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Review of Recent Unconventional Completion Innovations and their Applicability to EGS Wells

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ABSTRACT

About a decade ago the technology breakthroughs of horizontal drilling and multi-stage hydraulic fracturing allowed the oil and gas industry to economically access major undeveloped resources. Many operators have now moved into a well manufacturing phase to develop these resources. Whilst often less publicized, the cumulative effect from countless novel technologies and process optimizations has resulted in dramatically reduced break-even costs.

This paper provides a structured review and evaluation of technology innovations and operational learnings with a focus on the last 5 years. Examples of reviewed technologies with potential for future enhanced geothermal system (EGS) wells are downhole completion tools made of dissolvable metals and polymers. These materials have the potential to reduce stimulation time and costs. Furthermore, changes in perforating design, advanced diversion tools and micro proppants have resulted in significant increases in the stimulated rock volume of shale wells. In regards to operational learnings, the paper evaluates amongst others the applicability of zipper frac operations in EGS projects. Leveraging these technologies for future EGS wells could enable the geothermal industry to dramatically improve project economics.

1. INTRODUCTION

Various studies and papers have described the advantages of creating Enhanced Geothermal Systems (EGS) by performing multistage stimulation of the rock between a lateral injector and producer pair (McClure et al, 2014, Meier et al, 2015). In order to achieve successful multistage stimulation in a horizontal well, additional technologies need to be introduced beyond what has been applied on previous EGS projects. The breakthroughs made in shale oil and gas production by moving from vertical wells to horizontal multistage wells have been well publicized and described. This paper focuses on the countless innovations and results of continuous improvement efforts that led to break-even prices for shale oil and gas wells dropping by more than 50 percent since 2013 (Mlada, 2017). At a time where potential horizontal EGS wells are still in the planning phase, capturing the applicable learnings from shale oil and gas operations can be an opportunity to accelerate EGS technology.

This paper reviews state of the art unconventional completion equipment, stimulation design, as well as surface operations learnings. It will then evaluate the feasibility of these shale technologies for application in horizontal multistage EGS wells. The significant reduction in break-even prices seen in unconventional oil and gas projects can be tied to two interlocked developments;

1) Reduction of costs through continuous improvement and increase in operational efficiency

2) Dramatic increase in well productivity by an increase in stimulation intensity and simulation design optimization

This paper looks at these breakthroughs in three distinct areas:

- Multistage Technologies

- Stimulation Design Optimization

- Stimulation Operations Learnings

2. WELLBORE PARAMETERS

In order to evaluate stimulation equipment and processes for their applicability, a sample horizontal EGS well design had to be assumed. After reviewing designs and geological settings of existing EGS wells and planned pilot projects, a well with the following parameters was designed.

The lateral wellbore is placed at a depth of 4000 meter Total Vertical Depth (TVD) and has a length of 2000 meters, which is an average lateral length for an unconventional oil and gas well. The well has a 9 ⅝” production casing in the vertical section from surface to the kick off point. The curve and horizontal section feature an 8 ½” hole size and 5 ½” liner. Larger liner sizes are possible, however, 5 ½” is the most common size for horizontal oil and gas equipment allowing to benefit from the economies of scale and eliminating need for custom designs. By placing the liner hanger at the kick off point for the horizontal section, pressure drop in the vertical part of the wellbore is minimized. Depending on the stimulation and completion strategy, the lateral will either feature cement for annular isolation or external isolation packers.

In order to evaluate downhole equipment and service tools for temperature loads, a commercial well design software package was used to simulate wellbore temperature changes during and after stimulation. A reservoir temperature of 200 degrees Celsius and a static geothermal gradient from ambient surface to reservoir temperature were assumed. Lithology for the first 350 meters is shale and then granite. After a literature review, specific heat capacity and heat conductivity for granite were set at 1000 J/(KgK) and 2.8 W/(mK), respectively. Because of the range of values documented for granite, a sensitivity analysis for the respective high and low values was performed. The resulting differences in post injection temperatures were less than 10 degrees Celsius.

