Oil & Gas Authority

OGA Southern North Sea Tight Gas Stimulation

December 2017, Rev 1.0

Contents

Executive summary

The purpose of this document is to help industry assess the need for, and efficiently conduct, the stimulation of tight gas reservoirs in the UK Southern North Sea (SNS). The document is intended to provide relevant information aimed at existing and new entrant SNS operators who may benefit from an overview of the stimulation techniques and new technologies. The document has been prepared to support the technical content of the OGA Southern North Sea Tight Gas Strategy[1], published in June 2017 and available on the OGA website.

The term 'tight gas' is defined as an economic term used to describe low permeability gas reservoirs that produce primarily dry gas and where production rates and recoverable reserve values are uneconomic unless reservoir stimulation techniques are used.

In recent years, technological advances have successfully enabled SNS 'tight gas' offshore field developments. A combination of horizontal drilling and reservoir stimulation technologies have been applied to exploit such tight gas reservoirs with average permeability values ranging from as low as 0.01 to 1mD (millidarcy).

This document seeks to build on these experiences by documenting the breadth of issues relevant to the development of tight gas reservoirs in the SNS, ranging from the geology of the basin through to the deployment and execution of stimulation technologies.

This document also includes an assessment of technology versus well cost, well count and added reservoir value to illustrate how horizontal stimulation technologies might be expected to lower the well count required to develop a field and yield improved added value in terms of increased and accelerated reserve recovery.

It is expected that this document will be periodically revised and updated as technology and working practices evolve. Feedback will be sought through relevant industry work groups and events, such as the East of England Energy Group (EEEGR) Tight Gas Work Group and Technology Hackathon (held in May 2017) as well as anonymised insights obtained by the OGA through asset stewardship reviews.

[1] OGA Tight Gas Strategy https://www.ogauthority.co.uk/news-publications/publications/2017/southern-north-sea-tight-gas-strategy/

The regional context

The Southern North Sea

The SNS in geographic terms lies north east of the English Channel essentially constrained by Quadrants 41-57 as below although active fields to date have been restricted to Quadrants 41-54 (Figure 1).

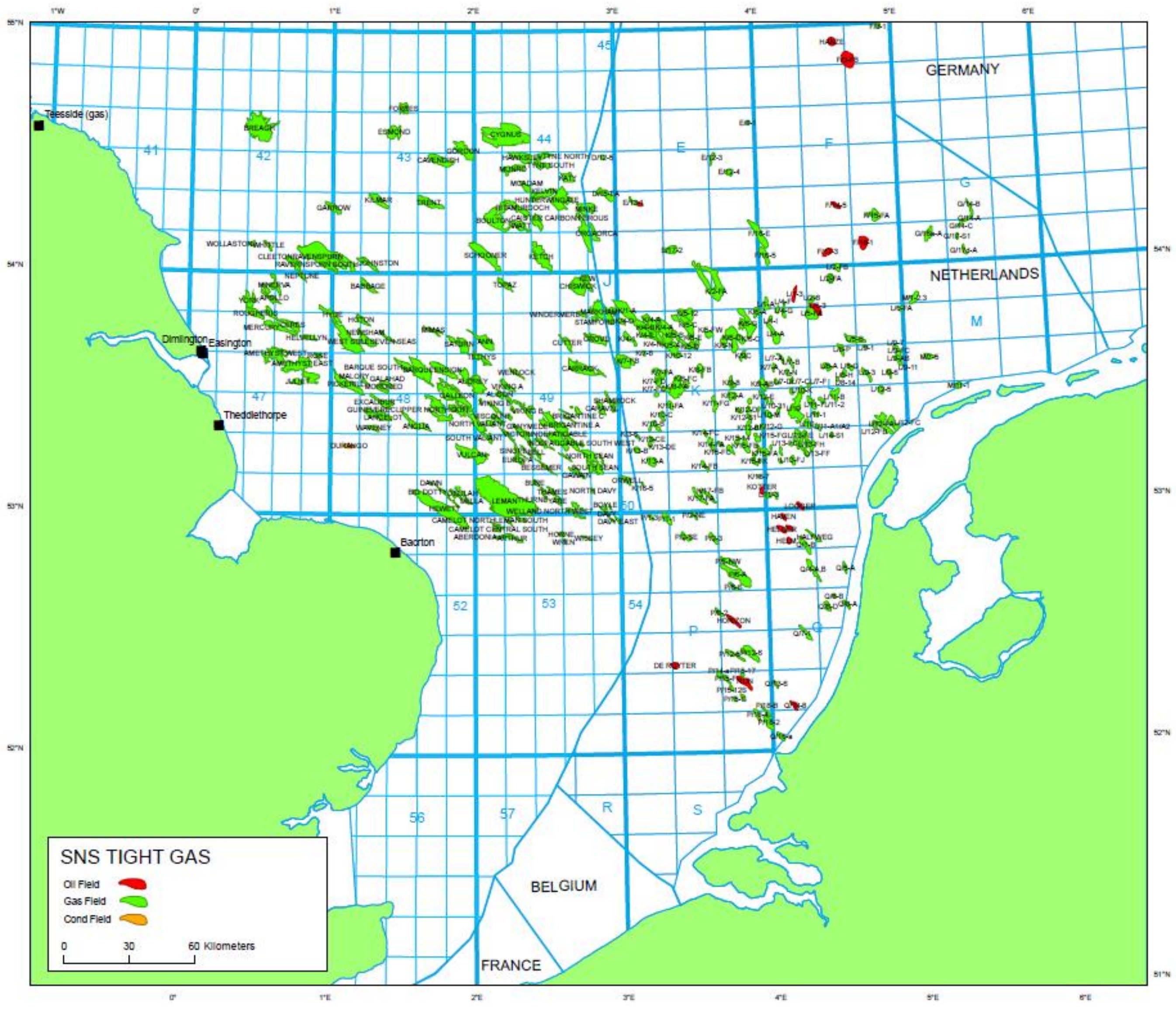

Figure 1: Southern North Sea

SNS Petroleum Systems

Overview

The most important source and reservoir rocks in aggregate terms for the SNS are illustrated below. The full spectrum of source and reservoir rocks is wider. It should be recognised that ‘tight gas’, by definition, is often targeting either brown or new field residual or poorer quality reservoirs than those developed historically.

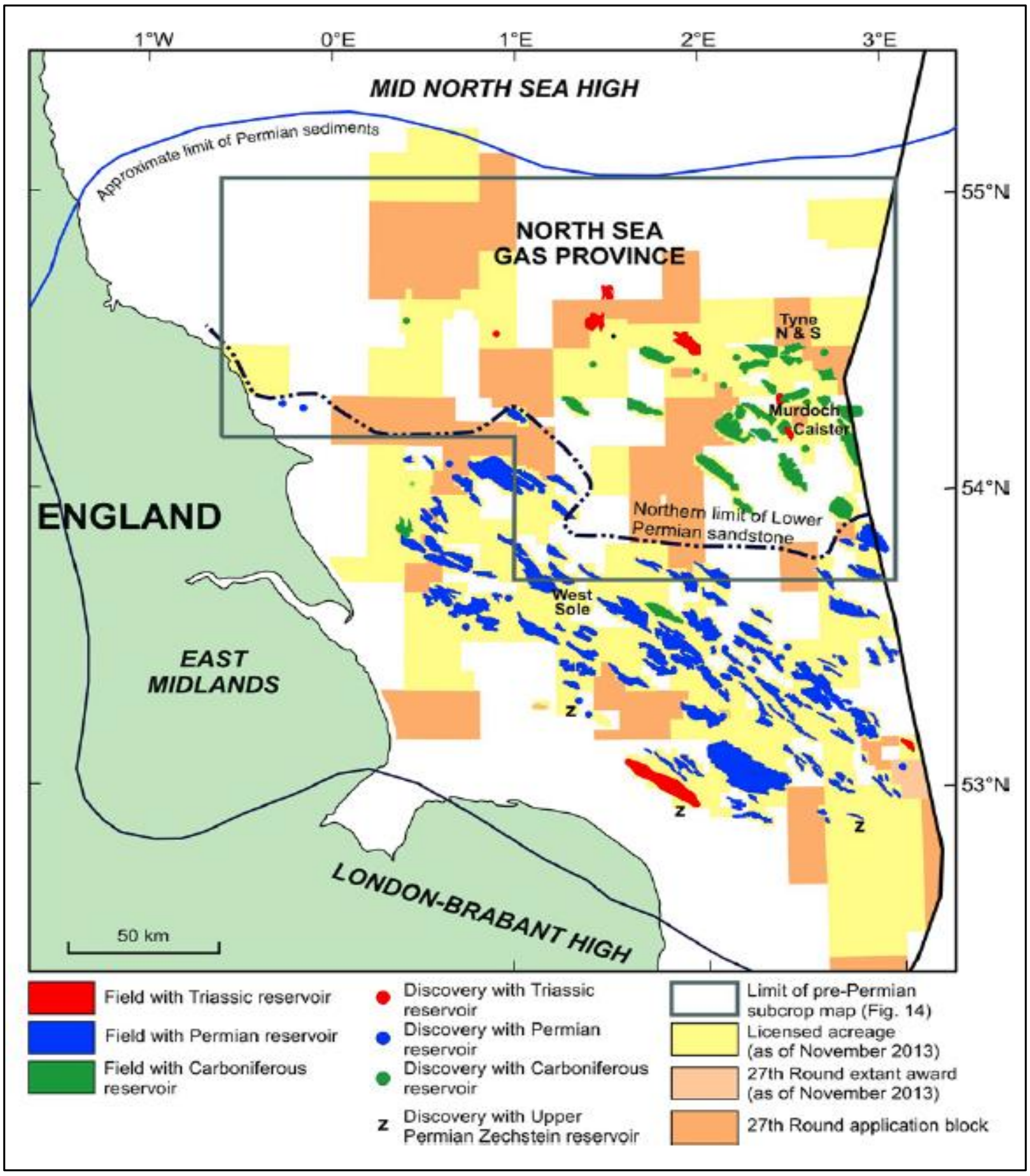

Figure 2: UKCS SNS fields and discoveries

SNS tight gas

Overview

The term tight gas is an economic term used to describe low permeability gas reservoirs that produce primarily dry gas where production rates and recoverable reserve values are uneconomic unless hydraulic fracturing is used. Most reservoirs considered to be tight gas are sandstone or carbonate formations.

SNS insight: In recent years, technological advances have enabled a number of SNS tight gas offshore field developments: Ensign [2], Chiswick[3], Breagh[4] [5], Clipper South[6]. A combination of horizontal and hydraulic fracturing technology was applied to exploit these reservoirs with average permeability values ranging from as low as 0.01 to 1mD.

Tight gas distribution by quadrant

With respect to further tight gas opportunities, an assessment of the remaining potential across the Southern North Sea has been undertaken by the OGA through an analysis of data submitted by operators and supplemented by the OGA's asset stewardship process. In total, the OGA estimates some 3.8 tcf of gas considered tight is still to be exploited. An illustration of the distribution of this volume is provided in Figure 3.

[2] Offshore Horizontal Well Fracturing: Operational Optimisation in the Southern North Sea, Langford, Marc Edmund; Holland, Brian; Green, Christopher Anthony; Bocaneala, Bogdan; Norris, Mark Robert 2013, SPE-166550-MS.

[3] The Chiswick Field: Long Horizontal Wells and Innovative Fracturing Solutions in a Low Permeability, Sandstone Gas Reservoir in the North Sea, Coghlan, Gerard Philip; Holland, Brian, 2009 SPE-124067-MS.

[4] Maximising Gas Well Potential In The Breagh Field By Mitigating Formation Damage, McPhee, Colin Alexander; Judt, Michael Richard; McRae, Darren; Rapach, John Michael, 2008, SPE-115690-MS.

[5] Successful Hydraulic Fracture Stimulation of Yoredale Carboniferous Sands in the UKCS, Jones, Peter; Symonds, Richard; Talbot, David; Jeffs, Paul; Kohok, Abhimanyoo; Shaoul, Josef; Spitzer, Winston, 2015, SPE-174171-MS.

[6] Clipper South Field: Fracturing Operations and Production Matching in a Low Permeability, Sandstone Gas Reservoir in the North Sea, Shaoul, Josef; Park, Jason; Bakhtiyarov, Albert; Fekkai, Sofiane; Jeffs, Paul ; Mandiwall, Darrell, 2013, SPE-164826-MS.

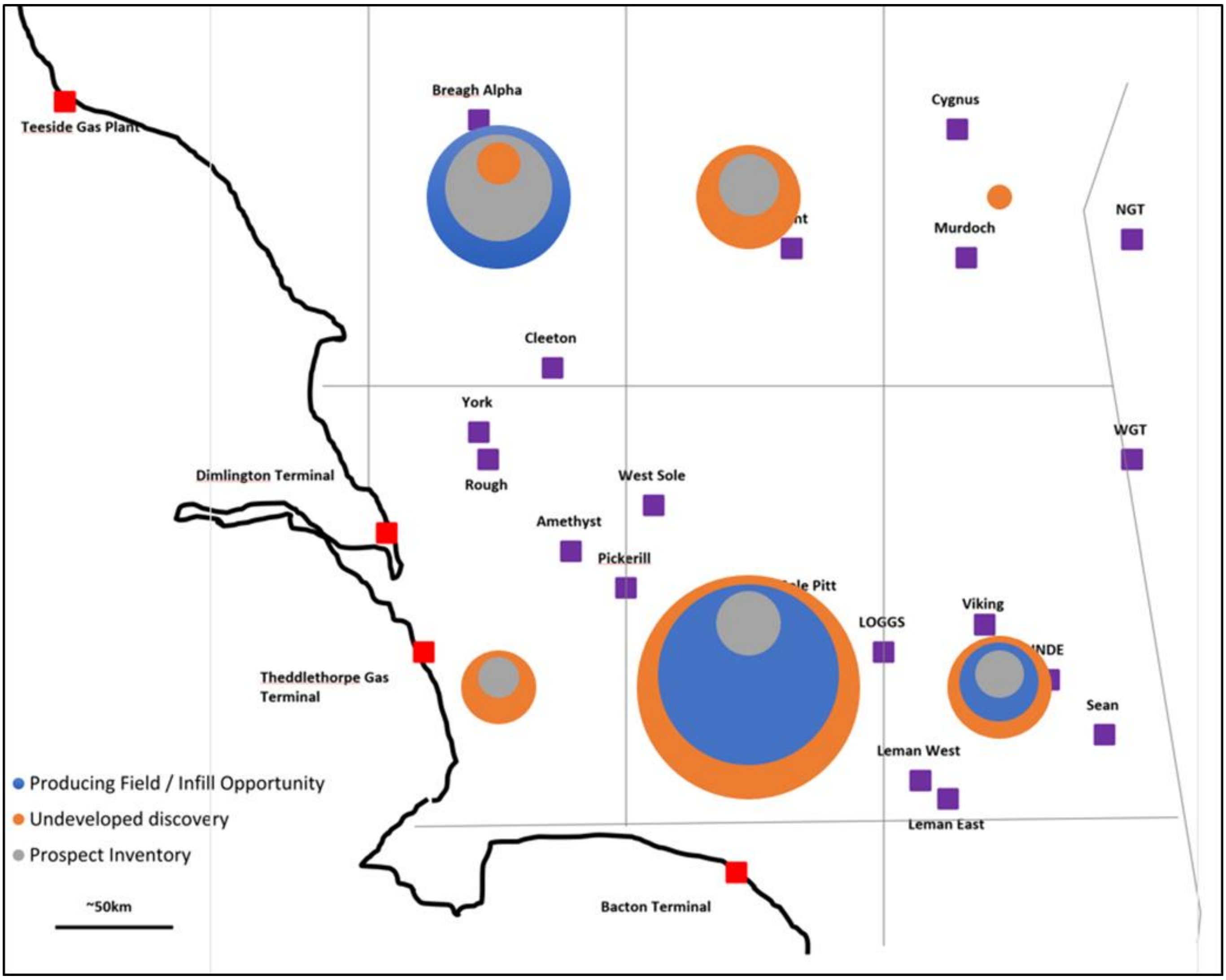

Figure 3: SNS tight gas distribution by quadrant (OGA)

Tight gas distribuition by geology

Based on data currently held by the OGA, a further breakdown of the tight gas opportunities within the SNS by geology is provided in Figure 4.

