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Development of Multi-Stage Fracturing System and Wellbore Tractor to Enable Zonal Isolation During Stimulation and EGS Operations in Horizontal Wellbores

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ABSTRACT

This paper discusses a recently awarded FORGE project for the development of the tools to be used in the construction of a subsurface heat exchanger, called GeoThermOPTIMAL. Unique casing sleeves that are used first as a system for rapid and inexpensive multi-stage stimulations and second to perform conformance control functions are presented. The proposed sleeves will be cemented in place and use a single-sized, large diameter dissolvable ball to open the sleeves for fracture stimulation. The ball passes through sleeves from the heel toward the well's toe, until the correct sleeve is located and actuated. After stimulation and the balls dissolve, the sleeves are open for immediate fluid injection. A separately designed wellbore tractor is then deployed to detect and control the injection entry points to create an effective EGS through paired horizontal injectors and open hole producers. The horizontal wells will be connected through a system of multiple networks of induced and natural fractures that can be controlled by opening and closing sleeves throughout the field life.

Two critical EGS well stimulation and operation technology gaps are addressed by these tools:

1. Development of multi-stage stimulation technology tools which do not have temperature limitations of the conventional "Plug and Perf" stimulation equipment and are designed to be cemented in place.

2. Development of conformance control methods using the same multi-stage stimulation sleeves using a novel wellbore tractor to detect fluid flow, and open, close, or modify the sleeve position in-situ for injection rate distribution.

The sleeves will be tested in surface flow loops, followed by testing in toe sections of oil wells if available, and finally at Utah FORGE. Concurrently, a hydraulic downhole tractor is being developed based on existing prototype designs with a fluid survey capability to detect fluid injection and production and allow shifting, plugging, or choking of fluid movement through the sleeves.

1. Introduction

Enhanced Geothermal Systems (EGS) comprise systems that inject water into wells, where the water travels through the reservoir and harvests heat from the hot rock; then, the resulting hot water is produced to the surface. Both vertical and horizontal well conceptual systems are illustrated in Figure 1, where water is injected down the blue wells, and travels through the fracture network, and eventually, to the red producing well where the hot water is produced to the surface.

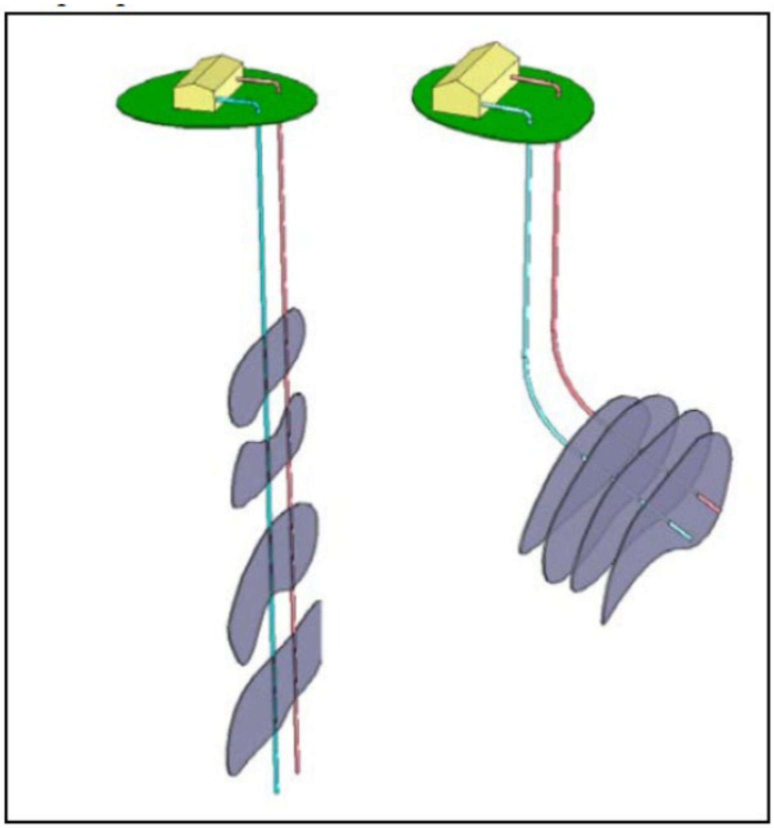

Figure 1. Two conceptual EGS well configurations (Polsky, et. al., 2008)

To make the EGS system economical, it was estimated that the amount of heated fluid necessary to generate 5 MWe (gross) is between 50,000-100,000 barrels per day (bpd). This would be dependent on the temperature of the resource rock, and the heat exchange rates achieved. This is a typical per-well generation capacity in the hydrothermal industry and is a good benchmark for an EGS project that should be close to fiscally feasible in today's market (Olsen et al, 2015). Another design parameter for economic EGS is the need for the well production to sustain the above rates with acceptable heat recovery for 20 to 30 years. To achieve these rates over the project life, the heat exchange drainage volume (HEDV) of the reservoir must be considerably larger than those in previous EGS projects. The HEDV of the reservoir can be increased by using extended reach and horizontal wells to access more naturally occurring fracture systems or other porosity systems, or by creating more induced fracture networks between horizontal wells with multistage fracturing techniques. A horizontal well system provides the opportunity to hydraulically fracture numerous zones resulting in a reservoir that can support the prospective flows without sacrificing reservoir integrity. To prevent the fluid from short circuiting between the injector and producing wells, flow needs to be detected and modified to ensure that the heat is harvested from the entire volume of hot rock to maintain the rates and temperature needed to maintain electrical generation. Additional hot fluid can be added to the system with a natural heated system, such as a binary power plant used in co-generation electrical generation plants, to provide sufficient additional heat and overcome the normal decline in heated water production from an EGS project.

2. Background

The closest operation from the standpoint of temperature and injection into horizontal wells is what is termed "SAGD" or Steam Assisted Gravity Drainage for heavy oil production, which is illustrated in Figure 2. Twin horizontal wells are drilled at shallow depths in close proximity to each other. Hot steam is injected into one horizontal well and recovers heavy oil in the other horizontal well. A paper that describes the SAGD and the use of sleeves can be found with the following diagrams (Webb 2019). The following three figures from Webb illustrate the process of SAGD, with lower portion of Figure 2 illustrating the use of Outflow Control Devices (OCD) to control the injection of the steam.

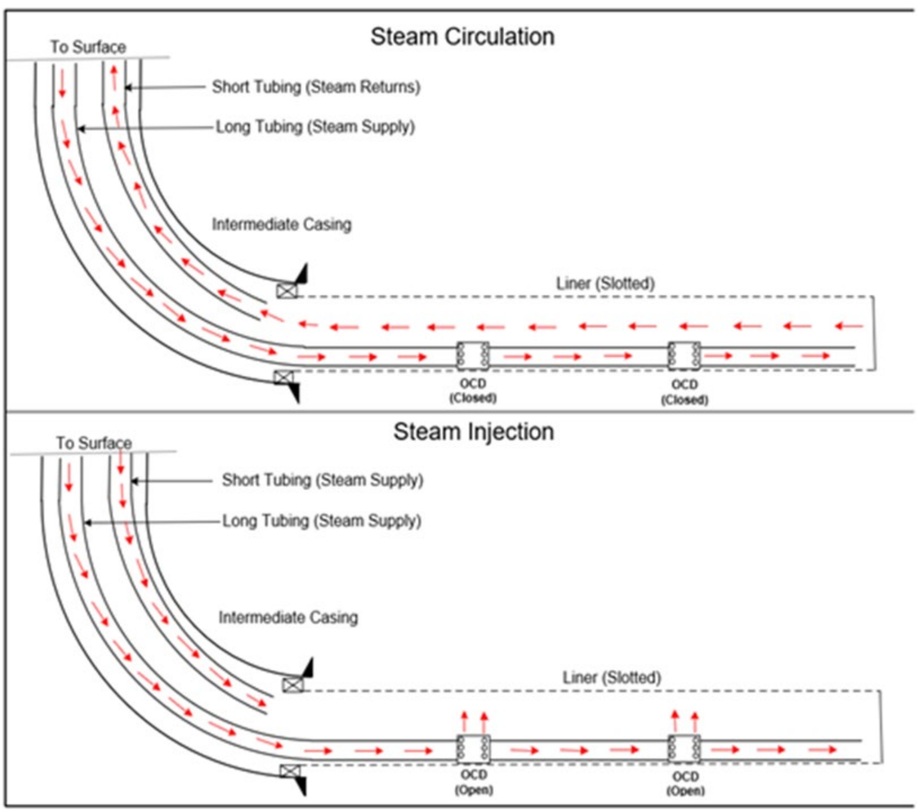

Figure 2. SAGD injector configuration during steam circulation and steam injection modes.

