegian environments with respect to adopting new technology in addition to Equinor.
- AkerBP and Lundin will have a higher operated production than Majors by 2019 and is expected to grow this share towards 2025.
- Equinor is growing its operated share significantly going forward with new volumes from amongst Johan Sverdrup, Johan Castberg and Aasta Hansteen.

Source: NPD; UCube; Rystad Energy research and analysis

Changed player landscape

5 major owner clusters: Equinor, Petoro, Majors, NCS E&Ps and other

Licensee landscape on the NCS – production by historic owner
Billion boe per year



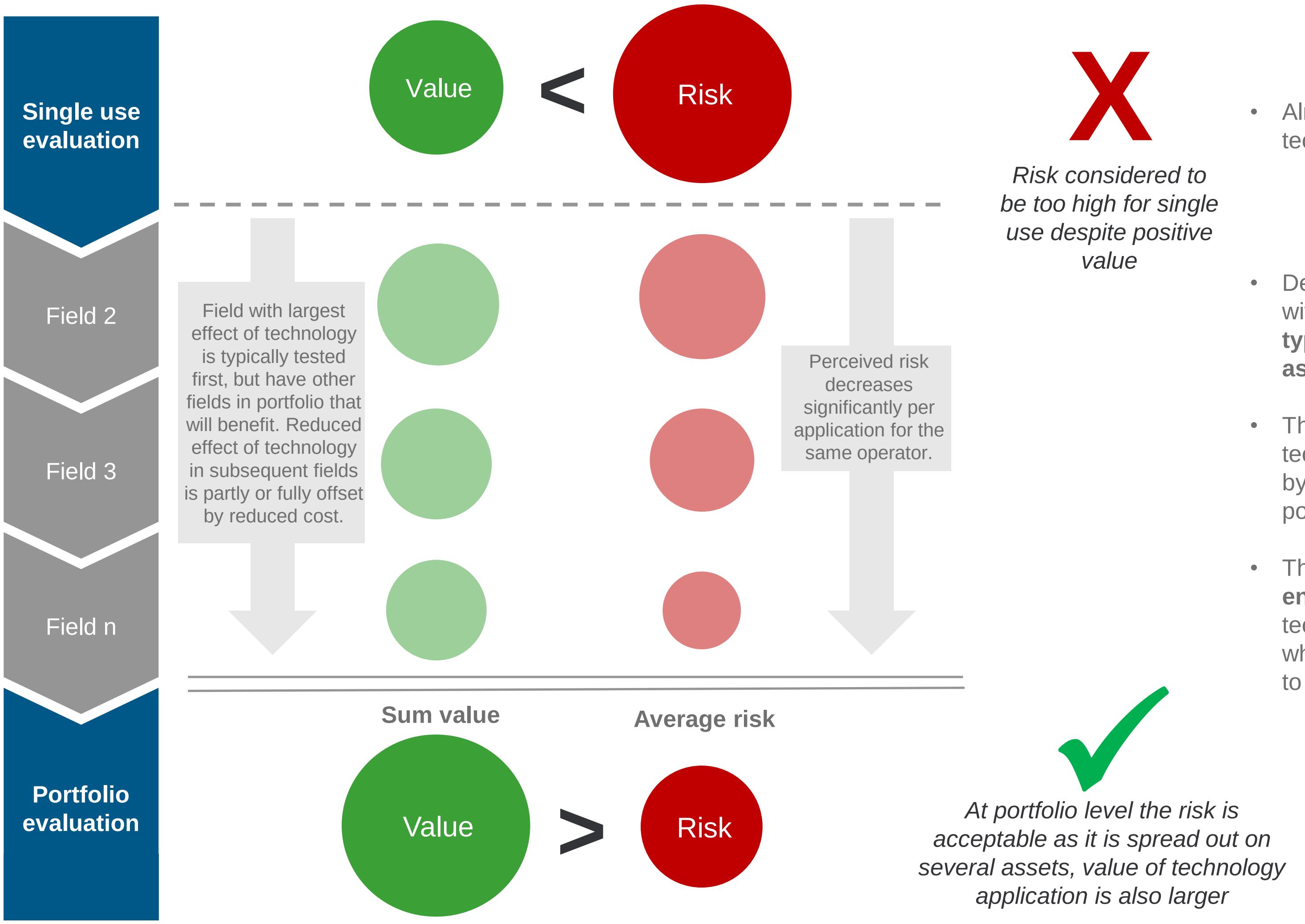
- The owner landscape on the NCS has transformed from many to fewer Majors following the mergers around 2000.
- Also, with the Hydro-Saga merger and Statoil-Hydro merger, the NCS was left with a few large owners holding production by the end 2007.
- Since then the player landscape has expanded significantly, with many new players in both the exploration and producing fields. The first driven by cash back on dry exploration wells.
- SDFI (Petoro) and Equinor currently account for the lion’s share of production on the NCS.
- Majors are holding on to their legacy assets (some only non-op) that are in decline.
- Other operators including dedicated NCS E&Ps like AkerBP, Lundin, Faroe, Point and VNG, now constitute a large part of current production and are expected to grow the most towards 2025.

Source: NPD; UCube; Rystad Energy research and analysis

Larger operators typically evaluate technology for both single use and portfolio

Single use vs. portfolio risk

Technology example with negative decision at field level but positive portfolio value



Field with largest effect of technology is typically tested first, but have other fields in portfolio that will benefit. Reduced effect of technology in subsequent fields is partly or fully offset by reduced cost.

Perceived risk decreases significantly per application for the same operator.

✗

Risk considered to be too high for single use despite positive value

✓

At portfolio level the risk is acceptable as it is spread out on several assets, value of technology application is also larger

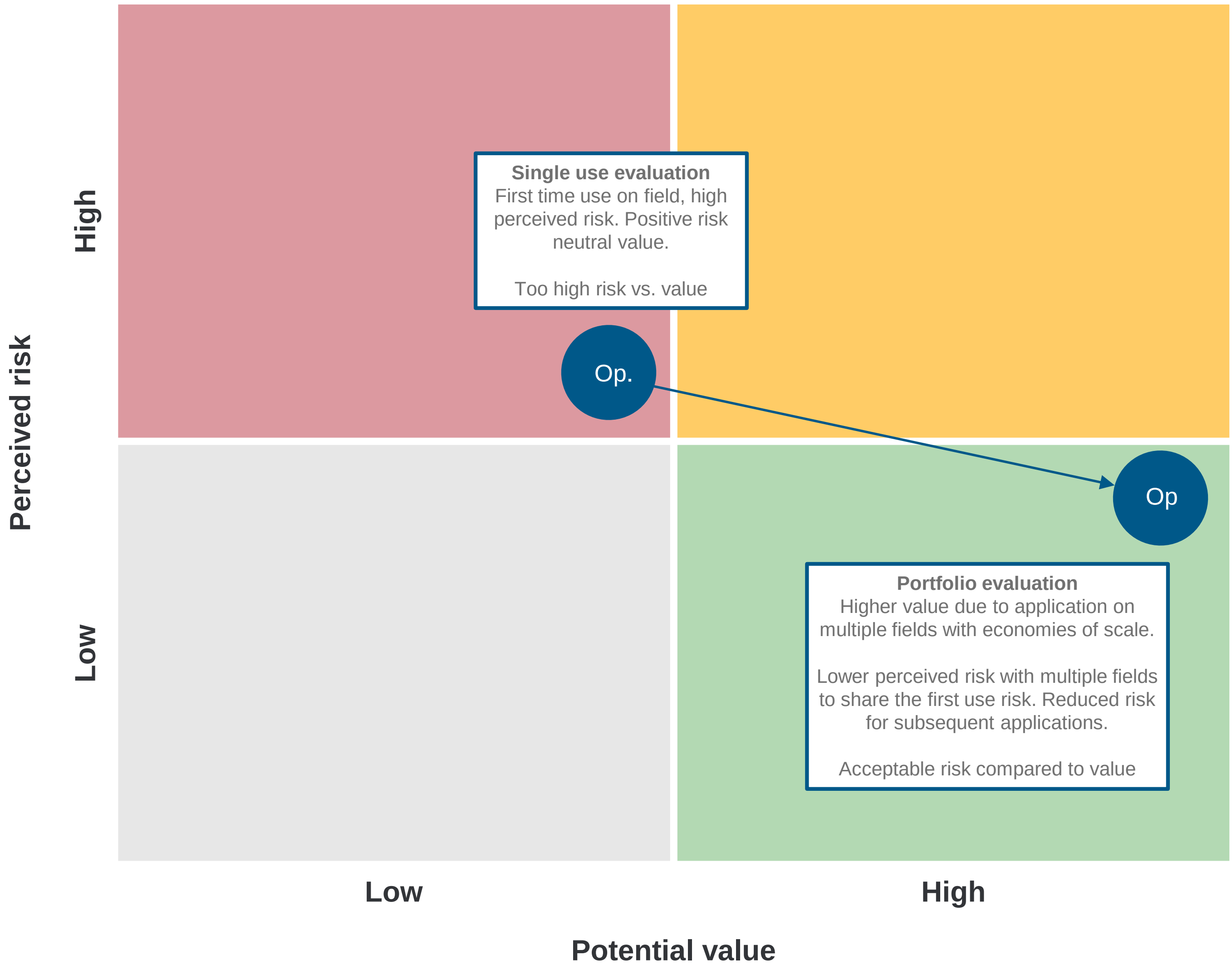
- Almost all operators evaluate the technology application at two levels:
  - **single use** (field or well)
  - **portfolio** of operated and owned assets
- Despite data and experience sharing within the license, **license partners typically evaluate application at asset level only.**
- The result is that application of a technology that is viewed as positive by the partner may not be viewed as positive by the other license partners.
- This holds **especially true for enhancing technologies** that do not technically enable developments, where no license wants to be the first to apply the technology.

> *That new technologies are stopped by the license is more the rule than the exception*
>
> CEO, NCS E&P

Source: Interviews; Rystad Energy

Visualizing the license: Operator positive to technology due to high portfolio value

Risk – value matrix



Single use evaluation
First time use on field, high perceived risk. Positive risk neutral value.

Too high risk vs. value

Portfolio evaluation
Higher value due to application on multiple fields with economies of scale.

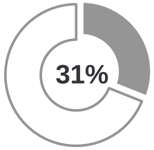
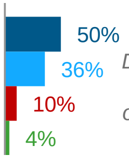
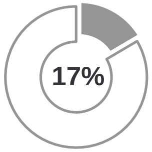
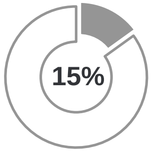
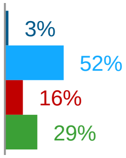
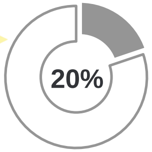
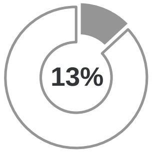
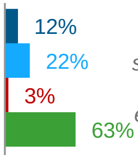
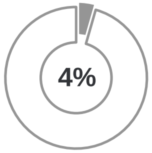
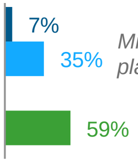
Lower perceived risk with multiple fields to share the first use risk. Reduced risk for subsequent applications.

Acceptable risk compared to value

Source: Interviews; Rystad Energy research and analysis

Large variance in investment opportunities, field portfolios and risk assessment

🟦 NCS 🟥 Shale
🟦 Other offshore 🟩 Other onshore

		Share NCS investments (capex '18-25)	Global investment opportunities (capex 18-25')		Global offshore portfolio	Risk evaluation process as partner	Assess-ment lead time
Equinor	equinor	 31%	 50% 36% 10% 4%	*Diverse, mostly offshore*	Very Large	**Thorough and rigorous evaluation** Often independent evaluation, can rely on internal risk data	Long
Petoro	petoro	 17%	 100%	*Offshore NCS only*	Large	**Positive and trust-based** High appetite for new technology, decision based on operator presentation	Short
Majors	ExxonMobil ConocoPhillips Chevron eni TOTAL	 15%	 3% 52% 16% 29%	*Diverse, shale and onshore exposure*	Very Large	**Thorough and rigorous evaluation** Independent evaluation, may involve parent organization, relies on own risk data	Long
Dedicated NCS operators	AkerBP VNG Norge Lundin Petroleum Faroe pointresources	 20%	 100%	*Offshore NCS only*	Small-Medium	**Independent review** Relies on operator data, but performs independent review	Short-Medium
Other operators	NEPTUNE ENERGY wintershall SPIRIT ENERGY PGNiG DEA REPSOL OMV MOLGROUP	 13%	 12% 22% 3% 63%	*Diverse, shale and onshore exposure*	Medium	**Independent review** Typically relies on operator data, but performs independent review, may run technical evaluation through parent company	Medium
License holder*	出光 Idemitsu Petroleum Norge LOTOS PANDION ENERGY CAPE OMEGA	 4%	 7% 35% 59%	*Mixed, some players large onshore*	Small	**Simple**, limited organization and competence to evaluate, relies on operator presentation	Short

- Due to **different investment opportunity sets**, companies within the license may have **different views on a technology decision** as a pure capex allocation issue.
- Also, **the field portfolio to apply a technology will give large value differences** for the different licensees.
- While operators have similar technology assessments systems as operators, the same **companies' role as a license partner** are different:
  - Larger companies conduct independent evaluations, smaller companies conduct a review based on operator presentation of technology
  - **Majors** and other operators with international parents, typically run **technology evaluation through HQ** for high risk / high value technologies.
  - Companies may use their **own experience / failure data** to evaluate technology – may **yield different results**
- The differences in process result in different lead times to evaluate technology, which may result in a conservative decision due to time-constraints in completing own assessment