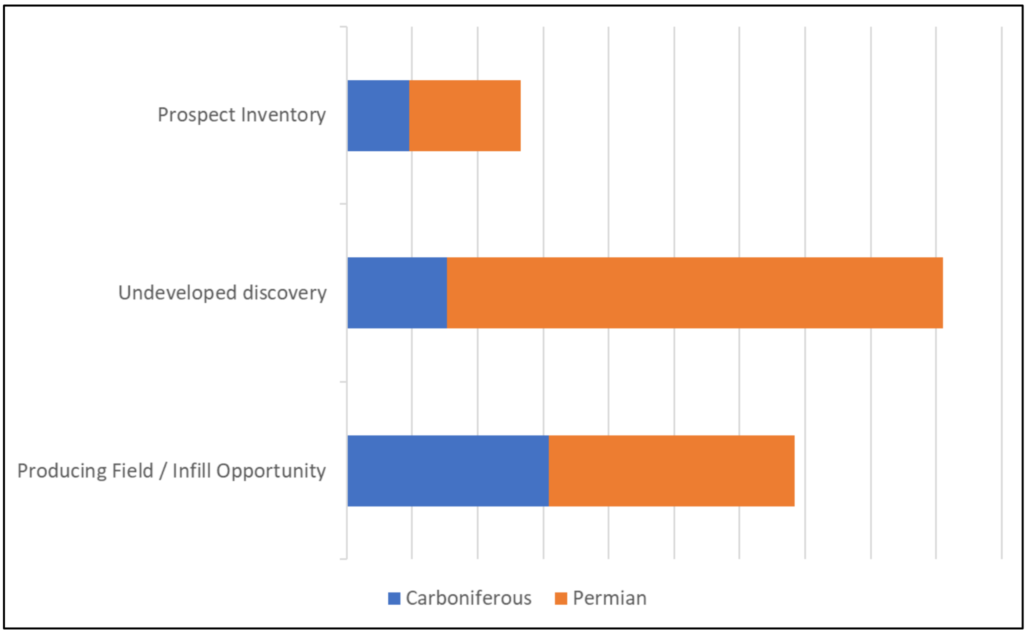

Figure 4: distribution of SNS tight gas opportunities by geology (OGA)

Permian sands are inherently better quality sands, locally enhanced by natural fractures. In contrast, the Carboniferous sands are likely to be more variable and compartmentalised both laterally and vertically which only adds to their tight gas complexity. It is perhaps therefore not surprising that there are almost twice as many tight gas opportunities in Permian age reservoir sands compared to the Carboniferous.

Operators are unlikely to initially target a tight gas opportunity, so it is not unexpected that there are few tight gas prospects that are being worked up; either Permian or Carboniferous age. The majority of tight gas opportunities are therefore located either in currently producing fields or discoveries. It is perhaps a measure of the maturity of the basin that some Permian infill opportunities have already been targeted but the majority of remaining Permian tight gas potential is in undeveloped discoveries. Whereas the less mature Carboniferous basin shows far fewer opportunities in undeveloped discoveries.

This section of the document will continue to be updated as further insight are developed through the OGA's asset stewardship process and as operators continue to develop the remaining tight gas developments across the SNS.

Stimulation overview

Well performance

Well productivity can be considered by reference to the vertical well inflow performance relationship equation[7]. The greater the permeability thickness product (kh), the higher the well productivity. In any given basin reservoir, kh values can have a range of several orders of magnitude. Over time, the quality of the available reservoirs to exploit declines as the basin matures. A further element of the maturing process is a decline in the reservoir pressure of producing fields which leads to a decline in available energy to force fluids from the reservoir to the wellbore and subsequently up the wellbore to surface.

The convergent nature of radial flow results in a logarithmic increase in pressure gradient as the wellbore is approached with the largest pressure drop or energy loss occurring in the immediate proximity of the wellbore (Figure 5). Consequently this near wellbore or well to reservoir interface is an area of important focus with respect well productivity.

Maximising the productivity of the well may be achieved by either reducing what is known as the skin effect (S), or reducing the flowing bottom hole pressure (Pwf) to lift the fluids from the well. It is the former approach of reducing the skin (S) that is the focus of stimulation, while the latter is essentially covered by the topic of artificial lift.

Gas well performance

A feature of gas well inflow performance is the significant impact related to the inherent high compressibility of gas and as mentioned above, the large near wellbore pressure drops associated with high velocity turbulence. This is reflected in the form of the example pseudo steady state vertical gas well inflow performance equation[7].

Skin

The near wellbore may be subjected to additional pressure drops caused by a variety of reasons that alter the radial and horizontal flow converging into the well. The ‘skin effect’ (S) term was introduced by Van Everdingen and Hurst (1949) to account for these additional (ΔPs) pressure drops (5).

The skin term is a dimensionless number which describes a zone of infinitesimal extent that causes steady state pressure differences ($\Delta \mathrm{Ps}$) that can be described as below (Equation 1).

$$\Delta Ps = (q/2\pi kh)S$$

Equation 1: skin related pressure drop

[7] Dake, L.P., Fundamentals of Reservoir Engineering, Development in Petroleum Science 8, Elsevier, 1991

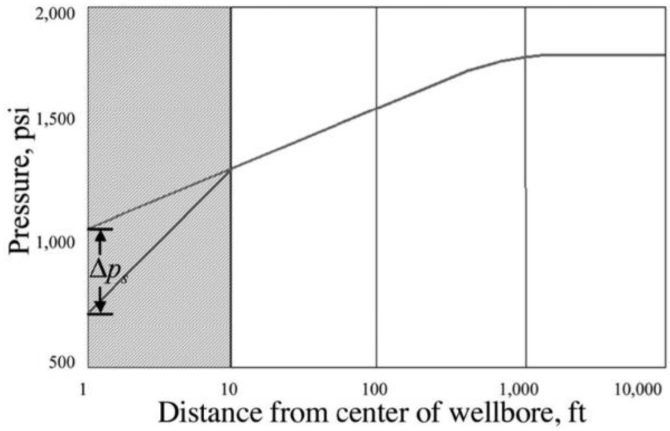

Figure 5: pressure vs distance from flowing wellbore

It can be readily seen that a positive skin has a negative impact on productivity, whilst a negative skin results in an improvement in productivity. The Total Skin effect is the combination of multiple different potential skin components such as the example skin types tabulated below.

Skin Type	**Description**
Formation Damage, and Permeability Reductions (Positive skin)	A positive skin can be associated with the following: drilling, completion, failed stimulation, injection fluid near wellbore invasion and damage (solids, liquids / emulsion blocking, wettability changes), condensate banking, scale, salts, wax asphaltenes, produced fines migration, relative permeability / saturation alterations.
Partial Penetration	In this positive skin scenario flow is forced to converge as it approaches the well because only part of the reservoir thickness has been drilled and or completed.
Completion Skin	In this positive skin scenario an additional pressure drop is created by excessive resistance to flow from the reservoir across the completion into the wellbore (e.g. gravel pack or perforation tunnels).
Deviation Skin	The impact of a deviated well compared to a vertical well is an increase in the along wellbore reservoir completion footage available for inflow which results in an improved productivity which can be expressed through the use of a negative skin term.
Stimulation skin (negative skin)	A negative skin value indicates enhanced productivity, typically resulting from stimulation.

Table 1: example skin types

Well design and delivery

Vertical

A vertical reservoir interval is the simplest and lowest cost option when drilled from a surface location directly overhead. This option is normally selected for initial exploration or appraisal wells where hydrocarbons, contacts and reservoir character have yet to be been determined in any detail to efficiently engineer or justify more costly well types.

SNS insight: Vertical or near vertical gas production wells were commonly used for the 100 to 300ft thick SNS reservoirs of moderate to high permeability. A cemented and perforated sand face with a 100ft perforated interval stand off to the gas water contact was typical for many large early SNS discoveries (e.g. Hewett, and Leman) developed with platforms, and dry trees.

Horizontal

Horizontal well technology allows multiple segments of the reservoir to be reached from a single surface location which lowers well costs. In production terms, relevant horizontal well technology benefits include:

- Enhanced rate productivity of a deviated skin due to a high ratio of along hole to vertical thickness (assuming an adequate lateral extent of the reservoir)
- Means to connect multiple fault bounded/isolated reservoir compartments and drain with a single well
- Means to maximise completion to gas water contact stand-off

SNS insight: This technology has been extensively used in the SNS for both new and brown field projects often in conjunction with subsea tie back or satellite normally unmanned installations (NUIs). It has allowed reserves to be accelerated or distant targets accessed. It has enabled the cost effective development of new small fields with low permeability reservoirs.

Typical reservoir section lengths achieved in the SNS range from 1,000ft to a practical well construction limit of circa 6,000ft. A 8-1/2” hole size is typically used in the shallower Permian (Rotliegend/Leman) and Triassic (Bunter) reservoirs. The deeper harder formations of the Carboniferous reservoirs are usually drilled with a 6” hole and in well construction terms practical section lengths are at the lower end of the quoted footage range.

Whilst a single horizontal bore can reach multiple targets, this requires a largely uniaxial alignment of those targets to make the well path practical in construction terms. Horizontal well performance can be negatively impacted if there is significant permeability anisotropy.

SNS insight: Common examples of vertical permeability anisotropy in SNS reservoirs are found with thinly bedded sand and shale sequences or within thicker sand units rich in clay content. Horizontal permeability anisotropy is common in fluviatile channel sand systems which are common in the Carboniferous SNS reservoirs where interconnectivity between individual channel bodies can be poor.

A challenge for horizontal wells is depth uncertainty in order to accurately set up and land out the horizontal or sub-horizontal section with respect key drivers or challenges such as the reservoir ceiling, best quality pay, gas / oil / water contacts, natural fractures, dipping beds, stratigraphic pinch out, faulting. Common techniques to narrow uncertainty include correlation between discovery wells and pilot bores, hedging with use of a 'hybrid slant' rather than a pure horizontal well, and geo-steering once drilling close to or within the reservoir. Geo-steering refers to the intentional directional control of a well, usually to keep the well path within the pay zone, that is achieved based on the results of downhole geological logging measurements carried out while drilling, rather than based on pre-determined three-dimensional geometric targets in space.

Multi-lateral

Multi-lateral technology provides a means to reach multiple small targets of varying azimuth, and or vertical separation using lateral bores drilled from a single cost effective mother bore. SNS field examples include Galahad[8], and Rita[9].

Stacked horizontal laterals are applicable in thick reservoir sequences with high vertical permeability contrasts or shale barriers between reservoir units.

'Herring bone' style multi-laterals are suited to thin oil reservoirs where close gas or water contacts present a coning risk. The laterals are a means to maximise reservoir contact (MRC) well inflow area which results in reduced drawdown and associated coning risks.

Thus multi-laterals offer an advantage in terms of the control and accuracy with which reservoir contact can be constructed.

A specific challenge for multi-lateral technology is the reliability of the mechanical downhole junction creation process, completed lifecycle junction integrity and well P&A.

In some scenarios a case may have been made historically for either multi-lateral or hydraulic fracturing solutions in low permeability or poorly connected reservoirs. The recent significant time efficiency improvements with multi-stage hydraulic fracturing technology however have strengthened the case for the latter.

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[8] Developing Small Tight Gas Reservoirs through Horizontal Drilling, Paterson, R., Moss, J., Williamson, B., SPE 36865, 1996.

[9] Successful Application of Dual Lateral Junction Technology To Develop a Marginal Gas Field in the Carboniferous Area of the UKCS Southern North Sea, Hatch, Andrew John; Rainer, Stuart Peter; Simmonds, Roger, 2010 SPE-128461-MS.

MPD / UBD

Managed Pressure Drilling (MPD) and Underbalance Drilling (UBD) refer to technologies where a reservoir is drilled using a drilling fluid gradient that is close / equal, or less than the pore pressure respectively.

The purpose of this approach is to minimise fluid losses and associated formation damage while drilling, which can be costly and substantial in depleted or low pressure / low fracture gradient, or naturally fractured dual porosity reservoirs, both in well fluids costs and well productivity terms.

SNS insight: The main SNS target for this approach has been low permeability fields with or without natural fractures which were considered viable provided the high positive skins being experienced with conventional overbalanced fluid losses could be reduced to zero with a prevention rather than cure approach to formation damage.

Challenges for MPD/UBD include: wellbore instability, particularly in interbedded sand shale sequences; the complexities of subsequent completion operations with regard fluid loss management; and the additional rig hardware and crew competency requirements.

Stimulation

Well stimulation refers to techniques which seek to improve the productive character of the reservoir rock either to remediate some form of formation damage or to enhance the inherently low productive potential of the native rock.

The two main treatment types are acid stimulation and hydraulic fracturing. Acid stimulation relies on the removal of acid soluble material from the wellbore formation face and reservoir. Hydraulic fracturing relies on the creation of high conductivity fractures propagated from the wellbore out into the formation.

SNS insight: Stimulation has been widely used in the SNS reservoirs. It represents a potential means to positively improve well performance in either sandstone or carbonate reservoirs with a range of scalable and flexible solution types and is particularly suited to tight, low permeability reservoirs and very low permeability reservoirs.

Stimulation techniques

North Sea stimulation

Stimulation offshore in the North Sea has been practiced from the very earliest days. The most common early form would have been the use of single stage vertical well acid treatments applied on initial discovery or appraisal well tests to see if an initial poor flow rate might be improved by acidising the near wellbore. Vertical well treatments progressed to treat beyond the near wellbore with higher hydraulic horsepower applied to create large single stage hydraulic or acid fractures. In thicker reservoirs, vertically stacked treatments were applied to several zones. The advent of horizontal drilling opened a new market of potential well stimulation candidates which promoted the development of multi-stage treatment discussed below.

Acid stimulation

Acid filter cake removal

Reservoir drilling fluid and completion fluid best practice is to minimise losses and optimise filter cake design to promote low lift off pressures, optimal clean up and return permeability of any filtrate losses and subsequent produced hydrocarbons. Acid soluble calcium carbonate weighting material is typically used where practical in place of denser but none acid soluble conventional barite for open hole screen or gravel pack completions to facilitate contingent acid stimulation should it be needed. In cemented and perforated liner completions, the use of barite is generally accepted as the perforated approach is considered adequate to penetrate beyond any typical filter cake, and filtrate loss near well bore damage. Logging tools typically report fluid invasion depths of the order of 4-6” with typical perforation tunnel lengths of 15” plus. Fluid mutual compatibility testing is carried out using ideally representative formation water, crude, and proposed drilling and completion fluids to ensure no adverse reactions in terms of emulsions or precipitates. The same compatibility testing approach applies to any stimulation fluids.

Options to enhance open hole completion filter cake clean up and removal include the circulation of a breaker fluid into the lower completion sand screen to open hole annulus when the lower completion is initially run and installed. A fluid loss valve above the lower completion is closed once the breaker is in place and the breaker reacts, destroying the filter cake whilst the upper completion is being installed.

The initial experiences of strong acids such as hydrochloric acid in vertical wells, creating losses led to the development of retarded acids, and less aggressive acid choices such as acetic acid, to enable the full displacement without losses of treatment into longer horizontal wells. Subsequently further alternate choices were developed including chelates and enzymes breakers. In many open hole stand-alone screen completion cases, oil based mud has been selected and used without breakers based on lower filter lift off return permeability, core flood test results and subsequent field results.

Filter cake remedial treatments to remove a positive skin that are carried out post an initial clean up and well test are typically achieved using coil tubing to spot / jet an open hole volume treatment in place, which is left to soak for circa 12 hours before the well is produced to clean up the well.

Acid matrix stimulation

Acid matrix stimulation refers to treatments carried out where acid is injected into the near wellbore at a pressure beneath fracture pressure.

In carbonate reservoirs where rock is dominantly composed (>50%) of calcium or magnesium carbonate material then hydrochloric acid is the favoured relatively straightforward common treatment choice. In sandstone reservoirs, the fraction of acid soluble material is lower and thus the acid stimulation potential in terms of mass of material that can be removed per unit volume is lower.

A further challenge with respect sandstone reservoirs is the complexity of mineralogical types in terms of detrital matrix grains, cements, and interstitial clays. The reaction chemistry is complex and a much higher risk exists of significant secondary adverse precipitative reactions that can create formation damage and emulsions. Tight sandstone are particularly sensitive as only minor adverse clay fraction changes can block narrow pore throats and drastically reduce permeability. Greater pre-screening and testing is therefore recommended for sandstone reservoir acid stimulations. A common approach involves the use of a combination of hydrofluoric and hydrochloric acid in instances where removal of both carbonate and clay content is required such as ‘dirty’ clay rich sandstones.