Coiled tubing can be used to shift sleeves or OCDs for SAGD as illustrated in Figure 3. The OCDs may utilize an Otis B sliding sleeve or other sleeve and shifting profile or may use a tool that grips the sleeve without a profile to open or close the device. An Otis-B sliding sleeve shifting tool is run on coiled tubing, past the OCD and its profile and is pulled back through the OCD to engage the sleeve and slide it to the open position. Mechanical shifting tools require no activation prior to engaging the sliding sleeve profile and utilize spring loaded keys that engage the profile and allow for force to be applied to the sliding sleeve. After the sleeve shifts to the open position, the keys on the shifting tool engage another profile, forcing the keys to retract inward and release from the profile inside the sleeve.

In addition, a hydraulically actuated shifting tool on coiled tubing can also be used to shift the sleeves by increasing surface pressure to extend the keys of the shifting tool. Once the sliding sleeve shift is complete, the keys of the shifting tool are released in the same way as the mechanical tool or by bleeding off the differential pressure causing the keys to retract back into the shifting tool. Hydraulic shifting tools allow specific sliding sleeves to be shifted open by extending or relaxing the shifting keys, whereas the mechanical shifting tool will locate into any shifting profile it is run through.

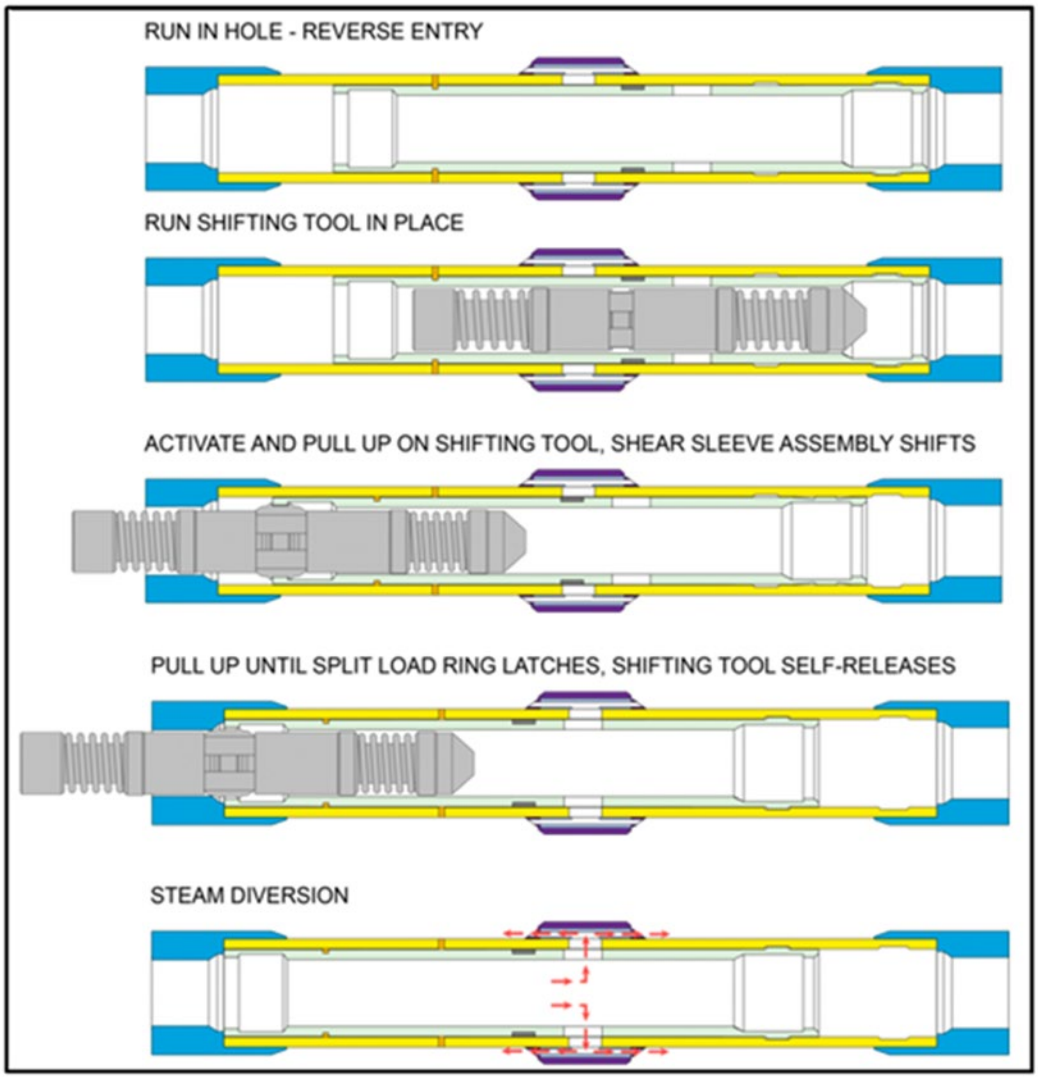

Figure 3. Coiled tubing shifting of OCD.

The ball-activated OCDs shown in Figure 4 uses a ball seat to initially open the sliding sleeve and still maintains a sliding sleeve profile to close or re-open the OCD. In this design, the sleeve is positioned in the closed position, requiring a downhole action to open the sliding sleeve. To open the sliding sleeve a specific sized dissolvable ball is dropped from the surface and pumped to the OCD. Once the ball lands on the ball seat that fits that specific size, pressure is applied, causing pins to shear and the sleeve to shift. Further pressure is applied, causing the seat to retract, and the ball to pass though, leaving a full ID through the device. The ball then dissolves. The shear force required to shift the sleeve is determined by the number of shear pins installed and is which determines the differential pressure required to shift open the seat. Once the sleeve is shifted, additional fluid is pumped to clear the tubing of the dissolvable ball. Figure 4 shows the ball-activated OCD during shifting.

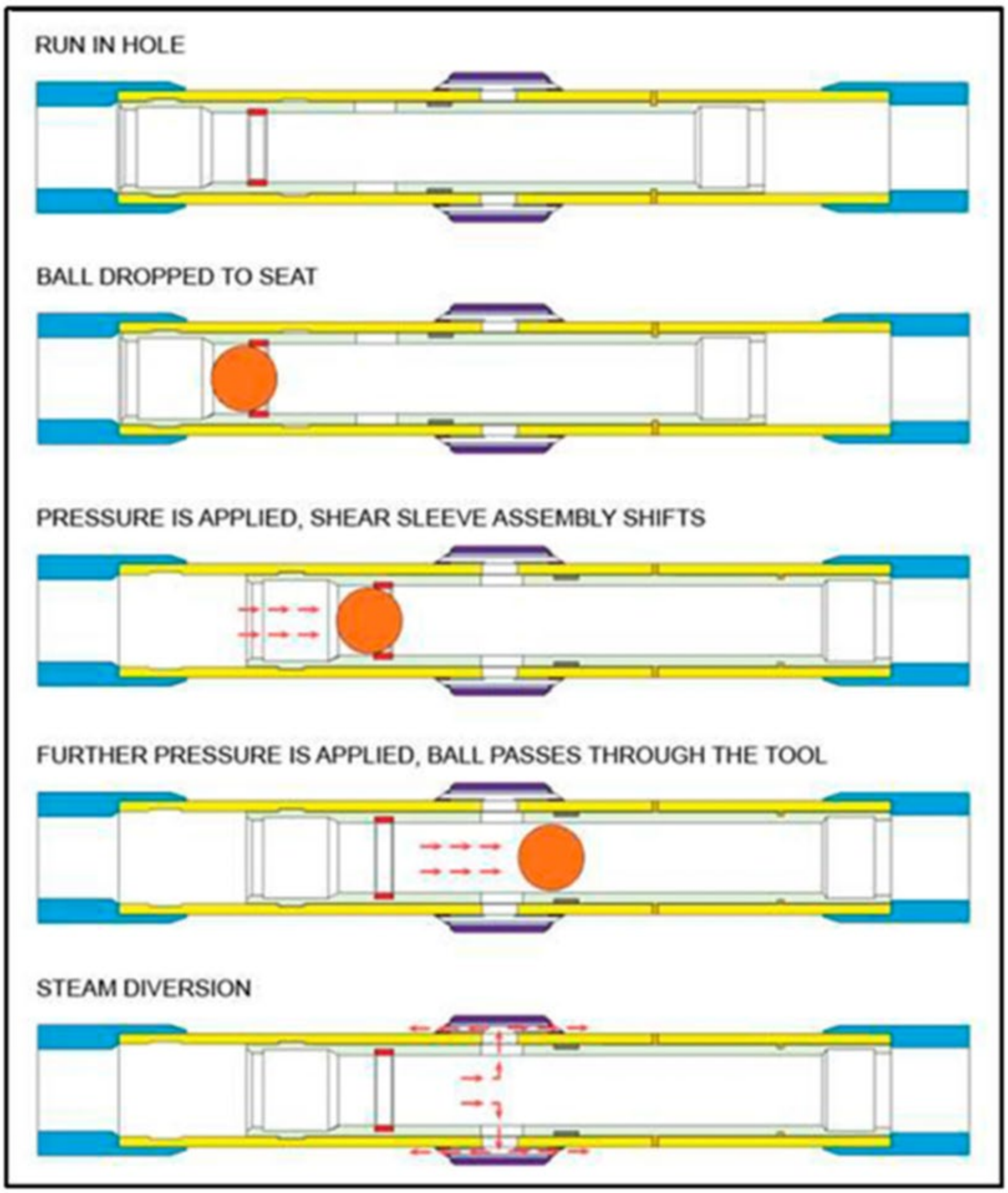

Figure 4. Ball actuated shifting of an OCD.

