DESTRESS

Demonstration of soft stimulation treatments
of geothermal reservoirs

D5.1: Description of Individual Completion Elements Required to Segment EGS Reservoir Section

WP 5: Demonstration cyclic hydraulic and multi stage treatments in granites and tight sandstones

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1 Introduction

Technical and economic success of deep geothermal development relies on our ability to reduce drilling risks and to reliably complete these wells. To that end, a technology that provides consistent good results, independently of environmental and subsurface conditions, is required.

Until today, drilling and properly completing deep geothermal wells has been a risky business. In the closely related oil and gas activities, the risk taken by the investors is balanced by the high reward that successful projects achieve by immensely offsetting the losses of the failed wellbores. Until today, the geothermal energy experiences similar risks, however, the potential reward is limited by the competition with other energy sources (nuclear, coal and gas for those competing for the power baseline supply), in a heavily regulated market. The economical acceptability of geothermal power generation requires low risk drilling and completion technologies that would work under many different geological conditions.

Thinking of Enhanced geothermal systems (EGS) in term of reservoir stimulation may be somewhat restrictive, if not misleading. When two wells are drilled into a petro-thermal formation, sometimes referred to as hot dry rock (HDR), there is normally no clear circulation path between these wells and when this path exists, the transmissivity is so low that no economical project is possible. EGS, in these circumstances (similarly to shale hydrocarbon projects) is indeed more about reservoir creation than conventional reservoir stimulation. The EGS is the reservoir itself. Therefore there is a lot at stake, for geothermal developers, in understanding the EGS creation process, and in developing technologies that achieve the EGS proper size and transmissivity to harvest the geothermal energy.

EGS developments must also comply with public acceptance in term of environmental impact. It is clear that excessive induced seismicity such as in the Basel Deep Heat Mining (DHM) project cannot be tolerated. The design of the reservoir creation has to minimize this impact by applying the latest knowledge available in crystalline rock stimulation and by adapting its seismic monitoring and surveillance network, as well as its real-time decision tool to anticipate seismic activity and manage the stimulation operations accordingly. This concerns is at the heart of this European Horizon 2020 DESTRESS project.

The EGS becomes an economical proposition, when enough rock surface can be contacted by the geothermal fluid, and when the flow path runs smoothly through a sufficient rock volume to minimize the energy depletion and have the project running over a long period, compatible with a positive net present value (NPV). To that end the well design and its completion system have to be engineered to maximize the chances of properly creating the EGS. In this task of the DESTRESS project, different options are discussed and the choice of the completion system selected for the Geo-Energie Suisse AG (GES) Haute-Sorne project is presented. The necessary tests and their current status before running different parts in a real geothermal well is also discussed. Other options for reservoir creation are debated with their potential benefits and associated risks. The developments that could make them work in an EGS project are discussed.

2 Background

When the DHM project was designed the thermal calculation called for a downhole heat exchanger covering $4km^2$. Assuming some geological conditions with an existing set of permeable flow paths, the distance between the two wells of the doublet in the reservoir section was determined. The first well was drilled vertically and completed barefoot, leaving 381m of 9 7/8” x 8 ½” open hole below the 10 ¾ x 7 5/8” production liner. After turning the well to fresh water the stimulation programme was undertaken.

A total of 11’570m^3 of fresh water was injected (Häring et al., 2008). The seismic activity showed a microseismic cloud that as a whole is near-vertical and has a predominant NNW-SSE orientation, at an approximate 11° angle with the maximum horizontal stress (ibid). Further analysis revealed a complex internal structure of the cloud composed of many fault segments deviating more or less strongly from the overall orientation of the microseismic cloud (Deichmann et al., 2014).

During the injection, a M_L 2.6 seismic event was recorded. Injection was stopped, but during the following shut-in period two tremors of magnitude ML 2.6 and 3.4 were successively recorded, thus ending the DHM project.

Studies on the Basel case as well as on other similar projects (Baisch et al., 2009) showed a correlation between the surface area exposed to the stimulation treatment and the induced seismicity recorded magnitude (Figure 1: Maximum magnitude (ML) as a function of the logarithm of the seismically active area for the injection, after Baisch et al (2009)

). As shown, the seismic hazard increases with increasing the stimulation area and the corresponding injected volume. Injected volume, in combination with other reservoir properties such as rigidity, can also be used to estimate an upper magnitude boundary (McGarr, 2014). Therefore, EGS engineering is bound by the necessity of limiting the stimulated area to limit the seismic hazards, while creating a downhole heat exchanger as large as possible for obvious efficiency reasons. This dilemma can be solved by decreasing the size of each individual flow path surfaces and by increasing the number of these flow paths. In other words, since one stimulated large fault is unacceptable, a multi-stage stimulated reservoir section could achieve the equivalent heat transfer area while maintaining the induced seismicity in check. That brought GES in 2011 to develop the multi-zonal stimulation concept aiming at preventing seismic events of large magnitudes (Meier P. et al., 2015).

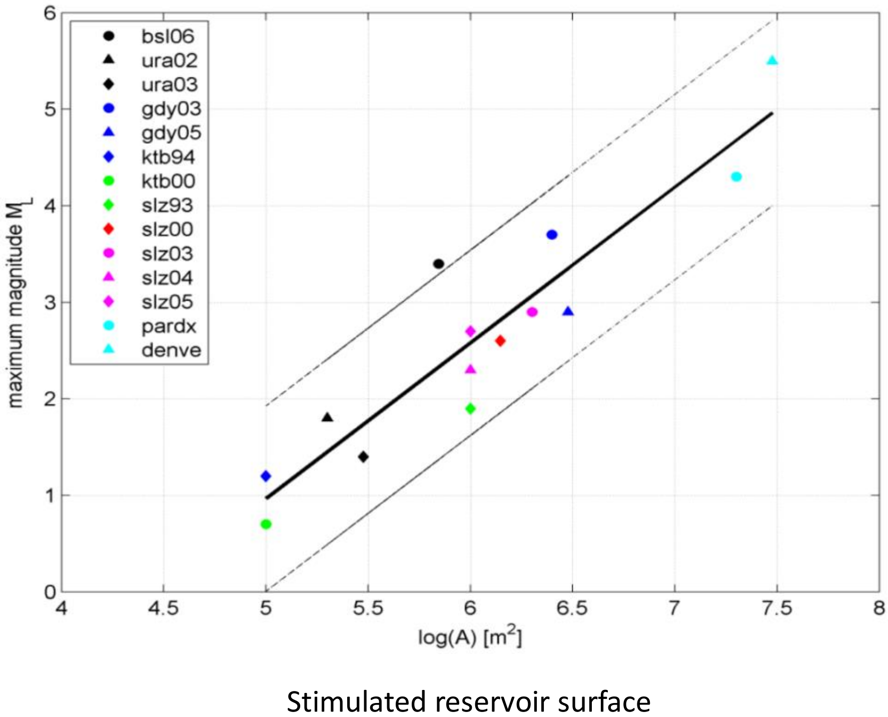


Figure 1: Maximum magnitude (ML) as a function of the logarithm of the seismically active area for the injection, after Baisch et al (2009)