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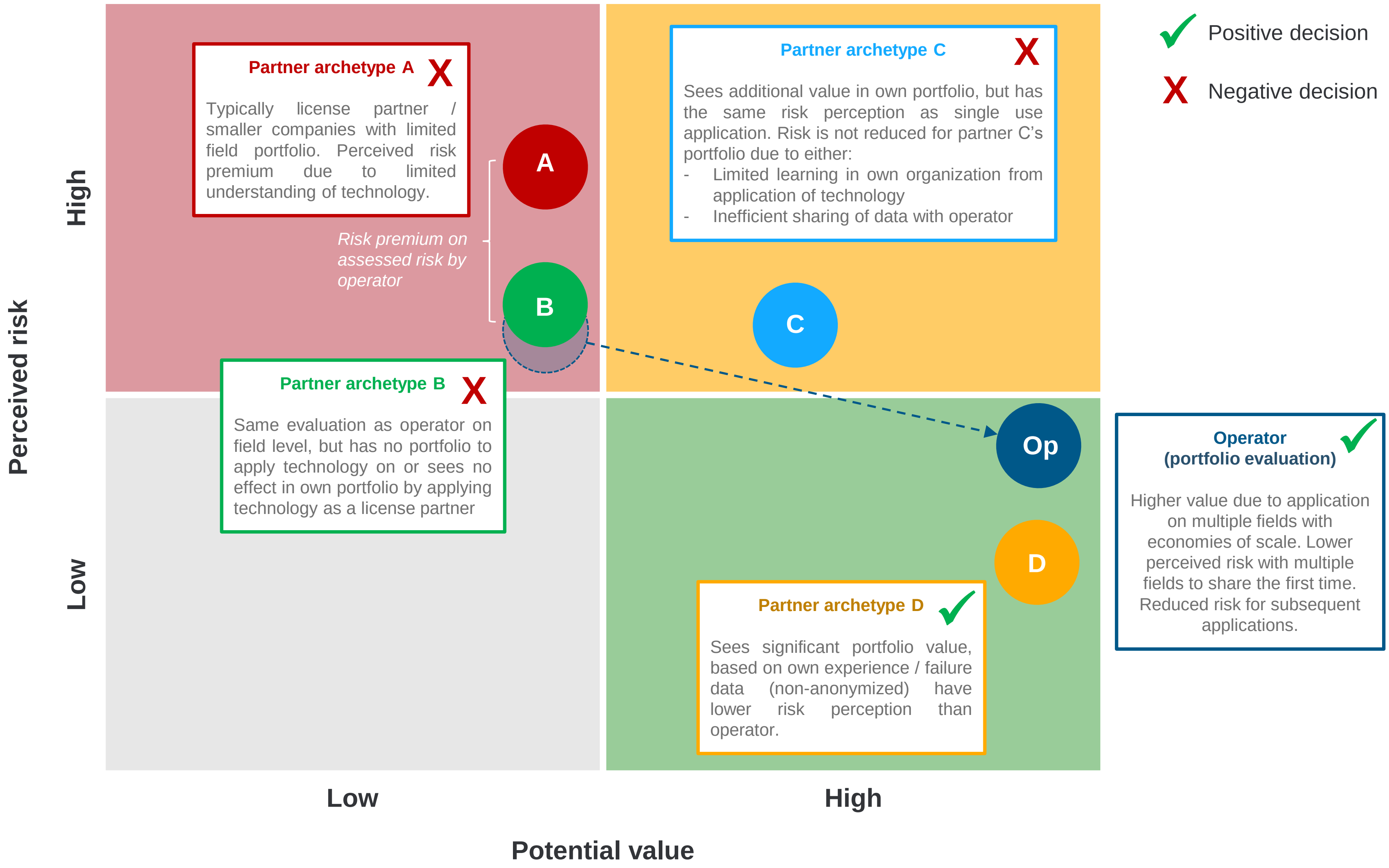
** Companies may be operators in other countries, but are only approved as license partners in Norway or only operates exploration licenses*

Source: Interviews; UCube;

Visualizing the license: Portfolio differences and risk assessment key differentiators

Risk – value matrix



✓ Positive decision

X Negative decision

Partner archetype A X

Typically license partner / smaller companies with limited field portfolio. Perceived risk premium due to limited understanding of technology.

Partner archetype C X

Sees additional value in own portfolio, but has the same risk perception as single use application. Risk is not reduced for partner C's portfolio due to either:

- Limited learning in own organization from application of technology
- Inefficient sharing of data with operator

Partner archetype B X

Same evaluation as operator on field level, but has no portfolio to apply technology on or sees no effect in own portfolio by applying technology as a license partner

Operator (portfolio evaluation) ✓

Higher value due to application on multiple fields with economies of scale. Lower perceived risk with multiple fields to share the first time. Reduced risk for subsequent applications.

Partner archetype D ✓

Sees significant portfolio value, based on own experience / failure data (non-anonymized) have lower risk perception than operator.

Source: Interviews; Rystad Energy research and analysis

Key observations from the operator–license perspective

Key observations	Rationale
1 **Technologies can stop in licenses due to differences in perceived value and risk**	*Licenses partners are prone to disagree on a technology decision with operator and other license partners due to several inherent elements:* • *Single use vs. portfolio value: Value of technology for each license partner is not limited to the field in question, but (ideally) to the portfolio of fields the licensee holds. As this portfolio is different for each license partner (non-existent for some) the value of the technology will be different* • *Risk assessment and technology competence – limited competence about the technology in question often results in increased perceived risk (premium).* • *Different investment criteria / capex allocation: Due to different investment opportunity sets, companies within the license may have different views on a technology decision from a pure capex allocation issue.* • *Different macro assumptions: For high cost high impact technologies, i.e. EOR; have long lead times from investment and long payback times. Such technology decisions will be impacted on macro assumptions. I.e. views on future oil prices trajectory, peak oil demand etc.*
2 **License partners do not get the same portfolio effect as operators in applying the technology for the first time**	• *Despite having a large selection of fields or cases to apply a new technology, the license partner still holds the single-use evaluation as the primary decision driver.* • *Much of this can be attributed to limited learning in the license partners organization. Risk perception is not reduced for projects the same license partner may run as operator.* • *Known examples of technologies that have had to be re-qualified by a operator that have previously approved the technology as a license partner.*
3 **Inefficient data sharing within the license**	• *Despite regulated access to all relevant data through the Joint Operating Agreement (JOA), inefficiencies in receiving relevant data from operator are reported as an issue.* • *Availability, delay in reception and understanding of the data are key obstacles when these are to be applied at other potential use cases for the license partners portfolio.*
4 **Operator brings in technology decision to the license too late**	• *Technology choices are typically presented to license partners at DG2, when the decision of concept is to be taken. If license partners are not able to conduct a proper evaluation in time for the decision – this can result in a more conservative evaluation.*

5 **Altered player landscape mostly beneficial with respect to technology adoption**	• *Benefits:*
	    • *Exit by companies that have investment priorities elsewhere is positive for technology decisions on the NCS. Technology decisions will not be blocked in licenses due to pure investment criteria and portfolio strategies*
	    • *New entrants have more agile decision processes and are more likely to align with operator assessment.*
	    • *Assumption that production-focused PE-backed ventures might have too-short time horizon to appreciate new technology has been refuted in interviews.*
	• *Potential challenges:*
	    • *Lower technology competence in new entrants than in the companies exiting the NCS – may result in higher perceived risk due to lower technological understanding*
	    • *Some new entrants have a smaller offshore portfolio (especially globally) to apply technology that is to be used for the first time on the NCS. May result in lowered portfolio value for decision makers.*

Source: Interviews; NPD

Index

Recommendations where OG21 can play an important role

Measure	What it is	What it solves	How to accomplish it

Technology champion forums	• Cross-industry forums for technology champions (owners) for high risk / high value technologies.
	• Champions within the E&Ps to be the focal point of technology application within the operator and towards suppliers.
	• Create a meeting point for operators, license holders, suppliers, R&D institutions and relevant regulators to share challenges, communicate needs (application areas) and data.
		• Address technology pipeline issues for suppliers as application targets will be visible in the such forums. Makes it easier for supplier to know what technologies have the widest application potential.
		• Nurture the technology champion. The champion is proven to overcome organizational hurdles and reduce perceived risk within the operator organization.
		• Combine operators with similar challenges, secure enough volume for application of technologies that requires repeat use.
		• Arena for sharing technology specific data and experiences so that license holders see portfolio value of application.
			OG21 role: Examine established mechanisms to create such forums and advocate for their creation
			• Norwegian Oil and Gas currently have at least two such forums established:
			  • Drilling Managers Forum
			  • P&A Forum
			• Identify champion candidates, participation by the "dugnad" principle, low cost measure.
			• OG21 cannot choose specific technologies as this challenge OG21s independence, but selection of technologies could have an outset in OG21 technology strategy.

Secure data sharing through inter-operability between platforms	Secure data sharing through interoperability between different data platforms currently being developed. Need to agree on protocols, data formats and data management principles. Delay of access rather than restriction would be a relevant measure to stock price sensitive and business critical data. Some key data types: • Historical: Non-anonymized failure data, equipment performance, well data, reservoir and flow data (only for license only). • Forward looking: Planned DG cycle of future projects brownfield and greenfield and public RNB files.	• Give partners rapid access to data through standardized pre-defined sharing principles. Enable the partner to see portfolio value for new technologies • Avoid requalification for already qualified technologies with other operators, by making non-anonymized data available • Addresses pipeline management for suppliers, possible application targets will be visible through public DG cycle. • Easier to quantify value of new technology, NCS as a offshore technology laboratory will be valuable for both operators and suppliers	**OG21 role: Monitor and advice current industry efforts to align data sharing efforts and advocate for government push** • Current Konkraft projects addressing this issue, OG21 to monitor efforts. • Regulators can set data sharing as requirement at license awards and approval of PDOs • Change JOAs to have openness as guiding principle rather than confidentiality. • Some data types can be published on NPDs existing platform for public access (i.e. planned DG cycle)
Regulator enforcement of the use of value adding technologies	The government has four formalized interaction points with operators that can be used to secure that the most value adding technologies are used: • Approval of operatorship: operator must demonstrate technology strategy and value optimizing KPIs. • License award: Technology adoption part of criteria for when new licenses are awarded. Operators must demonstrate historical track-record. • PDO approval: Similar to the discussion of alternative development concepts, high impact technology choices should be discussed. • License renewal: Evaluation of technologies with brownfield applications (i.e. EOR tech.)	• Rewards the most forward leaning technology companies. • Secures value optimized KPIs and a focused technology strategy in all operator companies, which should help to overcome operator internal obstacles.	**OG21s role: Encourage regulators to use existing interaction points to enforce the use of the most value adding technologies** • Regulators may have backing in existing regulations to enforce BAT (Petroleum Act §4.1), this can be clarified through acquiring legal opinion

Source: Rystad Energy research and analysis

Recommendations where OG21 can play an important role

Measure	What it is	What it solves	How to accomplish it
Build front-end capabilities within Petoro	• More resources to Petoro to develop alternative concepts and evaluate technology potential for licenses. • Unique position to see application potential and evaluate portfolio value on the NCS, due the number of fields in the SDFI portfolio	• Secure evaluation of best available technology and inform regulators of technology options in each individual license	**OG21s role: Be an advocate towards OED to provide more resources to Petoro** • Build front-end capabilities with Petoro (human resources), so that Petoro have the necessary capacity to optimize technology value over SDFI portfolio.
Full lifecycle standardized integrated contracts	• New standard contract from NORSOK for integrated setups and alliances also to include possible full lifecycle risk / reward sharing. • Relates to KonKraft's recent recommendation of standardized alliance and partnership contracts	• Will align incentives also for technologies that have positive effects post project delivery (i.e. volume improving technologies or opex reducing technologies).	**OG21s role: Influence NORSOK / KonKraft**
Change technology qualification standards	Change standardized technology qualification standards: • Change from design criteria to functional and acceptance criteria • Allow for continuous uptake of new technologies	• Current qualification (TRL) and decision making (DG) process is too rigid and linear for fast evolving technologies, technologies may be outdated once they are in production.	**OG21s role: Explore how these procedures can be changed and aligned across the industry**

Source: Rystad Energy research and analysis

Index

Relevant technologies selected by the individual TTAs in OG21

TTA 1 – Energy efficiency and environment

Electrification from onshore grid

- Utilizing the onshore grid to power installations on the NCS

Geothermal energy offshore

- Utilizing geothermal wells offshore for heating/power

Improved operations High North

- Improved solutions for "social license to operate" in the High North

Decarbonization of hydrocarbon value chains

- Power production with CCS
- Hydrogen production with CCS

TTA 2 – Exploration and increased recovery

Radical new EOR technologies

- New reservoir-mobilizing technologies for increased UR

CO2 for EOR and storage

- CO2 injection for EOR and for storage, including development of infrastructure

Water diversion

- Technologies combating water channels, allowing for more effective sweep of reservoir

Big data for exploration

- Automized screening of potential prospects based on big data

TTA 3 – Drilling, completions and intervention

Wired drill pipe

- High-bandwidth telemetry for increased downhole data

Robotic drill floors

- Automatic drill floor systems for more efficient drilling operations and HSE benefits