3. Previous EGS Work

A variety of EGS systems have been attempted since the first EGS effort to make a deep, full-scale EGS reservoir, termed Hot Dry Rock, took place at Fenton Hill, New Mexico with a project run by the Los Alamos National Laboratory. The history of EGS Systems is chronicled, with a thorough list of references that describe the state of the art (Olasolo, 2016). The EGS reservoir at Fenton Hill was first completed in 1977 at a depth of about 8500', with moderate temperatures of 185 °C. In 1979 the reservoir was enlarged with additional hydraulic stimulation and was operated for about 1 year.

The results demonstrated that heat could be extracted at reasonable rates from a hydraulically stimulated region of low-permeability hot crystalline rock. The methods of multi-stage fracturing of horizontal wells in the unconventional oil and gas industry that could be used for Geothermal completions were described in several publications including Eustes et. al, 2018. A review of previous attempts to use shale development techniques in EGS can be found in Gradl et al. 2018.

A previous attempt to develop horizontal well EGS technology is described in patent application US 2020/0217181A1 (Norbeck et al. 2020) which has been developed and awaits further testing in Utah at the DOE FORGE site. Norbeck documented that many unsuccessful prior attempts in EGS failed due to the inability to access enough heated rock with the injected water. This typically was caused by water short-circuiting between the injector and the producer, resulting in water produced that is not hot enough for a power plant. Norbeck described in his patent application:

> "the system has equipment selected from the group consisting of distributed networks , distributed fiber optic networks, pressure sensors , acoustic sensors, temperature sensors, smart well systems , intelligent completions , distributed temperature fiber optics , and distributed acoustic sensing fiberoptic; including obtaining data from equipment selected from the group consisting of distributed networks , distributed fiber optic networks , pressure sensors , acoustic sensors, temperature sensors , smart well systems , intelligent completions , distributed temperature fiber optics, and distributed acoustic sensing fiber optics; and, including: obtaining data from equipment selected from the group consisting of distributed networks , distributed fiber optic networks, pressure sensors, acoustic sensors, temperature sensors, smart well systems, intelligent completions, distributed temperature fiber optics , and distributed acoustic sensing fiber optics; and using the obtained data to in part select a perforation placement , a fracture plan, or both."

4. **GeoThermOPTIMAL**

A new system called GeoThermOPTIMAL improves upon Norbeck and others by relying on multi-purpose cemented sleeves that are first used for multi-stage fracturing, with a preferred embodiment allowing the intersection of induced fractures with open hole or "barefoot" producers detected by surface pressure measurements in the producers. The sleeves are then manipulated for use to control the EGS injection with tractors using flowmeters and other devices to shift sleeves to control injection. This simplifies the equipment needed and lowers both the capital costs of the systems and their operational costs. This system's use of cemented sleeves overcomes the need to perforate the casing and then plug those perforations either with injected diverters or by installing an inner tubing with sliding sleeves and packers for conformance control, allowing a much lower initial capital cost. The use of cemented sliding sleeves in the injection well and in a preferred embodiment, paired with a producing well(s) that are completed open hole, relying on the fracture stimulations to produce induced fractures which are detected when they intersect the producer wells by pressure signatures at the surface of the producer well which are shut in but capable of high-resolution pressure detection. The system would also perform all conformance and workover operations inside the cooler injection wells, which are cooled by the large volumes of injection water from the surface. This system, which is depicted in Figure 5, creates a subsurface heat exchanger for EGS application. This heat exchanger consists of a series of multistage hydraulic fractured horizontal wells, with blue injectors and red producers. The cooler water is injected down a well (6) and produced up wells (5) after harvesting heat from the rock (10) while traveling through the fractures between the injectors and producers. The hot water turns turbines or other means to generate electricity as depicted by surface equipment (1-4).

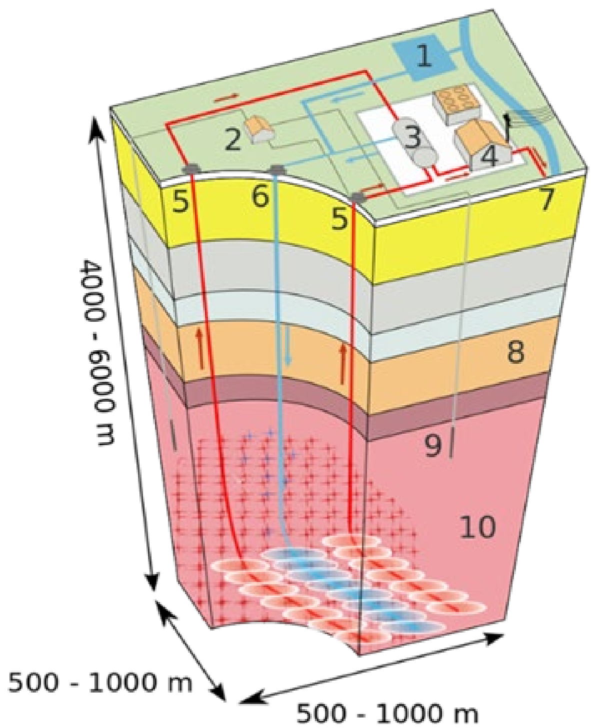

Figure 5. A conceptual diagram of an industrial scale EGS

GeoThermOPTIMAL improves EGS well stimulation and operation technology to provide hot water for electrical generation by addressing two critical and long recognized problems specific to the needs for the construction and operation of a subsurface EGS heat exchanger:

1. Multi-stage stimulation technology that has the speed of current shale development technologies but does not have the limitations of current stimulation tools and methods, such as the temperature limitations of conventional "Plug and Perf" stimulation techniques or the need for coiled tubing cleanouts.

2. Effective conformance control of the injected and produced water, solving the problem of fluid cycling by directly injected water fingering between injection and production wells

over limited volumes of the reservoir, bypassing most of the hot rock, leading to premature cooling of the produced water.

The multi-stage stimulation technique has been applied successfully to reduce costs in unconventional oil and gas wells but not in geothermal wells, due to temperature limitations and casing size limitations which this paper addresses.

5. Multi-Stage Fracturing for Geothermal Wells

Modern multi-stage fracturing of horizontal wells began nearly 30 years ago in the Barnett Shale in Texas. Prior to that innovation, fracture stimulation of an entire horizontal well was performed in one pump stage using distributed diverters but with limited success. Similar single stage stimulation attempts were made for geothermal applications by Alta Rock at Newberry EGS which also had limited success. Frac sleeves are mechanically simple with an outer tubular that connects to the casing string with a port and an inner tubular that moves downward when a ball lands in it to uncover that port. Thousands of frac sleeves have been successfully used in the oil and gas industry. The primary difficulty with existing frac sleeves is the method of locating the

Figure 6. Frac balls.

correct sleeve, which relies on a series of telescoping balls of increasing size from the toe to the heel of the horizontal well (Figure 6).

The two primary methods of current oil well multi-stage fracturing are “Plug and Perf” and “Frac Sleeves”. The primary limitations which prevent the use of “Plug and Perf” for EGS are the high temperatures which lead to high stresses and material/electronics failure which limit conventional stimulation efforts as seen in the packer used at FORGE well 58-32 (Figure 7) or the composite plug limitations. Composite bridge plugs are limited by temperature impacts on materials, but more importantly, by the need for the plugs to be removed by drilling out after the multistage fracturing process. Drilling large-diameter composite plugs is difficult and expensive due to small diameter coiled tubing buckling as it supplied weight on bit (WOB) to drill out the plugs, leading to the lock up of the coiled tubing before the entire horizontal length of the lateral can be cleaned out.

Figure 7 Well 58-32 packer

Conventional stimulation packers have several inherent limitations for EGS applications:

1. They have a variety of leak paths that must be sealed with elastomers in the presence of severe thermal stresses resulting from high temperature.

2. They must grip the wellbore, seal it, and maintain the seal throughout the lifetime of the high-temperature wells.

3. The packers and tubing take up valuable inner diameter space of the wellbore which increases the diameter of the wellbore to maintain desired injection and production rates or limits those rates, reducing heat recovery potential.

4. The installation of tubing and packers, plus perforating through the casing, are inherently expensive and slow. The installation of smaller tubing in the cased wellbore between the packers will also limit the water rates possible or cause the expense of the system to increase due to much larger wellbores needed.

5. The packers can actually initiate fractures instead of providing isolation by reducing the internal wellbore pressure and lowering the breakdown pressure needed at that point.