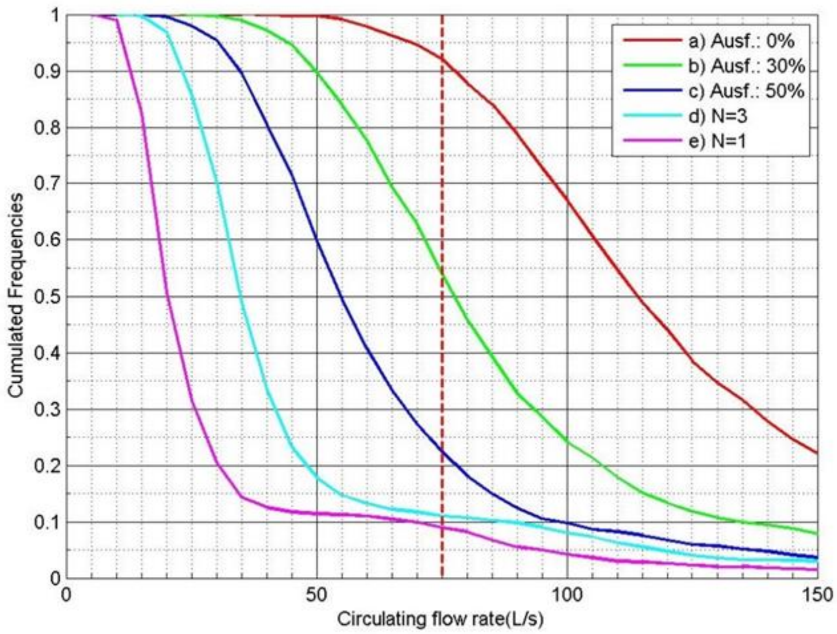


Figure 3: Cumulative frequency distribution of flow rates for an example of a granite at a depth of 1.5 km for different number of stages. (Meier and Ollinger, 2016)

Since several individual zones were to be stimulated, the extra cost of adapting and running a more complicated system than attempting this operation in the conventional barefoot condition had to be justified. GES undertook a Monte-Carlo statistical analysis to evaluate the chances of achieving production and injection targets under various stimulation success ratios in a multi-stage stimulation programme (Meier and Ollinger, 2016).

In the base case example, the target flowrate of the well is of 75 l/sec, and the variant used for the analyses is the number of fractures successfully stimulated. Figure 2: Cumulative frequency distribution of flow rates for an example of a granite at a depth of 1.5 km for different number of stages. (Meier and Ollinger, 2016) describes the cumulative probabilities results from a single open hole active fracture up two the successful stimulation of 30 individual sections. For the above example, the target flowrate will be achieved in less than 10% of the cases when an inefficient completion string is used, while that flowrate will be possible in more than 50% when 30% of the stimulation stages are unsuccessful for any reason. In the most efficient case where individual stimulation of each section can be successfully performed, there are less than 10% of the cases that will not achieve the target flow rate.

An internal GES study (Ollinger D., 2015) extends this probability analysis to an economic analysis, showing that the marginal investment cost to improve the probability of successfully stimulating individual sections was a very attractive proposition, at least in terms of probability of achieving or exceeding a target electric power production (Table 1). Even though the extra investment to enable sectioning the reservoir drain and individually stimulating these sections is high (60% of the base case) the benefits are obvious; even with half of the stages failing, the electric power outcome is multiplied by a factor of 2.9. In the ideal case where all stimulation stages are successful, the corresponding electric power produced is 6.2 times higher than in the single stage approach.

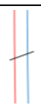
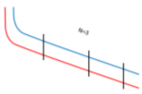
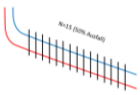
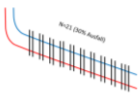
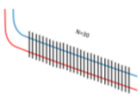
Utilisation System		Increase Factor for:	
		El. Power	Costs
	Vertical Single-Open-Hole-System, 1 fracture	1	1
	Single-Open-Hole-System, 3 fractures	1.8	1.2
	Multi-Stage-System; 50% failure rate of stages.	2.9	1.6
	Multi-Stage-System; 30% failure rate of stages.	4.2	1.6
	Multi-Stage-System; 0% failure rate of stages.	6.2	1.6

Table 1: Relative values for electric Power and drilling costs for 5 different utilisation systems. The first variant (vertical Single-Open-Hole-System with one utilizable fracture) is used as reference (After Ollinger D., 2015).

Therefore, the evidences presented herein show that a robust multi-stage completion system combines two major benefits in deep geothermal projects:

1. Reduction of the risk associated with induced seismicity linked to EGS creation via hydraulic stimulation
2. Reduction of the risk of poor production/injection results and the associated uneconomical power production project.

The development of a multi-stage system that would fit the requirements of geothermal projects is an essential part of making power production through geothermal plants an economical alternative to conventional baseline power production. It is also the tool that can make geothermal production work in many different geological settings, while decreasing the risks that have plagued a number of these early projects.

3 Examples from the oil and gas industry

The recent interest in shale gas and shale oil plays, can be traced back to Mitchell Energy and Development attempts at fracturing the Barnett shale in 1998. With this movement, led by the

United States' hydrocarbon industry, the use of multiple hydraulically fractured drains to produce low permeability hydrocarbon formations has gained momentum.

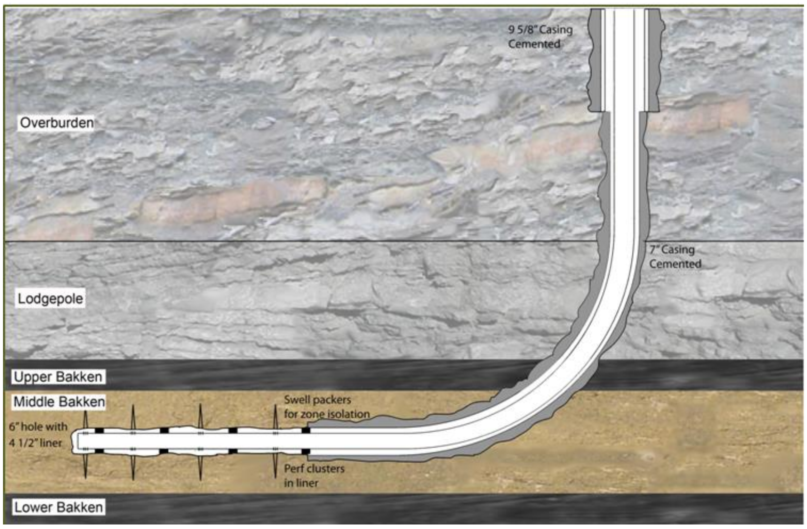


Figure 4: Example of similar completion technology used in the Bakken field, courtesy of EERC

To service these now accessible formations, numerous service companies have developed a string of methods and tools that allow to routinely apply stimulation treatments in segmented wellbores.

These new technologies offer the opportunity to benefit from developments already available on the market and some of them tested in thousands of oil or gas wells (Olsen et al., 2015).

The early multi-stage stimulation completion systems used successive perforation and plugging by sand plugs, the same material used as the propping agent for the fracturing operation (Norris M.R.et al, 1996). This early experience in combining horizontal drilling and multiple hydraulic fracturing to produce a chalk formation in an offshore field was using the only technologies available on the market at that time. It necessitated a clean-up trip to regain wellbore access after all stimulations had been performed. In a quest to ever improve operational efficiency, especially where well construction cost is a critical part of project profitability, the multistage tools where engineered to allow continuous stimulation operations.

Today, apart from the traditional successive perforate – stimulate – plug operational sequence commonly referred as "Perf and Plug", and that requires a cased and cemented reservoir drain, many alternative options for both open-hole and cased-hole applications are available from various service companies. An example of such a completion string application can be found in Etohuko et al., 2014. All these methods include a way of dividing the drain into individual isolated sections and a system that allows the connection between the wellbore tubulars and the reservoir rock face, to stimulate selectively and then to produce or inject from/into the reservoir.

Figure 5: Example of a multi-frac system, courtesy of Packer Plus Energy Services Inc.

The hardware manufactured for the oil and gas industry is readily available up to a nominal outside diameter of 5 ½ in. (140mm), maximum size that is normally run in hydrocarbon wells. Because the geothermal industry has to operate at a much higher flow rate (>40l/sec), the similar technology, to be readily applicable would require to be enlarged to a minimum of 7in. (178mm) nominal outside diameter (OD). Whenever these systems include elastomer, these would have to be developed and tested for higher temperatures than those normally experienced in the oil and gas wells, with a minimum of 150°C (300°F).

In the following the current options are discussed. This discussion highlights the selection of the completion system eventually selected for GES Haute-Sorne project.