P&A PWC

- Innovative single-run well P&A technique saving rig days

All electric subsea

- Electrically operated subsea equipment, instead of hydraulics

TTA 4 – Production, processing and transport

Unmanned and automation

- Unmanned facilities more reliant on automatic operations to reduce cost and increase regularity

Subsea boosting

- Subsea boosting of production resulting in accelerated production and increased UR

All electric subsea

- Electrically operated subsea equipment, instead of hydraulics

AUVs

- Autonomous underwater vehicles for remote operations and reduced personnel

Rystad Energy's focus technologies based on TTA selections

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TTA3

AUVs

- Autonomous underwater vehicles for remote operations and reduced personnel

Key takeaways & characteristics of the TTAs' technology fields

TTA 1 – Energy efficiency and environment

- Technologies relating to environment and power sources
- Technologies are often *by themselves* risk reducing, many of the technologies are non-intrusive
- Value pertains to obtaining social license to operate
- Example technology with high perceived risk is electrification from onshore grid

TTA 2 – Exploration and increased recovery

- Technologies relating to exploration and increased recovery
- Technologies are often capex intensive and for brownfield application relating to EOR initiatives subsurface, and the assessed risk is often high and in itself a showstopper
- Value pertains to increased recovery of volumes
- Technologies are often intrusive and the feedback-/payback loop has a long time horizon

TTA 3 – Drilling, completions and intervention

- Technologies relating to drilling and completion
- Technologies are often related to enhancing drilling efficiency, and increasing safety onboard the rig
- Value pertains to cost reduction in drilling operations by reducing expensive rig time, but also through increased recovery as smaller drill targets become profitable
- Example technology with high perceived risk is robotic drill floor solutions

TTA 4 – Production, processing and transport

- Technologies relating to production, processing, and transportation of hydrocarbons
- Technologies span a wide area of applications relating to topside- and subsea facilities, and other infrastructure
- Value in this diverse category is derived from multiple sources: Increased volumes, cost reductions, flexibility in tiebacks, etc.
- Example technology with high perceived risk is subsea boosting

Defining key parameters relating to technology evaluation

TTA1	TTA2			TTA3		TTA4		
Electrification from onshore grid	Radical EOR	CO2 EOR	Water diversion	Robotic Drilling	P&A PWC	All electric subsea	Unmanned/ Automation	Subsea boosting

Application parameters	Value driver	• One or more important value drivers motivating oil companies to utilize the specific technology. The most common value drivers are increased reserves, accelerated production, and cost reduction.
	Enabling/ Enhancing	• Enabling technologies are defined from a technical perspective, not from an economic perspective. Lean development concepts allowing for development of marginal resources is in this context defined as enhancing. The same logic applies for technology lowering drilling cost, thus allowing for smaller targets and addition of reserves normally not recovered. An example of an enabling technology in this context would be the introduction of horizontal drilling at Troll
	Setting	• The setting for a technology application is split into three areas: Greenfield (new developments), Brownfield (producing fields), and Drilling (during drilling operations). The setting is important as it relates to three distinct environments in which new technology may be introduced and utilized
	Single field/ portfolio	• Some technologies need a portfolio of fields/applications to reduce risk and increase business case value to an acceptable level, while other technologies can be justified by single applications. This dimensions plays into different companies' portfolio sizes, the related motivation to implement technologies, and the changes in work process required to accommodate value creation from technologies
	Cross discipline	• New technologies require a varying level of involvement from different disciplines within an oil company. If application of a given technology requires **significant** involvement from more than one discipline within a company, more internal barriers can come into play in the adaptation of the technology. These barriers may relate to resistance against changes in departments' work processes and/or technology implementation into the processes
Risk	Intrusive	• An intrusive technology is defined as a technology that has direct negative impact in terms of lower recoverable resources and/or deferred production in the case of technology failure.
	Risk description	• This dimensions describes the main risks identified for the individual technology from an oil company's perspective
	Application inhibitor	• Main application inhibitor, either defined as assessed risk, perceived risk, or other inhibitors in the form of regulations, etc.

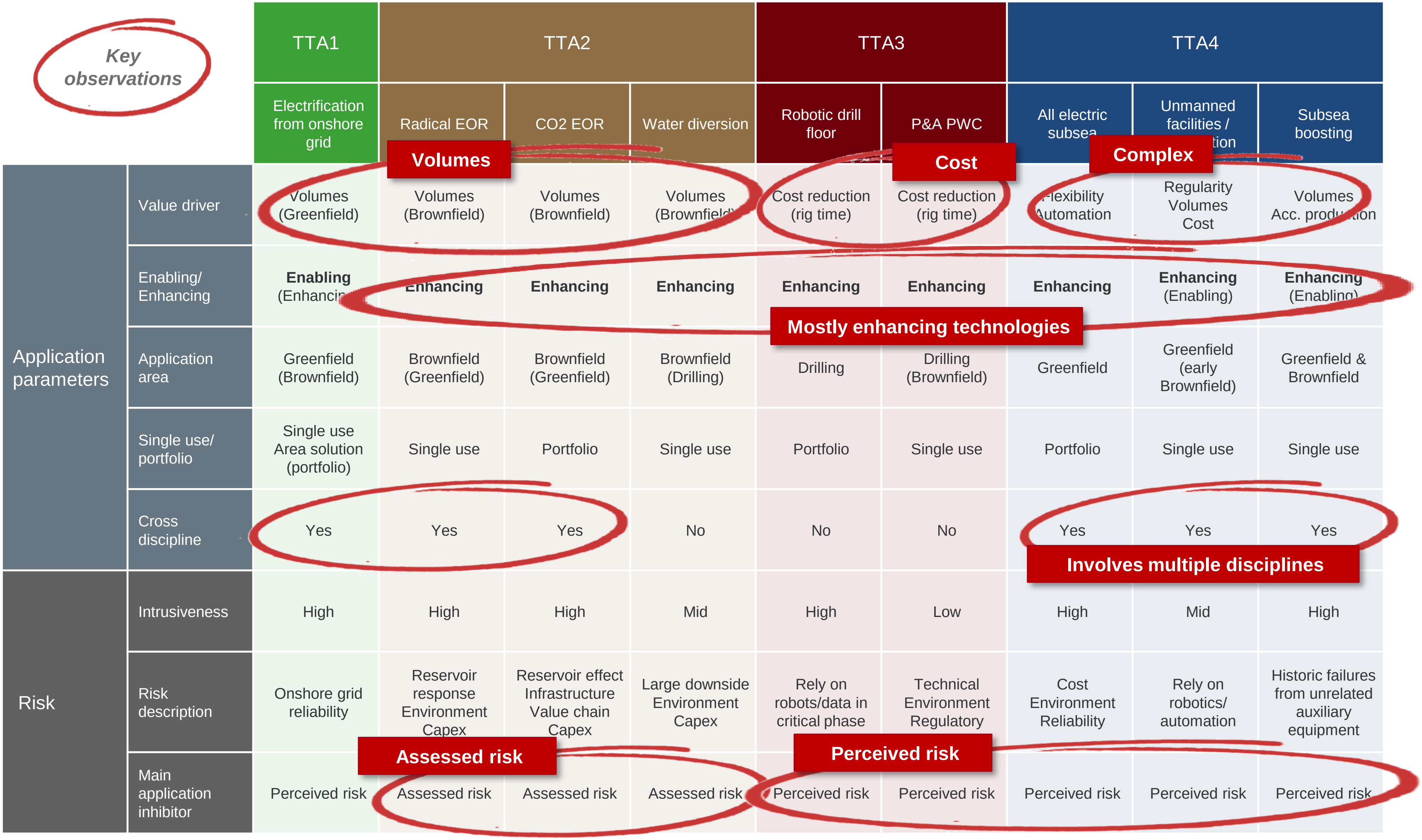
Source: Rystad Energy research and analysis

Example technology assessment

		TTA1	TTA2			TTA3		TTA4		
		Electrification from onshore grid	Radical EOR	CO2 EOR	Water diversion	Robotic drill floor	P&A PWC	All electric subsea	Unmanned facilities / automation	Subsea boosting
Application parameters	Value driver	Volumes (Greenfield)	Volumes (Brownfield)	Volumes (Brownfield)	Volumes (Brownfield)	Cost reduction (rig time)	Cost reduction (rig time)	Flexibility Automation	Regularity Volumes Cost	Volumes Acc. production
	Enabling/ Enhancing	**Enabling** (Enhancing)	**Enhancing**	**Enhancing**	**Enhancing**	**Enhancing**	**Enhancing**	**Enhancing**	**Enhancing** (Enabling)	**Enhancing** (Enabling)
	Application area	Greenfield (Brownfield)	Brownfield (Greenfield)	Brownfield (Greenfield)	Brownfield (Drilling)	Drilling	Drilling (Brownfield)	Greenfield	Greenfield (early Brownfield)	Greenfield & Brownfield
	Single use/ portfolio	Single use Area solution (portfolio)	Single use	Portfolio	Single use	Portfolio	Single use	Portfolio	Single use	Single use
	Cross discipline	Yes	Yes	Yes	No	No	No	Yes	Yes	Yes
Risk	Intrusiveness	High	High	High	Mid	High	Low	High	Mid	High
	Risk description	Onshore grid reliability	Reservoir response Environment Capex	Reservoir effect Infrastructure Value chain Capex	Large downside Environment Capex	Rely on robots/data in critical phase	Technical Environment Regulatory	Cost Environment Reliability	Rely on robotics/ automation	Historic failures from unrelated auxiliary equipment
	Main application inhibitor	Perceived risk	Assessed risk	Assessed risk	Assessed risk	Perceived risk	Perceived risk	Perceived risk	Perceived risk	Perceived risk

Source: Rystad Energy research and analysis

Example technology assessment – key take aways



Key observations

		TTA1	TTA2			TTA3		TTA4		
		Electrification from onshore grid	Radical EOR	CO2 EOR	Water diversion	Robotic drill floor	P&A PWC	All electric subsea	Unmanned facilities / tion	Subsea boosting
Application parameters	Value driver	Volumes (Greenfield)	Volumes (Brownfield)	Volumes (Brownfield)	Volumes (Brownfield)	Cost reduction (rig time)	Cost reduction (rig time)	Flexibility Automation	Regularity Volumes Cost	Volumes Acc. production
	Enabling/ Enhancing	**Enabling** (Enhancing)	**Enhancing**	**Enhancing**	**Enhancing**	**Enhancing**	**Enhancing**	**Enhancing**	**Enhancing** (Enabling)	**Enhancing** (Enabling)
	Application area	Greenfield (Brownfield)	Brownfield (Greenfield)	Brownfield (Greenfield)	Brownfield (Drilling)	Drilling	Drilling (Brownfield)	Greenfield	Greenfield (early Brownfield)	Greenfield & Brownfield
	Single use/ portfolio	Single use Area solution (portfolio)	Single use	Portfolio	Single use	Portfolio	Single use	Portfolio	Single use	Single use
	Cross discipline	Yes	Yes	Yes	No	No	No	Yes	Yes	Yes
Risk	Intrusiveness	High	High	High	Mid	High	Low	High	Mid	High
	Risk description	Onshore grid reliability	Reservoir response Environment Capex	Reservoir effect Infrastructure Value chain Capex	Large downside Environment Capex	Rely on robots/data in critical phase	Technical Environment Regulatory	Cost Environment Reliability	Rely on robotics/ automation	Historic failures from unrelated auxiliary equipment
	Main application inhibitor	Perceived risk	Assessed risk	Assessed risk	Assessed risk	Perceived risk	Perceived risk	Perceived risk	Perceived risk	Perceived risk

Volumes

Cost

Complex

Mostly enhancing technologies

Involves multiple disciplines

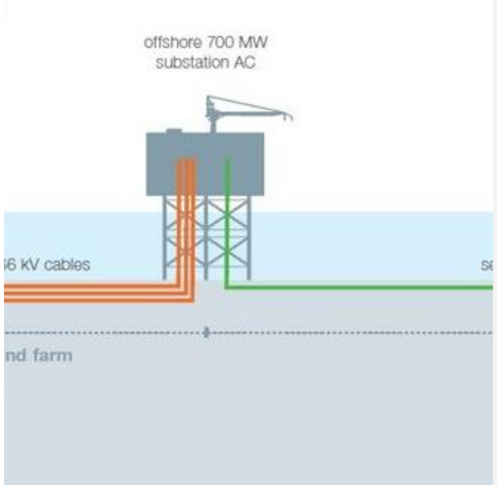
Assessed risk

Perceived risk

Source: Rystad Energy research and analysis

Offshore electrification using onshore grid might secure social license to operate

Technology description



- Powering offshore installations using the onshore power grid, instead of gas turbines
- Several offshore fields on the NCS are electrified from the onshore grid for both political and economic reasons
- Due increased business and societal focus on CO2 emissions, increased electrification of offshore developments using the onshore grid in gaining traction

Risk description and barriers of implementation

- Electrification of offshore installations can underpin social license to operate, new facilities will likely see pressure to use electricity from shore
- The Norwegian government can influence the source of power for future development concepts through the PDO approval process
- Lack of gas export infrastructure and cases of gas re-injection, utilizing gas for power generation is the most common power solution
- Onshore grid uptime, both frequency and average length, is a concern for operators
- Project lead time risk relates to introducing new technology and relying on new/other suppliers
- Positive economics of an electrification project might require a portfolio of fields within the a defined area