As with the filter cake removal / breaker technology a key element of acid matrix technology is the controlled placement of any treatment in a timely manner. The normal goal is to seek to treat all zones equally or divert more treatment into underperforming low permeability zones.

Diversion can be achieved in three ways; ‘back pressure’ rate diversion, mechanical (coil tubing and straddle packers, ball sealers on perforations, ball drop actuated sleeves, perforation and plug to isolate toe heel operations) or chemical. For vertical intervals less than 100ft then a simple multi ball sealer on perforation diversion approach may be most suited. For longer horizontal wells, ball drop actuated sleeves or chemical diversion technologies are more applicable. This technique has been used in the SNS on Zechstein carbonates in the Hewett and Wissey Fields.

Acid fracturing stimulation

Acid fracturing stimulation refers to treatments carried out where acid is injected into the near wellbore and beyond at pressures above fracture pressure. The combination of large acid volumes pumped at higher rates and pressures results in the creation of complex etched fractures and wormholes that penetrate deeper into the formation to provide a significantly larger inflow area or ‘effective well bore radius’ than that typically associated with near wellbore matrix stimulation treatments.

Large scale acid treatments both matrix and acid fracturing are extensively practiced in the North Sea in horizontal Cretaceous chalk wells which are predominately found in Denmark (Hess, South Arne Field) and Norway (Ekofisk Field). Natural fractures play a significant role in offsetting the low permeability matrices in many cases. Acid fracturing serves to improve wellbore connectivity directly with the matrix by creating new fractures and wormhole structures, and indirectly by creating links and enhancing the conductivity of any existing natural fracture networks. Successful ball drop actuated multi-stage acid treatments were undertaken by Hess on the South Arne Field in Danish sector in 2014.

Hydraulic fracturing

Slick water hydraulic fracturing

Slick water hydraulic fracturing stimulation refers to treatments carried out where simple none viscous fluids are injected into the near wellbore and beyond at pressures above fracture pressure. They rely on a combination of large fluid volumes pumped at high rates and pressures to create linear etched fractures that penetrate deep into the formation to provide a significant increase in inflow area or 'effective well bore radius'.

Propped hydraulic fracturing

Propped hydraulic fracturing stimulation refers to treatments carried out where viscous proppant laden fluids are injected into the near wellbore and beyond at pressures above fracture pressure. They rely on the combination of large fluid volumes pumped at high rates to create linear fractures that penetrate deep into the formation to provide a significant increase in inflow area or 'effective well bore radius'.

The proppant serves to maintain the fracture width and its associated conductivity as the well is produced. Use of proppant results in an excess volume of treatment in the wellbore that must be subsequently removed. This is commonly achieved with using coil tubing to progressively wash down through the proppant slurry, with or without nitrogen lift as required.

A risk with propped treatment over the production lifecycle of the well is that proppant can be back produced from the well after the initial clean-up which can create fill or blockages in the wellbore, subsea flowlines, or platform surface plant. An option to reduce this risk is to use resin coated proppant which promotes point contact adhesion between formation and proppant 'grains' once in situ and subject to fracture closure pressure and ambient temperature. In the immediate wellbore area where pressure drop is most acute the proppant can also serve to ensure perforation tunnels are kept open and any formation sand production risk is minimised.

Horizontal multi-stage fracturing

Horizontal multi-stage fracturing (Figure 6) refers to the practice of performing a sequence of 500 to 1000ft spaced stimulation treatments from the toe of the well to the heel.

In the past, the standard approach was to run and cement a liner, then to perforate, stimulate and set a bridge plug in the liner to provide isolation before repeating the same steps for the next stage.

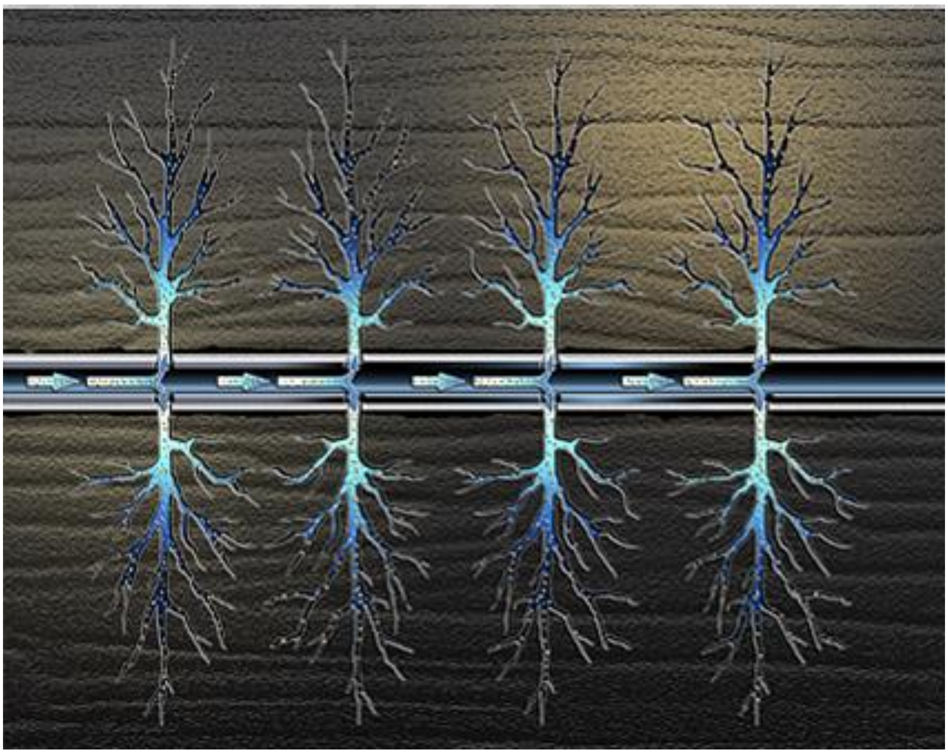

Figure 6: Horizontal multi-stage hydraulic stimulation (www.fracfocus.org)

On completion of all the stages, the plugs were milled out and any excess proppant was removed using coil tubing. Variations in approach have included the use of sand plugs as opposed to bridge plugs to eliminate plug setting and milling / recovery time. Coil has been used to: jet perforate; pump treatments; monitor downhole pressures (including the monitoring of high rate treatments pumped down the coil tubing / upper completion tubing annulus); provide over and underbalance proppant clean out; and nitrogen lift to enable well clean up.

Ball drop stimulation sleeves

The most significant advance in recent times has been use of 'ball drop' actuated multi-stage stimulation sleeves as shown with a Halliburton example below (Figure 7). These are run as an integral part of a standard cemented liner or an open hole liner system with each stimulation sleeve placed between pairs of annular open hole isolation packers. In the initial systems, coil tubing was used to manually open and close the stimulation sleeves as required. The deeper and longer the horizontal section, the more onerous and challenging coil tubing access becomes and the greater the operational hours involved.

The ball drop actuated system however has greatly increased the time and thus cost efficiency of the multi-stage fracturing process. Balls of progressively fractionally larger sizes are dropped and pumped onto the integral seat at the base of the stimulation sleeve stage about to be treated. The ball and seat serve to simultaneously isolate the stage below and enable hydraulic pressure to be applied from above which provides the force to open the treatment sleeve.

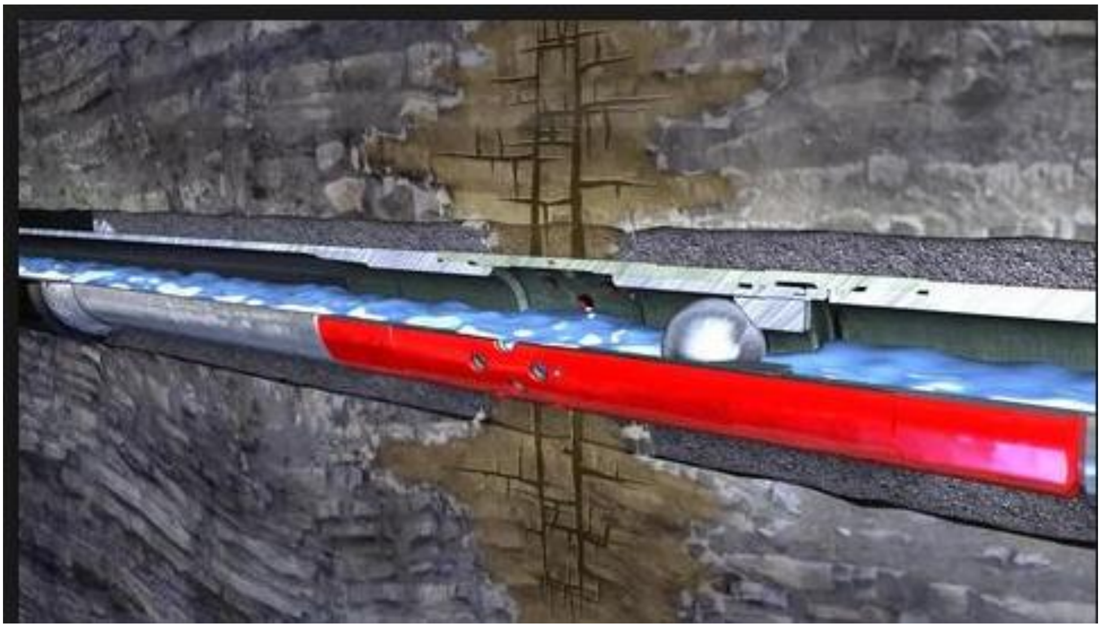

Figure 7: Ball drop stimulation sleeve (Halliburton)

An offshore multi-stage propped hydraulic fracturing process might now be completed in a week rather than more than a month as had been the case historically. Multi-stage acid fracturing treatments where no proppant clean out is required can now be completed in a matter of a few days.

Whilst small scale treatments might be contemplated with a rig based spread and a single delivery of chemical stocks and potable water, standard or larger multi-stage stimulation treatments have generally required and relied on the larger chemical and fluid capacities and proven functionality and competency of dedicated stimulation vessels; but with vessels re-stocking at port between stages still required particularly for potable water. The turnaround time between stages to re-stock has always been a critical bottleneck but this has become more acute with the improvements in downhole efficiencies described above.

SNS insight: One recent approach in the development of the Ensign Field[2] has been the development of seawater rather than potable water based fracturing fluids. Whilst seawater based fracture fluids have been widely available globally these have not until recently been used in the UKCS.

Another key area to target for efficiency improvements with multi-stage horizontal hydraulic proppant treatments is accurate placement of the tail end of each proppant stage. If the tail is over displaced, the most critical section of the fracture at the wellbore is left un-propped and thus may subsequently close. This can occur with a ball drop system if a ball is dropped late, becomes stuck, or held up. Alternatively if a ball is dropped early or overtakes the preceding tail due to stratified flow conditions then the stage is under displaced. The tail is typically formulated with coarser proppant to deliver highest permeability at the immediate fracture to wellbore interface where production pressure drops are most acute.

This means some of the benefit of the tail will be lost as the stage is prematurely shut off and some of the tail may be diverted to start the next stage which may in a worst case lead to a premature screen out with the stage effectively lost. If caught early then, although costly, the option may still exist to use coil tubing to clean out the excess proppant and re-start the treatment of the prematurely opened stage. For this reason automated ball drop systems with release indicators and monitors have been developed, mono-bore completion conduit pathways to avoid ball hold up are recognised as optimal, and evaluation of planned versus actual 'drop times' based on pressure seat landing spikes are real time factored into treatment pumping and ball release schedules.

As the number of multi-stage ball drop actuated fracturing sleeves increased, it was recognised that the number of selectively sequentially operated sleeves that could be installed in a well was becoming constrained by the achievable physical engineering tolerance limit of the telescoping ball seat size geometries that incrementally decrease in diameter between the heel and toe of the well. This has led in recent years to advances in materials to produce fracture sleeve treatment balls that reliably conform to tighter gauge tolerances, and resist seat embedment thus enabling the use of closer tolerance seat sizes and approximately doubling the number of stages than previously achievable with this equipment.

A residual issue with the ball seat actuated fracture sleeves is that the seats present multiple restrictions in the lower completion. During the hydraulic fracture treatment, the multiple restrictions can result in large aggregate heel to toe pressure drops which can become significantly restrictive on the rate and pressures deliverable downhole within the constraints of the well equipment and or available hydraulic horsepower.

Subsequent to the treatment, the fracture sleeve balls and seats potentially pose a wellbore access restriction for any subsequent re-entry. The balls are either back produced, made of material which dissolves after several weeks, or can be milled out in conjunction with the seats using coil tubing. In addition to degradable balls some service providers are also now offering degradable seats.

In onshore USA, the current maximum number of stages per well record was recently reported as reaching 123 stages (Eclipse Resources, Purple Hayes Well, Ohio Utica Shale, May 2016). This number of stages would preclude the use of ball seat sleeve technology based on geometric constraints and it is understood to have been achieved using basic slick water fluids in an low permeability reservoir with coil tubing used to manipulate the fracture stimulate sleeves. A similar variant approach practiced to support high stage number efficiencies is to use coil to sequentially jet perforate intervals of a cemented and perforated liner.

It can be seen that proppant treatments are more challenging to deliver using multi-stage fracturing technology than solids free acid treatments. One approach is to accept 'stage losses / failures' by relying on many well and many stages. Whilst the many well approach works very successfully in onshore USA, it is more challenging in the North Sea; with SNS fields commonly developed with only a few wells and each more costly. It should be noted that the transfer of onshore USA practice typically requires the development and proving up of equipment, tools, and techniques in the larger bore sizes and operation of same at greater depths typical of the SNS when compared with the onshore USA market. If propped multi-stage treatments are carried out then quality control measures throughout are crucial and some redundancy of stages is advisable.

RFID technology

An alternate to ball seat actuated fracture sleeves is the use of Radio Frequency Identification Technology (RFID) which uses miniature actuation tags (Figure 8) pumped from surface with the treatment fluids to sequentially open and close fracture stimulation sleeves as required. This offers the merit of a mono bore geometry without the additional pressure drops or post job mechanical restrictions that may be associated with the ball seat technology.

Figure 8: RFID technology actuation flag

SNS Insight: Shell and partners Esso, ConocoPhillips and Centrica have recently used Weatherford's RFID technology on the Galleon PG11 well[10].

The primary benefit of the technology was to eliminate or reduce the use of coiled tubing between frac stages, thereby reducing operational risk but also reducing both operational cost and time, with a saving of approximately 2 to 3 days per frac compared to conventional techniques. The benefit of the technique was to some extent offset by the requirement for greater contingency costs in the event of actuation flag malfunction, due to higher intervention and recovery costs.

[10] SPE papers 181012-MS and 181265-MS

Hydraulic fracture monitoring and integrity verification

An area of increasing focus in recent years has been the development of micro-seismic technology using geophones placed at surface and deep in the wellbore to monitor and 3D map the actual pathway and geometry of hydraulic fractures as they are created.

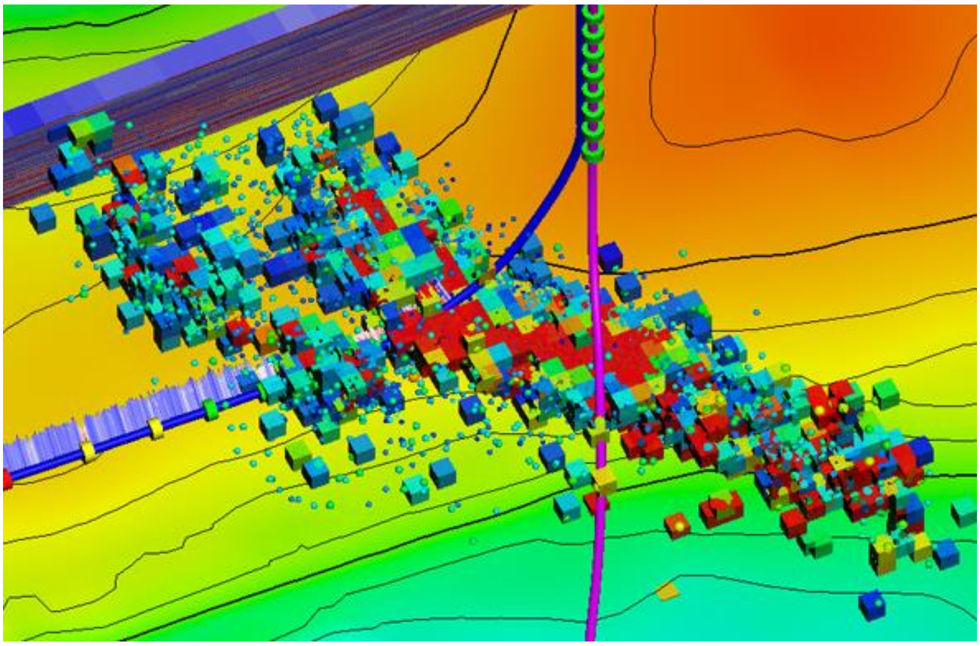

Figure 9: Micro-seismic (www.ocean.slb.com)

This technology provides assurance with respect to excessive fracture height growth risks: well casing shoe integrity, reservoir seal integrity, premature water and or gas breakthrough / coning. Micro-seismic also allows a comparison to be made between planned versus actual fracture height, width, and direction in more detail. This greatly reduces uncertainty to help make clear what works and does not work so that treatment selection and techniques can be honed more effectively and efficiently. Treatments may be adjusted in terms of pump rate, pump pressure, treatment fluid volume, viscosity and the size and concentration of proppants or sand in order to create the most effective fractures and ensure the required fracture geometries are achieved.