Cemented casing sleeves are proposed to overcome these problems that make EGS systems too expensive and inefficient. Cemented sleeves have been used successfully in oil and gas well horizontal completions, proving that cement sleeves can successfully initiate fractures through cement without perforations (Bozeman, 2009) (Stegent, 2011), Cemented casing sleeves also minimize the large thermal effect forces acting on the downhole equipment due to temperature changes in the unrestrained tubulars between packers. The casing sleeves can be used with packers, but in the preferred method, are cemented in the wellbore, with the cement hardening to provide annular isolation between the sleeves. The cement distributes forces from the casing to be resisted by the encapsulating cement, lowering the resultant stresses in the tubulars and sleeves, to avoid packer failures such as those documented in the photo above ("FORGE 58-32 Injection and Packer Performance – April 2019").

The dual-purpose sleeves are first used to rapidly stimulate the well, using multi-stage fracturing techniques, to create the network of induced fractures between injectors and producers, and then control the flow by opening, closing, or adjusting the flow with the same sleeves to modify the injection profile. A series of large, single sized ball actuated frac sleeves, described in patents US 8,991,505 and US 9,562,419 for the multistage fracturing, utilize these frac sleeve advantages for speed. A dissolvable ball would be used to open each sleeve, beginning with a pressure activated toe sleeve and then systematically stimulate the formation through each sleeve consecutively back to the heel, using a ball to actuate each sleeve to the open position and plug off the previous frac stage prior to performing the next frac stage.

The balls dissolve following the stimulation operations, avoiding the need for cleanout operations prior to injection. The proposed frac sleeve technology builds on the successful history of frac sleeves used in both oil and gas and geothermal development. Another method may use coiled tubing to shift sleeves for fracturing in a similar manner to those described in Patent 8,794,331; but this method is limited in horizontal well length in geothermal wells that require large casing diameters due to buckling of the coiled tubing and does not have a methodology to detect fluid flow for conformance control.

The proposed method allows closely spaced frac entry points in the horizontal injectors with induced fractures to be initiated as close as every 40' (every range 3 casing joint) and permit optimal frac spacing as desired. The frac sleeves described in US 9,562,419 use a unique two-pressure actuation system that can be controlled from surface to locate and activate the correct sleeve, allowing the use of a nearly infinite number of frac stages during stimulation. This method can be used to stimulate the entire length of wellbore rapidly, including large diameter wellbores. The use of a low-cost and rapid multistage fracture stimulation with cemented casing frac sleeves would eliminate packers used in conventional stimulation. These same frac sleeves that are used for fracture stimulation are also modified to be shifted for flow control to prevent short circuiting of injection fluid over a limited area of the reservoir.

The proposed method would use alternating injectors and producers comprised of one or more extended reach or horizontal wells, where the injector is cased and equipped with cemented casing sleeves as described above, with the producers completed open hole to reduce costs. Multistage hydraulic fracturing using cemented sleeves in the injectors would continue with each stage until the induced fracture had reached the open hole producing well. The fractures intersection of the producing open hole wellbore, sometimes called a "frac hit", would be detected by an innovative technology inspired by "Sealed Wellbore Pressure Monitoring" developed by Devon Energy to detect the arrival of stimulated or induced fractures using pressure observations in sealed offset producing wells. By using open hole producers equipped with pressure gauges at the surface, the fracture arrival would be detected in the production wells by a pressure spike at the surface. Injection in the injector could continue with flow up the producing well until the fracture connection cleans up and has sufficient connectivity to the injector for EGS operations. A variety of technologies, such as fiber optic cables using distributed sensing techniques, or microseismic sensing can be used as well.

The horizontal injector equipped with the sleeves described above would also be used to effectively detect and then control the flow of the heat-carrier fluid solely from a long-reach injector through the network of induced and existing fractures and produced from a barefoot long-reach well to improve heat recovery. Large volume injectors needed for EGS entail the need for large wellbores, making conventional techniques unable to shift sleeves in horizontal wells using coiled tubing, due to buckling of the small diameter coiled tubing in large diameter horizontal wellbores. Instead, tractors and other devices with fluid flow survey capability would be used to overcome this limitation to detect “thief zones” and use a sleeve shifting capability to plug or choke fluid movement through the sleeves based on real time fluid survey data to control the subsurface EGS heat exchanger, by opening, closing or modifying the injection points to improve heat drainage from the rock. This would maximize heat recovery and minimize water temperature declines. Further, the injection fluid would cool the injection wells greatly, allowing more conventional electronic systems to be used in the cooler environment for the detection of fluid flow and avoid the corrosion and scaling tendencies of geothermal waters.

The sleeves themselves (Figure 8) use a unique, simple, two-pressure actuation system that can be controlled from surface to locate and activate any desired sleeve. This sleeve is described in US Patent 9,562,419. The sleeve utilizes fingers on the end of the inner sleeve. The fingers are made of a ductile alloy so that they may flex and return to their original position without experiencing any plastic deformation or fatigue. High pressure sufficient to pass the ball through the frac sleeves is used until the desired sleeve is reached. At high pressures, the fingers elastically deform to allow the ball to pass through without activating the sleeve. Low pressure and time activate the sleeve. Once the sleeve has been activated, it has a compressed spring which has stored energy that can move the sleeve back to the initial position. This technology can be used to stimulate the entire length of a wellbore rapidly, including large diameter wellbores.

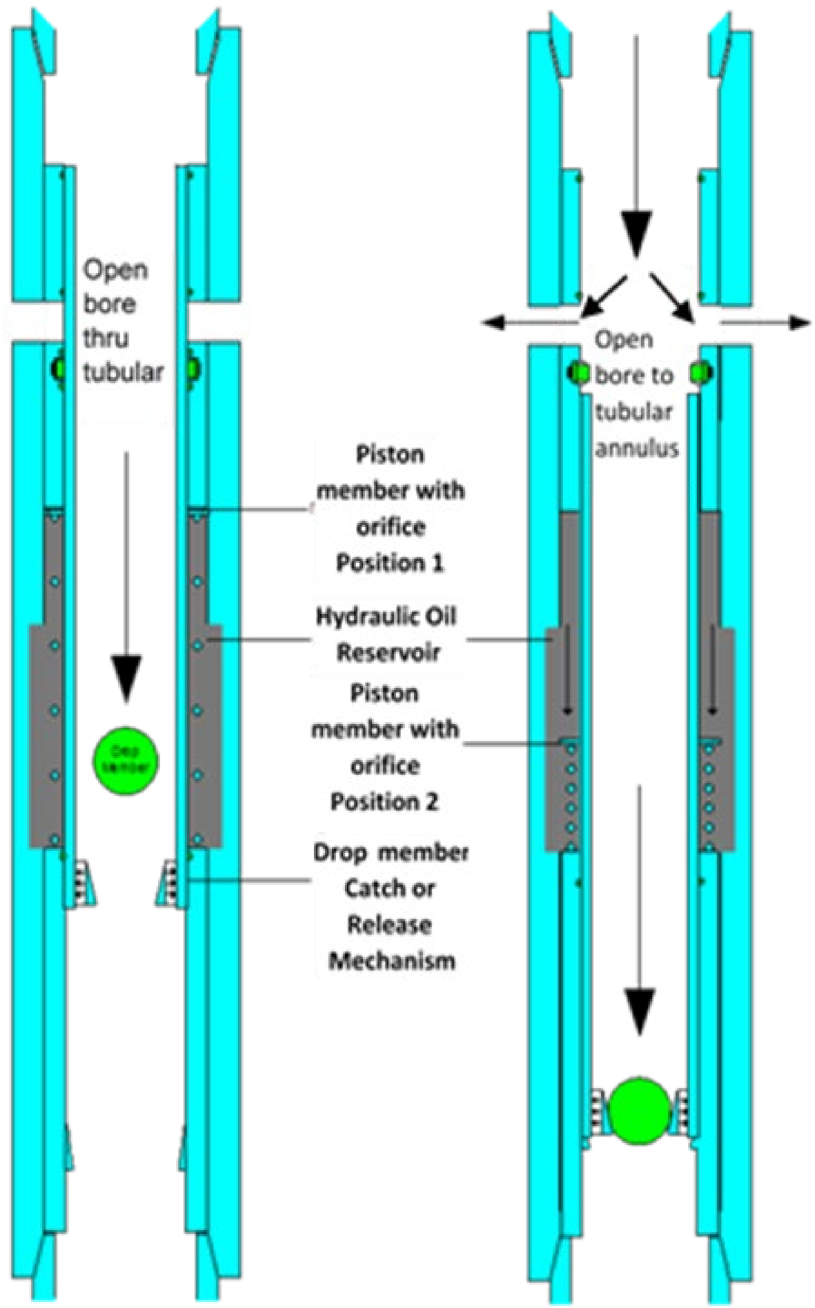

Figure 8 Casing frac sleeve design.

As described above, the ball is held by the finger of the tool until sufficient pressure builds to pass the ball to the next tool. This technology to pass a ball has been used many times to set hydraulic tools and then increase pressure to blow the ball to the rathole at the bottom of a vertical wellbore. These pressure spikes allow the operator at the surface to understand exactly where the ball is and the pressure a previous sleeve required to pass the ball. A tool made by Stage Completions which uses a unique collet for each sleeve, uses these pressure spikes to track their tools progress in a wellbore (Figure 9) in a similar manner the ball will pass the device we propose (Stage Completions PR, 2017).