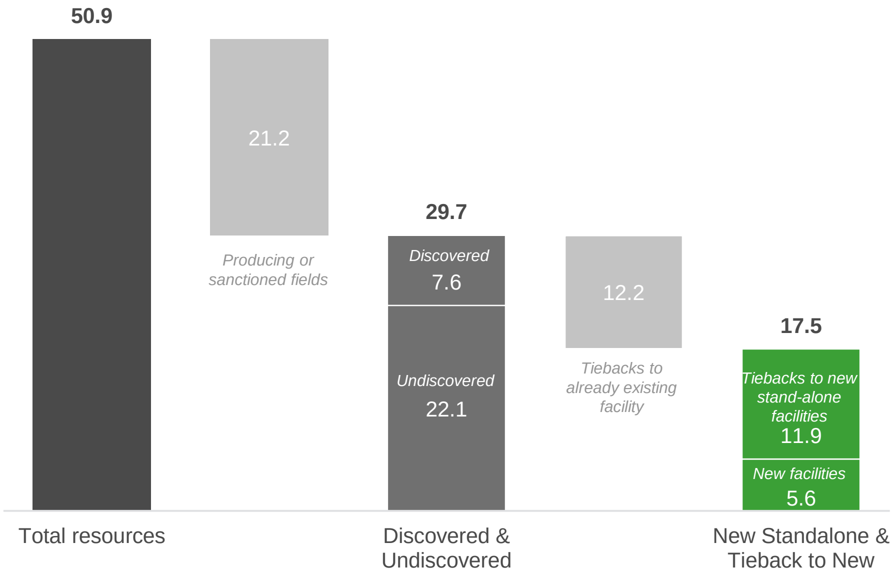
Application type	[✓ Enabling]	Enhancing		This study assumes electrification will be important for the social license to operate on the NCS going forward, driven by both companies' and societal focus on reducing CO2 emissions. The technology is thus considered an enabling feature of new field development concepts by securing social license to operate. NPV positive area solutions for brownfields will be enhancing.
Setting	[✓ Greenfield]	Brownfield	Drilling	Although some fields on the NCS have been electrified in the brownfield phase due to superior economy vs. gas turbines, the main value of the technology is in securing new developments, and is the main focus when evaluating this technology
Viability requirement	[✓ Single use]	Portfolio		Each greenfield development project evaluated independently from a social license to operate perspective. However, depending on nearby gas export infrastructure and the potential to create an electrified hub, the business case for hub electrification can make sense economically as well.
Organization	Single discipline	[✓ Cross-discipline]		Using electricity from the onshore grid is something that affects every discipline involved in the engineering and construction of the facilities in a greenfield development.
Risk type	[✓ Intrusive]	Non-intrusive		Electrification of offshore facilities will likely entail a back-up feature to run emergency systems, but not full operations. Onshore grid downtime and damages to cables will cause production shutdown and the technology is thus considered intrusive.
Application inhibitor	Assessed risk	[✓ Perceived risk]	Other	Disregarding any government-imposed regulations on electrification, the two main concerns of operators is onshore grid uptime (incl. power transmission and reliability), and execution risk related to investment costs in remote areas such as the Barents Sea.

Sources: Rystad Energy research and analysis; TTA input;

Offshore electrification could potentially secure 17.5 billion boe license to operate

Remaining resources on the NCS

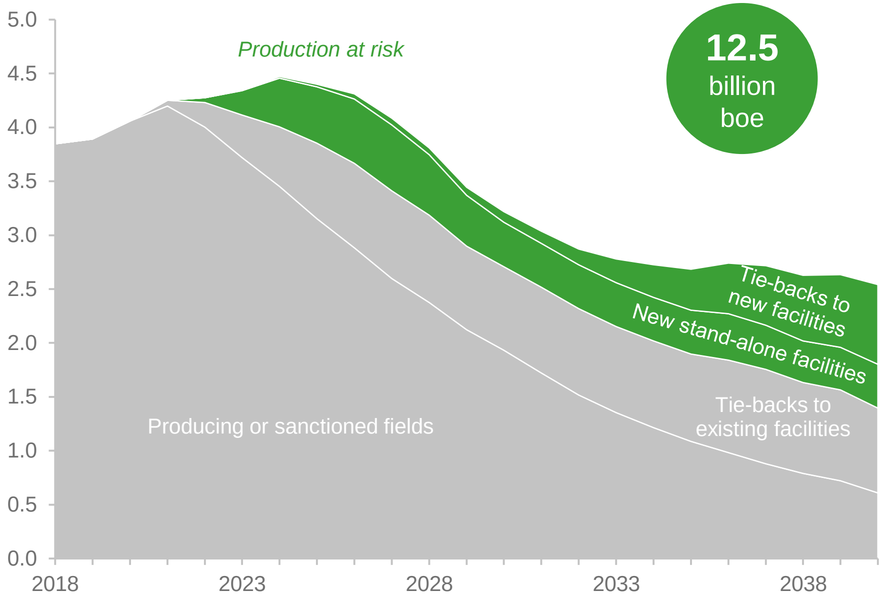
Billion oil equivalents



- Rystad Energy estimates remaining resources on the NCS to be 51 billion barrels of oil equivalent as of 01.01.2018 across producing assets, assets under development, discoveries, and undiscovered resources
- Rystad Energy has singled out new standalone developments and tiebacks to new standalone development as “resources at risk” if electrification becomes required to secure license to operate.
- Resources at risk are:
  - Standalone new developments: 5.6 billion boe
  - Tiebacks to new standalone developments: 11.9 billion boe

Indicative effect on NCS production (2018-2040)

Million oil equivalents per day



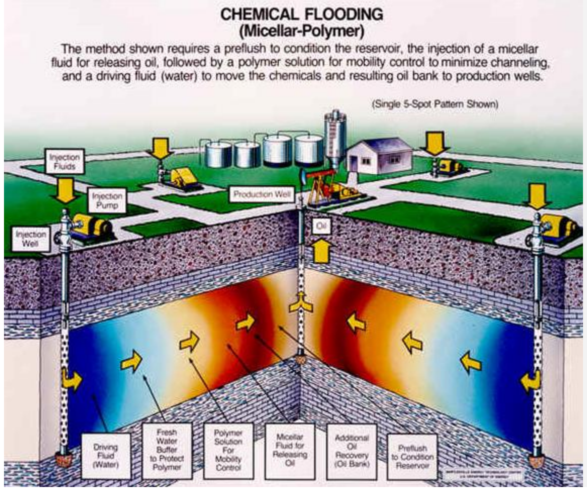
- The chart above outlines the indicative effect outages of the resources at risk would have on the NCS production profile from 2018 to 2040
- From 2018 to 2040, the resources at risk are estimated to contribute with 12.5 billion barrels of oil equivalent to the NCS total production.
- The large majority (66%) of the resources at risk is located in the Barents, and most of the Barents Sea resources are at this point undiscovered

*Report on improved drilling efficiency and reduced costs from TTA3 dated October 2014 published on OG21 webpages

Sources: Rystad Energy research and analysis

Radical new EOR methods – risk relates to effect on reservoir and environmental concerns

Technology description



CHEMICAL FLOODING
(Micellar-Polymer)

The method shown requires a preflush to condition the reservoir, the injection of a micellar fluid for releasing oil, followed by a polymer solution for mobility control to minimize channeling, and a driving fluid (water) to move the chemicals and resulting oil bank to production wells.

(Single 5-Spot Pattern Shown)

Radical new EOR methods include various types new methods offshore for targeting immobile oil in the reservoir:

- Polymer flooding
- Surfactant / ASP cocktail
- Smart water (low-sal)
- MEOR (microbial EOR)

Risk description and barriers of implementation

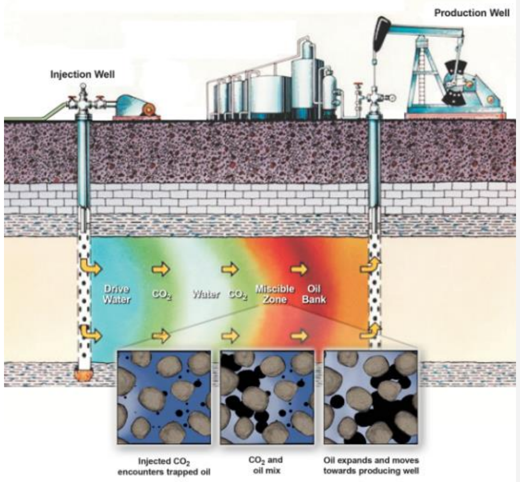
- Many of the technologies have limited track-records offshore and uncertain effect on the reservoir is a key risk factor.
- Common for the EOR technologies is also that they take a long time before effect is seen and the payback time is therefore long.
- Several of the methods use chemicals that are labeled as red or black on the NCS, environmental risk is a key barrier
- Handling of back-produced chemicals and polymers in particular is complicated and requires changes to topside processing facilities
- Limited field performance knowledge both for operational and EOR potential estimation

Application type	Enabling Enhancing	• Fields typically need to be large in order to be viable for EOR methods, as such EOR technologies is not enabling small marginal fields, but providing higher recovery on large fields that will be sanctioned without the technology.
Application area	Greenfield Brownfield Drilling	• Typical brownfield application relevant on the NCS, the large fields that are prime candidates are typically already producing with some exceptions • Greenfield implementation could be beneficial as the process system must be setup to deal with chemicals
Viability requirement	Single use Portfolio	• Single field application will drive viability, chemical solution will typically be tailored for the individual field • Due to the large amounts of chemicals needed, specialized vessels that could be shared between licenses could help the economic case.
Organization	Single discipline Cross-discipline	• Requires the involvement of multiple disciplines with changes in process system topside and in execution phase with specialized vessels.
Risk type	Intrusive Non-intrusive	• Intrusive to the reservoir, potential to significantly alter the reservoir behavior.
Application inhibitor	Assessed risk Perceived risk Other	• High uncertainty with regards to effect on reservoir, especially for offshore applications with larger well spacing. As such, assessed risk is the main inhibitor. • Also, long payback time due to long response time before effect on the reservoir is seen is an inhibitor

Sources: Interviews; TTA input; US DOE (image);; Rystad Energy research and analysis

CO2 for EOR and storage – need for extensive infrastructure and larger field portfolio

Technology description



- 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 <u>immobile oil</u>
- CO_2 that emerges with the oil is separated and re-injected into the formation.
- The technology requires large quantities of available CO2 for injection.

Risk description and barriers of implementation

- Reservoir risks are lower than the other technologies
- The most mature EOR technology for releasing immobile oil is CO2. High certainty that it will have positive effects on the reservoir.
- The application has proven successful onshore with regular applications in amongst Texas where it has been used extensively for +20 years
- Effect on the reservoir is expected to be positive, and there is less technical risk with this method than the two other EOR methods suggested.
- With CO2 being far more corrosive than typical streams of processed and unprocessed natural gas, there is risk and cost associated with upgrading production system is high
- Also, significant amount of CO2 needs to be gathered and transported, a key barrier for this technology.

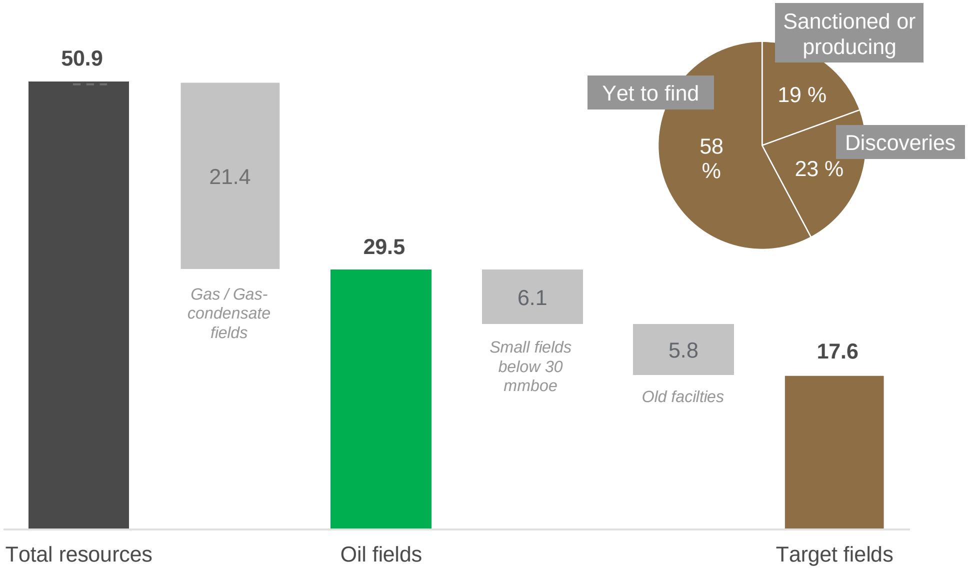
Application type	Enabling [✓ Enhancing]	• Fields typically need to be large in order to be viable for EOR methods, as such EOR technologies is not enabling small marginal fields, but providing extra volume on large fields that will be sanctioned without the technology.
Application area	Greenfield [✓ Brownfield] Drilling	• Typical brownfield application relevant in Norway, where most of the field candidates are found. • Greenfield implementation could be beneficial due to challenges with corrosion when including CO2 in the injection and production streams. This may entail significant changes to existing production and processing equipment.
Viability requirement	Single use [✓ Portfolio]	• High infrastructure requirements for this type of technology will likely require multiple fields for project viability. Source and transport of the large CO2 amounts needed is one of the key technology barriers.
Organization	Single discipline [✓ Cross-discipline]	• Requires multiple disciplines to complete project. Complex infrastructure solution, multiple fields likely involved in addition to full field involvement
Risk type	[✓ Intrusive] Non-intrusive	• Intrusive to the reservoir, CO2 may dissolve reservoir rock • Intrusive to the production system, may damage process equipment due to more corrosive streams than original design
Application inhibitor	[✓ Assessed risk] Perceived risk [✓ Other]	• One of the most documented EOR techniques in terms of effect on the reservoir. Assessed risk is still the main inhibitor when comparing potential value to the high cost of implementation offshore with new gathering and transport infrastructure and topside modifications. Sourcing the necessary CO2 for application carries political and cross border elements.