4 The different zonal isolation options

As demonstrated in the previous paragraphs, the wide application of geothermal power generation depends on our ability to consistently create an efficient EGS. This requires a technology that ensures consistent stimulation of the geothermal reservoir. Stimulation, be it mechanical, hydraulic or chemical, must be properly placed where it will effectively increase the transmissivity of the targeted rock formation. To ensure the proper placement of that treatment, a robust way of segmenting the drain, i.e. zonal isolation is necessary.

It must be kept in mind that hydraulic isolation between two permeable segments, with any kind of system identified so far, cannot be tested, let alone remediated. Therefore it is important for an EGS project to select the system that will have the highest probability of success in a particular application. To that end, laboratory testing and sophisticated simulation techniques have to help the completion engineer to make an informed decision.

Before reviewing the zonal isolation methods currently on the market, it is worth looking at some specific issues that the zonal isolation may face in a geothermal environment and that should not be overlooked.

4.1 Breakouts

Geothermal wells for DHM projects are often drilled in the crystalline basement: Basel, Haute-Sorne, Pohang, Soultz-sous-Forêt.

The combination of a large hole, a brittle rock, an anisotropic stress field and the desired low mud weight to prevent invasion of the permeable system, makes more likely the occurrence of breakouts. In the specific case of BS-1 well (Basel) an ultra-sonic borehole imager was run. The analysis of the open hole section was performed and is discussed in Valley B. and Evans K.F., 2009.

Basel-1 is a vertical well that was drilled to 5000m in the granite basement. On the image log (Figure 5: image log from the hole drilled in the crystalline basement in Basel (2006)), a lemon-shape cross-section (Figure 6: BS-1 (Basel) hole cross-section, courtesy of Benoit Valley, UNINE.) of open hole is clearly observed on long sections (ibid). In the worst case, maximum breakout observed was 8 ½” x 13" for a wellbore drilled with an 8 ½” (216mm) roller cone drill bit.

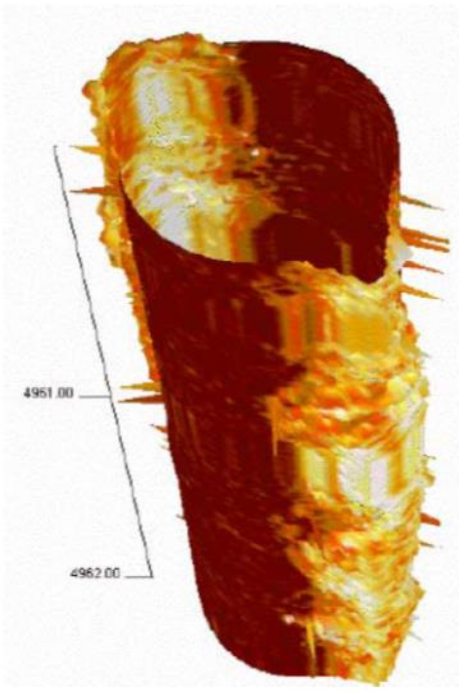


Figure 6: image log from the hole drilled in the crystalline basement in Basel (2006)

In light of that borehole measurements, it appears that no technology currently available on the market can reliably and consistently perform an adequate zonal isolation, regardless of other parameters such as temperature or fracture gradient.

Figure 7: BS-1 (Basel) hole cross-section, courtesy of Benoit Valley, UNINE.

The need to develop such a system for the reliable EGS construction in deep dry geothermal projects is therefore established.

In paralleled, effort must be deployed to enhance drilling into crystalline rock and to properly size and orient the wellbore to limit breakouts. Nonetheless, breakouts are to be expected in such projects, and a more reliable zonal isolation solution will work even better in more cylindrical holes. Such a solution would also benefit to the oil and gas industry for which zonal isolation is still a critical issue (Benge G., 2011).

4.2 Temperature

It is expected that geothermal EGS producer wells will operate at more than 150°C. The target temperature for the Haute-Sorne project is 170°C minimum, Soultz-sous-Forêt reservoir temperature approximates 200°C, and the Paralana project in Australia was targeting a 190°C bottom hole temperature, let alone Jolokia-1 in Australia where 278°C where measured at 4911m vertical depth.

Sectioning a drain for EGS creation under these conditions requires the necessary attention. Temperature affects cement strength. Strength retrogression is the phenomenon under which cement degrades with time at high temperature. Specific cement slurry formulations have been developed by the service companies to prevent or to decrease the rate of degradation of the set cement, while allowing the liquid cement slurry to maintain the necessary pumping time for a safe placement.

Elastomers are greatly affected by temperature and some specific compounds have to be used for the appropriate temperature range. Some of these compounds are today available for up to 200°C. They have been used in specific applications such has steam flooding in heavy oil SAGD (steam assisted gravity drainage). For very high temperature application, metal packers have been developed such as the Packer Plus Inferno system designed for operating at 315°C (Olsen et al. 2015).

For EGS wells, because the stimulation phase will include the injection of large quantities of stimulation fluid, the downhole isolation will experience temperature shocks between the cooling injection phases and the warming shut-in or production ones. The pipes lining the isolation material will also contract and expand with these temperature changes thus affecting the isolation quality. It is therefore important that the isolation system could withstand temperature changes while still providing the required seal under the stimulation differential pressure.

4.3 Cementing

Cementing has been used to seal pipe annuli and to prevent communication between geological formations of different characteristics for decades. The operation consists on replacing the drilling fluid around the pipe by circulating a liquid cement slurry down the pipe and up the annulus, and let it set a defined lapse of time known as wait-on-cement (WOC).

Even though the technology is considered mature, the Macondo catastrophe (Benge G. 2011) reminds us that achieving a tight zonal isolation through cementing remains an operation requiring engineering and specialized services.

The main critical aspects of cementing to achieve the required isolation can be listed as:

- drilling fluid conditioning (circulation) prior to cementing,
- pipe centralization,
- fluid design and rheology achieving drilling fluid removal,
- pump rate,
- pipe movement during cement placement.

The formation fracturing gradient must also be such that the slurry hydrostatic pressure prior to cement setting and the friction pressure experienced during the cementing operation do not break any exposed geological formation. But what might be the overarching parameter for good cement placement remains the drilled hole calibration. In light of paragraph 4.1 above, cementing maybe applicable in settings that exhibit an isotropic stress field around the wellbore, but becomes a questionable technique when confronted to hole cross-sections such as seen in BS-1. In that case, and for cementing to become an EGS zonal isolation method of choice, more engineering has to be undertaken with respect to drilling fluid removal and cement placement.

On the temperature side, BJ services claims to have a cement design sustaining 316°C, Schlumberger Well Services 350°C, and Halliburton 370°C. Therefore, from a cement design standpoint, the temperature issue seems to have been solved by the major service companies.

The other issues related to cementing the reservoir section that are still pending are:

1. The risk of invading the permeable system with the cement slurry, thus permanently damaging the geothermal reservoir, should the EGS creation not be able to by-pass or render this damage irrelevant.
2. Cementing the pipe in the reservoir section obviously requires a technology to regain access to the reservoir formation and its permeable system. This issue is discussed later in this document and is far from anecdotal.

4.4 Multi-Packer Systems

There are basically four types of packers on the market: the mechanically set elastomer packer, the inflatable packers or external casing packers (ECP) the solid expandable packers and the swellable elastomer packers.

4.4.1 Mechanically and hydraulically set packers

These have an internal mechanism that is activated either by a mechanical movement of the pipe or by hydraulic pressure. Once activated, rubber element expand outside under mechanical compression. This type of packer is routinely used inside casing for testing, as production packers, or special completion operations such as gravel-packing. The expansion of the packing elements under compression is limited, and as such, not particularly suited for open hole applications in which irregular wellbores are found (Valley and Evans, 2009).

4.4.2 Inflatable packers (ECP)

Inflatable packers are an elastomeric bladder mounted on a steel mandrel fitted with hydraulic ports and valves. The packer are run to depth with the casing or completion string. When on depth, the internal pipe pressure is increased to activate the inflation mechanism. The packer's bladder fills with the injected fluid until it seals unto the borehole wall. These systems are commonly used as contingent sealing equipment in casing cementing operations.