A further relevant monitoring technology is fibre optic distributed temperature sensing (DTS) and distribution acoustic sensing (DAS) technology which can be used to generate a form of virtual production log in terms of fluid injection and production from hydraulic treatment intervals.

An alternate widely used virtual production log technology is that of chemical tracers; (www.tracerco, www.resman.no). Minute quantities of uniquely fingerprinted oil or water soluble chemicals can be used to monitor either the return of injected fluids from each stage or the production of oil or produced water.

These virtual inflow technologies are particularly relevant in high angle horizontal subsea wells where production logging is expensive and or mechanical access may be restricted by multi-stage ball seat equipment.

Alternate solutions

Fishbones

In reservoirs of limited thickness and low permeability with minimal stand-off between the wellbore inflow depth and the fluid contact(s), then a horizontal well would likely be considered. If the reservoir were also composed of thin sand shale laminated sequences then vertical communication would be poor. A risk of using hydraulic fracturing in this geometrically constrained environment is the lack of precision with respect fracture height growth. Excess fracture height may result in premature water or gas production.

'Fishbones,' is a recent example of niche technical innovation company that has sought to address this type of scenario[11] [12]. The product is deployed integral to a production liner. It comprises hydraulically actuated 'hollow needles' that are orthogonally deployed, radiating out from the liner once in situ across the reservoir section.

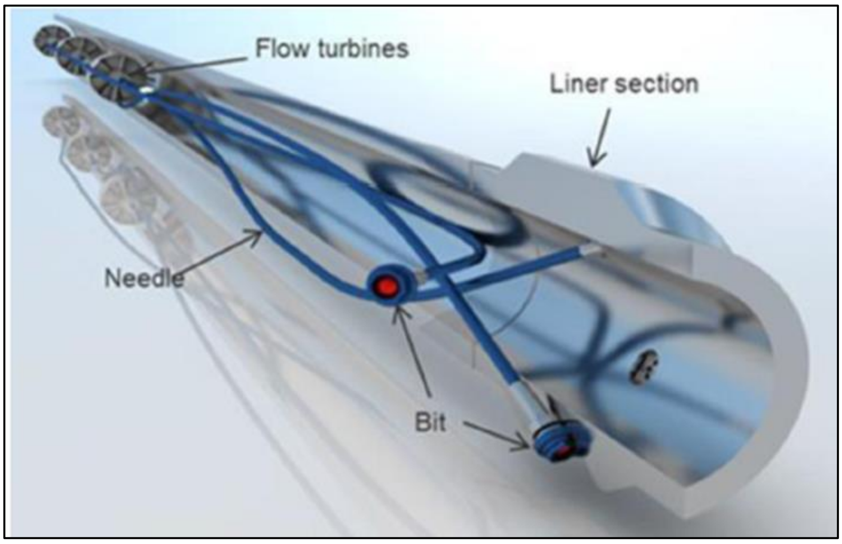

Figure 10: Fishbones - MLDST

Each of the four needles per joint provide up to 40ft long micro-tunnel formation penetrations that enhance the effective wellbore radius to improve the productivity of the well. Needle deployment is powered hydraulically with formation penetration aided by jetting action supported by use of either acid, or sacrificial miniature drill bits on one end of each needle powered by a turbine on the other end sitting inside the liner.

The technology is relatively new with six onshore and two offshore installations completed worldwide as of December 2016. Jetting accounted for seven runs, and with one drilling run completed using the Multilateral Drilling Stimulation Technology (MDST) System (Figure 10). The MDST installation was in a horizontal lateral leg of a tight thin oil bearing sandstone reservoir in the Aasgard Field in Norway and designed to avoid gas coning from an adjacent underlying formation.

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[11] Rice,K.,Jorgensen, T., Solhaug, K., Technology Qualification and Installation Plan of Efficient and Accurate Multilateral Drilling Technology for Sandstone Oil Application, SPE 174035-MS, 2015.

[12] Torvund, S., Stene, K., Jensaas, H., Statoil ASA, Renli, J.K., Jorgensen, T., Fishbones A.S., First Installation of Multilateral Drilling Stimulation Technology in Tight Sandstone Formation, SPE 180390-MS, 2016.

Enhanced perforating

A common characteristic of SNS tight sandstone reservoirs tends to be relatively greater hardness. Deeper Carboniferous horizontal reservoir sections are commonly drilled with a 6" open hole size and completed with 4-1/2" liner equipment. This combination may or may not be also combined with partial reservoir pressure depletion. Each of these elements present an increased perforation challenge and or cost. Options to perforating long horizontal intervals under optimised underbalance conditions to promote perforation tunnel clean up include the use of tubing conveyed perforating (TCP) guns deployed and set on an anchor in the production liner.

For shorter intervals,TCP guns can be deployed on the base of the upper completion tailpipe. If the guns are left in hole however this prevents any subsequent through tubing remedial or logging access to the reservoir should it be required. If a shoot and pull prior to running the upper completion approach is used an appropriately engineered perforating fluid loss pill should be spotted before perforating. This serves to minimise losses and enable ready backflow of the bridging medium / materials from the perforation tunnels during clean up flow.

Another approach used historically was to use coil tubing to enable long gun strings to be deployed with an underbalance condition maintained during perforating and 'live well' gun recovery. A challenge with this method was the increased time involved in live well long gun recovery, and an increased associated gas hydrate risk.

Whether perforating is being carried out solely for production or prior to hydraulic fracturing careful planning, design and operational execution is essential.

In addition to the continuous advancement of conventional shaped perforation charge design other technological enhanced perforating options in recent years include dynamic underbalanced perforating optimisation techniques (e.g. Schlumberger PURE[13]), mixed metallic charge liners that exothermically react post tunnel perforation formation (e.g. Paradigm Geokey Connex Reactive Perforating Charges [14] [15]), and triple charge gun systems based on the convergent charge alignment of charges to achieve constructive shockwave interaction to maximise perforation efficiency (e.g. TriStim, Delphian Ballistics[16])

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[13] Behrmann,L., Johnson,A.B., Walton, I.C., Schlumberger, Hughes, K., Chevron, New Underbalanced Perforating Technique Increases Completion Efficiency and Eliminates Costly Acid Stimulation

[14] Diaz, N.J., Nasr-El-Din, H.A., Texas A&M.Univ., Bell M.R.G, Hardesty, J.T., GeoDynamics, Inc., Hill, A.D., An Evaluation of the Impact of Reactive Charges on Acid Wormholing in Carbonates, 2010.

[15] Behrmann,L., Johnson,A.B., Walton, I.C., Schlumberger, Hughes, K., Chevron, New Underbalanced Perforating Technique Increases Completion Efficiency and Eliminates Costly Acid Stimulation.

[16] McGuire, W.J. and Sikora, V.J. 1960. The Effect of Vertical Fractures on Well Productivity. J Pet Technol 12 (10): 72-74. SPE-1618-G.

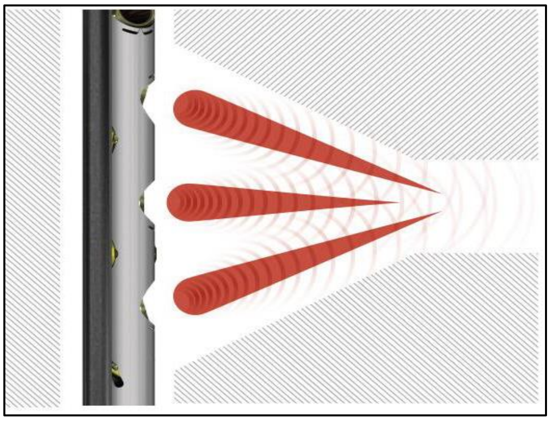

Figure 11: TriStim cone (www.delphianballistics.com)

Summary

This theory and practice discussion above highlights how the two major enablers for tight gas reservoirs in the UK SNS in recent years has been the cost effective application of horizontal and hydraulic fracturing technology.

The range of horizontal well technology has been increased due to continuous technology improvements in areas including those of directional drilling, real time logging, geo-steering, fluid design, fluid loss management and perforation optimisation. However it is technical and cost effective advances in horizontal multi-stage hydraulic fracturing that has enabled the economic development of even tighter reservoirs than previously achievable.

For those reservoirs where hydraulic fracture height growth is an issue due the proximity of water then micro seismic enhanced monitoring technology might be applicable or alternate solutions such as ‘fishbones’ might be considered.

Stimulation vs reservoir type fit

At an early screening stage, the following reservoir variables are particularly key to determine the stimulation techniques most appropriate.

Permeability

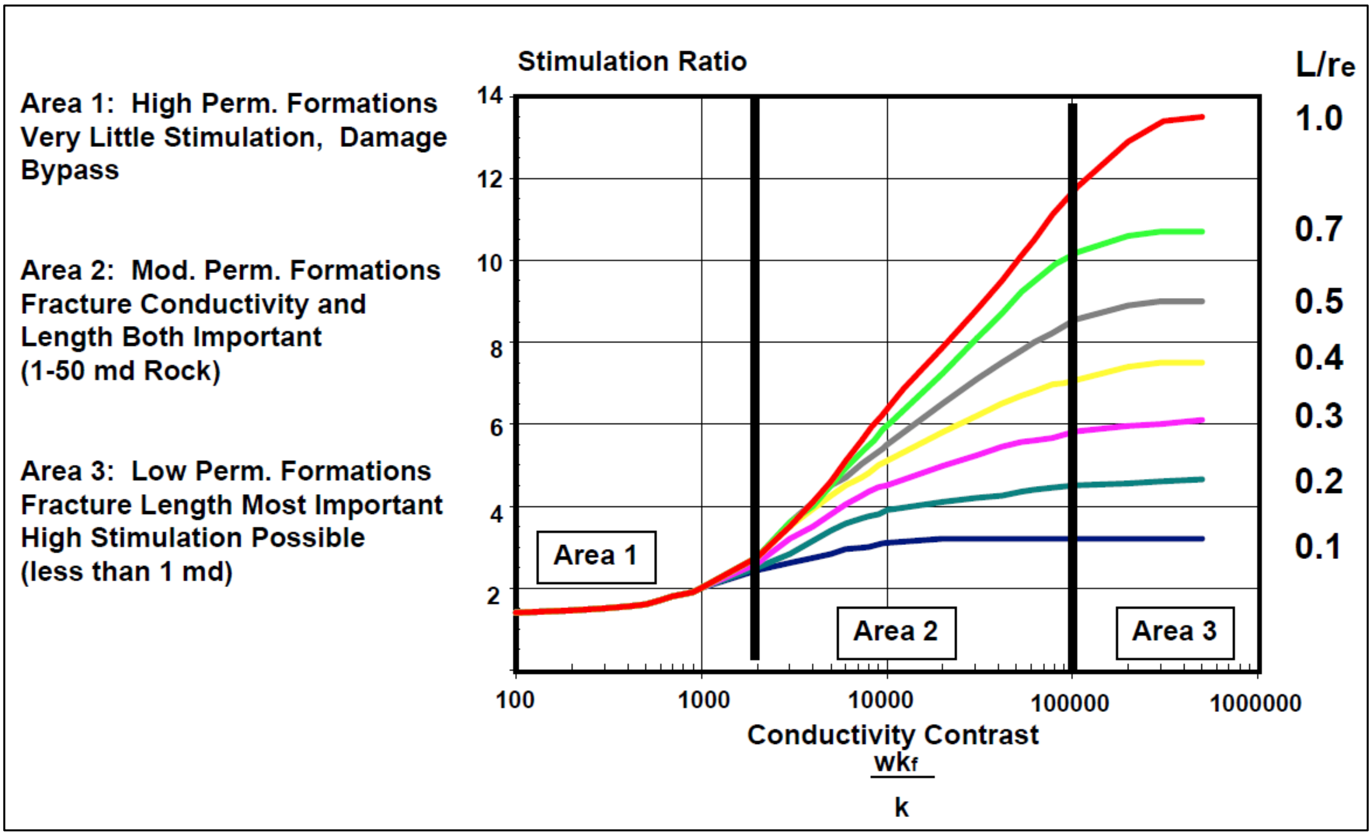

Figure 12: Folds of increase

The generic figure above, based on McGuire and Sikora 1960[17] illustrates the folds of increase principle as a function of the conductivity contrast between the reservoir and a hydraulic fracture examined for a range of fracture lengths relative to reservoir drainage radius.

In the example chart above reservoirs of high permeability (Area 1 >50mD) then the role of stimulation is restricted to bypassing near well bore damage with relatively short fractures of maximised width.

In reservoirs of moderate permeability (Area 2 - 50mD) then significant gains in terms of folds of increase are seen for each fractional increase in fracture length. In reservoirs of low permeability (Area 3 <1mD) then significant increases in production can only be achieved with fractures of greatest length.

In terms of Southern North Sea tight gas reservoirs, this relationship explains and drives typical fracture half lengths of 200-300ft.

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[17] McGuire, W.J. and Sikora, V.J. 1960. The Effect of Vertical Fractures on Well Productivity. J Pet Technol 12 (10): 72-74. SPE-1618-G.

Reservoir fluid distribution and structure

A series of conceptual reservoir type scenarios[18] are considered below to allow discussion in regard to appropriate stimulation solutions.