Sources: Interviews; TTA input; OG21 workshop (23.05.2018); Rystad Energy research and analysis

CO2 and radical new EOR projects can contribute with up to 1 billion barrels

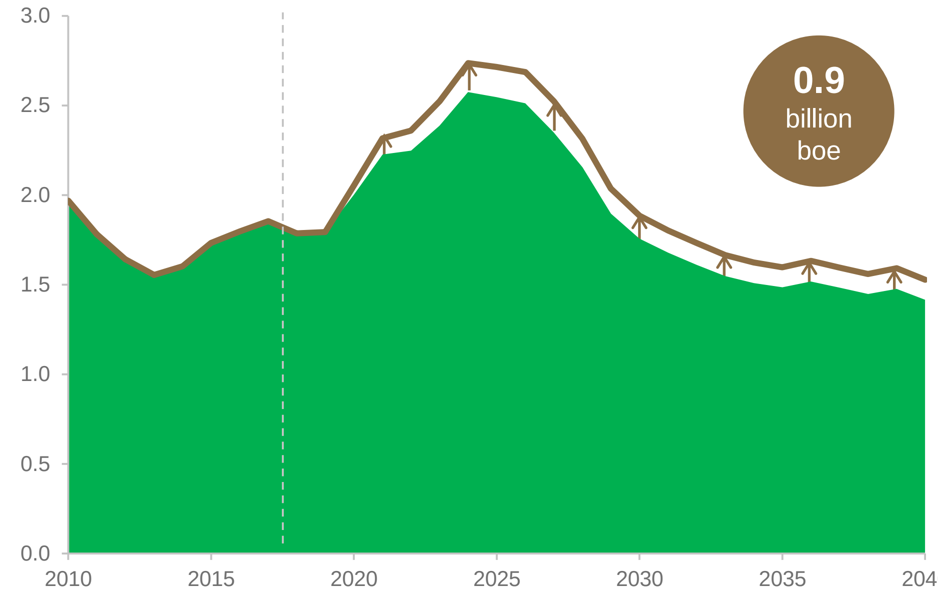
Remaining resources on the NCS

Billion barrels of oil equivalent as of 01.01.2018



Indicative effect on oil fields on the NCS (2018-2040)

Million boe/d



- These technologies are only applicable on oil fields that use water as the drive method, this excludes 40 percent of the remaining resources on the NCS located in gas and gas-condensate fields.
- Small fields are excluded from due difficulty with economics and typically the lack of sufficient wells and injectors.
- As retrofitting of existing platforms requires expensive modifications on infrastructure, deck space and suboptimal well spacing, the EOR potential is only considered viable on relatively new facilities.

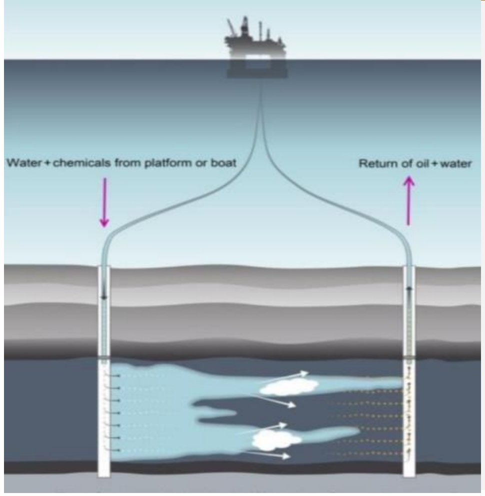
- Onshore CO_2-EOR and ASP (Alkaline-Surfactant-Polymer) flooding have achieved an increased recovery rate of 4-15%. EOR potential offshore is likely lower than what is observed onshore due to lower well density, thus this analysis assumes incremental recovery rates of 2-7%. Impact given to all producing fields from 2020.
- 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.

*Reservoir Complexity Index

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

Water diversion deep in reservoir/near well: increasing mobility control in the reservoir

Technology description



- The main goal of the technology is to improve sweep in the reservoir, and increase recovery of mobile oil.
- This is completed by diverting water flows through less permeable parts of the reservoir.
- This can be completed by injecting foam cement, gel and silicate products.
- At least two successful pilots on the NCS with foam cement on Ekofisk and sodium silicate on Snorre.

Risk description and barriers of implementation

- Technology is intrusive to the reservoir and could have significant unwanted effects on reservoir performance
- Existing solutions that have been proved to work with both foam cement, gel and silica products
- Risks generally on the technical side, but with environmental issues with some products
- Further development of modelling and simulation techniques to accurately predict the effects of in-depth water diversion.
- Snorre silicate project noted close cooperation with the license partnership, with early and frequent involvement, as key success criteria for implementation
- Positive NPV for the expected case was the defining decision criteria (not for the low case

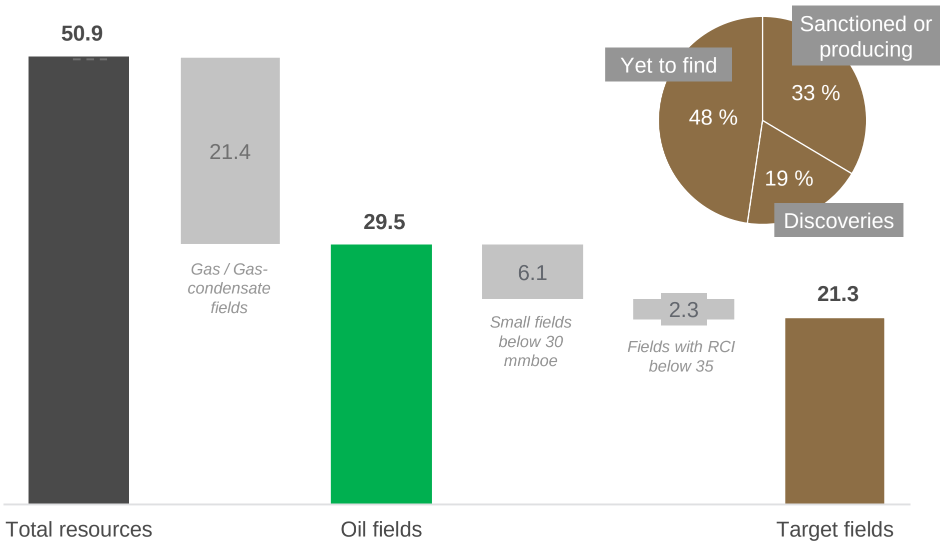
Application type	Enabling	**Enhancing**		• Enhancing technologies that gives higher recovery of mobile oil in the reservoir and reduces water breakthrough. Always applied in the brownfield phase and will by design not enable the development of a field.
Application area	Greenfield	**Brownfield**	Drilling	• Brownfield application only, but decision to use technology can be taken on a well by well basis. Full field implementation more likely as technology matures.
Viability requirement	**Single use**	Portfolio		• Both Snorre and Ekofisk applications were single use applications with positive NPV, but there could be positive portfolio effects could include shared use of LWI across licenses.
Organization	**Single discipline**	Cross-discipline		• Compared to other IOR/EOR technologies this does not involve any topside modifications and is smaller in scale. Typically two disciplines involved; reservoir and drilling and well. Minor interference with operations on the platform for Snorre silicate project.
Risk type	**Intrusive**	Non-intrusive		• Intrusive technology, can risk reducing flow to or plugging producers, especially with the use of cement. With the use of lighter chemicals, process problems due to breakthrough of chemicals in the producer.
Application inhibitor	**Assessed risk**	Perceived risk	Other	• Assessed risk is the main application inhibitor, due to the intrusiveness. Reservoir uncertainty is very much the name of the game in oil and gas, and little perceived risk is added to the initial evaluations.

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

Water diversion with high potential impact on the NCS

Remaining resources on the NCS

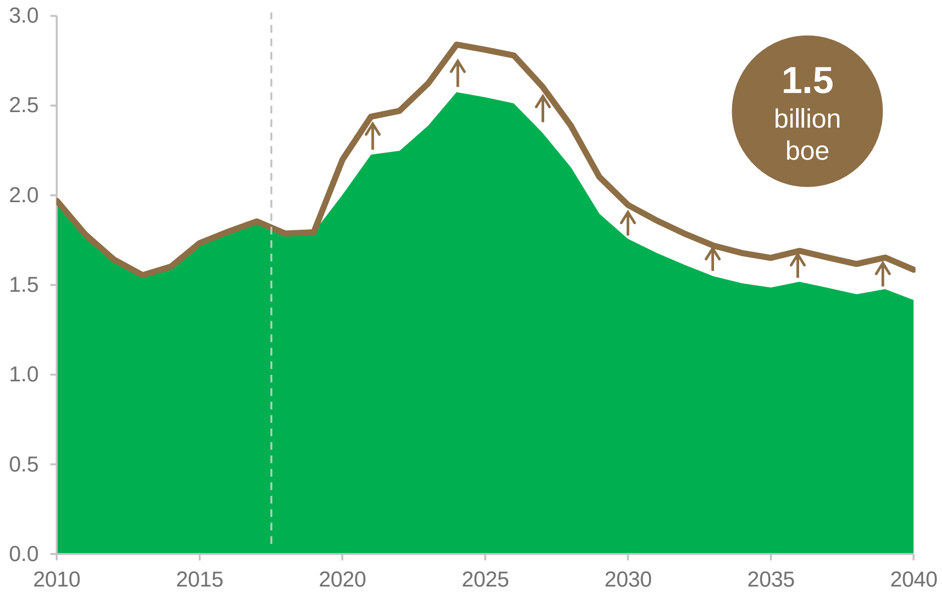
Billion barrels of oil equivalent as of 01.01.2018



- These technologies are only applicable to oil fields that use water drive as (potential) recovery method. This excludes 40 percent of the remaining resources on the NCS located in gas and gas-condensate fields.
- Small fields are excluded from due difficulty with economics and typically lack of sufficient wells and injectors.
- Also, very uniform fields are excluded from the target fields, 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.

Indicative effect on oil fields on the NCS (2018-2040)

Million boe/d

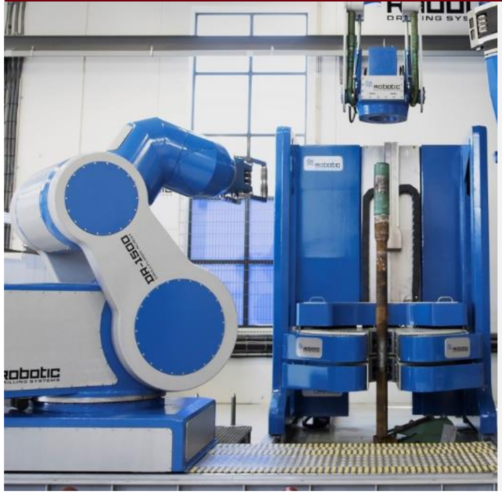


- Onshore methodologies have proven that it is possible to achieve 5-30% incremental recovery rates due to increased mobility control. EOR potential offshore is likely lower due to larger well spacing, thus this analysis assumes incremental recovery rates of 2.5-15%. Impact given to all producing fields from 2020.
- For producing and sanctioned fields the recovery rates are estimated on a field-by-field basis The higher RCI the better the effect. 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.