According to Baker Hughes, at geothermal temperature, these packers should be inflated with cement (Mannheim P., 2016). That means that either this system is used as a supplemental system to ensure the hydraulic seal of a cemented liner, or that a special workstring and inflation tool has to be run to inflate each packer individually with cement. Even though inflatable packers offer by nature a greater aptitude at sealing in irregular wellbores than mechanical packers there is no guarantee as to their ability to provide sealing under extreme hole conditions such as describes in paragraph 4.1. Extensive testing would be required before running this type of equipment as the sole drain segmentation mean for EGS creation.

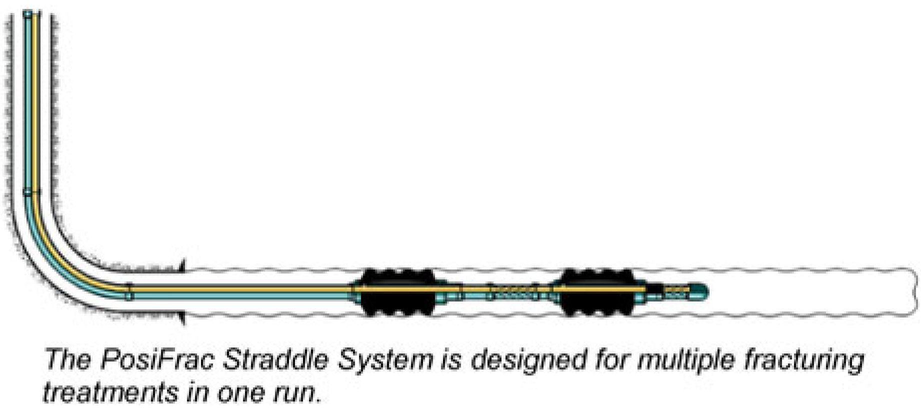


Figure 8: Example of a straddle stimulation tool, courtesy of TAM International, Inc.

This inflatable packer technology could also be used to temporarily straddle sections of the drain for individual stimulation. A workstring conveying two inflatable packers with an injection port in between, as presented in Figure 7: Example of a straddle stimulation tool, courtesy of TAM International, Inc., would allow the independent stimulation of individual sections. Each stimulation sequence would involve placing the tool across the zone of interest, inflating the tow packers, pumping the stimulation job, and deflating the packers before moving to the next section. The workstring could also include some measuring devices that would provide all sorts of downhole measurements for real-time or post-mortem analysis. This system would also offer the maximum operational flexibility for the stimulation sequence and the largest possible diameter open for the geothermal loop.

Figure 9: Example of damaged inflatable packer in Triemli.

However, crystalline formations can exhibit highly abrasive surfaces (Mohamed N. et al, 2009), and the durability of the elastomeric envelope after having extensively dragged onto a long open hole section has to be proven. The unfortunate experience of running inflatable packers in a crystalline formation in Triemli (Switzerland) is a case in point (Figure 8: Example of damaged inflatable packer in Triemli.

and Figure 9: Example of damaged inflatable packer in Triemli well.

). Though attractive on paper, the lack of reliability of such a system cannot be justified on operations that are in search of lowering operational risks.

Figure 10: Example of damaged inflatable packer in Triemli well.

4.4.3 Solid expandable packers

Figure 11: drawing of a drain section isolated between two steel packers, courtesy of Saltel Industries

A ruggedized version of the inflatable packers is the solid expandable or steel packers that do not rely on an elastomeric bladder but on a deformable steel sleeve that is permanently expanded when the inflation pressure is applied in the running string. These products have been also primarily used to replace or as a contingency device for cement operations, but a provider also developed a version for multi-stimulation applications.

This type of technology would likely not suffer the problems experienced in Triemli. However, there is no evidence that the type hole section with breakouts such as in Basel could be sealed with these devices. Here again, additional engineering and testing is needed before enough confidence is gained to recommend its conditions of utilisation.

4.4.4 Swell packers

Figure 12: Swellable elastomer packer, Courtesy of TAM international, Inc.

Packers based on swellable elastomer are available in oil base activating fluid version and in water base activating fluid, geothermal completions are obviously interested by the latter. A reactive elastomer sleeve is mounted onto a packer mandrel. When in contact with its activation fluid, the elastomer starts expanding in all directions (Figure 12: Expansion of a Swell packer in a lemon shape hole, courtesy of TAM international, Inc) until the space available is filled. Swellable elastomer offers the opportunity to simplify completion operations while providing zonal isolation in irregular holes. Additionally, because of their ability to self-heal from scratched by swelling, swellable elastomers are not regarded as highly sensitive to abrasion. This is an appreciable feature when running in holes that may seriously wear any surface it contacts.

Figure 13: Expansion of a Swell packer in a lemon shape hole, courtesy of TAM international, Inc.

Several manufacturers are offering products of different characteristics based on proprietary technology. Some packers of this type have been already used in high temperature application, especially to segment completion of steam injection wells in Canada. However this technology must be tested and better understood to be implemented with an acceptable degree of confidence within the geothermal industry. The pending questions are:

1 The ability to run a large number of these packers to depth without setting them prematurely prior to reaching well bottom (TD).
2 The ability to seal and provide enough resistance to differential pressure during the stimulation phase in largely asymmetrical wellbores.
3 Long term durability of the seal in case these packers are used to seal-off sections of excessive injectivity (thief zones) later on in the life of the geothermal operations.

5 Connection between wellbore and formation

5.1 Perforations

Modern guns are using explosives in conical shaped charges to perforate steel casing, cement sheath, and to penetrate as far as possible into the formation behind. Perforating is a required companion of cased and cemented well completion. In the case of a selectively stimulated drain the perforating operation must be performed in sequence along the stimulation sequence to inject the stimulation fluid each time in the selected interval.

The use of perforations to regain access to the reservoir face requires that the part of the drain already stimulated are plugged before new perforations are opened to stimulation, hence the “Perf and Plug” technique. Because of this plugging requirement, the stimulation sequence can only be performed from toe to heel, or from bottom to top. The guns are run across the deepest section of interest and fired in position and the perforated section is stimulated. After the stimulation, the section is covered with a sand plug and the next section of interest is perforated. Alternatively, the section can be isolated with a mechanical device plugging the casing ahead of the stimulated section. The second stimulation is performed and another plug is positioned. As many perforating/stimulation/plugging operations as necessary are performed in sequence.

After all the zones of interest have been treated, the wellbore is cleaned out (or the plugs are retrieved). Today, some service companies also offer mechanical plugs that dissolve over time in completion fluid, thus not requiring the clean-up trip.

Even though the Perf and Plug technology has proved to be effective in the oilfield (Norris et al, 1996), its utilisation for EGS creation would require answering a number of issues.

1 On the one hand, perforation technique is the one that gives more flexibility in selecting what segment to actually perforate and how many holes to shoot, thus allowing a precise placement, almost surgical, of the stimulation treatment. On the other hand, because the stimulation sequence must happen in the top to bottom order, it offers no flexibility in the spacing of two consecutive stimulation treatments. Until EGS development is better known, this feature may be detrimental to the optimisation of the EGS creation operations.
2 The proper shooting of the perforation requires a precise knowledge with respect to the permeable targets, these must be properly identified through potential losses recorded during the drilling phase and the use of logs such as borehole tele-viewers. It requires also a thorough placement of the guns across the zone of interest.
3 The penetration of the perforations into the crystalline basement is largely unknown. Explosives used in shaped charge are notoriously affected by temperature, their exposure to

high temperature decreasing their efficiency. In highly deviated holes outside the reach of electric line, tubing conveyed perforators (TCP) guns may take a long time to reach bottom. Alternatively, they can be conveyed faster by coiled tubing (CT), however, coiled tubing operations can become quite tedious for long wells, when large tubing reels have to be shipped to location. Moreover, using coiled tubing for gun conveyance requires that this equipment remains on-site for the entire duration of the "Perf and Plug" phase, and that could result very costly as the stimulation stages increase.