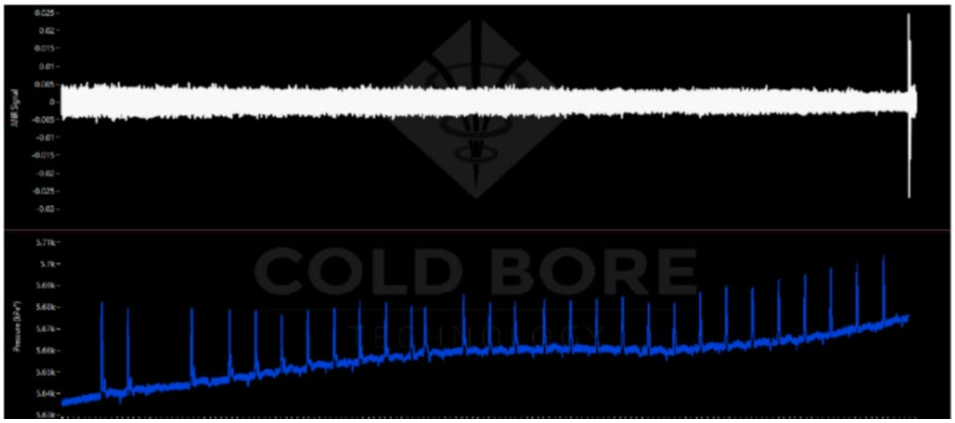

Figure 9 Pressure indications of sleeves.

Each sleeve would have a corresponding ball that would be dropped. If there are 50 desired frac points, 50 sleeves would be installed in the casing or a liner. The first sleeve at the toe would be a toe sleeve, which is hydraulically actuated with pressure only and the each of the next 49 stages would be stimulated by 49 balls dropped during the fracture stimulation process, with pressure spikes at the surface similar to those displayed in Figure 9. It may be desired to run several different diameters of sleeves, which could be accommodated by running sleeves designed for several sizes of balls. Once the well stimulation is completed, all sleeves are open.

The system is shown in Figures 10 and 11, where the injection well with cemented sleeves are on the left and the open hole completed producer is on the right. Figure 10 has a series of frac stages in various stages of fracturing. Stage 1 has a completed fracture stimulation, with the fracture intersection of the producing well from the injector detected with a change in pressure at the pressure gauge at the surface on the wellhead. As the induced fracture arrives at the production well, the pressure of the induced fracture will increase the pressure in the wellbore, which is sealed at the surface. This increase in pressure will be measured with a pressure gauge with recorded pressure history convenient for analysis. The producing well could be opened at the surface, allowing flow to improve the connection between the injection and producing wells at that portion of the formation. This fracture connection between two wells may be a discrete induced fracture, or a series of fractures, including natural fractures and formation permeability, or a combination. The fluid injection at the injection well may be optimized with a propping mechanism, or a stimulation fluid, or an injection rate and pressure protocol, depending on the formation and experience with the technique. The system which uses an open hole extended reach lateral is significantly less expensive than a cased and cemented producer, which requires a stimulation program to connect to the induced fracture system from the injection well.

Figure 11 depicts the connections between the injection and producing wells through the rock between the wells. The casing sleeves are placed in the casing string or liner by threaded connections to the joints of casing, allowing the spacing of the induced fracture system to be as large or small as desired by the designers of the EGS. All the frac sleeves are in the open position, with the wellbore blocked to fluid injection by the balls. If dissolvable balls are used, they will dissolve and allow the well to be immediately available for injection. If balls are used are not dissolvable, they may be drilled out, or flowed back, and prevented from wellbore blockage by devices designed to prevent the balls from blocking the sleeves. The balls are nearly the size as the drift diameter of the casing, allowing tools to pass through the sleeves for diagnostics and to shift the sleeves, which is not possible with conventional ball drop sleeves. Ideally discrete fractures would be created, but the system can be used where a permeable connection exists between injectors and producers that also has connectivity between flow paths, with little or no distinction between in situ permeability and the conductivity of the induced fractures.

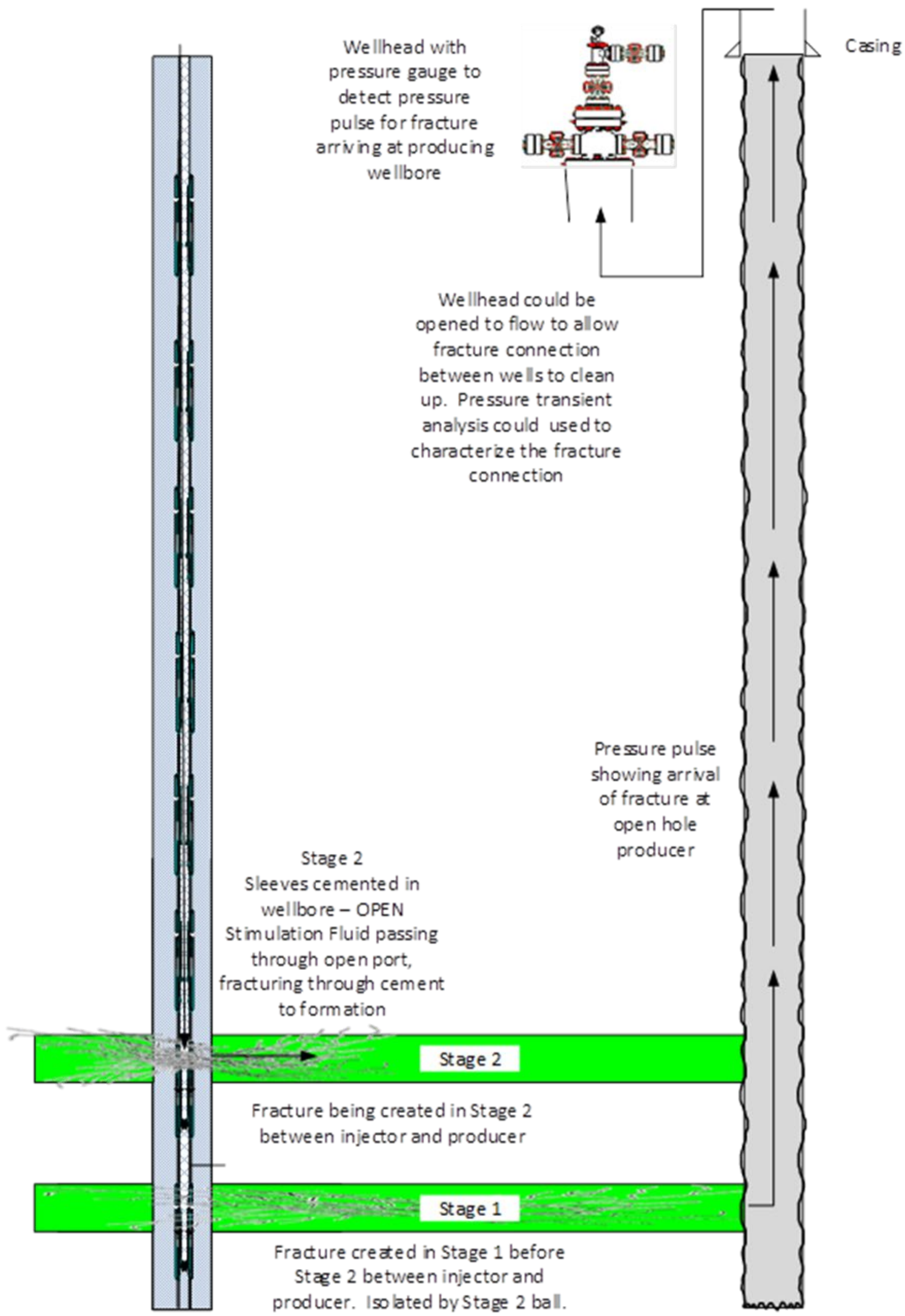

Figure 10 Plane view of a Injecting Well fracturing into connection with Producing Well