Multiple runs for injections of up to 12 hours followed by a 5-hour shut in period were simulated. The temperature profiles generated for this were then used during evaluating of stimulation equipment and strategies. Figure 1 shows temperature profiles for multiple injection rates at the end of a 10-hour injection period and after a 5-hour post-stimulation shut in period. The simulation presents the case for the first stage of a stimulation sequence. The wellbore temperatures for sequential stimulation stages would be even colder, since the pre-injection temperature would be lower. The sudden change in temperature at 3900 meter depth is a transient effect during the early phases of heat up and is due to the change in wellbore capacity between the 9 5/8” casing and the 5 ½” liner.

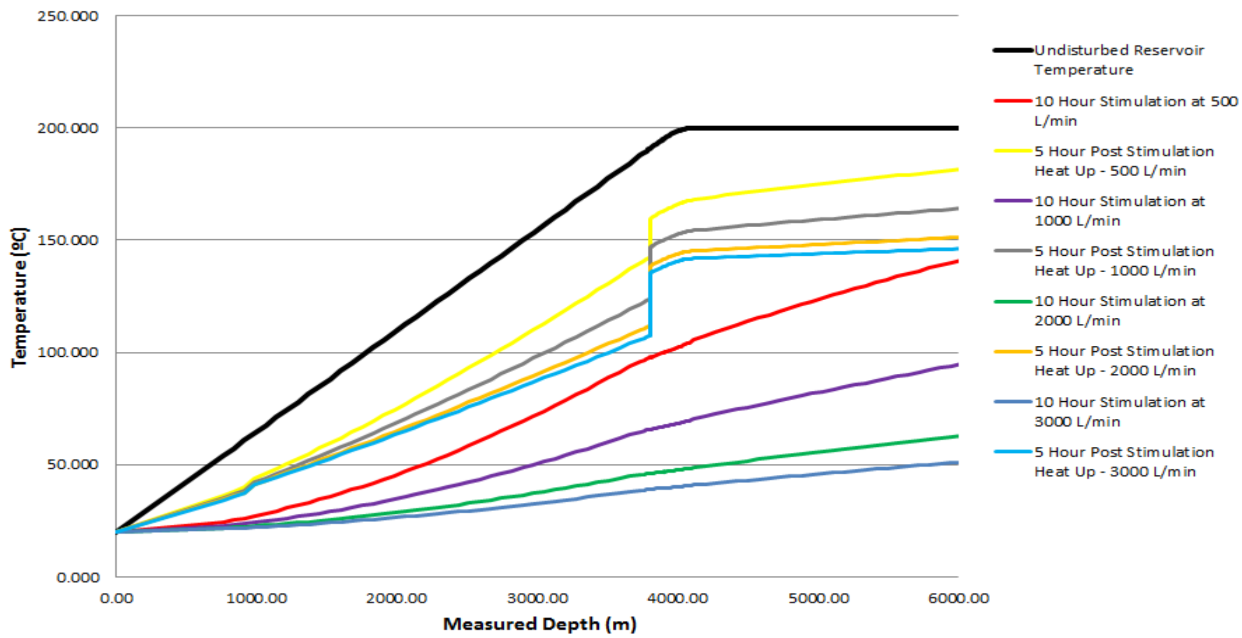

Figure 1: Wellbore temperature as a function of depth for various stimulation and heat up scenarios

3. MULTISTAGE TECHNOLOGIES

The category of multistage technologies includes all mechanical tools and processes that are utilized to isolate between stages/zones along a horizontal well. The two main multistage well technology approaches used are plug and perf completions and sliding sleeve systems.