4 The cement slurry filtration may plug the entrance of the permeable system. That permeable system has then to be opened again that also would call for deep penetrations that could by-pass that damaged zone.

5 Existing guns shoot radially. When the well intersects a network of fissures, shooting charges radially may not maximize the chances of intersecting these fissures and recovering the connection with the permeable medium.

6 Recovering the plug, either sand of mechanical may require an additional rig or CT operation that could also damage the newly stimulated fissure network in case of losses during that operation. The new self-degrading material could be a solution to this, if their solubility is confirmed at downhole geothermal conditions.

With regards to the perforation technology available on the market today, the investigation undertaken in the scope of the Pohang operations with the technology leading company Schlumberger revealed that:

- High temperature explosive are available up to 100hrs at 230°C which is compatible with most geothermal application and beyond the required performances in the scope of the DESTRESS project.
- Using the most efficient charges on the market, 4 ¾" TCP (tubing conveyed perforators) guns inside an 8 ½" wellbore could achieve a penetration between 20 and 40 cm with the following rock parameters:
  - Granite
  - Young's modulus: 33.5 GPa (28GPa~45GPa) (4 to 6.5 million psi)
  - Density: 2.63 g/cm3
  - Porosity: 0.5 %
  - Uniaxial compressive strength (UCS): 90.3 MPa (70~111 MPa) (10,000 to 16,000 psi)

5.2 Sliding sleeves

5.2.1 Ball operated:

When industrializing the shale oil and gas hydraulic fracturing operations, service companies have developed sleeves mounted with with ball seats of increasing diameters from bottom to top. These sleeves, also referred to as "frac sleeves", are opened in sequence during the injection by dropping balls of increasing diameters.

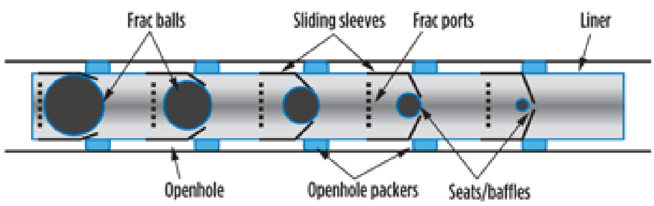


Figure 14: Ball activated sliding sleeves, courtesy of http://blog.sina.com.cn

Attractive from an operational efficiency standpoint, the system requires a toe to heel stimulation sequence that cannot be used until we know the impact of the selected sequence on the soft stimulation effectiveness. In case that the well pressure has to be bled-off, this system should be able to do it, but not sequentially. In any case, it has not been designed with that intention and a deeper analysis should assess the risk of a potential failure at bleeding off during a soft stimulation sequence.

Additionally, these systems, until recently required flowing back the balls to surface (not necessarily feasible when downhole pressure is low, and a clean-up trip to mill out the restrictions linked to the ball seats.

Today, some equipment providers have overcome these issues by providing balls and seats made of soluble material. However, additional work would be required to understand the speed and fluids involved in the dissolution process.

These systems may in the future improve the economics of EGS projects. For the time being, the pre-determined stimulation sequence is the main reason for not recommending the system before the other limitations can be studied in more details.

5.2.2 Mechanically operated:

The mechanically operated sliding sleeves have been on the market for decades, incorporated at various levels of a completion string. They are usually operated by slickline, whenever communication or shut-off between the production string and its annulus was required.

The slickline is using either an opening or a closing shifting tool to operate the sleeve to the desired position.

At a deviation angle of more than 60°, this equipment is beyond the reach of slickline. In these cases, either a tractor to pull the wire or a coiled tubing (CT) can be used to reach and operate the desired action downhole. Alternatively, some sliding sleeves can be remotely actioned with hydraulic or electric control lines. These sophisticated systems are expensive. In case of multiple sleeves (GES project plans on running 30 devices), a highly-engineered system would have to be developed to minimize the number of control lines and ensure the reliability of the system at geothermal conditions. The tools to connect the control system to surface while maintaining a large internal diameter is still to be designed.

Figure 15: Mechanical sliding sleeves, Courtesy of Kentor Ventures Ltd.

In theory, this type of equipment, when used in a multi-zone completion, could not only serve as a selective stimulation tool, but also as a flow control system during the life-time of the well. Indeed, a relatively simple intervention could achieve a redistribution of the production or injection pattern by easily shutting off a thief zone. In practice, the long-term (20 years minimum life of a geothermal well), would require that these sleeves are still operational after years downhole.

For a segmented geothermal drain that requires multiple individual stimulations these mechanical sliding sleeves are an attractive proposition, provided that:

- They can be found in diameters compatible with the high flow requirement, i.e. larger than the common oil and gas completion diameters.
- They can be manipulated with flexibility and at reasonable costs

5.3 Perforated pipe

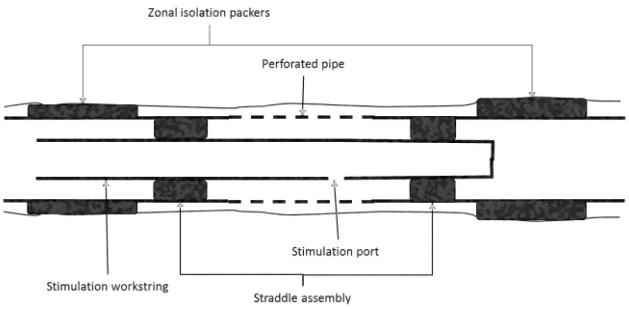


Figure 16: Workstring straddling a perforated joint for selective stimulation

The communication between the wellbore and the reservoir could be achieved by a perforated pipe mounted between the zone isolation devices. It would similar to having the sliding sleeves presented here above run in a permanently open position. The selective stimulation would then be performed through a workstring that would terminate with a straddle assembly. The bottom hole assembly would straddle the perforated section to achieve selective injections. Because the straddling system is then run inside pipe, it could be a fairly robust technology. However, because of the requirement for running a fracturing workstring, this solution implies that the rig has to be kept on-site for the duration of the stimulation period. This solution must be subject to a cost/benefits analysis and might be attractive under certain situations.

6 GES selection for Haute-Sorne wells

The Haute-Sorne project comes after the Basel experience presented in the previous sections of this document. Further analysis (see paragraphs 1 and 2) concluded in the necessity of developing a multi-segment stimulation system that would lower the risks associated with geothermal projects, by better engineering the EGS creation. To that end, Geo-Energie Suisse A.G. had developed an innovative design consisting of a properly oriented and stimulated wellbore. The borehole is segmented, and each segment is individually stimulated to accommodate for the required injection (and production) flow rate evenly across a defined rock mass.

6.1 Haute-Sorne EGS specifications and requirements

In the Haute-Sorne wells, the selected completion system must comply with the following requirements:

- The system must allow pinpoint stimulations, up to 50 l/sec (19 bpm) of 30 individual sections.
- The maximum anticipated bottom hole static temperature is 180°C
- Bleed off must be possible after each stimulation to mitigate the seismic risk
- To improve the project NPV an important requirement is the minimization of energy losses in the entire system. Among these, friction losses throughout the pipes plays a major roles, hence the requirement for maximizing the internal diameter of the completed well from TD

to surface. Therefore, the system must exhibit the maximum possible internal diameter fitting the 8 ½” open hole.

- The system should allow for the maximum flexibility during the stimulation operations and not force the stimulation sequence along the drain.
- If possible, a downhole measurement system should be installed. That system would ideally give real-time information during the stimulation phase to indicate where the stimulation is taking place and to feed to seismic monitoring system. Should that not be possible, a downhole system that could provide post-mortem information is desired. Later is the document, the difficulty of installing such sensing systems is debated in paragraph 8.
- To limit the financial exposure, as well as improving the safety of the stimulation operations, it is desired to operate the completion rigless.