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

Drill Floor Robotics: Increase drill floor efficiency, and reduce manual labor in red zone

Technology description



- Drilling rigs have varying degrees of robotic systems enhancing drill floor efficiency, however, significant potential exists to decrease manual labor on the rig floor through remotely operated machinery
- Implementation of additional robotic features on the drill floor will be gradual
- Autonomous rigs responding to downhole feedback algorithms for optimal drilling performance is the end game, where drill floor robotics play a crucial role

Risk description and barriers of implementation

- Implementation of drill floor robotics on rigs requires large investment incl. non-productive yard stays, and organizational changes
- Rig owners are not necessarily incentivized to increase effectivity due to contract models, unless a specific rig falls below acceptable efficiency
- Reducing offshore manning may trigger resistance from unions
- Also the practicality in replacing all red zone rig personnel is questioned. The "unlimited" amount of specialized tools and procedures when running drill pipe and completions call for some manual touch
- Actual drill floor efficiency gains must be proven, and will be a function of the operator controlling the robots (automatic, not autonomous)
- Limited risk of dropping tools downhole and reliability/uptime of the system must be proven, as downtime causes a hard shutdown of operations, potentially in critical stages of the drilling operation
- Operators may tend to operate slightly sub-optimal, instead of relying fully on robotics and risk major malfunction and long shutdowns

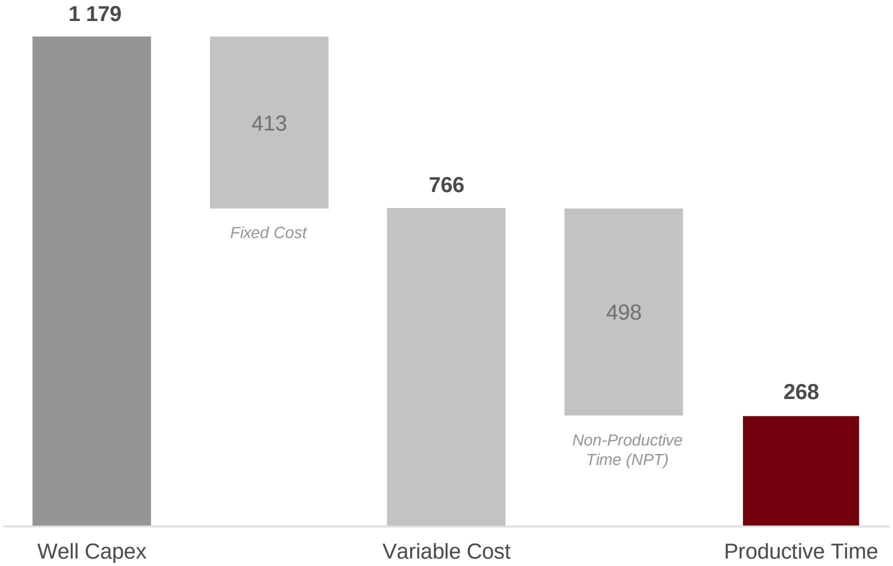
Application type	Enabling [✓ Enhancing]	Drilling robotics increase drilling efficiency and addresses "Invisible Lost Time" normally classified as productive time. Drilling performance ensures that operations are repeatedly done in the most optimal way. The technology can reduce CAPEX and OPEX, and improve HSE by removing personnel from red zone
Application area	Greenfield Brownfield [✓ Drilling]	Drilling robotics will by definition only apply to the drilling setting. The main value driver relates to offshore rig operations, due to the high and time-dependent cost, although onshore rigs and platform rigs are secondary application areas.
Viability requirement	Single use [✓ Portfolio]	From a rig owners' point of view, the initial investment would be paid off across several applications, and is thus dependent on a portfolio of wells provided by a number of operators. Drilling efficiency constitutes a comparative advantage, and will likely drive rig attractiveness in the market
Organization	[✓ Single discipline] Cross-discipline	Drilling & Well (D&W) is the only department within the oil company who must adapt to new remotely operated systems on the rig. However, as D&W is only hiring the rig, the rig owner is most affected in terms of reduced personnel and changes in the work processes
Risk type	[✓ Intrusive] Non-intrusive	Drill floor robotics failure and subsequent delay of project start-up will affect production timing, and the technology is thus classified as intrusive. Contingency planning for manual labor to take over operations if the system experiences critical malfunction, is assumed limited
Application inhibitor	Assessed risk [✓ Perceived risk] [✓ Other]	Rig owners hesitant to invest in robotics unless required to make rig competitive. Operators hesitant to give too much control to digital technologies and robotics in the face of perceived risk of uptime and actual efficiency gains. Unions likely not to comply silently if offshore manning is reduced.

Sources: Rystad Energy research and analysis; TTA input;

Drill floor robotics may reduce NCS well capex by 54 billion NOK from 2018 to 2040

Forecasted well capex on NCS (2018-2040)

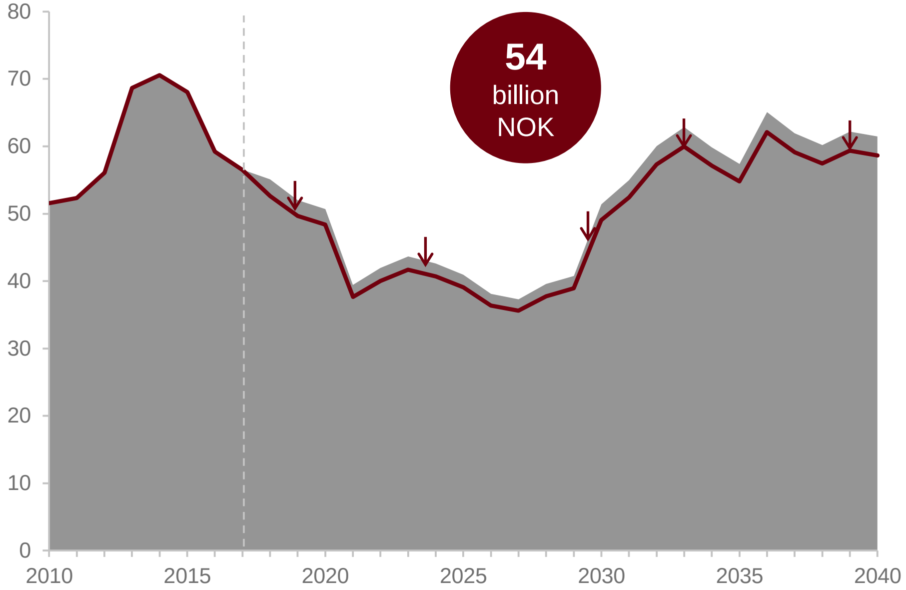
Billion NOK (real 2018)



- Rystad Energy estimates well costs on the NCS to total 1179 billion NOK (real 2018) from 2018 to 2040
- Rystad Energy data concludes 65% of well cost is time-related e.g. rig rate, service, and logistics, totaling 766 billion NOK to 2040. 413 billion NOK is thus related to consumables and other fixed costs
- On average, Rystad Energy data shows only 35% of time spent constructing offshore wells is classified as Productive Time (PT). 15% is classified as non-productive time (NPT), like waiting on weather, and 50% relates to other operations like preparation, completions, P&A, etc.
- Productive time is thus assumed to account for 268 billion NOK of NCS well cost until 2040

Indicative effect on well capex on NCS (2018-2040)

Billion NOK (real 2018)



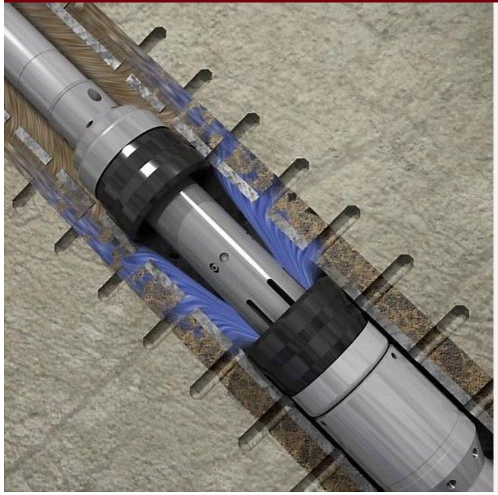
- A report* from TTA3, the group on drilling and intervention in OG21, quoted a third-party report from 2010 estimating cost saving potential for offshore applications of automated/autonomous drill floors of up to 20% to 30% on time-based operations. On the basis of this report, Rystad Energy has assumed a 20% cost reduction in rig-related productive time in this exercise
- A 20% cost reduction in productive time, proportional to the variable cost, implies a total cost reduction of 54 billion NOK (real 2018) related to well costs on the NCS from 2018 to 2040

*Report on improved drilling efficiency and reduced costs from TTA3 dated October 2014 published on OG21 webpages

Sources: Rystad Energy research and analysis

Perforate, Wash, Cement (PWC): Step change in P&A technology

Technology description



- Step change P&A technology reducing time and thus cost relating to setting cross-sectional cement barriers
- Relies on perforation of casings to access the annular space instead of milling entire sections of casing
- One-run application instead of several runs required by other methods
- Next generation PWC allows for rig-less P&A using coiled tubing and wireline

Risk description and barriers of implementation

- PWC P&A technology has over 200 successful applications worldwide
- However, individual operators feel required to qualify the technology despite the solid track record and proven effect of technology
- This leads to slower adaptation of the PWC technology
- In addition, operators feeling comfortable with conventional P&A process of section milling tend to delay adaptation of PWC until a significant number of targets are available in a P&A campaign
- Verification of the annular cement barrier integrity through cement bond logging has a larger perceived risk compared to section milling and cross-sectional cement barrier
- However, some operators have trusted experts in cement bond logging and have created qualification matrices for PWC barriers sharing the same operational parameters, greatly increasing efficiency
- Regulations must adapt to multiple casings applications, and new plugging materials as the technology evolves

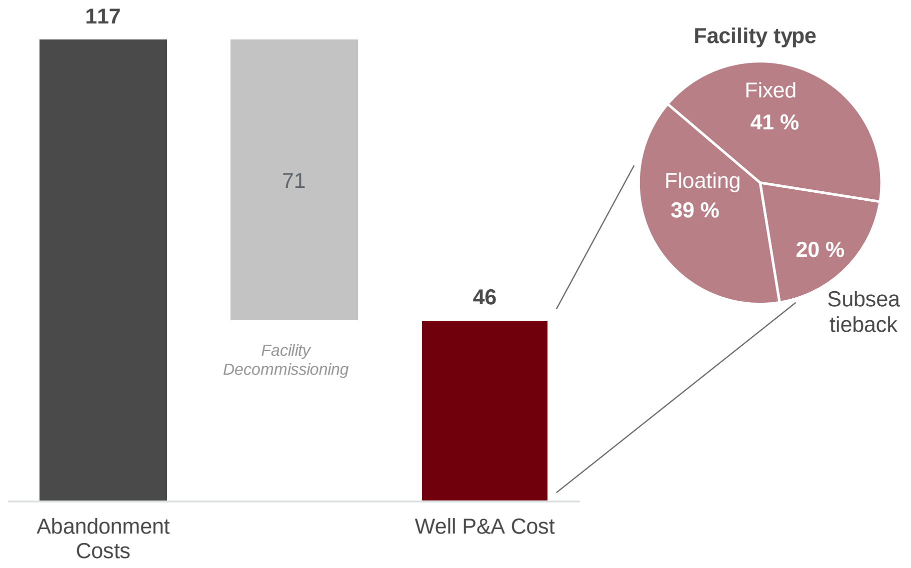
Application type	Enabling [✓ Enhancing]	PWC technology reduces P&A time compared to other methods, and is thus an enhancing technology. The next generation of PWC technologies will include rig-less coiled tubing and wireline conveyed tools to perform through-tubing P&A, allowing P&A without the costly need of pulling and disposing of production tubing from the well
Application area	Greenfield [✓ Brownfield] [✓ Drilling]	P&A activities are typically conducted on a large scale at cease of production before decommissioning of infrastructure. However, the application area is well by well, and decision to use this technology does not necessarily need to impact any other operations. Also, P&A is also conducted on wildcats and appraisals as well as when doing slot recoveries, a common process on the NCS
Viability requirement	[✓ Single use] Portfolio	PWC technology is economically robust in a single-well scenario, and is not dependent on a portfolio effect. However, several P&A targets (e.g. field campaigns) should be available for first-time users to successfully develop and implement the required work processes to make the PWC technology a staple in their P&A tool box
Organization	[✓ Single discipline] Cross-discipline	The PWC technology is considered to mainly affect the drilling & well department within an oil company, and by extension the operational personnel on the rig working on behalf of the D&W department
Risk type	Intrusive [✓ Non-intrusive]	The PWC technology is non-intrusive in the sense that no production or reserves will be negatively impacted in the case of application failure. If a tool failure or cement setting failure occurs, the procedure can be run again, with no consequence other than additional cost
Application inhibitor	Assessed risk [✓ Perceived risk] Other	The need for qualification of the technology despite the solid track record globally, as well as the need to verify the annular cement barrier for every application, reducing PWC efficiency, are considered two inhibitors. As the PWC technology evolves, regulations must follows suit, to realize PWC's potential for cost-efficient P&A on the NCS

Sources: Rystad Energy research and analysis; TTA input;

P&A cost reduction potential of 16 billion NOK from 2018 to 2040 utilizing PWC on the NCS

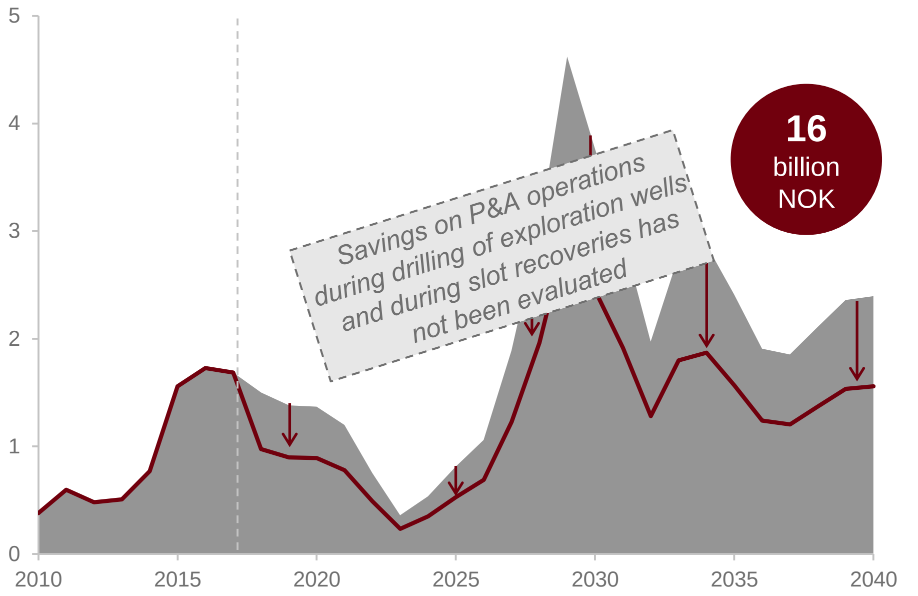
Forecasted abandonment costs NCS (2018-2040)