3.1 Plug and Perf Completions

Plug and perf completion is a methodology where isolation between stages is achieved by setting bridge plugs inside the horizontal liner. Plugs used for hydraulic stimulation can either be designed as solid body tools that provide fullbore isolation after installation or plugs with a hollow body that incorporates a ball seat. For the latter design full isolation is achieved when a ball that is pumped downhole from surface lands in the ball seat of the plug. This variant of plugs is often called frac plugs and provides operational advantages, like the capability to flow back from multiple zones prior to drilling out the plugs.

In plug and perf completions, injection into the rock is established by perforating the cemented or uncemented liner. The most common and cost effective process for installing the bridge plug and perforating the liner is to utilize wireline. In order to move the wireline tools into the horizontal section of the wellbore, fluid is continuously injected from surface (Blanton et al., 2006). The pressure differential across the wireline bottom hole assembly (BHA) generates a force that pushes the tools down the lateral. This process is called pump down. Plugs and guns can also be transported on coiled tubing or a conventional tubing string, but the cost and time required for these methods result in them rarely being used. In horizontal oil and gas wells, plug and perf is mostly combined with a cemented annulus, but this methodology has and can be applied in both cemented or uncemented wellbores.

3.1.1 Perforating Strategies

Whereas most other technologies result in one stimulation initiation point per stage, when plug and perf is combined with a cemented annulus, multiple perforation clusters can be placed. By stimulating more than one cluster of entry holes per stage, economies of scale are created that can increase the number of stimulated zones per well at low overall cost. For average shale wells a plug and perf stage consists of between 3 to 10 perforation clusters, with each perforation cluster having between 4 to 15 entry holes.

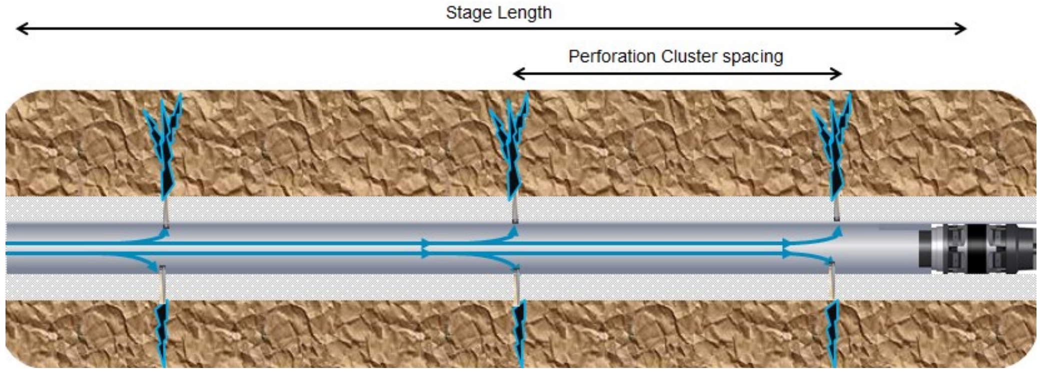

Figure 2: Cemented Plug and Perf Schematic with 3 Perforation Clusters

The most common approach to achieve consistent stimulation of all perforation clusters in a stage is Limited Entry Design (LED). This design approach manages the pressure drop per perforation cluster in an attempt to equalize the flow rate through each of the clusters (Bellarby, 2009, Cramer, 1987).

The following equation describes the perforation pressure drop of a stage:

$$\Delta P = \mathrm{Q}^2 \frac{8\rho}{\pi^2 \ N^2 D^4 C^2} \tag{1}$$

Where, ΔP, ρ, N, D, C are perforation pressure drop, fluid density, number of perforations per stage, perforation diameter and discharge coefficient of the perforations, respectively.

A standard target pressure drop for a plug and perf LED in a horizontal oil and gas well is 6,500 to 7,000 kPa. On a stage level, uncertainties exist in regards to the exact values for C and D, but microseismic data and isotope tracer logs have shown good diversion effectiveness when designing for this pressure drop range. The applicability of this technology for EGS would largely depend on the planned stimulation rates and the expected differences in stimulation pressures across a stage.