6.2 Haute-Sorne selected equipment

The selected completion design of the Haute-Sorne project is based on careful analysis of the merits of currently available techniques and of the risks associated with each of these technologies. Considering the requirements and all these aspects, Glovelier-1 (GVL-1), the first well of the Haute-Sorne project completion design includes:

1. Segmenting the drain with water swellable packers
2. Accessing each zone with reclosable mechanical frac sleeves that can be operated either with slickline, wireline or coiled tubing.

6.2.1 Justification for using swellable packers:

- 200°C rated water swellable packers are available from many different packer suppliers.
- The activation of the swell packers (200°C rated – 7500 psi differential pressure) can be delayed 10 days, thus allowing retrieving the string and running in again in case of problems. Additionally, because the swelling process is an osmotic one, they can be run in a salt saturated environment thus preventing any swelling before the well is turned to fresh water.
- The use of water swellable elastomer offers the opportunity to simplify completion operations while providing zonal isolation in irregular holes. The installation of these packer is straight forward, with no movement or setting pressure involved. Swell packers have no moving part.
- In case of breakout such as those experienced in Basel-1 well, swell packers will keep on swelling until reaching the borehole wall, thus providing sealing even in case of large breakout, regardless of the shape of these breakouts.
- Swell packers are self-healing. Even though scratching may occur during installation in this abrasive rock environment, sealing with swell packers should remain effective.
- Once the completion is set the drilling rig can be released and time allowed for the packers to seal before mobilising the stimulation equipment. The stimulation is then performed rigless.
- Centralizers and gauge rings will be used to reduce friction and to protect swellable elastomer during the installation process.

6.2.2 Justification for using reclosable frac sleeves:

- Mechanical frac sleeves can be operated in whatever order thus not requiring a fixed bottom-up stimulation sequence.
- Slickline (S/L), wireline (W/L) (with or without tractor) or coiled tubing (CT) can manipulate the mechanical sleeves, depending on the well trajectory.
- Pressure can be either maintained or bled off after each stimulation, thus adding operational flexibility.
- No flowback and no milling is required after the stimulation operations.
- This equipment already exists from different completion hardware suppliers.
- High temperature versions of frac sleeves have been developed essentially for steam injection wells (SAGD) in Canada and are rated 350°F (177°C) or higher.
- Mechanical sleeve could be moved at a later date to alter the injection /production downhole flow profile and optimise the power production.

6.2.3 Further investigation with respect to these devices

Swell packers and mechanical sliding sleeves have been on the market for some time now, and they have proven their efficiency in oil and gas completion applications. However, they have not been used in geothermal application and the volume of activity on the EGS market is such that there is little to no experience in this environment. Therefore, there is a necessity to clarify the behaviour of this equipment in the geothermal sector.

Swell Packers

- Oil and gas completion strings seldom exceed 5 ½ in, in nominal diameter. In the geothermal industry, this is too small to achieve the economical circulation rates.
- The high temperature versions have been developed for steam flooding (SAGD) applications. Therefore, the completion string is run to bottom under mild temperature conditions. The heat is applied later, when the string is in place. Therefore, risks of premature setting for these elements activated at high temperature do not exist.
- As described in paragraph 4.1, large breakouts can be found in geothermal holes targeting the crystalline basement. As the swell packer expands, its compound absorbs water and becomes softer. The ability of providing enough seal to the differential pressure experienced in the stimulation phase is unknown. Indeed, swell packer providers are able, for a given packer, to produce data showing the pressure differential rating versus the ID to be sealed; however, that is always in a cylindrical shape, what driller would name a “washout” configuration. The breakout shape is quite different and probable more severe, depending on how the elastomeric compound deforms and rearrange itself during the swelling process.
- Even if logging data can provide information on where the hole is best suited to place the packers, thus increasing the chances of achieving zonal isolation, the completion string may not reach bottom because of operational problems. In these conditions, the EGS will have to be developed within a sub-optimal situation. The completion and stimulation engineers will then have to make informed decisions on to how best develop the EGS. Data on the swell packer behaviour in a breakout environment will then be critical to take the best approach.

Mechanical sleeves

- Widely used in oil and gas completion strings, there are very few models exceeding 5 ½ in, nominal diameter. This diameter is too small for geothermal projects, in particular those involving EGS, such as Haute-Sorne. Larger OD versions (>6”) are currently offered by only a limited number of manufacturers
- The temperature rating of sliding sleeves is chiefly due to the type of elastomer when this material is used for primary or back-up seals.
- The operability of the sleeves after years in the hole, in case flow profile has to be modified for production optimization is unknown.
- Initially, it was envisaged that the well trajectory could be kept under 55° deviation from the vertical to ensure wireline access and reduce the cost of operation. Operating the completion with slickline was indeed a cost saver because the rental cost of a slickline unit is well below any other downhole intervention mean. Therefore, the Glovelier-1 well was initially design with a maximum hole deviation of 55°. However, when investigating the feasibility of the slickline operations, it appeared that this mode of operation was not straightforward and posing a number of risks

Slickline operation of the mechanical sleeves

- No reference could be found for similar operations in term of depth and well configuration (large bore)
- The tool that would be used with slickline can only open when mounted in one direction or closed when reversed. The tool operates each sleeve that it passes. Therefore, to open sleeve number n, the operation would necessitate running in hole with the opening tool, open sleeves number 1 to number n, pull the slickline out, take off the opening tool and install the closing one, run in hole and close all sleeves from sleeve 1 to sleeve n-1. These operations increase the risk of failure of the slick line as well as of the sleeves themselves (since the top sleeves would undergo up to 30 opening/closing cycles).
- Additionally, simulation performed by a wireline services provider (Mannheim P., 2016) shows that the main risk resides in the ability of the slickline to reach the deepest sleeves and then its ability to operate enough downward and upward forces to close and open the sliding sleeves.
- A lack of operability experienced during field work would necessitate the mobilization of additional equipment at a substantial additional cost and considerable and expensive time delay.
- In addition, the well inclination may not be optimal at 55° from vertical with respect to borehole stability and the risks of failure of zonal isolation may be higher at 55° than closer to horizontal. To maximize the chances of success of reaching the objective flow rates, keeping the option of drilling the reservoir section at a higher angle is a prudent approach.
- Slickline failure might result in lengthy and expensive fishing operation(s) potentially requiring the urgent mobilization of heavy equipment (coiled tubing or heavy duty slick line reel), not necessarily available on the European well intervention market.
- Given the current knowledge and experience in deep geothermal wells, maintaining the cost below a level that would ensure the economic success of a project is secondary to ensuring a technical success. Therefore, the focus must be at reducing operational risks to the very minimum acceptable level. To mitigate the risks associated with slickline

operations, it appears that a tool with retractable dogs would be much more suitable to manipulate the sliding sleeves. These tools need power to operate, this power being either electric and operated with wireline, or hydraulic and operated with coiled tubing.

Electric-line tractor and stroker operation of the mechanical sleeves

- Tractor and stroker have been on the market for many years, Welltec being the Danish company at the forefront of that technology. This equipment is powered through an electric cable, the same cable used for downhole measurement.
- The E-Line tractor can be used in any kind of well trajectory thus allowing much more flexibility on the well design.

Figure 17: Wireline tractor Well Tractor®, courtesy of Welltec®

Figure 18: Well Stroker®, courtesy of Welltec®

- The stroker allows to transmit the required forces where needed. This solution would then use a retractable shifting tool that would not require manipulating more sleeves than necessary to achieve a given injection configuration.
- References of operations with similar borehole lengths and at similar temperatures are available.
- The tractor and stroker can be transported to the well site without particular transport system, they are frequently air lifted for offshore operations.