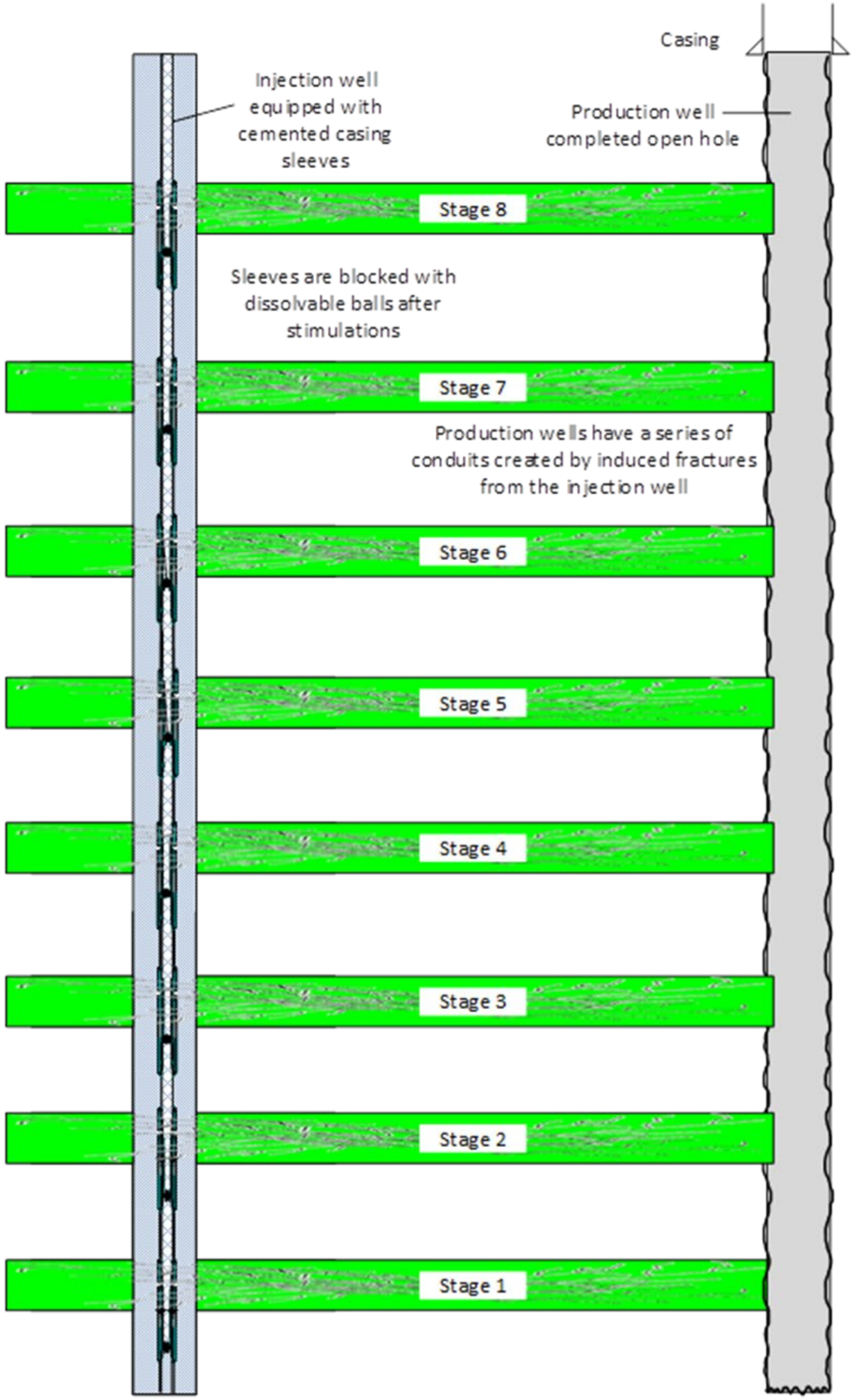

Figure 11 Plane view of an Injecting Well with all stages connecting with Producing Well

6. Conformance control

One of the biggest challenges in EGS is the effective management of fluid flow between the injector and producer to maximize heat recovery per volume of fluid injected. This method using casing frac sleeves lends itself for the dual purpose of conformance and stimulation control. This method uses tractors, or the inertial forces of the injected fluid, to deploy a flow meter to detect the sleeve(s) that are allowing injected fluid to short circuit to a producing well and a shifting tool to close those sleeves to redistribute the injected fluid into reservoir areas of less heat recovery. This conformance control is similar to those used for the control of oilfield waterfloods. Where inertial forces are unable to deploy the shifting tools, in a manner similar to deployment of composite plugs and perforating guns in horizontal wells, coiled or jointed tubing could be used, until the horizontal reach of coiled tubing is limited in larger diameter wellbores (such as those needed for economic EGS injectors) due to helical buckling.

Figure 12 illustrates the GeoThermOPTIMAL subsurface exchanger. Two horizontals are shown, with an injection well completed with five cemented sleeves that have been connected to the offset, open hole producer with five induced fractures. The multi-stage fracturing of each stage is accomplished used dissolvable frac balls starting at sleeve 5 and ending at sleeve 1. The balls dissolve, leaving each of the five sleeves ready for injection. For a industrial system, the horizontal laterals may be 3 to 5,000 meters long and equipped with many cemented sleeves. When conformance control is needed a tractor can be used in the large diameter injectors to close sleeves as needed, where coiled tubing will be buckle. The tractor will be equipped with a means to detect flow and may be assisted in horizontal movement by injection flow.

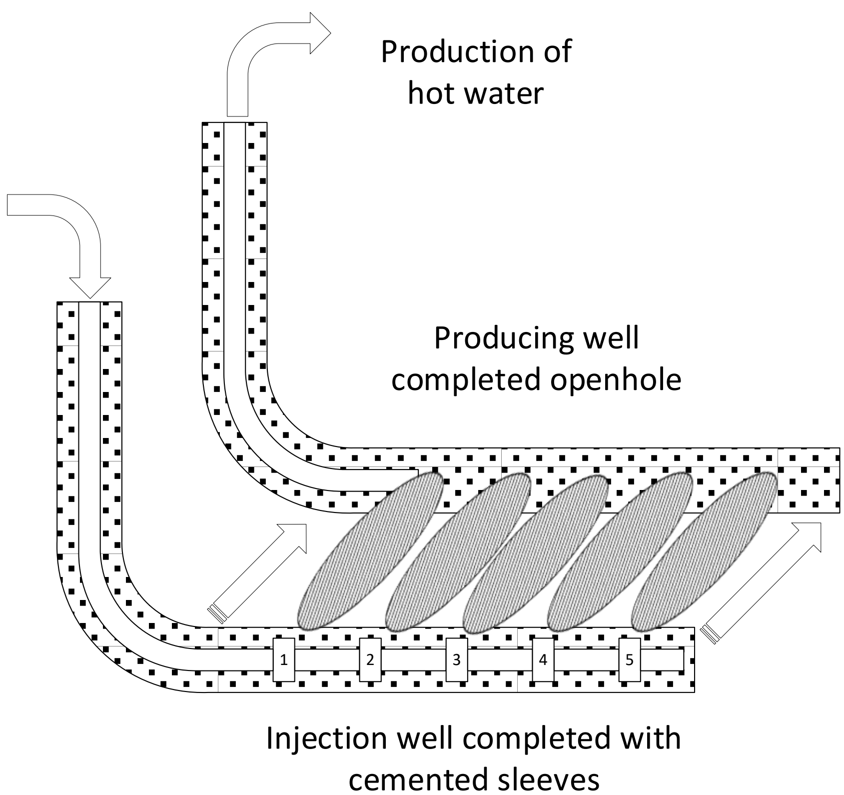

Figure 12 Subsurface heat exchanger.

The tractor is described in US Patent 10,927,625. The tractor uses hydraulic pressure which is either provided by a hydraulic pump (electric tractor on wireline) or wellbore fluid (hydraulic on coiled or jointed tubing). The tractor design is simple with one embodiment using a mud motor to provide the needed torque and rotation speed. It can be controlled either with hydraulic pumps at the surface, which control a floating mandrel to deploy the wheels of the tractor or downhole electric pumps with telemetry or short hop communications. The tractor could be electric or hydraulic or a hybrid of the two. Other methods of shifting the sleeve, including pumping the shifting tool down the well with the high rate of injection to the "thief" sleeve(s) could be used depending on conditions. The use of the tractor and shifting tools in the injection wells would allow the tractor and electric tools to operate in a much cooler injection wellbore which will be easier on the seals and electronics, with less scaling and corrosion to foul the sleeve mechanisms.

Large volume injectors needed for EGS entail the need for large wellbores, making conventional techniques unable to shift sleeves in horizontal wells using coiled tubing, due to buckling of the small diameter coiled tubing in large diameter horizontal wellbores. As pictured in Figure 13, water is injected down the injection well, with the preferred embodiment being water injected down the casing, with no inner tubing, with the injection water depicted by the black arrows. The water is injected down the casing, and is divided equally between each sleeve, travels down the induced fracture, harvesting heat, represented by the red arrows from the hot rock. The water is heated by the thermal transfer from the rock and may also contain water native to the hot rock, and travels down the induced fractures to the open hole producer, where it is produced to the surface.

Figure 14 depicts a more realistic view of an EGS system, where the fluid distribution from the injection is not uniform. Two injection points, labeled Stage 7 and 8, which represent the injection points nearest the heal of the horizontal injection well, are receiving a much higher volume than other stages. This may need to be remedied by choking the injection points, forcing injection fluid to move down the lateral to the other injection points. Or injection may be following the path of least resistance, represented by fluid entering the injection point labeled Stage 2, and may be due to the presence of a high permeability streak, natural fractures, or a fault system that causes the injection fluid to short circuit between the injection and production well, leaving most of the hot rock with unharvested heat.