Billion NOK (real 2018)



Indicative effect on P&A cost* on NCS (2018-2040)

Billion NOK (real 2018)



- Rystad Energy estimates abandonment costs on the NCS to total 117 billion NOK (real 2018) from 2018 to 2040, of which Facility Decommissioning amounts to 71 billion NOK and Well P&A Costs* totaling 46 billion NOK
- The abandonment cost is mostly modelled and estimated to occur and expended in the years following production shutdown. The abandonment cost is estimated proportionally to greenfield capex for a field
- Of the 46 billion NOK in estimated well P&A cost, 41% relates to wells at fixed platforms, 39% to floaters (semisubs and FPSOs), and 20% to subsea tiebacks

- BP (now AkerBP) stated in 2016 PWC technology reduced average P&A days per well by 45% at the Valhall Field in the North Sea. The average cost reduction per well P&A'd was **35%****
- Assuming an average cost reduction of 35% in P&A costs across the NCS using PWC techniques implies a reduction of 16 billion NOK
- New generations of PWC technology aim to accommodate rig-less P&A, implying coiled tubing (CT) and wireline operations without pulling production tubing. The lower rate of rig less P&A and faster running times have the potential to reduce cost by **80%***** in some instances

*Excludes P&A cost related to slot recovery and exploration drilling **Article authored by Mark Sørheim of HydraWell in EPMag March 1, 2018 ***HydraWell third generation PWC technology P&A campaign example as presented by NORWEP April 13, 2018

All electric subsea – another step towards “The Digital Oilfield”

Technology description

- All electrical subsea equipment, opposed to the industry standard of electro-hydraulic controlled subsea equipment
- Considered the production system of the 21st century increasing subsea sensory, data access and system interaction capability for the operator
- An important step in "The Digital Oilfield", giving the operator flexibility, optionality and automatic production systems

Risk description and barriers of implementation

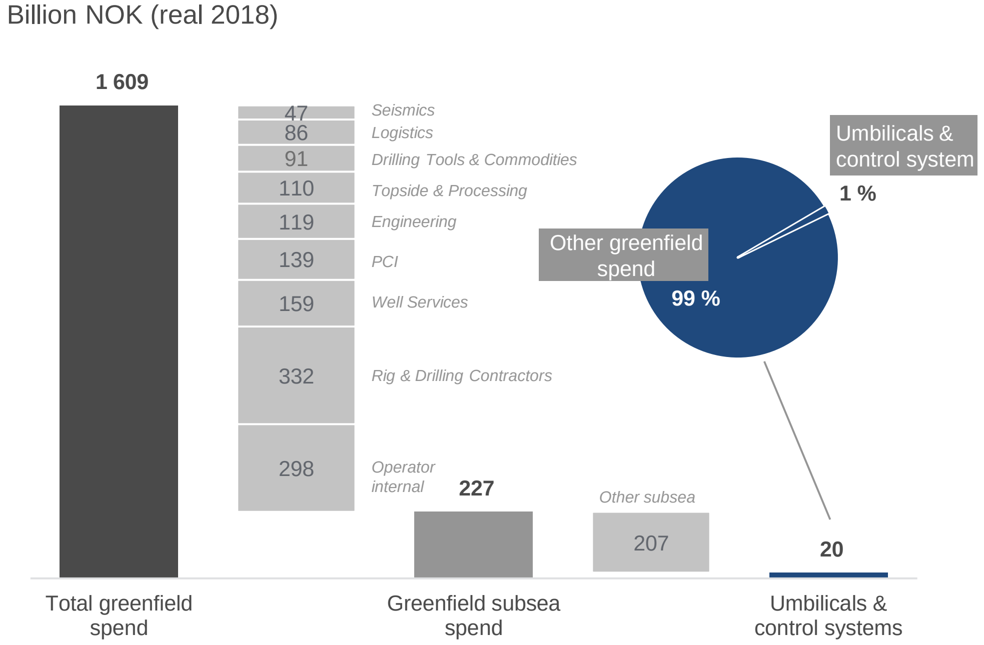
- Lack of holistic approach with regards to integration of disciplines involved in implementing this technology for optimal system utilization
- Although the SURF/SPS business case is good, it affects the drilling and well department (D&W) without any added benefit on their part
- High perceived risk associated with fail-safe-close actuators like the electrical downhole safety valves (DSV) and actuators on the XMT, especially considering the inaccessible working environment subsea for electrical equipment
- Very few all electric applications as fast modulated valves and true zero hydraulic discharge is an absolute need - the all electric adaptation is thus slow. All electric technology faces mature electrohydraulic technology and breakthrough is only happening when cost are at an industrialized level
- Full synergies will not be captured and suboptimal system design is achieved if one merely replace hydraulic actuators without fully capitalizing on electronic solutions and the added benefits

Application type	Enabling [✓ Enhancing]	The standard industry solution for subsea production system control is electrohydraulic cables, whereby the hydraulics operate the production valves and choke valves. Going all electric is an enhancing technology offering more data gathering and performance monitoring capabilities, increased flexibility and optionality, and savings related to the hydraulic system
Setting	[✓ Greenfield] Brownfield Drilling	Installing a holistic all electric subsea control system is only applicable to greenfield projects. Although electrical BOPs is currently being developed, the main focus of this technology example review is on the production side meaning the SPS/SURF scope, in addition to the hydraulic power unit topside
Viability requirement	Single use [✓ Portfolio]	Adaptation of an all electric subsea approach will likely entail a company-wide ambition of going all electrical in all future greenfields, as the mobilization cost and changes in work processes to capture all the upside unlocked by all electric is significant. Adaptation maybe correlated with an oil company's commitment to "The Digital Oilfield"
Organization	Single discipline [✓ Cross-discipline]	Introducing all electric subsea solutions will significantly increase the level of information the operator receives from subsea sensors, and thus increase the operators potential to micromanage production – even use machine learning algorithms for optimal production support. A holistic implementation of all electric will require mobilizing several disciplines
Risk type	[✓ Intrusive] Non-intrusive	The XMT, or the production tree, is a vital piece of equipment in the SPS and problems relating to the electrical system causing loss of communication, or inability to verify the integrity of the system, will result in fails-safe-close production shutdown. Potentially deferred production makes this an intrusive technology
Application inhibitor	Assessed risk [✓ Perceived risk] Other	There is a high perceived risk in the industry going from hydraulic to electric actuators. Although more parts which can fail, electrical actuators have for the large part dual redundancy. The fears about battery reliability powering the electric actuators have proven unfounded according to suppliers with 15-years and over a 150 subsea electric actuators installed globally

Sources: Rystad Energy research and analysis; TTA input;

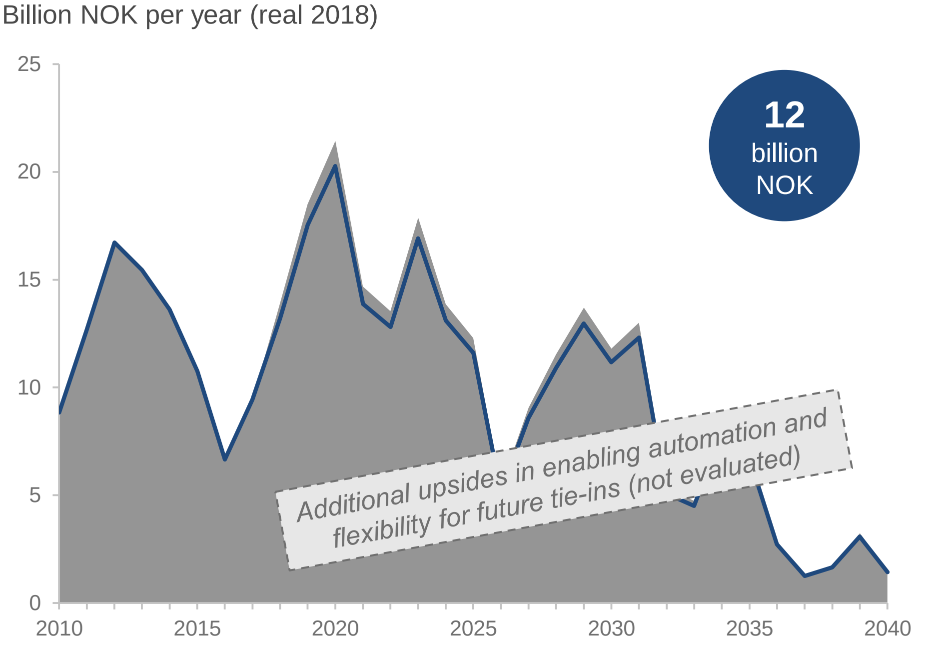
All electric subsea has the potential of reducing NCS cost by 14 billion NOK from 2018-2040

Greenfield spend on the NCS (2018-2040)



- Rystad Energy estimates E&P expenditure associated with new greenfield developments on the NCS to amount to above 1.5 trillion NOK (real 2018) from 2018 to 2040
- ~230 billion NOK, or 14 % of E&P expenditure, is estimated to be subsea scope, i.e. SURF, SPS and subsea services
- Rystad Energy has identified CAPEX related to the subsea control system and umbilicals, forecasted to entail expenditures of 20 billion NOK, as two segments benefitting from all electric in terms of reduced costs, making up ~1% of total expenditure from 2018 to 2040

Indicative effect on NCS subsea expenditure (2018-2040)



- The chart above outlines the indicative effect of lowered SPS control system cost and umbilical cost on the NCS subsea expenditure from 2018 to 2040
- In an all electric scenario. AKOFS studies indicate a ~85%* reduction in umbilical capex and 25%* reduction in SPS control system capex for a best case scenario, reducing cost associated with these items by 59% or 14 billion NOK from 2018 to 2040 on the NCS
- Rystad Energy acknowledges other potential benefits including easier installation/handling, decreased opex, increased HSE, increased flexibility and optionality regarding tiebacks and future field expansion
    - Example: In some areas of the world, hydraulic fluid consumption cost is reported as high as 4% to 8% of OPEX**, as a typical four well system may consume five tons of hydraulic fluid per year*

*SPE paper 27243 presented at OTC by Aker Solutions, May 2016 **SPE paper 27657 presented at OTC by TechnipFMC, May 2017

Sources: Rystad Energy research and analysis

Unmanned facilities / automation – Industry focuses on cost, value is in improved regularity

Technology description

- "The technology" is rather a field of technologies encompassing sensors, software incl. big data analytics, data platforms, robotics, and mechatronics that enable production platforms and subsea production systems to operate with little or no human touch
- Touted as the "next big thing" in order to achieve significant cost savings from lowering need for or doing away with offshore manpower

Risk description and barriers of implementation

- Lack of holistic approach with regards to integration/alteration of work processes in order to fully leverage effect of automation; silos and friction between oil company departments and/or between oil companies and suppliers mean retention of "old" organizational structures and legacy software systems that do not "speak" to one another
- Cost focus among oil companies hinders adoption as focus remains on recouping additional capex spent on automation related equipment and software through opex savings. This overlooks significant value creation driven by improved field regularity and recovery
- Clear perceived risk that "trusting a machine" over a human being is not safe
- Operators are generally reluctant to share data with equipment suppliers, thus hampering ability of suppliers to leverage learning across installations to improve design and operation of their equipment

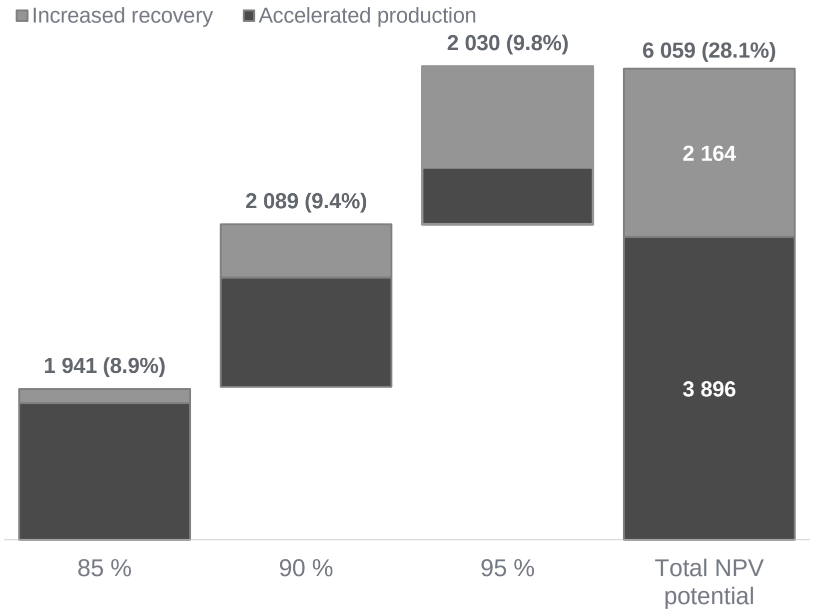
Application type	Enabling [✓ Enhancing]	The predominant application of unmanned / fully automated production facilities is in order to enhance the economic viability of a development. Although this lowers the break-even oil price for the project, the technology is therefore normally not enabling the development in itself (at least in technical terms).
Setting	[✓ Greenfield] Brownfield Drilling	Although retrofitting equipment and systems in order to "switch" an installation from manned to unmanned is possible, the established "modus operandi" of existing facilities makes this hard. As such, the technology is primarily considered applicable in greenfield developments.
Viability requirement	[✓ Single use] Portfolio	Application of automation technology for a given development will have a business case (or lack thereof) *in itself* and is not reliant on wider portfolio application to be considered valuable.
Organization	Single discipline [✓ Cross-discipline]	As for all electric subsea solutions automated systems increase the amount of information the operator receives e.g. from sensors, and thus increase the operators ability to micromanage production – e.g. by applying machine learning algorithms for production optimization. Holistic implementation of automation will require mobilizing several disciplines from reservoir to export
Risk type	[✓ Intrusive] Non-intrusive	Although not clear cut on this dimension, reliance on automated systems over human presence in the event of failure *may* result in production shut-in that would otherwise not have occurred. As such, the technology is considered intrusive although in an indirect/"light" manner
Application inhibitor	Assessed risk [✓ Perceived risk] Other	There is high perceived risk in the industry w.r.t. to automation and the related topic of data sharing. Also, the "fear of the machine taking control" is prevalent even though society as a whole is embracing automation in several other sectors, e.g. banking/finance, transport, manufacturing, etc.