Coiled tubing operation of the mechanical sleeves

- Coiled tubing (CT) intervention is a standard operation in many deviated wells.
- Coiled tubing allows to deliver treating fluid at specific depths if needed.
- Equipment can be powered downhole using either pump hydraulic power or using an electric cable installed inside the coiled tubing.
- However, CT simulation (ibid) shows that this solution would work with a maximum well deviation of 80° in Haute-Sorne for a 2” coiled tubing.
- A CT solution would also be a logistics challenge: 2 reels would have to be brought on site and the pipes be welded together in Haute-Sorne. The feasibility of bringing a large CTU in Glovelier is still under investigation. Since the European market is very small for this service, the availability of the equipment cannot be guaranteed for the coming years.

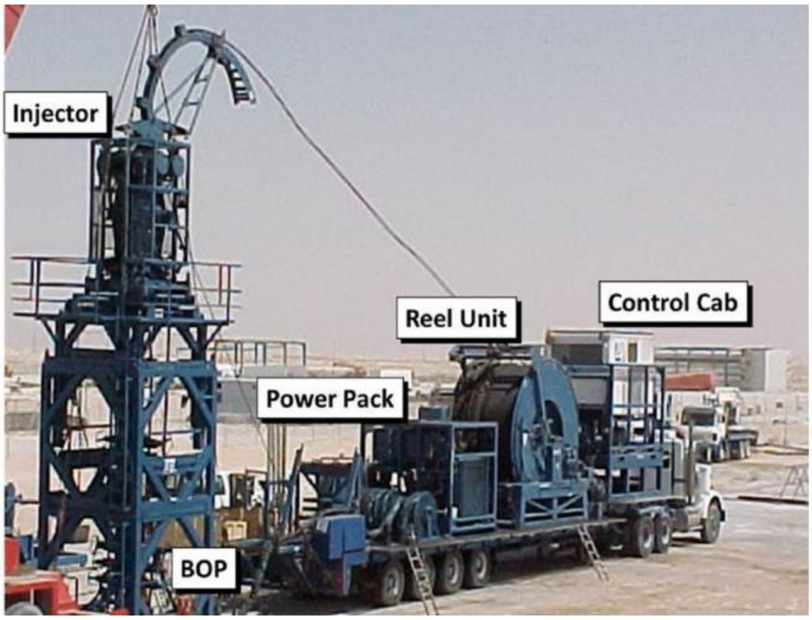


Figure 19: Coiled tubing unit in operation, courtesy of Baker Hughes international.

Rig operation of the mechanical sleeves

Keeping the rig on site to operate the completion during the stimulation operation is an option that has also been contemplated. The rig has all the power and capability of operating the completion in the well that it has drilled.

However, the rig based solution is by far the most expensive in terms of equipment, personnel and power required without showing a clear benefit compared to other solutions.

Conclusions with respect to the operation of the mechanical sleeves

- The limitations in Slickline operability at great depths and high angles is an unnecessary high risk to the project. Other solutions exist that have been investigated.
- The Tractor and Stroker solution is the most elegant, offering also the greatest flexibility and is readily available.
- The CTU solution is logistically more challenging (the transport issues to a well site is geography dependent) while offering less flexibility and reliable cost estimates are highly market dependent in a volatile environment.
- Using the rig during the stimulation campaign is economically unjustifiable.
- Based on these conclusions, it was decided, for the Haute-Sorne project to lift the deviation constraint of 55° maximum thus allowing to be more flexible on the trajectory, taking into account well stability and reservoir parameters as the main priorities.

7 GES tests for the Haute-Sorne solution

The above selected equipment was developed and used in oil and gas application. As previously described in paragraph 6.2, a number of questions are pending with respect to their ability to effectively segment the wellbore while allowing the individual stimulation operations.

7.1 Swellable elastomer tests

The completion equipment providers do usually produce for their products the following charts:

1. The elastomer expansion with time under specific temperature and fluid environment
2. The differential pressure that a fully swollen packer can sustain for a specific hole diameter.

In deep geothermal crystalline formation, there is some flexibility of what fluid can be left in the hole to let the packer swell, in particular in terms of salinity. The amount of breakout is more difficult to apprehend, because it is mainly dependent on a stress field that is largely unknown and on a formation rock's compressive strength that is a mere guess before the well is drilled. In all cases, no data exist for these packers' performance in holes with non-cylindrical shape.

Four packer manufacturers have agreed to have their equipment tested under GES conditions. They are all based on a 6 5/8" base pipe to wrap more elastomer than on a 7" pipe.

7.1.1 Test Programme

In the scope of the DESTRESS project, Solexperts A.G. has been contracted to conduct a series of test on swell packers with the aim of:

3. Selecting the most promising equipment to conduct more costly tests.
4. Evaluate the performance of the selected equipment under the simulated pressure and temperature conditions
5. Eventually, work with the selected provider to improve their equipment performance if needed.

The initial test consists of understanding and establishing a benchmark of the swelling process in a cylindrical hole and under controlled conditions. Afterwards, the four packers from the different providers are to be tested in parallel in similar test conditions.

Eventually, the following will be produced:

- A chart of the pressure evolution against the borehole wall versus time at low temperature (<60°C). This temperature was selected for two reasons: firstly, the temperature had to be maintained below 100°C to allow the tests to be performed at atmospheric pressure, and secondly because the distributed pressure sensor to capture the pressure that the swelling elastomer applies onto the borehole is limited to 60°C.
- Produce values of the differential pressure that these packers can sustain once they are fully swollen inside a breakout borehole, similar to the one observed in Basel.

After these tests are performed and analysed, the course of action is:

1. Select the swell packer to be used in Haute-Sorne

2 Should it be necessary, work closely with the manufacturer to improve the selected packer
3 Build an autoclave allowing the testing on the selected packer in a full scaled environment, at high temperature and pressure.