Another difference between oil and gas completions and a potential EGS development well is that in oil and gas wells, the injection rate during stimulation is significantly higher than the rate through the perforations during production of oil, gas and water. Therefore, pressure drop across the perforations is not a major concern during the production phase. In an EGS injector well the pressure drop could increase injection pressures unnecessarily. At the same time, a perforation pressure drop in an EGS injector well could provide a means to achieve better injection diversion and counter the risk of preferential injection into one cluster. The impacts erosion and potential scale could have on perforation pressure drop during long term injection would have to be further studied.

If LED is not utilized as part of the stimulation design, or if post stimulation diagnostics show that limited entry is ineffective, diverters are regularly used to improve cluster efficiency in unconventional oil and gas wells. Multiple diversion techniques are available (Van Domelen, 2017). Most common is the use of thermally degradable fibers and particles. This technology has already been successfully applied on geothermal wells (Cladouhos et al., 2015) and therefore will not be further evaluated as part of this paper.

Two additional technologies are regularly used for stimulation diversion: ball sealers and perforation pods. Ball sealers are balls made from degradable or non-degradable polymers. They are dropped from surface during stimulation operations, land in perforations that are actively taking fluid and shut them off. Degradable ball sealers (Erbstoesser et al., 1988) degrade based on downhole temperature and reestablish flow through the perforation. Non degradable ball sealers fall off once the pressure differential has stopped and can be recovered as part of the plug drill out. A major issue with ball sealers is that they are inefficient in irregular sized perforations. Also, degradable ball sealers have limited differential pressure ratings.

A more recently introduced diversion method is perforation pods. These are pod shaped knots made of dissolvable fiber and are designed to plug off perforations in a cemented or uncemented wellbore. Their advantage over ball sealers is that whereas ball sealers are losing effectiveness in holes that are not round, perforation pods get squeezed into any shape of perforation. Currently available perforation pods are only effective up to temperatures of 140 degrees Celsius. However, as the wellbore temperature modeling showed, if pumped as part of a continuous injection stimulation treatment, cool down would still make their use possible in a 200 degree Celsius reservoir. Due to their recent introduction to the market, little published data is available for perforation pods, but they appear to be another viable way to divert between perforation clusters (Senters et al., 2018). Effectiveness of all diversion strategies depends on well circumstances, and especially given the differences between EGS and oil and gas reservoirs, trials would need to be accompanied by diagnostics to determine the optimum diversion strategy.

3.1.2 Bridge Plug Options

The most common plug types are composite bridge plugs (CBP). These are plugs mostly made of composite material and have very short drill times when they are removed from the wellbore after all zones in a well have been stimulated. Continuous improvement of composite bridge plug designs has resulted in reduction of the amount of composite material, leading to shorter and shorter drill out times. Composite plugs are currently available for temperature ratings up to 205 degrees Celsius. With wellbore cool down due to fluid injection as calculated earlier, composite plugs could be used for EGS reservoirs with temperatures up to approximately 230 degrees Celsius.

Beyond CBP's, there are also cast iron and aluminum plugs available that are rated at even higher temperatures and rated for longer duration isolation. Nevertheless, these are rarely used in unconventional oil and gas wells due to the longer time they take to drill out at the end of the stimulation process. The metal debris they generate is also hard to lift out of long horizontal wells. Once all stages have been completed, plugs are usually drilled out either with coiled tubing or with a hydraulic workover unit. Average plug drill out times for composite plugs are between 5-20 minutes depending on plug and mill design, allowing for efficient drill out operations.

Drill out times for frac plugs have decreased considerably in recent years. However, even with these improvements, this post-stimulation intervention still adds considerable cost and time to the well construction process. This is especially true for areas with a less developed oil and gas service infrastructure. In recent years, alternative frac plug designs have been developed to eliminate the drill out process. These plugs are also often used in extended reach laterals where clean out operations become more difficult.