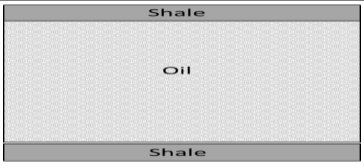
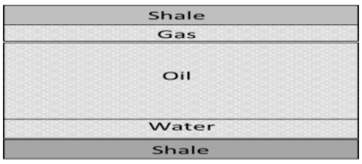
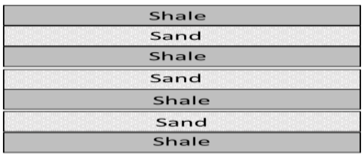
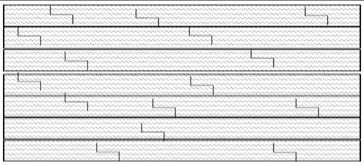
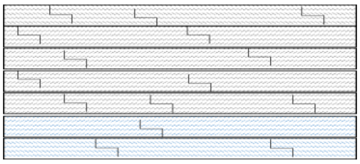
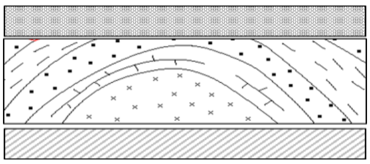
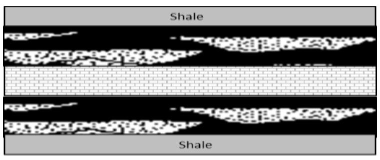
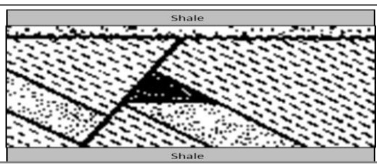
<table>
<tr><th colspan="3">Drainage Volume Characterisation</th><th colspan="5">Well Type</th></tr>
<tr><td>1</td><td>Thick and Homogenous Reservoir with no Gas Cap or Aquifer.</td><td>
</td><td>Vertical</td><td>Vertical Hydraulically Fractured</td><td>Slant Well</td><td>Horizontal Well</td><td>Horizontal Hydraulically Fractured</td></tr>
<tr><td>2</td><td>Thick and Homogenous Reservoir with Gas Cap or Aquifer.</td><td>
</td><td>Vertical</td><td>Vertical Hydraulically Fractured</td><td>Slant Well</td><td>Horizontal Well</td><td>Horizontal Hydraulically Fractured</td></tr>
<tr><td>3</td><td>Layered Reservoir</td><td>
</td><td>Vertical</td><td>Vertical Hydraulically Fractured</td><td>Slant Well</td><td>Horizontal Well</td><td>Horizontal Hydraulically Fractured</td></tr>
<tr><td>4</td><td>Laminated Reservoir</td><td>
</td><td>Vertical</td><td>Vertical Hydraulically Fractured</td><td>Slant Well</td><td>Horizontal Well</td><td>Horizontal Hydraulically Fractured</td></tr>
<tr><td>5</td><td>Naturally Fractured Reservoir</td><td></td><td>Vertical</td><td>Vertical Hydraulically Fractured</td><td>Slant Well</td><td>Horizontal Well</td><td>Horizontal Hydraulically Fractured</td></tr>
<tr><td>6</td><td>Naturally Fractured Reservoir with Water Flooding</td><td></td><td>Vertical</td><td>Vertical Hydraulically Fractured</td><td>Slant Well</td><td>Horizontal Well</td><td>Horizontal Hydraulically Fractured</td></tr>
<tr><td>7</td><td>Strudctural Compartment</td><td></td><td>Vertical</td><td>Vertical Hydraulically Fractured</td><td>Slant Well</td><td>Horizontal Well</td><td>Horizontal Hydraulically Fractured</td></tr>
<tr><td>8</td><td>Stratigraphic Compartment</td><td></td><td>Vertical</td><td>Vertical Hydraulically Fractured</td><td>Slant Well</td><td>Horizontal Well</td><td>Horizontal Hydraulically Fractured</td></tr>
<tr><td>9</td><td>Elongated Compartment</td><td>
</td><td>Vertical</td><td>Vertical Hydraulically Fractured</td><td>Slant Well</td><td>Horizontal Well</td><td>Horizontal Hydraulically Fractured</td></tr>
<tr><td>10</td><td>Attic Compartments</td><td>
</td><td>Vertical</td><td>Vertical Hydraulically Fractured</td><td>Slant Well</td><td>Horizontal Well</td><td>Horizontal Hydraulically Fractured</td></tr>
</table>

Figure 13: Reservoir type vs stimulation solution

An initial starting point in considering reservoir type is an understanding of formation tops, fluid types, contacts, and structural controls. Each exploration and appraisal well seeks in conjunction with seismic data to build an improved understanding of these elements.

Thick and homogenous reservoir with no gas cap or aquifer

In a scenario of a thick and homogenous reservoir with no gas cap or aquifer where mobility is low then a vertical well with a conventional single vertical hydraulic fracture treatment is appropriate. If the permeability to viscosity mobility ratio (k/µ) is high and sanding is a risk, as is common with high porosity / high permeability sandstones, then a stimulation treatment known as a 'frac pack' may be the most appropriate choice. A frac pack treatment can be installed in an open or cased hole. The reservoir interval is perforated before a sand control screen lower completion is installed.

The screen annulus and perforation tunnels are then gravel packed. In the case of a high rate water pack, fluid and gravel are injected into the perforation tunnels at a pressure lower than formation fracture pressure, whilst for a frac pack treatment the treatment is performed at higher than fracture gradient pressure to result in the creation of short length high width propped fractures based on Tip Screen Out techniques (TSO). The screen and gravel frac pack serves to prevent perforation tunnel collapse and sand production, whilst providing durable high conductivity reservoir access and a means to bypass near wellbore damage as illustrated below.

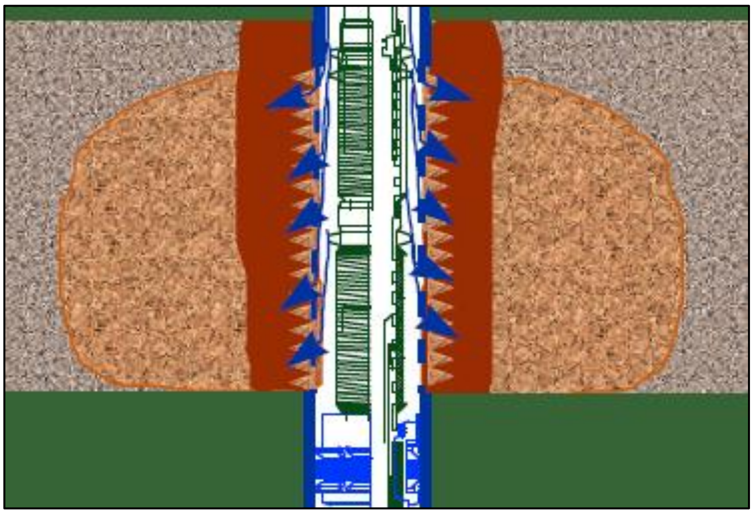


Figure 14: Frac pack treatment (www.BakerHughes.com)

Well performance is potentially improved by use of a slant well to increase reservoir contact area whilst at the same time compensating for any significant vertical to horizontal permeability contrast (Kv/Kh). If vertical permeability is good then a horizontal well may be the optimal choice.

The use of hydraulic fracturing within the slant or horizontal well cases will result in fractures orientated longitudinal or transverse to wellbore subject to the well being drilled on an maximin or minimum horizontal stress azimiuth respectively. The merits of longitudinal versus transverse to wellbore orientated fractures have been subjected to debate and study. It is broadly recognised that as permeability decreases, then the case for transverse fractures increase as concerns relating to near wellbore crowding / turbulence that longitudinal might address diminish whilst the merits of twin 'X, Y' axis areal reach is maintained. The ability to select the azimiuth on which the wellbore is drilled however is commonly contrained by factors such as reservoir structure orientation, and surface location.

Thick and homogenous reservoir with gas cap or aquifer

In a scenario of a thick and homogenous reservoir with a gas cap or aquifer where water or gas contact stand-off is minimal, then a vertical well with a combination of only the upper part of the interval perforated and a carefully managed drawdown approach may be appropriate.

In the event that mobility is low and a single vertical hydraulic fracture treatment is considered, then fracture height would need to be carefully controlled with only a relatively small fracture treatment appropriate.

The most likely preferred choice would be a non fractured horizontal wellbore with optimised stand-off to either gas or water contact or both as applicable.

Layered reservoir

In a layered reservoir scenario of sand and impermeable shale, then a vertical well provides access to each sand layer. If mobility is low then a hydraulic fracture treatment can be considered for each layer. A separate treatment may be required for each layer due to the impediment to fracture height growth that the bounding shale layers may impose.

A slant well provides the merit of accessing each layer and may also be sufficient to increase production by increasing wellbore to reservoir contact footage to acceptable levels without hydraulic fracturing.

Another approach for larger layered reservoirs is the use stacked laterals based on multilateral technology with a horizontal leg drilled and completed in each layer.

If mobility is low then a slant well combined with multistage hydraulic fracturing provides an optimal means to overcome the shale barriers in terms of vertical connectivity and improve layer inflow performance with increased contact area achieved with a series of hydraulic fractures.

Laminated reservoir

In a laminated reservoir scenario of thin sand and impermeable shale layers then a high contrast between vertical and horizontal permeability exists ($Kv/Kh <<0.1$) at the small scale level. Although in theory a vertical well provides access to each thin sand layer, in thin sands perforation shot density may become a constraint, and some layers may be left unperforated unless multiple perforating runs are considered. Hydraulic fracturing provides a means to efficiently connect multiple thin sands with adequate fracture height growth more achievable with only thin shales layers to overcome. Further, inflow performance of each sand layer is improved with the increased contact area associated with the hydraulic fracture.

A slant well provides the merit of accessing each layer and may also be sufficient to increase production by increasing wellbore to reservoir contact footage to acceptable levels without hydraulic fracturing.

The use of horizontal or stacked laterals based on multilateral technology with a horizontal leg drilled and completed in each layer are both less effective in laminated systems where multiple vertical permeability barriers operate over a scale of inches.

If layer mobility is low then a slant or horizontal well combined with multistage hydraulic fracturing provides a means to overcome the shale barriers in terms of vertical connectivity and improve layer inflow performance with increased contact area achieved with a series of hydraulic fractures.

Naturally fractured reservoir

In a naturally fractured reservoir then the fractures if open and conductive provide a potential means to significantly enhance the permeability of the reservoir matrix rock.

Critical to well choice is an understanding of the nature of the natural fracture network in terms attributes such as; azimuthal orientation or strike, inclination, width, degree of mineralisation / conductivity, spacing or intensity, variation in areal, vertical extent, and formation or sub-formation.

In an extensional basin tectonic environment such as the Southern North Sea, then fracture inclination will generally be toward the vertical hence a vertical well will encounter fewer natural fracture than a horizontal well. However if a vertical well is drilled at a locus of high natural fracture intensity then productivity may be adequate without hydraulic stimulation.

Hydraulic fracturing provides a means to improve inflow performance by improving connectivity between the vertical wellbore and natural fractures. It should also be noted that drilling fluid losses whilst drilling through zones of abundant natural fractures can create formation damage and that subsequent hydraulic fracture treatment provides a means to bypass this damage, as well as opening, widening, etching, and or holding open with proppant the natural fractures.

A slant well provides the merit of intersecting an increased number of natural fractures and thus delivering improved inflow performance. The well azimuth would ideally be normal to the direction of maximum horizontal stress to ensure the maximum number of natural fractures are encountered. Hydraulic fracturing would provide a means to re-open / open as multiple natural fractures that have been encountered.

A horizontal well enhanced with a hydraulic fracture treatment to connect to the natural fractures would also be potentially appropriate particularly if a sub-zone or horizon is identified as being more competent and thus containing a concentration of natural fractures. The horizontal well could target and remain in this layer with subsequent production based on overlying or underlying zones produced via the targeted zones fracture network.

Naturally fractured reservoir under waterflood

When considering wells for a naturally fractured reservoir under water flood then the main concern is to minimise the risk of premature water breakthrough. Injection wells should be planned to inject at a sufficient stand off from the hydrocarbon leg and avoid extensively fractured reservoir intervals directly overlain by the producing hydrocarbons. Similarly, producer wells need to carefully risk assess hydraulic fracture treatment height growth and stand off to water contact over full lifecycle. The combination of water flood and hydraulic fracturing therefore appears most suited to scenarios of very thick reservoirs or where water is laterally distant.

A more common choice for water flooded natural fracture reservoirs would be use of horizontal wells with maximised stand off and carefully regulated drawdown or injection along the length of the producer and injector wellbores respectively.

Structural compartment

When considering reservoirs that are sub-divided into compartments by structural faulting then the dimensions of the compartment are key. A challenge is that prior to drilling only major faults identified by seismic may be known, and that numerous further smaller faults that are beneath the resolution capability of seismic imaging remain hidden.

In a scenario of high to moderate permeability with a compartment of adequate reserve size a vertical well may be sufficient. If mobility is high and a sanding risk present a sand control completion may be appropriate. If mobility is low then a hydraulic fracture treatment would likely create a fracture with an azimuth parallel with the bounding fault planes in the maximum horizontal stress direction and thus serve to efficiently drain the block or compartment reserves.

In the scenario where the compartment reserves are inadequate then slant or horizontal well paths can be considered to connect to reserves either side of the fault planes. This must consider the risks of managing uncertainty in relation to the relative and absolute depth of the reservoirs units on each side of any fault. If the offset is too great then a separate well or multi-lateral well approach may be needed to reach each reservoir compartment. The risk of fluid losses whilst drilling across any faults must also be considered. Water contacts may also be different on either side of the fault effecting stand-off, and water breakthrough risk. A pilot and slant well combination, and subsequent hydraulic fracture treatment in low mobility cases and where water stand-off is adequate may provide a means to efficiently deliver reserves and enhanced well performance.

Stratigraphic compartment

Stratigraphic compartment is defined here to consider non layer cake or uniform pay where reservoir units vary in thickness as noted in the cases related to ancient marine transgressions. This can lead to a pinching out of a reservoir unit or a series of reservoir lenses between none pay.

When considering reservoirs that are sub-divided into stratigraphic compartments then the dimensions of the compartment are key. A challenge is that prior to drilling only major features may be identified by seismic and that significant detail is beneath the resolution capability of seismic imaging. As more wells are drilled, geo-facies models are improved and reservoir distribution understanding improves.

In a scenario of high to moderate permeability with a compartment of adequate reserve size, a vertical well may be sufficient. If mobility is high and a sanding risk present a sand control completion may be appropriate. If mobility is low then a hydraulic fracture treatment would create a fracture with an azimuth paralell with the maximum horizontal stress direction and could more efficiently drain the compartment reserves.

In the scenario where the compartment reserves are inadequate then slant or horizontal well paths can be considered to connect to adjacent reservoir reserves. This must consider the risks of managing uncertainty in relation to the relative and absolute depth of the reservoirs units in each compartment. If the offset is too great then a separate well or multi-lateral well approach may be needed to reach each reservoir compartment. Drilling risks associated with drilling at high angle through a combinaiton of pay and non pay must be considered.

Water contacts may also be different in compartment effecting stand-off, and water breakthrough risk. A pilot and slant well combination, and subsequent hydraulic fracture treatment in low mobility cases, and where water stand-off is adequate may provide a means to efficiently deliver reserves and enhanced well performance.

Elongated compartment

Elongated compartment is defined here to consider non layer cake or uniform pay where reservoir units are significantly elongated in one direction. Perhaps the most well known example woud be stacked fluvial sand channel systems that are elongated in the direction of the paleo current or drainage direction of the ancient rivers from which they were deposited.

When considering reservoirs that are sub-divided into elongated compartments then the dimensions of the compartments or channels and degree of connectivity are key. A challenge is that prior to drilling, only major features may be identified by seismic, and that significant detail is beneath the resolution capability of seismic imaging. As more wells are drilled geo-facies models are improved and reservoir distribution understanding improves.

In a scenario of high to moderate permeability with a compartment of adequate reserve size a vertical well may be sufficient. If mobility is high and a sanding risk present a sand control completion may be appropriate. If mobility is low then a hydraulic fracture treatment would create a fracture with an azimuth parallel with the maximum horizontal stress direction and could more efficiently drain the compartment reserves.

In the scenario where the elongated compartment reserves are inadequate then slant or horizontal well paths can be considered to penetrate and connect to multiple adjacent compartments or channel sand reserves. Alternatively a multilateral approach can be considered with multiple slant laterals dropping away from a motherbore. Drilling risks associated with drilling at high angle through a combination of pay and non pay must be considered. Water contacts or reservoir pressures may also be different in different compartments effecting stand-off, water breakthrough and drilling fluid loss risks. A pilot and slant well combination and subsequent hydraulic fracture treatment in low mobility cases and where water stand-off is adequate may provide a means to efficiently deliver reserves and enhanced well performance. Establising the direction of the maximum horizontal stress and thus the direction of the hydraulic fracture that will be created is important. This information together with the orientation, dimensions and a statistical analysis of the distribution of the channel sands allow the orientation of the wellbore to be optimised to maximise reservoir connectivity and reserve recovery. A key fracturing challenge in this type of reservoir is whether an appropriate combination of fracture height and width can be achieved to connect multiple channels adequately. Where high permeability channels are encountered, fluid losses increase, net fracture presure drops, and fracture growth is curtailed.

Attic compartments

In this scenario, steeply inclined beds are considered with a gas cap, an oil leg and basal water present. A vertical well is not applicable as it carries too high a risk of water or gas coning. Two recommended potential options are a horizontal well that penetrates multiple of the dipping bed layers at right angles to the strike of beds with an optimised balance in terms of stand-off to the overlying gas and underlying water. A risk of this approach is early water or gas coning breakthough in the event of a high variation in permeability between each layer. If reserves are adequate then an alternate approach to deal with high permeability contrasts might be separate well penetrations or laterals into each sand orienated parallel to the strike of the dipping beds.

The use of hydraulic fracturing in this environment would not be recommended based on the risk of creating a pathway for premature gas or water breakthrough.

Stimulation project and operations planning

Design

Hydraulic fracture stimulation design

In terms of developing a hydraulic fracture stimulation design, key input includes rock properties, pore pressure, earth stress profiles, reservoir properties and clarity on the constraints or requirements of the well and surface architecture. A clear understanding of geological planar structural elements such as bedding, laminations, 3D character of layer thickness and areal extent and connectivity, and natural fracture distribution patterns is crucial to selection of the appropriate stimulation technique and to achieve an optimal design.

The collated input data provides the means to determine the horsepower required to generate the fracture, the barriers to fracture growth, the fracture dimensions, and orientation (Figure 15), the proppant, fluid rheology, clean up requirements and a suitable execution plan and associated costs.