In this system, tractors and other devices with fluid flow survey capability, such as spinner survey tools, temperature sensors or even weight indication on the wireline at the surface as the tools move past the sleeve(s) receiving much of the injection fluid, are used to overcome this limitation to detect "thief zones" and use a sleeve shifting capability to plug or choke fluid movement through the sleeves based on real time fluid survey data to control the subsurface EGS heat exchanger, by opening, closing or modifying the injection points to improve heat drainage from the rock to maximize heat recovery and minimize water temperature declines. Further, the injection fluid would cool the injection wells greatly, allowing more conventional electronic systems to be used in the cooler environment for the detection of fluid flow and avoid the corrosion and scaling tendencies of geothermal waters. This system uses tractors, the inertial forces of the injected fluid or a combination, to deploy a flow detection device, such as a spinner or temperature meter, and/or the tension on a wireline, to detect the sleeve(s) that are allowing injected fluid to short circuit to a producing well and a shifting tool to close those sleeves to redistribute the injected fluid into reservoir areas of less heat recovery. This conformance control is similar in purpose to the control of oilfield waterfloods. Where inertial forces are unable to deploy the shifting tools, in a manner similar to deployment of composite plugs and perforating guns in horizontal wells, coiled tubing could be used, until the horizontal reach of coiled tubing is limited in larger diameter wellbores (such as those needed for economic EGS injectors) due to helical buckling, at which point the tractor capabilities could be used. Figures 15-16 illustrate this in practice

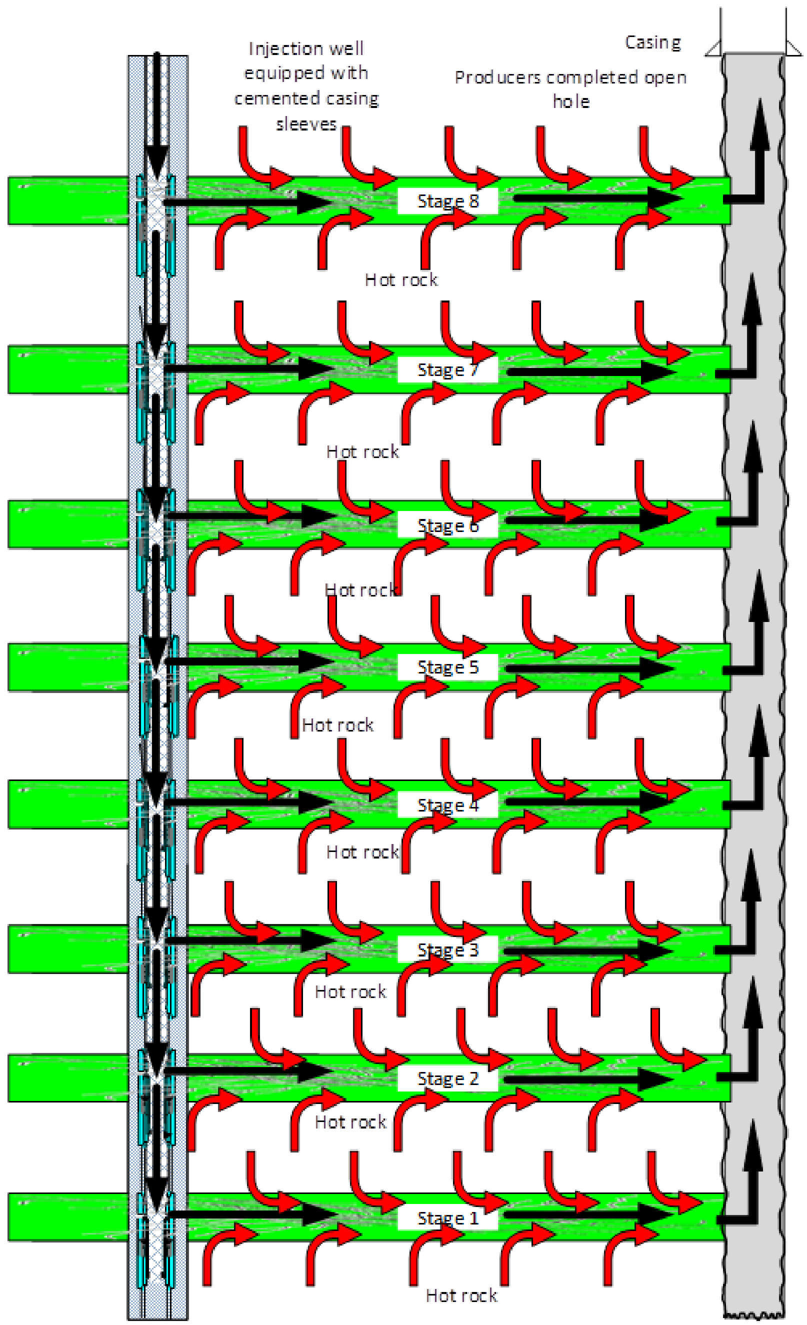

Figure 13 - Plane view of an Injecting Well with all stages connecting with Producing Well

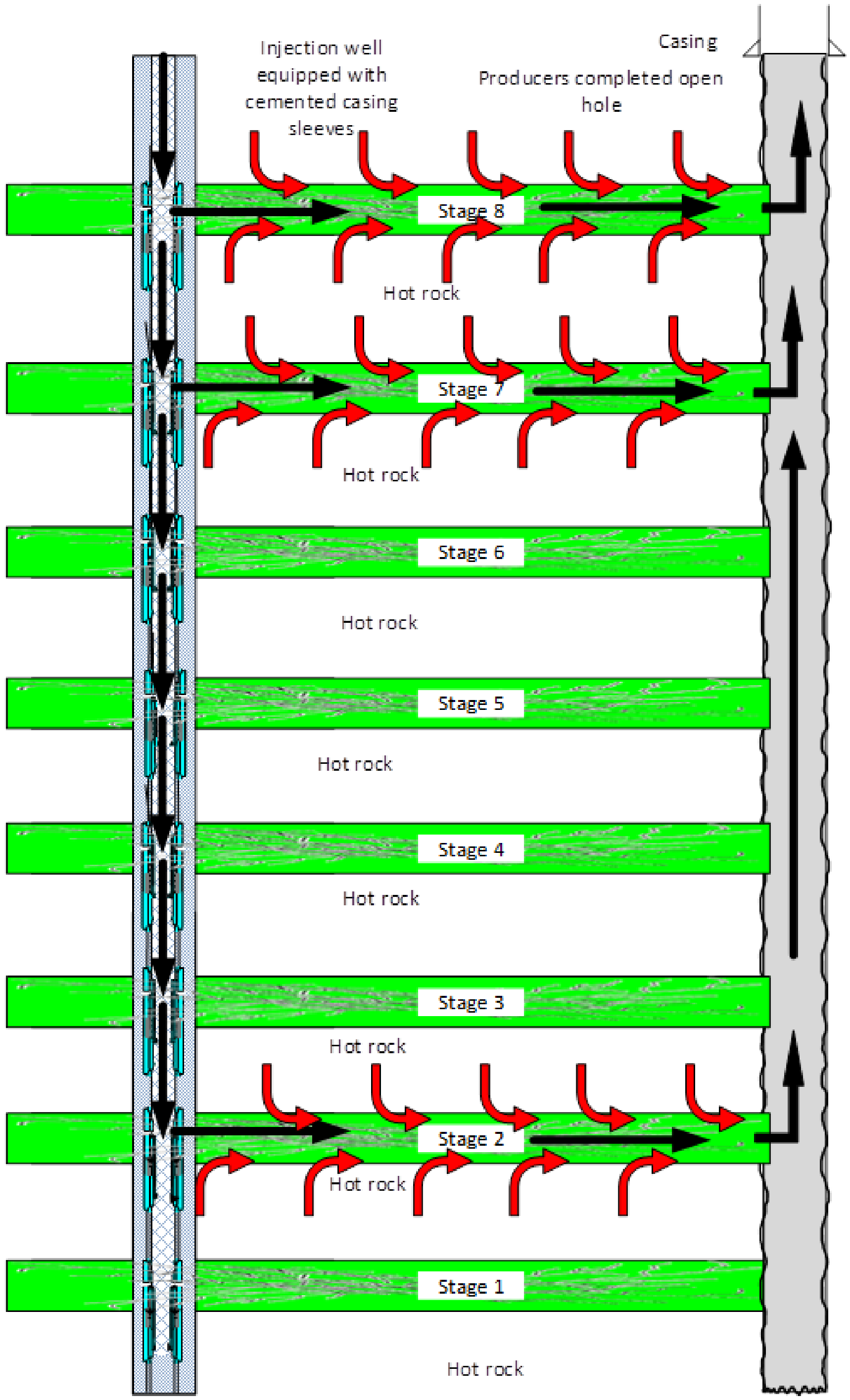

Figure 14. Plane view of an Injecting Well with not all stages connecting with Producing Well