Dissolvable plugs are built with materials that dissolve through temperature degradation and/or rapid corrosion upon reaction with the wellbore fluid. Multiple manufacturers offer dissolvable plugs, but there are two main material categories that plugs are made of; degradable polymers and degradable metals, in most cases magnesium or aluminum alloys (Fripp et al., 2016). Degradable polymer plugs have very good degradation properties, but are limited by their working temperature range from 80 degrees Celsius to approximately 130 degrees Celsius. At temperatures below this range, the polymer will degrade very slowly. At temperatures above this range there is the risk of the plugs losing integrity during the stimulation operation. Magnesium or aluminum alloy based plugs can be used in colder and hotter temperature reservoirs than polymer based plugs. Dissolvable metal plugs are currently rated up to 175 degrees Celsius, and given cool down and pump down operations, this means that they are options for geothermal zonal isolation. Many of the higher temperature alloys require salinity to dissolve. Therefore before any application in an EGS well, dissolution testing with formation brine must be performed.

Another plug type, big bore plugs, are bridge plugs with a large internal diameter (ID) that provides close to full internal wellbore diameter after dissolution of the ball (Allen et al., 2014). These plugs are designed to have a very slim walled body and a large internal bore. Isolation to the previous stage is achieved when a large diameter dissolvable metal ball lands in the plug. The dissolvable balls will degrade within days to weeks and only the large ID plug will remain in the wellbore. Currently available plug designs have temperature ratings of up to 225 degrees Celsius, which when accounting for dynamic cool down, opens up reservoirs with static temperatures of more than 250 degrees Celsius. A downside is that this technology leaves a permanent wellbore restriction behind, reducing the ID of the liner by about 25 mm. Since the plug itself contains steel, drilling out the plug to reestablish full wellbore diameter would be slow and costly.

3.2 Sliding Sleeve Systems

Sliding sleeve completions are systems where a sleeve is shifted open by various methods to establish injection into the reservoir. Actuation of the sleeve can be achieved by landing balls in a ball seat, by applying force to the sleeve via a service tool or a sleeve internal power source, like a battery.

3.2.2 Ball Activated Sleeve Systems

The most popular sleeve systems are ball-activated sleeves (BAS). In these systems, sleeves with gradually increasing ball seat diameters are installed in a wellbore starting at the deepest injection point. During stimulation operations, the respective ball is dropped from surface to open a specific sleeve. Once the ball lands in the sleeve ball seat, pressure builds up upstream of the seat until the hydraulic force overcomes the shear pins that prevent the sleeve from shifting. Maximum stage count for the above described ball drop system is more than 60 stages for open hole completions with annular isolation packers between stages, and about 30 stages for cemented systems. The lower stage count for cemented systems is due to the larger ID requirements for cementing the liner. The balls that activate the sleeves are in most cases dissolvable metal balls that dissolve within days or weeks after the stimulation, depending on water salinity and temperature. Once the balls have dissolved, full connection to all zones of the wellbore has been reestablished.

BAS systems are the highest efficiency multistage stimulation technology available. However, they have lost significant market share to plug and perf completions due to their stage count limitations at a time when stimulation intensity is increasing significantly across all shale plays. They are still a popular choice when less than 60 individually stimulated zones are targeted or where less oil and gas service infrastructure is available. One of the advantages of sleeve systems is that they do not require a drill out operation post stimulation. At the same time, that means the ball seats in the completion will create ID restrictions. If a full ID wellbore is required, the ball seats can be drilled out. Ball seat drill-out times are comparable to composite frac plug drill times.

3.2.3 Coiled Tubing Activated Sleeves

A technology that eliminates the lack of a full ID wellbore and the stage count limitations associated with ball activated sleeve systems are coiled tubing activated sleeves (CTAS). This technology has been increasing in popularity over the last 5 years. The sleeves are installed as part of the liner running process and cause no or only minor wellbore ID restrictions. During the stimulation process, these sleeves are shifted with a shifting tool that is run on coiled tubing. This shifting tool allows to selectively shift sleeves, pump a stimulation treatment down the coiled tubing annulus and move on to the next stage. Some of the sleeve designs have the option to close the sleeve again post stimulation, allowing to stimulate or test zones in the lateral in any sequence. This provides considerably more flexibility than the other completion techniques described. All these operations can be done without requiring a trip to surface.