An indication of some of the range of core, log, well, lab and field test derived data types and uses is provided below.

1. Permeability - (core and well test) to scale fracture size for optimum fracture conductivity.
2. Porosity – to determine hydrocarbons in place and scale potential variations in rock mechanics properties.
3. Sonic logs – (Dipole Shear Imaging) to determine continuous horizontal stress profile and rock mechanics properties, to determine / confirm natural and hydraulic fracture direction.
4. Core Rock Mechanics – to calibrate log derived rock mechanical properties and stresses.
5. Oil / Gas / Water Saturations – to determine where to avoid fracturing.
6. Formation density log – to determine lithology.
7. Pore Pressure (MDT) - to modify stress profile for depletion. To project post stimulation productivity.
8. Wireline micro fracture testing (Duel Packer MDT) - to obtain directly measured horizontal stresses to calibrate the sonic derived log for tectonic effects.
9. Formation Crush Strength – for determination of optimized proppant selection or acidizing medium.
10. Proppant Conductivity Testing – to optimize proppant sizing, resin coating, and flow back control.
11. PVT Data - to determine hydrocarbons in place, and to project post stimulation production performance.
12. Real time bottom hole pressure – to accurately determine well PI, and well response during fracturing operations.

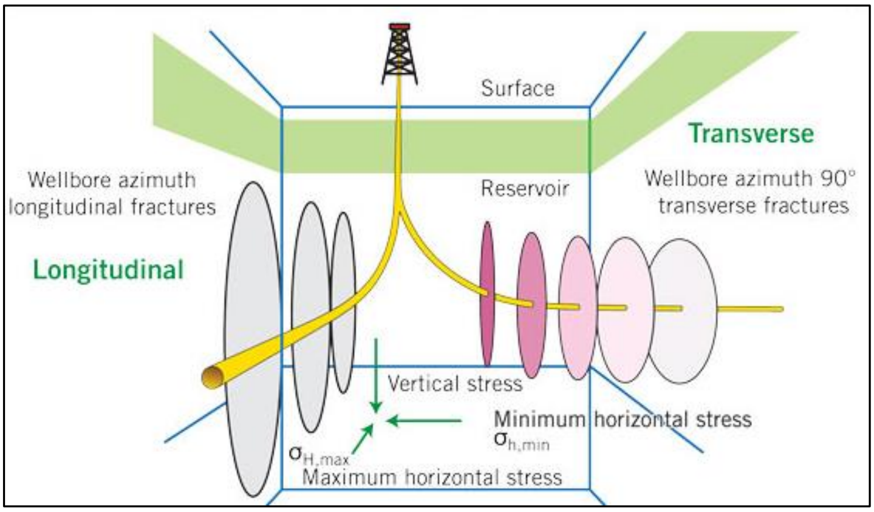


Figure 15: Hydraulic fracture orientation (www.ogi.com)

The specific rock properties required include Young Modulus, Poisson's Ratio, and Unconfined Compressive Strength. The Earth stress profiles, Vertical Overburden (S_{-V}), Horizontal Maximum (S_{-H}), Horizontal Minimum (S_{-h}), describes variation with depth of the in situ stresses in terms of magnitude and direction. Elastic and inelastic rock properties, and in situ earth stresses derived from the various well, log, core, lab, field test, and theoretical sources are used to model the fracture initiation and propagation process.

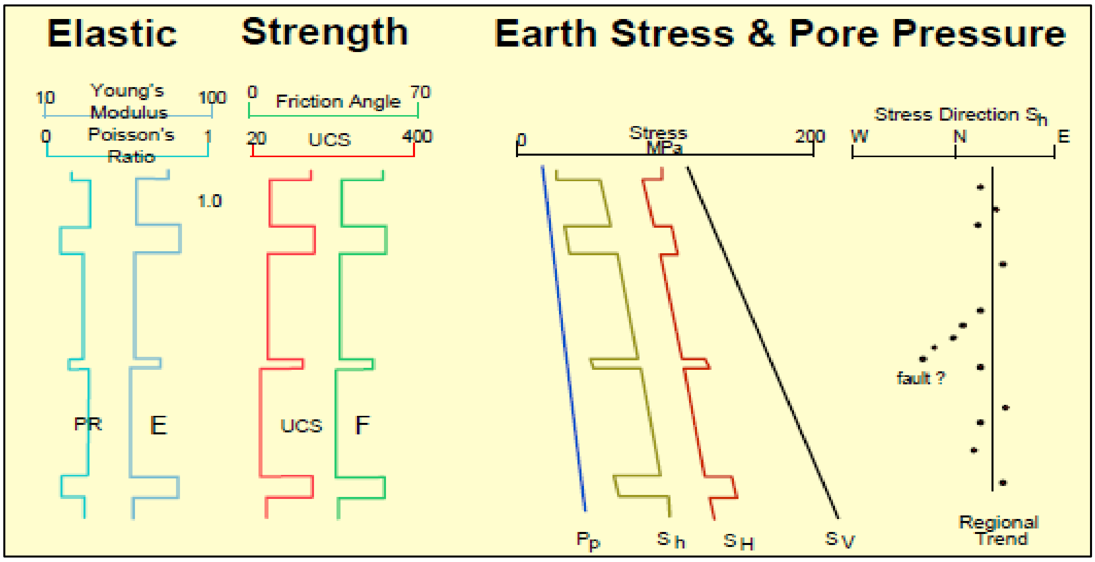


Figure 16: Rock mechanical properties[17]

Fracture propagation simulation software (e.g. MFRAC, fracCADE, FRACPRO) is used to establish the range of fracture geometry (half length, height, width), and fracture conductivity values that could be achievable given the potential variance in input data.

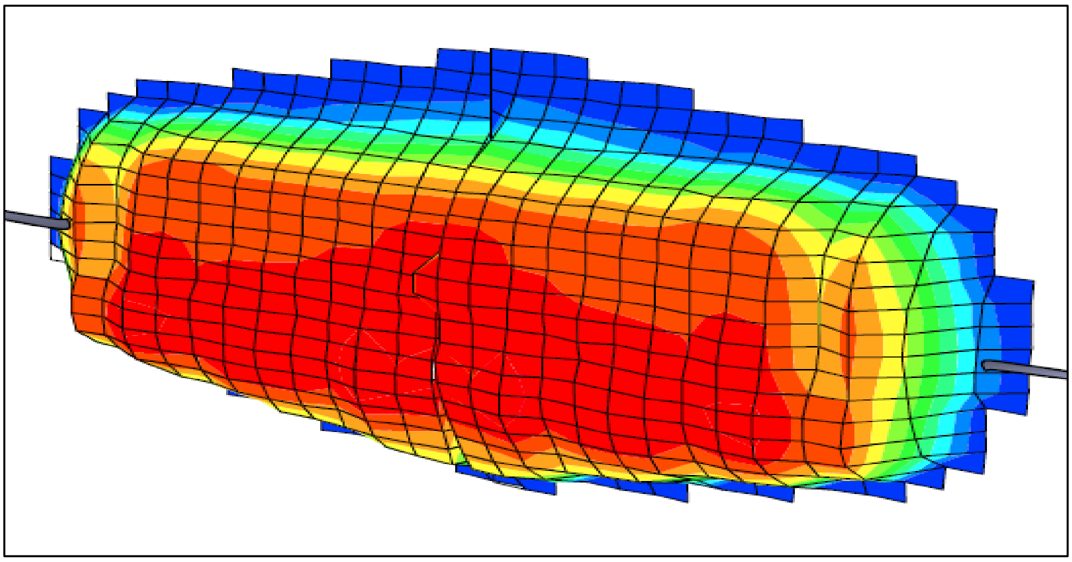


Figure 17: Fracture geometry

Key reservoir properties include porosity, permeability, fluid contacts and layer thicknesses. The well trajectory and completion are particularly important aspects of the well design in terms of enabling or constraining stimulation design choice. The surface facilities are a key influence on the execution method.

Production performance

Well productivity and reserve recovery of hydraulic stimulated wells can be examined using analytical and numeric simulation methods. Although both approaches are still widely used analytical techniques are considered more commonly used to perform initial stimulation option screening exercises, or well performance quick look sense checks rather than comprehensive detailed engineering studies. This reflects the increased availability of cost effective numeric simulation software, enhanced functionality, thus potential increased model realism and added value.

In basic analytical techniques, the fracture is considered as a modification to productivity of the well without any consideration of the physical matrix – fracture interaction. Numeric transient simulation rather than pseudo steady state analytical type simulation provides additional or enhanced capability to consider full lifecycle aspects of geological heterogeneity, reservoir structure, injection or depletion in terms of fracture closing or widening, multi-phase flow, water or gas coning, non-Darcy flow, reservoir geometry and well location, vertical communication, and flow convergence effects amongst other things. Software platform and application improvements are increasingly made to allow improved convergence and integration between static geological full field model, geo-mechanical model, discrete fracture network model, upscaled dynamic full filed and sector / well models, and real time well and seismic data acquisition.

The production profile output from the well and reservoir performance modelling provides a basis for subsequent petroleum economic evaluation typically expressed in terms including net present value, rate of return on investment, and payback period.

Well design

Aspects of well design that require particular attention in stimulation wells include the following:

1. Tubing stress analysis and casing design to cope with elevated planned and unplanned stimulation loads associated with high pressure and high rate pumping, thermal cooling, premature screen out.
2. Annular overpressure management.
3. Wellhead / HP riser selection.
4. Hydraulic pressure loss analysis and optimization.
5. Sand / chalk face lower completion design.
6. Material selection – with respect use of high volume acid and corrosion inhibition strategy.
7. Contingent wireline, electric line, coil tubing access to deviated / horizontal wellbores.
8. Use of downhole real time gauges, chemical tracer or fibre optic inflow, or micro-seismic hydraulic fracture performance and integrity monitoring technology.
9. Wellbore clean Up (eff. / constraints, downhole monitoring, surface metering, ullage, separation, disposal, performance evaluation).

Operations

Rig / vessel / platform configuration options

The most common SNS configuration for large scale stimulation treatments is a jack up rig above either a subsea or platform well. The platform may be either a manned or a normally unattended (NUI) platform. The rig is used to initially drill / workover, and complete the well prior to stimulation operations commencing. A dedicated stimulation vessel is then hooked up to the well and the stimulation treatment completed.

Subsea well / rig

If the well is a subsea well then a rig is normally kept on location for the clean-up flow to remove spent treatment fluids and or excess proppant from the wellbore. Coil tubing is used to mill out balls / seats, clean out excess proppant and nitrogen lift the well as required. Once the well is producing dry gas with a minimal Base Sediment and Water fraction it is shut in and control is handed over to a host platform to be produced via a subsea flowline to the host asset as required. The reason for the clean up to the rig is to avoid the risk of contaminating or blocking subsea flowlines or creating process platform upset with solids such as produced sand or proppant, and spent treatment, mud, or brine fluids that may pose emulsion or hydrate risks.

Platform well / rig / stimulation vessel

In the case of a platform well then there may be scope to stimulate or clean up without the rig to reduce the overall project cost. This is more likely to be the case for larger manned platforms rather than NUIs which are by design minimalistic. A rig-based job would typically involve simultaneously spotted equipment for coil tubing, well testing / clean-up, nitrogen, and stimulation operations, with personnel on board the rig approaching or at maximum capacity during this period.

Platform well / no rig / stimulation vessel

If either the stimulation operation or subsequent clean up flow is to be attempted without a rig then a staged approach is usually required. Equipment for each stage has to be mobilised and de-mobilised on the critical path thus the operations sequence takes longer but without incurring a daily rig cost.

Where accommodation is restricted, then activities may be restricted to day shift work only with twice daily helicopter shuttle to a supportive host platform or an overnight return to shore. Alternatively a walk to work arrangement might be in place involving a temporary adjacent accommodation vessel. Multi-skilling of crews may be appropriate for some tasks.

Solutions include the use of hydraulic mast intervention towers, tool strings or bottom hole assemblies with minimal rig up height, equipment with combined functionality such as dual drum wireline winches, and other specialist compact or adapted equipment suited to the site configuration, deck footprint, loading and crane constraints.

Typically NUI platforms can accommodate wireline or electric line operations but not coil tubing operations due to either deck, crane limitations that would be exceeded. Hybrid approaches to this include vessel based coil tubing control cabins, reels, tanks and pumps with a platform based intervention mast, injector head and BOP configuration.

Stimulation vessel, converted supply vessel or rig / platform based stimulation package

The use of a dedicated fracture stimulation vessel is the most obvious and straightforward choice for large scale stimulation treatments.

Figure 18: Dedicated stimulation vessel

The temporary conversion of a supply boat for use as a stimulation treatment vessel is an alternative approach that has been used in the North Sea where access to a dedicated stimulation vessel was not readily available to meet the well stimulation schedule required.

Significant additional work is required to mobilise and de-mobilise the vessel and commission systems and as a result, this could be expected to add an additional costs increment. A campaign approach would offer a means to reduce the cost per well of this increment.

Figure 19 - Converted supply vessel

The supply vessel can be configured to suit in terms of equipment specification level.

Long lead items

A minimal critical mass of data is first required to allow option screening to be completed. The initial selected option or options are fine-tuned as candidate specific well data is acquired as the well is drilled. The initial fracture or stimulation study will establish the most suitable treatment, likely achievable fracture geometry, number of stages and the expected productivity and reserve recovery.

If the candidate well and associated infrastructure is an existing entity then these, like the subsurface, will form the boundary conditions. However if the well has yet to be constructed then the opportunity to optimise any stimulation treatment by removing / avoiding constraints is at a maximum. Timely completion of a suitable fracturing study (1-3 months) to define treatment parameters such as treatment pump rates, pressures, fluid types, stage numbers will allow subsequent work on the well, well completion, rig selection, wellhead, xmas tree, high pressure riser, stimulation surface treatment configuration to be fully optimised in a timely manner with respect long leads (6-9 months). The simplest operational approach is to perform the treatment through the upper completion once installed.

SNS insight: For SNS fracture treatments this typically requires 10k psi rated completion equipment with or without a riser system as required, both of which need to be compatible with the proposed treatment fluids and well fluids. If suitable completion equipment cannot be sourced within the available timeframe a temporary fracture treatment work string may be required but this will add additional time and cost to the treatment programme.

Interface / fluids risk management

Stimulation treatments involve the use of large volumes of high pressure and sometimes acidic fluids. This introduces a range of additional hazards, risks, and logistical challenges that have to be managed. This includes focus on high pressure pipework, emergency shut systems, material selection, overpressure management, annulus venting systems, vessel to rig/platform communication systems, station keeping, provision of adequate flow back ullage, evaluation, wellbore proppant clean out, separation, treatment and disposal of returned fluids and proppant.

Contractual

Service providers

Major Tier 1 service providers offer a wide range of products and services for well and stimulation delivery needs. Size and global coverage means they can provide multi-discipline experts or ‘champions’, global lessons, R&D investment, quality high volume manufactured goods and the bulk of the industry’s trained personnel.

Tier 2 or smaller service providers often seek to compete across a narrower product, service or geographic area based on differentiators such as niche expertise, local experience, enhanced customer service, and bespoke / innovative / new technology products and services.

A number of models for technical innovation and change exists in the industry. Typically operators, service companies, governments and industry shared bodies identify technology ‘bottlenecks’ or ‘issues’ prior to supporting initiatives for change or funding internal or external research, JV companies, joint industry projects, proof of concept, prototype trials and or donor wells.

The advances in fracturing techniques in tight gas and shale gas reservoirs has been very heavily driven by the US shale gas revolution, which has provided technique and technology product and service solutions that are now being implemented globally. In addition to technology and techniques other approaches to lowering job supplier costs include:

1. Multi-well contracts to enable supplier and operator economies of scale as discussed below.
2. Bundled services which involves taking a larger range of service from a lesser number of suppliers to cut administration, enable multi-skilling and sharing overheads more widely.
3. Alliances are a similar means to a similar end with complimentary supplier companies providing a comprehensive service offering via a single contract to lower the clients' and suppliers' contract management costs and provide benefits as a result of shared resources, bulk buying, planning and operating efficiencies and expertise.
4. Contractor alliances to provide full suite of services.

Shared resources / campaign

Multi-well campaigns are a strategy for achieving economies of scale, technical operating efficiencies, and scheduling flexibility which can be applied by a single operator across single or multiple assets and by multiple operators working together.