Sources: Rystad Energy research and analysis; TTA input;

Enabled by automation, slight regularity improvement creates 70 BNOK in societal value

Value impact from improved regularity through automation (Johan Castberg example)

Billion NOK (Jan 1st 2018)

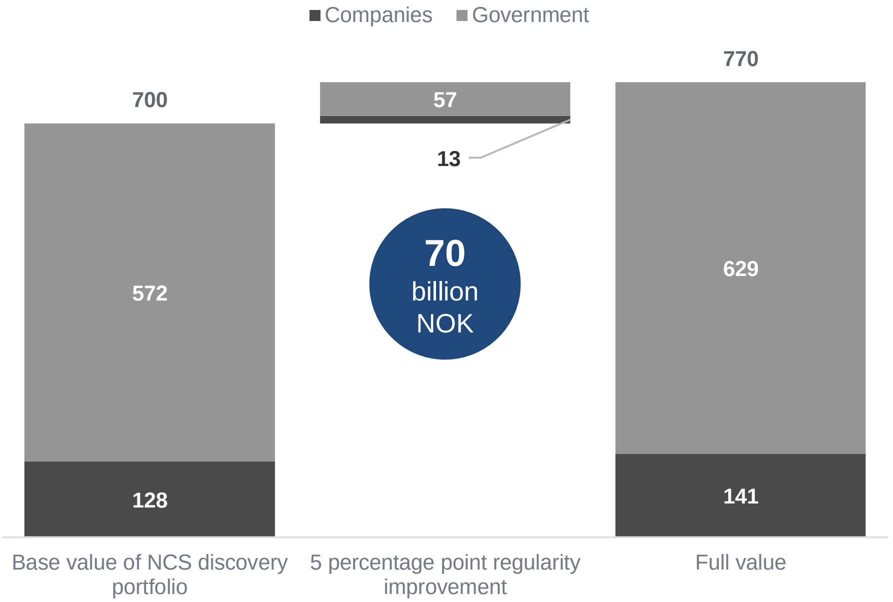


The chart above depicts the revenue side value impact pertaining to the partners in the Johan Castberg development from improving regularity in 5 percentage point intervals from the Rystad Energy base case of 80%*. Value is driven by 1) increased recovery, and 2) accelerated production. Observations:

- If regularity is improved by 5 percentage points, Castberg value increases by 10% or NOK 2 billion as seen from January 1st, 2018. Autonomous systems are known to operate closer to optimum than if humans are "at the steering wheel" and will realize better regularity
- This compares to a value impact of approximately NOK 1 billion in opex savings if no human ever sets foot on the installation over its 30 year life span (assumes 2/4 rotation and 140 people onboard "saved")

Indicative revenue side value effect on NCS developments

Billion NOK (Jan 1st 2018)



The chart above shows the revenue side societal value impact from improving regularity by 5 percentage points for all yet-to-be-sanctioned discoveries on the NCS. Observations:

- Societal value creation from improved regularity is 70 billion NOK for each 5 percentage point improvement
- Due to tax system effects, 81% of value creation pertains to the Norwegian government
- As many of these developments are subsea tie-backs and therefore by design unmanned, it is the *revenue side value creation* that is of interest here, not cost savings; in many cases cost will actually be higher due to a (slight) increase in capex

*"Regularity score" based on comparing monthly production to "local peak" in a rolling five month time window for 850 offshore fields globally
Sources: Rystad Energy research and analysis

Subsea boosting – enhancing the productions stream for improved project economics

Technology description

- Subsea pumps reducing production system back-pressure, thus prolonging production plateau, accelerates production, and increases recovery
- Booster pumps with have different technical solutions and operational envelope, i.e. single phase and multiphase depending on the field
- Cost-effective, reliable, high differential pressure multiphase boosters eliminating the need for subsea separation is the next step in booster applications.

Risk description and barriers of implementation

- Perceived risk of intrusive rotating mechanical equipment requiring lubrication oil feed, functioning sealing systems at a large upfront cost. Suppliers addressing this with better predictive maintenance, boosters with inherent redundancy systems, and no fluid seal barriers
- Brownfield application more challenging compared to a holistic greenfield approach. Industry investigating tying success of pump to the operational performance of the field, to delay payment and reduce operator risk
- Balancing the wellhead performance from comingled multi-well or multi-template field completions with several subsea boosters increase production system control complexity
- Subsea boosting is a cross-discipline effort affecting the whole production chain from reservoir to the processing facilities
- Unplanned subsea repairs and interrupted production can results in large costs for the operators, often scaling with water depth, in the case of mechanical failure of intrusive equipment

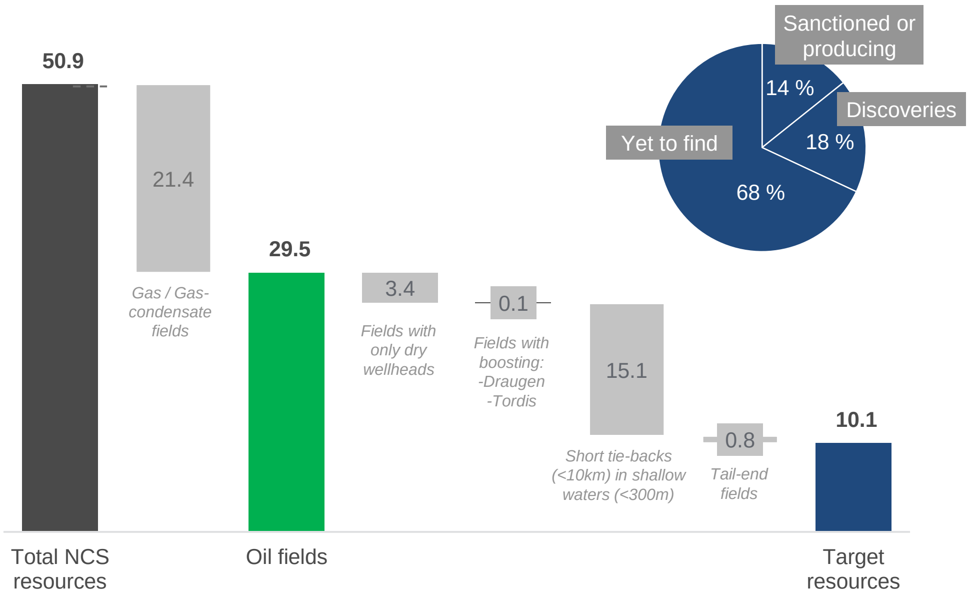
Application type	Enabling [✓ Enhancing]	Subsea boosting reduces the production system backpressure felt by the reservoir and allows for accelerated production and increased recovery. In some marginal cases, subsea boosting is an enabler , e.g. Wisting, however , the majority of the value is located in enhancing the production profile of all oil fields thus increasing the net present value of the asset
Setting	[✓ Greenfield] [✓ Brownfield] Drilling	Subsea boosting can be applied both greenfield and brownfield. Brownfield applications can increase recovery with existing infrastructure and prolong the lifetime of the asset. Greenfield applications accelerates production, thus increasing reserves and provides opportunities for field layout optimization and system wide design
Viability requirement	[✓ Single use] Portfolio	Studies have shown the potential for considerable returns for single-use subsea boosting applications in brownfield scenario, including total installed cost (TIC) capex related to topside modification and subsea installation*. The move towards more cost-effective multiphase boosters, without subsea processing, makes it viable for single-use applications on even smaller fields
Organization	Single discipline [✓ Cross-discipline]	Increased production volume, longer plateau, increased recovery, and facility lifetime as a consequence of subsea boosting entails an holistic approach to implementation and considerations across disciplines within the operator. The production chain starting in the reservoir and ending at the topside processing facility must accommodate the added benefits of the booster pump
Risk type	[✓ Intrusive] Non-intrusive	The cost of mechanical failures of subsea equipment increase with depth. Unplanned subsea repair operations and deferred production is a large risk for operators. However, proximity probes closer to bearings and rotor for predictive, opposed to corrective maintenance, of the pump**, and booster with inherent redundancy***, is expected to mitigate intrusiveness
Application inhibitor	Assessed risk [✓ Perceived risk] Other	Perceived risk of booster breakdown and production shutdown is the primary. However, many suppliers have solid track records for subsea boosters. Manufacturers are improving on fluid seal barriers, lubrication issues, and redundancy continuously. The all-electric Modular Compact Pump*** with magnet motors, no barrier fluid, and no rotating shaft is one such advancement

*SPE 27639 by TechnipFMC at OTC, May 2017 **SPE 27747 by AKOFS at OTC, May 2017 ***SPE 28658 by Baker Hughes at OTC, May 2018. Sources: Rystad Energy research and analysis; TTA input;

Subsea boosting potential of increasing NCS production by 400 million bbls from 2018-2040

Estimated resources on the NCS (2018-2040)

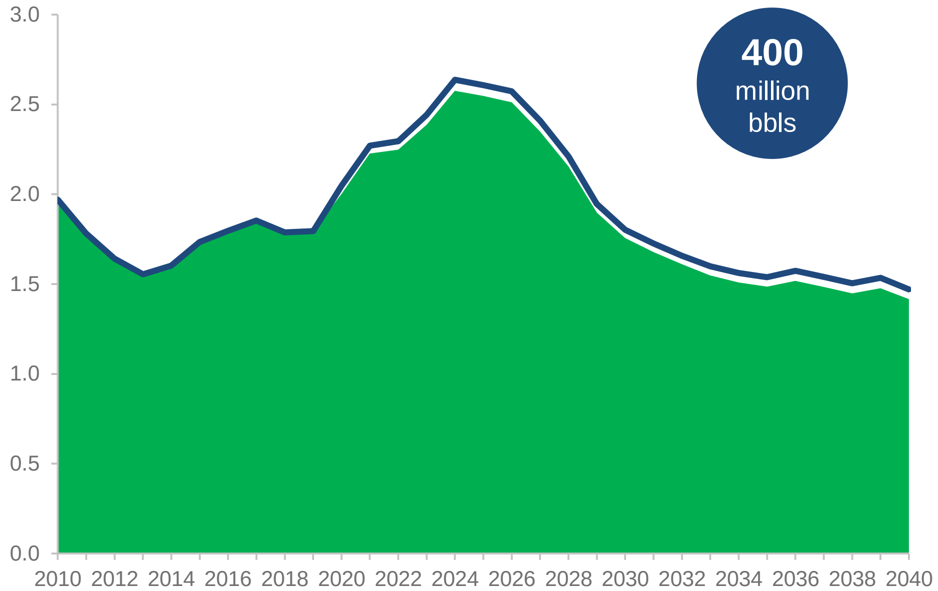
Billion barrels of oil equivalent as of 01.01.2018



- Rystad Energy estimates the remaining resources on the NCS to amount to 51 billion barrels as of 01.01.2018, of which 29 billion is located in fields classified as “oil fields”
- Rystad Energy has identified the target resources of 10 billion barrels, mostly greenfield subsea tiebacks and FPSOs (Barents Sea), for subsea boosting based on field characteristics
- Target resources have been identified through excluding:
  - Fields with dry wellheads - future and currently producing
  - Fields on the NCS with production already being boosted
  - Subsea tiebacks with tiebacks distance < 10km in water depths < 300m
  - Fields in tale-end phase with recovery of discovered resources above 75%, where implementation of subsea boosting considered too late

Indicative effect of boosting on NCS oilfield production (2018-2040)

Million bbls per day



- The chart above outlines the indicative effect of subsea boosting on the production profile of **oilfields** on the NCS from 2018 to 2040
- Notable sanctioned target fields include: Heidrun, Tyrihans, Johan Castberg, Maria, Goliat, Fenja, Trestakk, and Knarr.
- Wisting is one of the discoveries where boosting will be enabling.
- Yet to find (YTF) makes up the majority of the target fields’ resources, and is dominated by the Barents Sea future potential
- A boost factor of between 7.5% and 15% has been applied to the assets based on water depth and greenfield or brownfield application
- The resulting production profile for the target fields is increased by 400 million barrels of oil equivalents from 2018 to 2040

*SPE paper 27243 presented at OTC by Aker Solutions, May 2016 **SPE paper 27657 presented at OTC by TechnipFMC, May 2017

Sources: Rystad Energy research and analysis