The CTAS method also provides additional downhole data acquisition options. The coiled tubing acts as a static fluid column during stimulation and can therefore be used to gather real time bottom hole treatment pressures. Additionally, these tools can be run with memory sensors to record temperatures and pressures above and below the sleeve during treatment (Gustavo et al., 2018). The main argument against this completion methodology for development phase oil and gas wells is the additional daily cost that comes with the requirement for a coiled tubing unit in addition to stimulation equipment.

3.3 Annular Isolation

With the exception of limited entry plug and perf, all completion technologies presented can be applied to uncemented or cemented laterals. Due to the negative impact inefficient annular isolation can have on stimulation efficiency, considerable focus needs to be put on annular isolation optimization.

In multistage open hole laterals, annular isolation is achieved by installing open hole packers between stages. In unconventional oil and gas wells, this is done with either swell packers or mechanical packers. Swell packers are joints of pipe wrapped with swellable polymers that react with the wellbore fluid and create an annular seal. Depending on the swellable polymer, the elements either react with water or hydrocarbons. The mechanical open hole packers utilized in horizontal multistage completions are derived from cased hole packer models and designs exist for bottom hole temperatures up to 315 degrees Celsius.

A major concern with both types of packers is isolation efficiency, especially in light of wellbore break-outs or wash-outs. Post-frac diagnostics data from high pressure and high temperature applications in horizontal oil and gas wells regularly show lack of annular isolation (Briner et al., 2016). Explanations that have been provided are insufficient isolation due to washouts or breakouts, longitudinal fracture growth along the wellbore, shrinking off the swell packer OD due to cool down (Evers, et al., 2008), divalent ions preventing packer polymers from swelling (Al-Yami et al., 2008) or initiation of fractures by the forces that apply to the wellbore wall during setting of mechanical packers. Furthermore, location and number of stimulated zones cannot be controlled in open hole completions. Figure 3 shows an example of an open hole sliding sleeve completion with unknown location and number of stimulated zones.

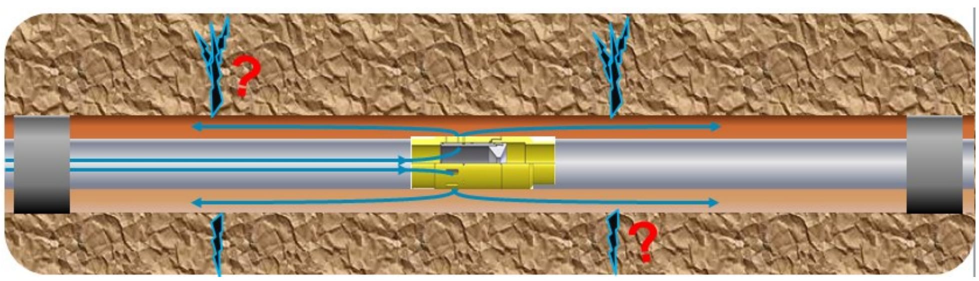

Figure 3: Sliding Sleeve System with Open Hole Annular Packers

Advanced open hole packers are an oil and gas technology that provides higher expansion ratios and can potentially seal off breakouts and washouts better than conventional mechanical or swell packers. They are generally not used in onshore unconventional horizontal wells due to the higher costs, but have successfully provided long term isolation in offshore water injector wells, where zonal isolation is critical to well success (Bardsen et al., 2014). Multiple designs are available. Whilst they are not used in unconventional oil and gas wells they might have applications in EGS wells. The specific designs are not further evaluated in this paper, but the respective vendors are listed in the vendor directory provided.