These campaigns can be based on shared rig or vessel ‘clubs’ that have been negotiated at improved ‘multi-well’ economies of scale rates from the supply chain. These may include agreements to share the overall cost of weather downtime between members to even out seasonal fluctuations. Use of a well management provider can be considered as an appropriate means to ensure continuity of learning across the campaign and ongoing performance improvement.

Cost and schedule challenges

A challenge for many stimulated wells in the North Sea is to minimise the costs associated with waiting on the availability of a stimulation vessel. The planned versus actual days to drill a well can vary significantly and a window of flexibility is needed for the start and end dates for any stimulation operations. In most cases, a primary and secondary vessel is identified and operational planning is carried out for both. If schedule slippage beyond an agreed window, typically two weeks, cannot be further accommodated by the primary vessel due to prior commitments then the secondary vessel can be used.

New technology vs stimulation cost savings and added value

Reservoir characterisation

Lack of seismic resolution, reservoir complexity and low net to gross ratios are factors in many Southern North Sea reservoirs that constrain the ability to accurately locate and quantify gas reserves.

The effective use of stimulation requires adequately detailed input data in terms of: permeability; in situ stresses; rock strength; reservoir pressure; gas water contacts and structural, stratigraphic and intra-formation scale; planar and none planar barriers or connectivity enablers such as natural fracture networks.

Therefore any technology that allows the subsurface reservoir character to be more effectively and cost efficiently defined will potentially enable improvements in stimulation results.

SNS insight: A good recent SNS example is improved sub-salt seismic imaging through the Zechstein salts to map the poor net to gross channel sand systems of the Dinantian Carboniferous in Block 43 NE of the Crosgan, and Breagh Fields[5]. 'Dense, high quality seismic data interpretation, integrated with prestack inversion results, has resulted in a detailed understanding of the Dinantian play fairway and a comprehensive prospectivity analysis for new intra-Carboniferous play types. Successful recognition of significant, high value prospectivity has been validated by detailed prestack inversion analysis, which appears to be an essential part of the exploration workflow in the Lower Carboniferous play of the northern margin of the Southern North Sea's Silver Pit basin'.

Well construction and stimulation techniques

The value of horizontal drilling and completion technology has already been extensively discussed as a key enabler in delivering increased reservoir contact at reduced cost. Extended Reach Drilling (ERD) operates at the outer edge of this outwardly expanding envelope.

Stimulation technology[3 5] particularly multi-stage stimulation builds on the foundation of horizontal well technology to achieve even greater and more cost effective reservoir contact[8 19].

Significant advances have been made in the tools, techniques and services that provide data and allow evaluation, wellpath optimisation and well planning whilst drilling. These include services known variously as logging whilst drilling[20 21], seismic while drilling, geo-steering, real time pore pressure, fracture prediction, geo-mechanics and sampling whilst drilling[22].

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[19] Stewart, D.A, et al; Optimisation of Deep Carboniferous Exploration Well Drilling in the Southern North Sea; SPE 23121

[20] Schlumberger Oilfield Review, July 1992; Logging While Drilling: A Three Year Perspective

[21] Schlumberger Oilfield Review, Spring 2012, 24, no 1; Sonic Logging While Drilling – Shear Answers

[22] Villareal, S, et al; Sampling While Drilling: An Emerging Technology; SPE-159503-MS.

An important aspect in this area is the real time detection of natural fracture networks using a variety of techniques such as spurt loss, sonic imaging, and downhole torque analysis.

Advances in evaluation of stimulation treatments include micro-seismic, inflow chemical tracers, distributed temperature and distributed acoustic technologies.

Another key is an integrated multi-disciplinary approach to planning, execution, evaluation and full cycle subsequent optimisation of future wells[23].

The applicability and added value or cost savings achievable on each well or field development project varies and generalisation is difficult. Further what is considered new, versus existing technology, also depends on the starting reference point.

For discussion purposes, a 25 well vertical field development is proposed into SNS Carboniferous channel sands. A base line vertical well cost (item 1), indicative cost of wells based on different design scenarios (items 2 to 8) and the nominal reservoir added value index[24] are provided.

Item	Description	Wells Required	Cost Per Well (£m)	Well Costs Field Total (£m)	Reservoir Added Value Index Total
1	Vertical Well	25	13	325	100
2	Horizontal Wells	15	15	225	150
3	…plus: Advanced Seismic Image Resolution of Targets	10	15	150	175
4	…plus: Multi-Stage Frac Well (8 stage)	6	19	114	200
5	…plus: Geo-Steering (LWD, Seismic etc)	6	20	120	220
6	…plus: Micro-Seismic Evaluation	6	21	126	230
7	…plus: Natural Fracture Network Characterisation	5	21	105	240
8	…plus: Inflow Chemical Tracer Monitoring Fibre Optic DTS / DAS Monitoring	5	22	110	245

Table 2: Technology vs well and development cost and added value (Source: Exceed study, Appendix A)

The table seeks to illustrate how horizontal drilling and fracturing technology applied in the SNS would be expected to lower the well count required to develop and field and yield improved added value in terms of increased and accelerated reserve recovery. Data acquisition and evaluation techniques serve to further optimise the efficiency of well placement and stimulation treatments.

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[23] Hydraulic Fracturing Performance Evaluation in Tight Sand Gas Reservoirs with High Perm Streaks and Natural Fractures, Parvizi, Hadi; Rezaei-Gomari, Sina; Nabhani, Farhad; Turner, Andrea; Feng, Wei Cher, 2015, SPE-174338-MS.

[24] The ‘reservoir added value index’ is an indicative measure of potential additional reserves produced by the wells

The areas where opportunity for new subsurface or well technology exists to further increase the added value achieved by stimulation includes the following:

1. Reservoir characterisation

2. Stimulation evaluation technology

3. Well construction and stimulation execution

Appendix A

SNS stimulation well costs

Purpose

The following content is from a study on reservoir stimulation conducted for the OGA by Exceed in 2017.

A series of detailed time and cost models have been prepared in this section to provide an initial benchmark for different Southern North Sea wells in terms of stimulation and completion complexity, as below. Costs are based on 2016 assumptions and are subject to future market changes.

1. **Well Inclination types:** vertical, slant (60 degrees inclination), horizontal.
2. **Completion / stimulation types:** cemented and perforated, sand control stand alone screen, single & multi-stage hydraulically fractured.

Model and assumptions

Key assumptions made in preparing the time and cost models are as follows:

1. Reservoir target depth of 10,000 FT TVDSS assumed
2. Total depths for the vertical, slant (60 degrees inclination), and horizontal well (multi-frac.3 stages) of 10,355, 16,600, 17,200 FT MDBRT assumed
3. Additional multi-frac stages added to horizontal well as 500 FT increments for total depth
4. The times and costs quoted are AFE Class III (BCE)
5. Offshore team based on 1 x DSV, 1 x NDSV, 1 x WSDE, 1 x DMC, 1 x subsea supervisor
6. Onshore team based on 1 x project manager, 1 x SDE, 1 x DE, 1 x DMC, 1 x subsea supervisor
7. Times are based on most likely times (P50)
8. Exchange rate US $1.30/£
9. Rig rate US $65,000/Day
10. Fuel rate assumed as £325 / MT rate
11. Supply vessel £8,000/day (excluding fuel)
12. Standby vessel £5,000/day (excluding fuel)
13. Ad hoc supply vessels £10,000/day (excluding fuel) used for mob, 36" and demob.
14. Anchor handling vessels £20,000/day per boat.3 boats used (excluding fuel & no mob/ de-mob charges)

15. Service company prices are based on 2016/17 rates
16. Assumed equipment turnaround - 7 days, personnel turnaround - 4 days
17. Assumes supply base is Great Yarmouth for trucking
18. No LCM or specialised cement chemicals have been included
19. Helicopter assumed at £3,700 per hour, and 2 hour round trip, 4 times a week.
20. OBM waste disposal estimated at £50,000
21. Onshore and offshore geologist supply not included.
22. For mob assumes rig is on hire 50nm from location, tow speed 3.5knots, de-mob assumes rig is off hire upon exit from 500m zone
23. No allowance is made for waiting on weather.

Outline programme steps

Outline programme steps were developed for each option as below.

The data illustrates a range of well timings and costs based on current pricing. Well timings and costs vary from 64 days and £13 million for a vertical cemented and perforated well to 94 days and £20.5 million for a horizontal hydraulically fractured well with 14 stages. Well timings and cost for a horizontal hydraulically fractured well with 3 stages are 81.3 days and £17 million. The time and cost effective nature of multi-stage hydraulic fracturing is apparent with an increment of 1 day or £318k cost increment per additional 500ft reservoir section drilled, and hydraulic fracture stage added. It should be noted that a lower increment per stage would apply if closer than 500ft spacing was adopted. The model is based on a single bit run. A higher cost increment would be likely for longer well lengths reflecting use of multiple bit trips (a rig day per 2000ft), and slower rates of penetration as mechanical and hydraulic drilling efficiency is reduced. Typical Southern North Sea reservoir horizontal section lengths range from 1000-4000ft.

Vertical well

Vertical Well Case	
Drilling, Mob, De-Mob.	**Time (Days)**
Mobilise Rig	2.00
Drill 36" Hole	1.75
Run & Cement 30" Conductor	1.25
Drill 17-1/2" Hole	9.75
Run & Cement 13-3/8" Hole	6.00
Drill 12-1/4" Hole	9.75
Run & Cement 9-5/8" Casing	2.50
Drill 8-1/2" Hole	5.75
Run & Cement 7" Liner	1.50
Drill 6" Hole	4.00
Completion & Stim (Excluded see below)	
De-Mob Rig	3.75
Drilling, Mob, De-Mob.Total	**48.00**
Vertical Well Case	
Cement & Perforate Option	**Time (Days)**
Run & Cement 5" Liner	3.00
Well Bore Clean Up	2.00
Install Xmas Tree (1 plug)	4.00
Tubing Conveyed Perforating (Shoot & Pull)	2.00
Install Upper Completion	2.50
Flow to Clean Up Well	1.00
Recover Riser, Install Xmas Tree Cap, etc	2.00
Cement & Perforate Total	**16.50**
Well Total	**64.50**
Vertical Well Case	
Screens Option	**Time (Days)**
Install Screens	3.00
Well Bore Clean Up	2.00
Install Xmas Tree (2 plugs)	5.00
Install Upper Completion	2.50
Flow to Clean Up Well	1.00
Recover Riser, Install Xmas Tree Cap, etc	2.00
Screens Total	**15.50**
Well Total	**63.50**
Vertical Well Case	
Single Frac	**Time (Days)**
Run & Cement 5" Liner	3.00
Well Bore Clean Up	2.00
Install Xmas Tree (1 plug)	4.00
Tubing Conveyed Perforating (Shoot & Pull)	2.00
Install Upper Completion	2.50
Flow to Clean Up Well	1.00
Perform Single Stage Hydraulic Propped Frac	1.00
Clean Up Well with Coiled Tubing	3.00
Recover Riser, Install Xmas Tree Cap, etc	2.00
Single Frac Total	**20.50**
Well Total	**68.50**

Table 3: Vertical well outline programme

Slant well

Slant Well Case (60 deg. Inclination)	
Drilling, Mob, De-Mob.	**Time (Days)**
Mobilise Rig	2.00
Drill 36" Hole	1.75
Run & Cement 30" Conductor	1.25
Drill 17-1/2" Hole	9.75
Run & Cement 13-3/8" Hole	6.00
Drill 12-1/4" Hole	14.50
Run & Cement 9-5/8" Casing	3.00
Drill 8-1/2" Hole	8.50
Run & Cement 7" Liner	2.00
Drill 6" Hole	5.50
Completion & Stim (Excluded see below)	
De-Mob Rig	3.75
Drilling, Mob, De-Mob.Total	**58.00**
Slant Well Case (60 deg. Inclination)	
Cement & Perforate Option	**Time (Days)**
Run & Cement 5" Liner	3.50
Well Bore Clean Up	2.75
Install Xmas Tree (1 plug)	4.00
Tubing Conveyed Perforating (Shoot & Pull)	2.50
Install Upper Completion	2.75
Flow to Clean Up Well	1.00
Recover Riser, Install Xmas Tree Cap, etc	2.00
Cement & Perforate Total	**18.50**
Well Total	**76.50**
Slant Well Case (60 deg. Inclination)	
Screens Option	**Time (Days)**
Install Screens	3.75
Well Bore Clean Up	2.75
Install Xmas Tree (2 plugs)	5.00
Install Upper Completion	2.75
Flow to Clean Up Well	1.00
Recover Riser, Install Xmas Tree Cap, etc	2.00
Screens Total	**17.25**
Well Total	**75.25**
Slant Well Case (60 deg. Inclination)	
Single Frac	**Time (Days)**
Run & Cement 5" Liner	3.50
Well Bore Clean Up	2.75
Install Xmas Tree (1 plug)	4.00
Tubing Conveyed Perforating (Shoot & Pull)	2.50
Install Upper Completion	2.75
Flow to Clean Up Well	1.00
Perform Single Stage Hydraulic Propped Frac	1.25
Clean Up Well with Coiled Tubing	3.50
Recover Riser, Install Xmas Tree Cap, etc	2.00
Single Frac Total	**23.25**
Well Total	**81.25**
Slant Well Case (60 deg. Inclination)	
Multi-Frac	**Time (Days)**
Run Open Hole Lower Completion with Ball Drop Frac Sleeves & Annular Swell Packers	3.50
Well Bore Clean Up	2.75
Install Xmas Tree (2 plugs)	5.00
Install Upper Completion	2.75
Flow to Clean Up Well	1.00
Perform Multi-Stage Hydraulic Propped Frac (2 Stages)	1.25
Clean Up Well with Coiled Tubing	4.00
Recover Riser, Install Xmas Tree Cap, etc	2.00
Multi-Stage Frac Total	**22.25**
Well Total	**80.25**

Table 4: Slant well outline programme

Horizontal well

Horizontal Well Case	
Drilling, Mob, De-Mob.	**Time (Days)**
Mobilise Rig	2.00
Drill 36" Hole	1.75
Run & Cement 30" Conductor	1.25
Drill 17-1/2" Hole	9.75
Run & Cement 13-3/8" Hole	6.00
Drill 12-1/4" Hole	14.50
Run & Cement 9-5/8" Casing	3.00
Drill 8-1/2" Hole	8.50
Run & Cement 7" Liner	2.00
Drill 6" Hole	6.00
Completion & Stim (Excluded see below)	
De-Mob Rig	3.75
Drilling, Mob, De-Mob.Total	**58.50**
Horizontal Well Case	
Cement & Perforate Option	**Time (Days)**
Run & Cement 5" Liner	3.75
Well Bore Clean Up	2.75
Install Xmas Tree (1 plug)	4.00
Tubing Conveyed Perforating (Shoot & Pull)	2.75
Install Upper Completion	2.75
Flow to Clean Up Well	1.00
Recover Riser, Install Xmas Tree Cap, etc	2.00
Cement & Perforate Total	**19.00**
Well Total	**77.50**
Horizontal Well Case	
Screens Option	**Time (Days)**
Install Screens	4.00
Well Bore Clean Up	2.75
Install Xmas Tree (2 plugs)	5.00
Install Upper Completion	2.75
Flow to Clean Up Well	1.00
Recover Riser, Install Xmas Tree Cap, etc	2.00
Screens Total	**17.50**
Well Total	**76.00**
Horizontal Well Case	
Single Frac	**Time (Days)**
Run & Cement 5" Liner	3.75
Well Bore Clean Up	2.75
Install Xmas Tree (1 plug)	4.00
Tubing Conveyed Perforating (Shoot & Pull)	2.75
Install Upper Completion	2.75
Flow to Clean Up Well	1.00
Perform Single Stage Hydraulic Propped Frac	1.25
Clean Up Well with Coiled Tubing	3.50
Recover Riser, Install Xmas Tree Cap, etc	2.00
Single Frac Total	**23.75**
Well Total	**82.25**
Horizontal Well Case	
Multi-Frac (3 Stages)	**Time (Days)**
Run Open Hole Lower Completion with Ball Drop Frac Sleeves & Annular Swell Packers	3.75
Well Bore Clean Up	2.75
Install Xmas Tree (2 plugs)	5.00
Install Upper Completion	2.75
Flow to Clean Up Well	1.00
Perform Multi-Stage Hydraulic Propped Frac (3 Stages)	1.50
Clean Up Well with Coiled Tubing	4.00
Recover Riser, Install Xmas Tree Cap, etc	2.00
Multi-Stage Frac Total	**22.75**
Well Total	**81.25**