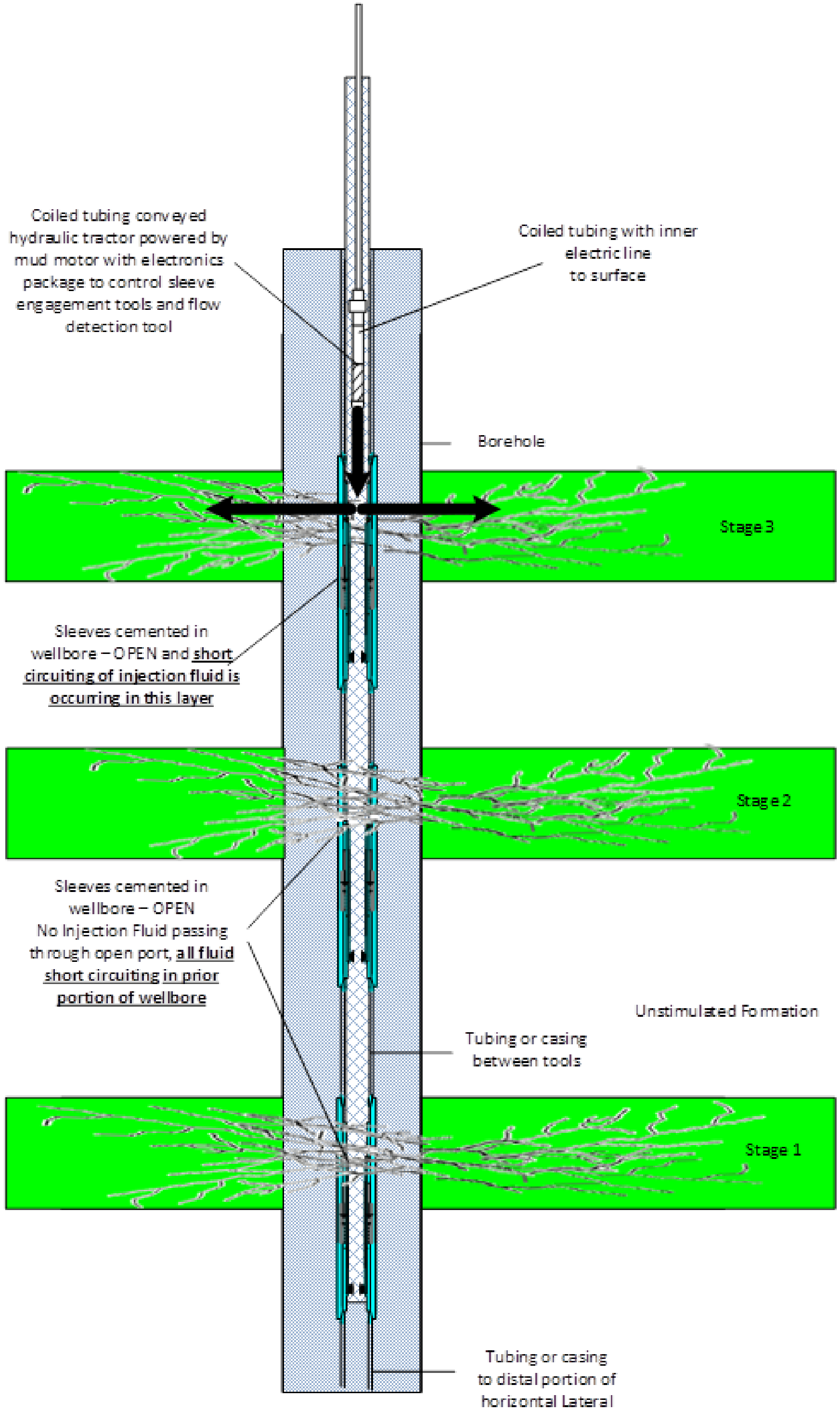

Figure 15 Plane view of an Injecting Well with one sleeve short circuiting to the producer

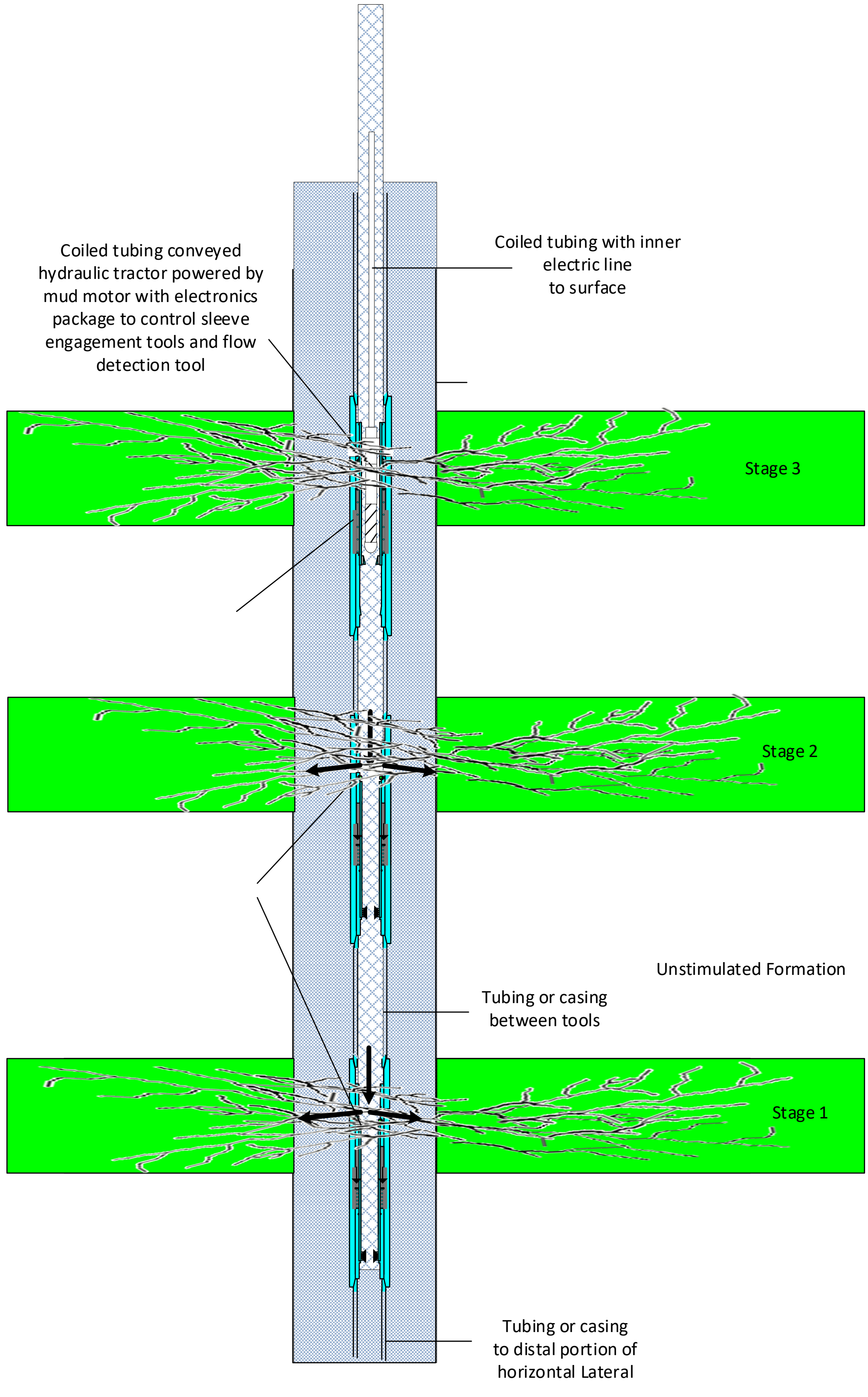

Figure 16. Plane view of an Injecting Well with sleeve closed to prevent short circuiting

7. Monitoring of induced fractures

Multi-stage fracturing micro-seismic images as well as rate transient analysis (RTA) have revealed long relatively planar induced frac system with “frac hits” are common occurrences in offset laterals (Morad & Angus, 2019). Similar long planar fracture systems have been observed with microseismic in Geothermal applications (Fu et al, 2020. Devon Energy has developed a monitoring technology (Sealed Wellbore Pressure Monitoring, SWPM) to use the frac hits to identify fracture arrivals at offset wells, providing positive measurement of the frac length and connection between the two wellbores, a technique that has been used on at least 1,500 stages (Haustveit, et al, 2020). This proposed method is inspired by SWPM to be used to detect hydraulic fractures intersection of offset wellbores and fracture systems. A preferred method would initiate an induced fracture from the individual cemented casing sleeves in the injection wells and would continue to propagate the fractures until the fractures arrive at the open hole producers and are detected and characterized by surface pressure gauges.

8. Innovations

Innovation 1: Novel multi-stage fracturing technology with casing frac sleeves actuated by dissolvable ball that eliminates need for expensive packers. *Impact*: Scalable, rapid and economic multi-stage fracturing technology for EGS environments.

Innovation 2: Novel approach using casing sleeves and a wellbore tractor to control conformance in injection wells minimizing need to complete producers. *Impact*: Economic technology for effective conformance control.

Innovation 3: Use of surface pressure analysis, inspired by Devon’s SWPM technology to monitor induced fractures in geothermal wells. *Impact*: Novel, low-cost technology to detect induced fractures arrivals in open-hole producers.

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