4. STIMULATION DESIGN OPTIMIZATION

A major trend over the last 5 years has been an increase in intensity of stimulation treatments and a focus on creating a large stimulated reservoir network instead of creating high conductivity discrete fractures. This objective is considerably closer to the stimulation requirements for an EGS reservoir than previous oil and gas stimulation strategies. This change in stimulation objective resulted in changes to the optimum number of stages or entry points, fluid design, proppant design and treatment rates.

4.1 Fluid Design

Whereas many early unconventional wells had at least parts of the stimulation treatment with highly viscous fluids and high proppant concentrations, the change in focus to generating large fracture networks resulted in most modern wells utilizing slickwater stimulation designs. The objective of a slickwater frac is to create a large network of primary and secondary fractures (Pearson et al., 2013). A means for this is to inject high volumes of low viscosity fluids at low average proppant concentrations. Besides improved reservoir contact, slickwater fluid systems also dramatically simplify the number and volumes of additives required. The primary additive of a slickwater frac is polyacrylamide friction reducers at low concentrations. Friction reducers reduce pipe friction during treatment by 70-

80% over fresh water by suppressing turbulences in the casing and liner (Zhi-yu et al., 2017). Additionally, slickwater systems are less sensitive to lower quality waters, allowing the use of non-freshwater sources for stimulation.

4.2 Proppant Design

The change in fracture geometry also impacts proppant size selection. The previous design philosophy of high permeability primary fractures led to the use of larger intermediate strength ceramic proppant (20/40 or 30/50 mesh size). The larger-sized proppants provided good fracture conductivity but at the same time limited proppant transport into secondary fractures. However since the major objective of a slickwater frac is to initiate a large connected fracture network, proppant design had to be adjusted accordingly. Current slickwater designs mostly focus on 40/70 and 100 mesh proppant. Again, this will result in lower conductivity of a single fracture, but the smaller proppant can enter secondary fractures and create a larger propped fracture network.

Proppant testing shows that for the effective stresses encountered in shale reservoirs, intermediate strength ceramic proppants are the optimum solution. However, the production uplift in oil and gas wells with ceramic proppants has not provided the rate of return required to improve economics over wells with natural sand. This resulted in sand being the predominant proppant in all North American shale plays.

In recent years, micro proppants have been introduced as a tool to further improve propping of micro-fractures (Dahl et al., 2015). Micro proppants are defined as proppants with mean particle sizes smaller than traditional 100 mesh proppant (0.149mm). Initial production data has shown improved productivity for oil and gas wells with micro proppant as part of the stimulation process, but data is still limited. Similar to the application of 100 mesh size proppant, the capability to enhance the conductivity of micro-fractures without creating pathways with high conductivity could be of value for future EGS wells.

5. STIMULATION OPERATIONS LEARNINGS

The main focus of operations improvements and innovations in shale stimulation has been related to time reduction, cost savings, improvements to employee safety and reduction of environmental impact.

5.1 Zipper Operations

A key improvement that also supported the increase in market share of plug and perf completions over sleeve completions has been the introduction of zipper fracs. During zipper frac operations, a wireline unit sets a plug and perforates a stage on one well while stimulating a neighboring well. Therefore, nearly continuous stimulation operations are possible. This increases utilization of stimulation equipment during plug and perf operations, which was previously one of the key disadvantages of plug and perf when compared with ball activated sliding sleeve completions. Studies of the effect of zipper fracture operations on fracture network geometry and productivity have yielded inconclusive results, pointing to the impact geology and stresses have on this interaction (Qiu et al., 2015). However, this has not stopped zipper fracs from becoming the standard operating method due to the considerable time and cost savings associated with them. Further work would be required to understand the impacts zipper fracs could have on the fracture network generated between an EGS well pair.