Table 5: Horizontal well outline programme

Timings summary

Well Type	Well Type	Drill, Mob, Demob (days)	Complete / Stimulation (days)	Well Total (days)
Cement & Perforate Vertical	Vertical	48.0	16.5	64.5
Screens Vertical	Vertical	48.0	15.5	63.5
Single Stage Frac Vertical	Vertical	48.0	20.5	68.5
Cement & Perforate Slant	Slant	58.0	18.5	76.5
Screens Slant	Slant	58.0	17.3	75.3
Single Stage Frac Slant	Slant	58.0	23.3	81.3
Multi-Stage Frac Slant (2 Stage)	Slant	58.0	22.3	80.3
Cement & Perforate Horizontal	Horizontal	58.5	19.0	77.5
Screens Horizontal	Horizontal	58.5	17.5	76.0
Single Stage Frac Horizontal	Horizontal	58.5	23.8	82.3
Multi-Stage Frac Horizontal (3 Stage)	Horizontal	58.5	22.8	81.3
Multi-Stage Frac Horizontal (4 Stage)	Horizontal	59.3	23.2	82.5
Multi-Stage Frac Horizontal (5 Stage)	Horizontal	60.0	23.6	83.6
Multi-Stage Frac Horizontal (6 Stage)	Horizontal	60.8	24.0	84.8
Multi-Stage Frac Horizontal (7 Stage)	Horizontal	61.5	24.4	85.9
Multi-Stage Frac Horizontal (8 Stage)	Horizontal	62.3	24.8	87.1
Multi-Stage Frac Horizontal (9 Stage)	Horizontal	63.0	25.2	88.2
Multi-Stage Frac Horizontal (10 Stage)	Horizontal	63.8	25.6	89.4
Multi-Stage Frac Horizontal (11 Stage)	Horizontal	64.5	26.0	90.5
Multi-Stage Frac Horizontal (12 Stage)	Horizontal	65.3	26.4	91.7
Multi-Stage Frac Horizontal (13 Stage)	Horizontal	66.0	26.8	92.8
Multi-Stage Frac Horizontal (14 Stage)	Horizontal	66.8	27.2	94.0

Table 6: Well timings summary

Cost summary

Well Type	Well Type	Drill, Mob, Demob Cost (£)	Complete / Stimulation Cost (£)	Well Total Cost (£)
Cement & Perforate Vertical	Vertical	9,568,771	3,731,448	13,300,219
Screens Vertical	Vertical	9,568,771	3,768,791	13,337,562
Single Stage Frac Vertical	Vertical	9,568,771	4,790,717	14,359,488
Cement & Perforate Slant	Slant	11,097,564	4,400,147	15,497,711
Screens Slant	Slant	11,097,564	4,304,460	15,402,024
Single Stage Frac Slant	Slant	11,097,564	5,723,435	16,820,999
Multi-Stage Frac Slant (2 Stage)	Slant	11,097,564	5,635,822	16,733,386
Cement & Perforate Horizontal	Horizontal	11,180,613	4,673,468	15,854,081
Screens Horizontal	Horizontal	11,180,613	4,514,367	15,694,979
Single Stage Frac Horizontal	Horizontal	11,180,613	6,005,669	17,186,281
Multi-Stage Frac Horizontal (3 Stage)	Horizontal	11,180,613	5,991,202	17,033,315
Multi-Stage Frac Horizontal (4 Stage)	Horizontal	11,267,613	6,222,202	17,351,315
Multi-Stage Frac Horizontal (5 Stage)	Horizontal	11,354,613	6,453,202	17,669,315
Multi-Stage Frac Horizontal (6 Stage)	Horizontal	11,441,613	6,684,202	17,987,315
Multi-Stage Frac Horizontal (7 Stage)	Horizontal	11,528,613	6,915,202	18,305,315
Multi-Stage Frac Horizontal (8 Stage)	Horizontal	11,615,613	7,146,202	18,623,315
Multi-Stage Frac Horizontal (9 Stage)	Horizontal	11,702,613	7,377,202	18,941,315
Multi-Stage Frac Horizontal (10 Stage)	Horizontal	11,789,613	7,608,202	19,259,315
Multi-Stage Frac Horizontal (11 Stage)	Horizontal	11,876,613	7,839,202	19,577,315
Multi-Stage Frac Horizontal (12 Stage)	Horizontal	11,963,613	8,070,202	19,895,315
Multi-Stage Frac Horizontal (13 Stage)	Horizontal	12,050,613	8,301,202	20,213,315
Multi-Stage Frac Horizontal (14 Stage)	Horizontal	12,137,613	8,532,202	20,531,315

Table 7: Well cost summary

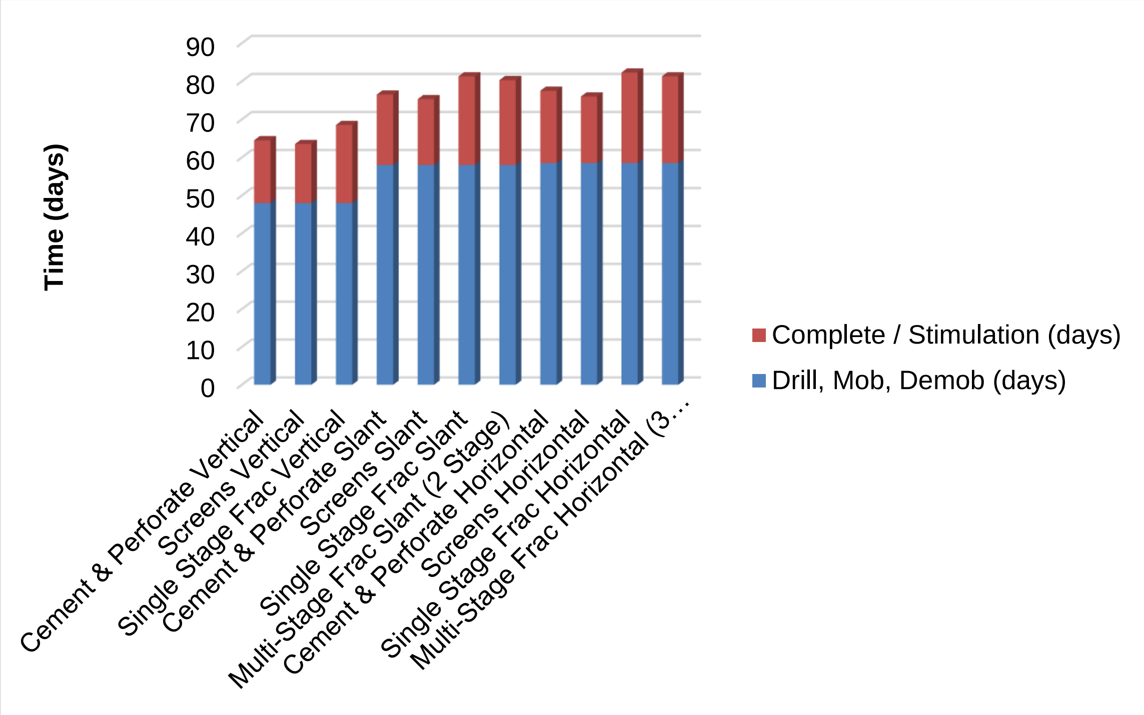

Figure 20: Well timings

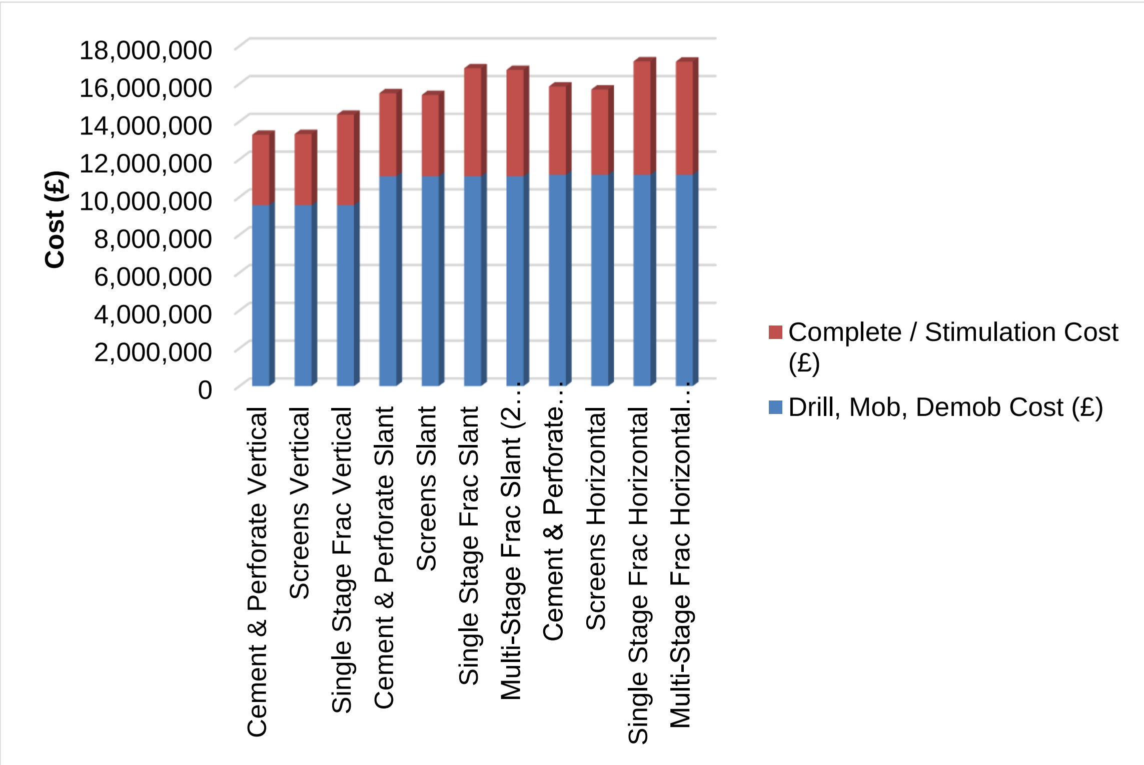

Figure 21: Well costs

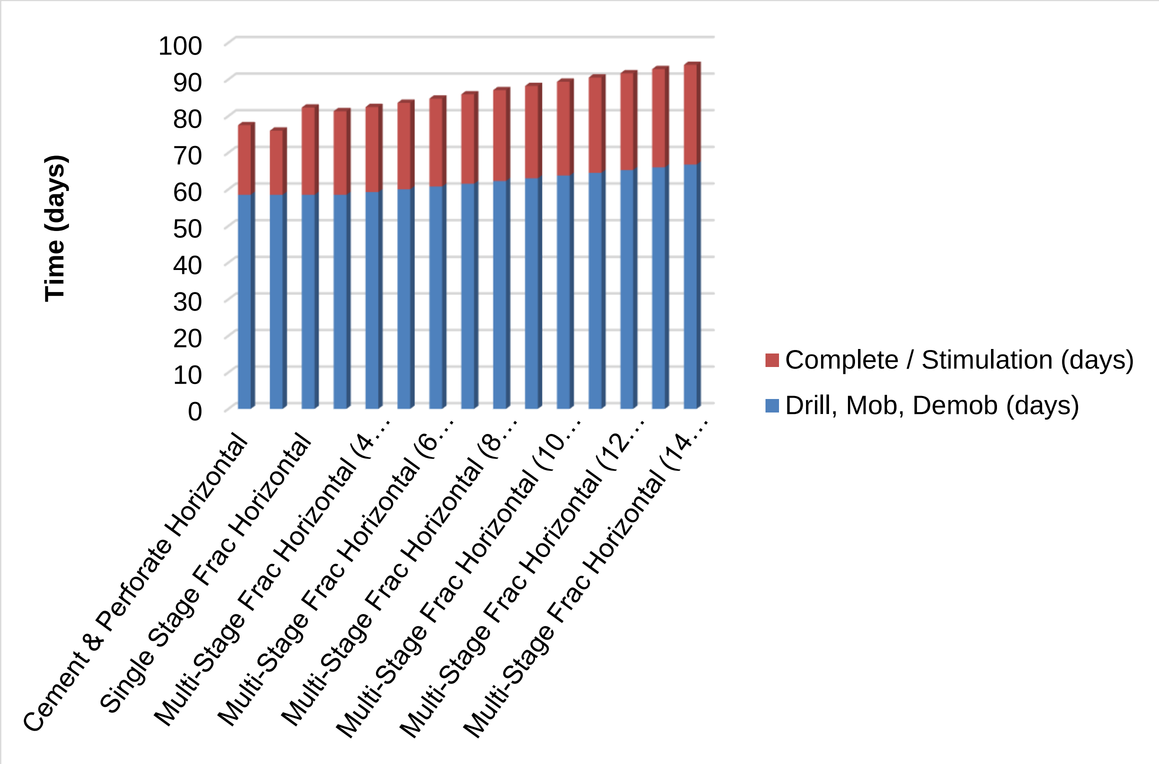

Figure 22: Horizontal well timings

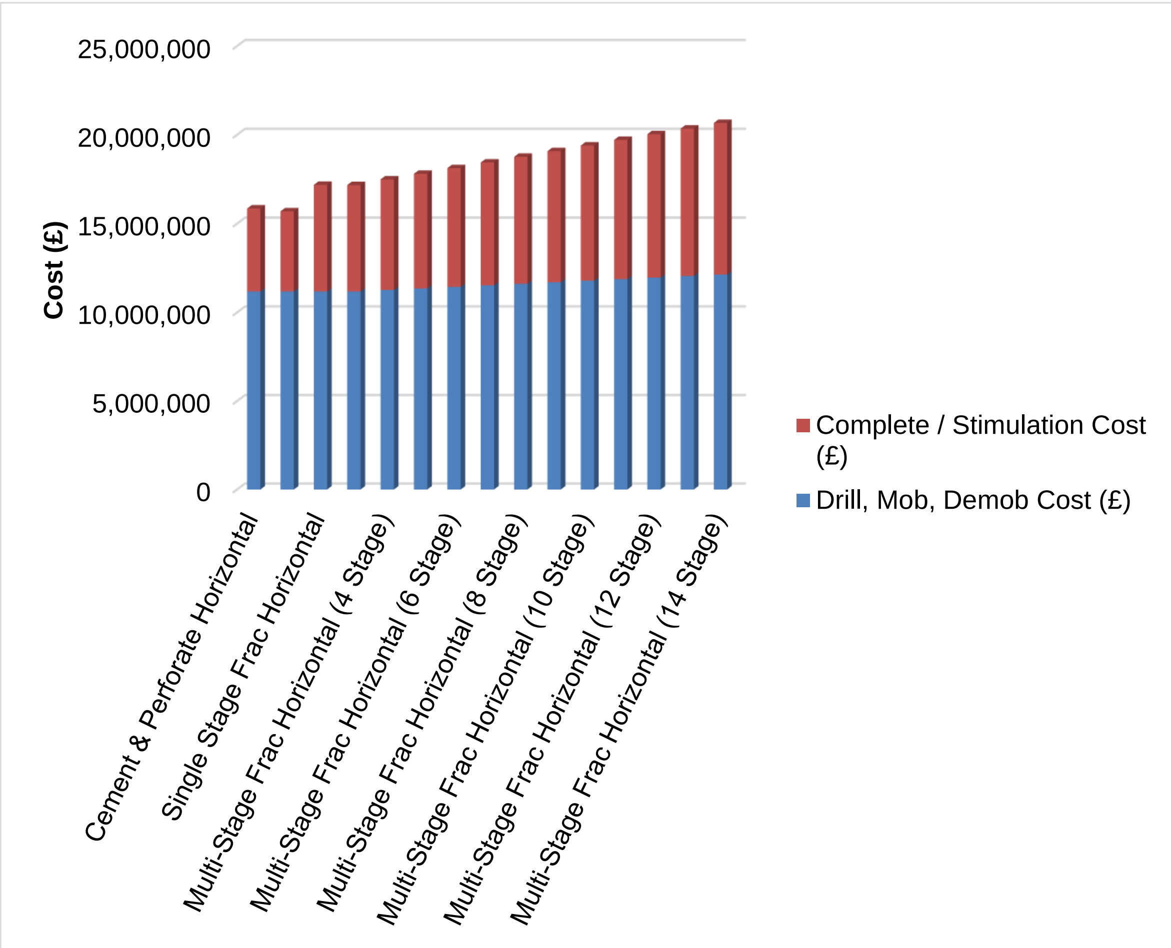

Figure 23: Horizontal well costs

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