5.2 Wellbore Clean Out and Drill Out Operations

Previously discussed technologies such as dissolvable plugs, flow through plugs and ball drop sliding sleeve systems were developed to eliminate the requirement for drilling out plugs or other wellbore equipment. However, most unconventional oil and gas wells are still drilled out with coiled tubing units after stimulation operations to ensure no wellbore blockages exist that could impact hydrocarbon production. Major advantages of coiled tubing units for this operation are the quick tripping speed and their pressure control capabilities. With increasing lateral lengths and higher stage counts, the difficulty of drill outs increased. Conventional coiled tubing cleanout procedures utilized viscous sweeps and short trips back into the vertical section to help clean out plug debris. Even though these process steps added significant time and cost to operations, they often did not eliminate costly stuck pipe incidents. Major efforts have been taken to improve these operations. Mill and bit designs have improved and new composite plugs are lighter and shorter, reducing the amount of debris generated when milling them out. A key change in operating procedures is related to cuttings transport in the lateral. A major finding by operators (Pope et al., 2017) was to focus on generating turbulent flow instead of designing the fluid system for low settling velocities. Turbulent flow in the coiled tubing annulus is achieved by maximizing annular velocity and minimizing viscosity. Introduction of larger CT diameters (2 ⅜” or 2 ⅝”) increased pump rates and reduced annular clearance leading to higher annular velocities. Larger diameter coiled tubing also increases lateral reach. Today, coiled tubing is regularly used to successfully clean out wells with lateral sections of more than 3 km within 24 – 48 hours, contributing to the major overall efficiency improvements the industry has achieved.

These and other operational cost savings are of high importance for unconventional oil and gas well economics, but appear of less significance for any EGS wells at this point in the development cycle. They should be considered as options when evaluating development economics or planning development wells.

CONCLUSION

This paper has demonstrated that based on their performance envelopes, many of the technologies used every day in unconventional oil and gas completions can be utilized in EGS wells. Due to the high number of wells drilled, these off-the-shelf technologies will have a cost and reliability advantage over any custom-designed solutions. Whereas costs might not be a key decision criterion when designing EGS demonstration wells, high tool reliability is essential for proof of concept wells.

Given the higher criticality of data gathering and exact control of stimulation placement in EGS wells, the coiled tubing activated sleeves described in this paper appear very well-suited for EGS research and demonstration wells. This is especially the case because this technique allows non-sequential stimulation along a lateral and provides high resolution downhole pressure and temperature data. For annular isolation, a cemented lateral provides the lowest complexity and highest probability of success. These factors made cemented laterals the primary zonal isolation method in unconventional oil and gas wells. If open hole laterals are needed to meet stimulation objectives, advanced open hole packers with high performance seal capabilities are available.

As a vendor neutral technology review, this paper did not compare vendor specific tool details. Figure 4 provides a non-exhaustive list of vendors for each of the technologies. This list can be used as a source for further engineering analysis and evaluation.

Technology	Supplier
Composite Bridge/Frac Plugs	BakerHughes, Downhole Technology, Forum Energy Technologies, Halliburton, Innovex, Magnum Oil Tools, Peak Completions, Schlumberger, Weatherford
Large Bore Frac Plugs	Baker Hughes, Magnum Oil Tools, Peak Completions, Schlumberger
Dissolvable Frac Plugs	Baker Hughes, Halliburton, Innovex, Magnum Oil Tools, Peak Completions
Ball Drop Sliding Sleeves	Baker Hughes, Nine Energy Services, Packers Plus, Peak Completions, TMK, Weatherford
Coiled Tubing Activated Sliding Sleeves	Baker Hughes, Halliburton, NCS
Mechanical Open Hole Packers	Baker Hughes, Nine Energy Services, Packers Plus, Peak Completions, TMK, Weatherford
Open Hole Swell Packers	Baker Hughes, Halliburton, Nine Energy Services, Swell X, TAM International, Tendeka, TMK, Weatherford
Advanced Open Hole Packers	Weatherford, WellTec
Microproppant	Halliburton, Carbo Ceramics

Figure 4: Select providers for reviewed technologies

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