7.1.2 Laboratory setup

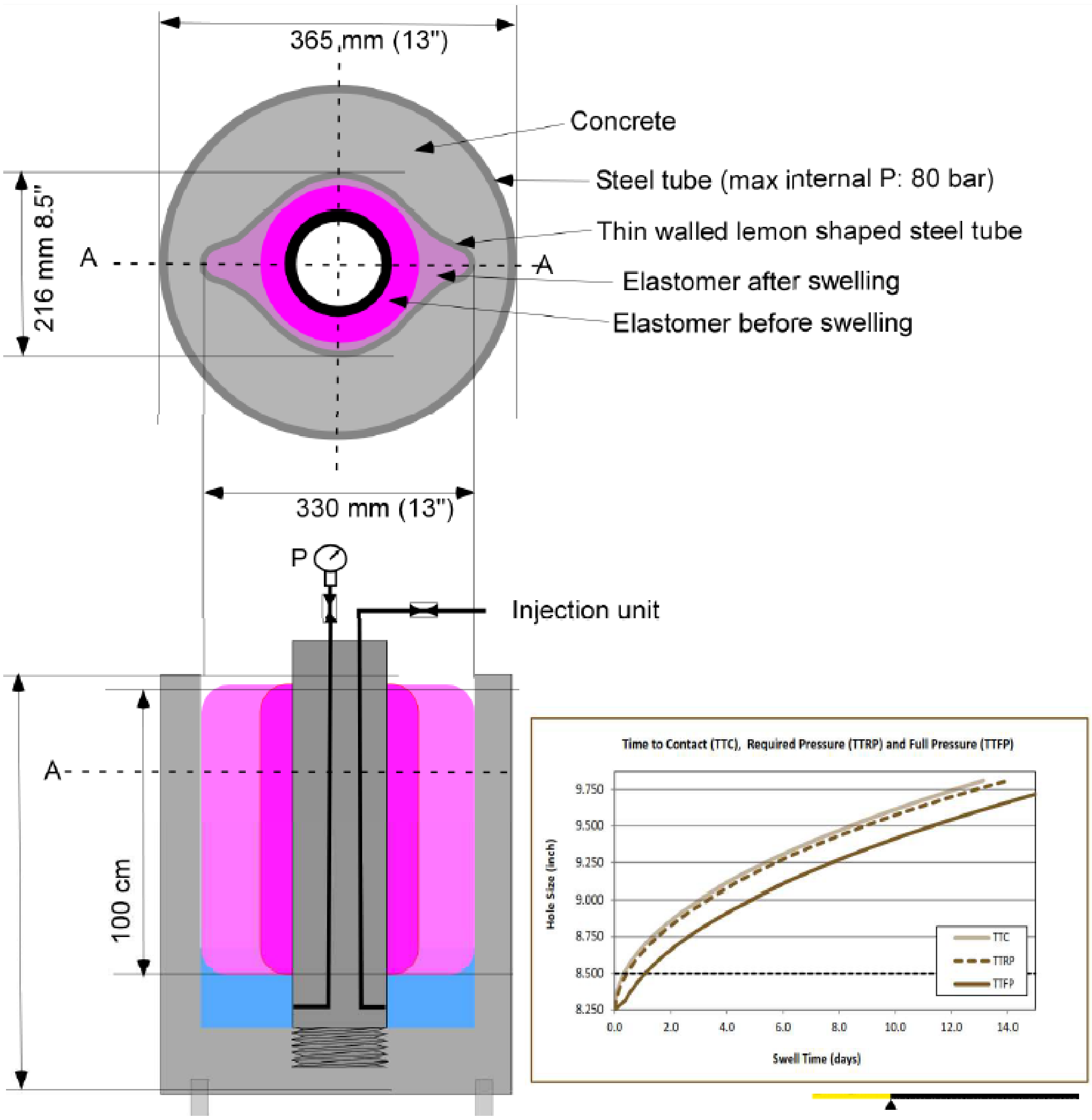


Figure 20: Laboratory setup of the breakout packer test. Courtesy of Solexperts AG

Atmospheric pressure test

These series of tests include for both one cylindrical benchmark test and for the four breakout shape test:

1 The measurement on the contact pressure development versus time
2 The measurement of the test temperature
3 Measurements of the differential pressure across the packer after swelling

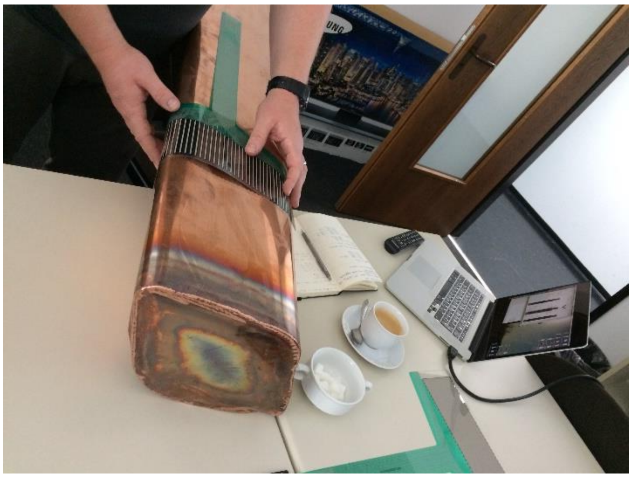


Figure 19: Laboratory setup of the breakout packer test. Courtesy of Solexperts AG show the setup that was designed by Solexperts AG to perform these tests. The cylindrical test bench is similar but for the cross-section that is circular. The thin wall tube mimicking the borehole wall is actually made of copper. It is equipped on the outside of 3 distributed pressure sensors distributed along the length of the packer and covering more than 50% of the circumference (Figure 20: the breakout shape with distributed pressure sensor, coffee cup and sugar cubes and Figure 21: The cylindrical shape mounted with the distributed pressure sensors.).

Figure 21: the breakout shape with distributed pressure sensor, coffee cup and sugar cubes

An injection tube allows circulation of the tap water used as the swelling medium. A small steel tube connects the bottom chamber to a pressure sensor, thus allowing to measure the differential pressure across the packer once the elastomer seals into the shape.
Before embarking onto the full-scale breakout tests with the four packers, it was decided to start with the cylindrical benchmark test that would also serve as a debugging test. A picture of this on-going test is presented **Error! Reference source not found.**.

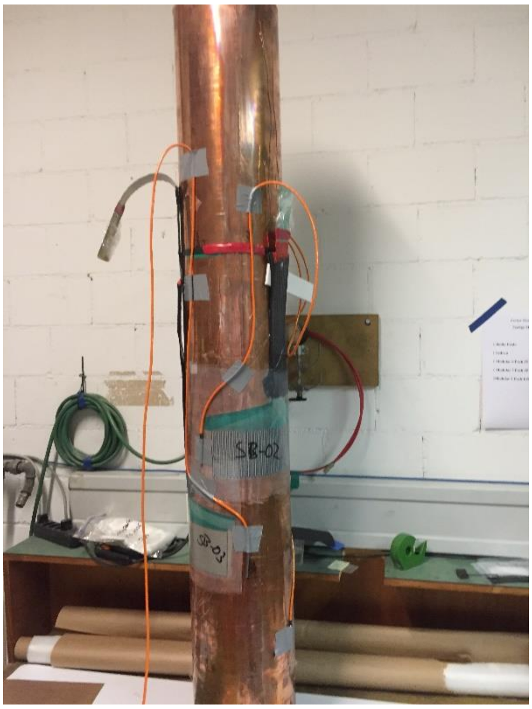


Figure 22: The cylindrical shape mounted with the distributed pressure sensors.

Once the atmospheric tests are performed, a specially built autoclave will be manufactured for the full size test in geothermal environment and in a breakout cross-section. This projected laboratory setup is shown Figure 23: The autoclave and laboratory setup for the full scale testing under geothermal pressure and temperature. Courtesy of Solexperts AG.

7.1.3 Test results

For the time being, the cylindrical test has confirmed that the swelling process is highly temperature dependent. After a few weeks, it was decided to add some heating devices to the test. It is too soon to report on the system and the results since the test is still on-going-. This report will be up-dated in the course on the project.

Figure 23: The on-going swelling benchmark test in a cylindrical shape.

Full scale test in pressurized autoclave

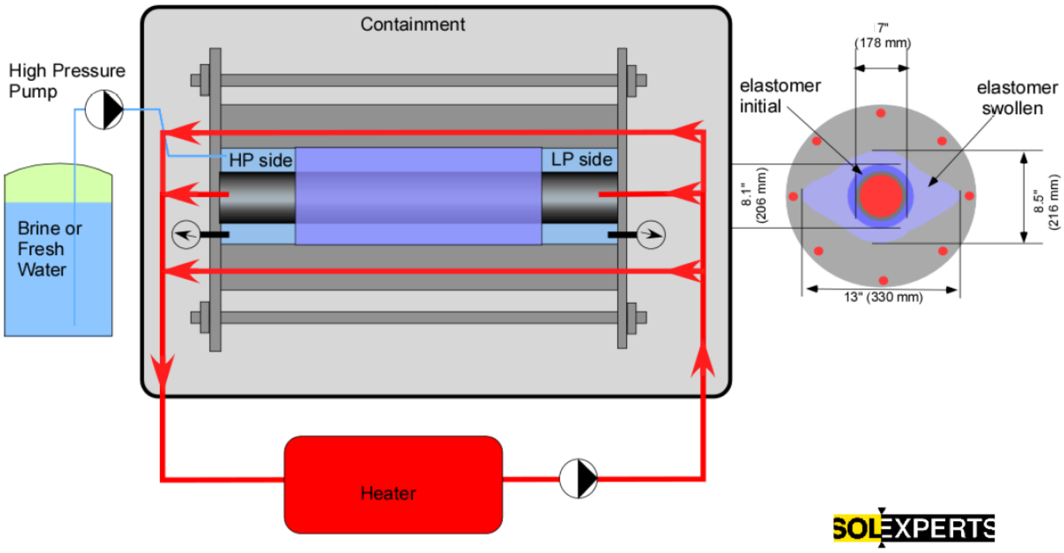


Figure 25: The autoclave and laboratory setup for the full scale testing under geothermal pressure and temperature. Courtesy of Solexperts AG

7.2 Sliding sleeve test

A large bore diameter sleeve that can be operated rig less is a critical component of the multi-stimulation system reliability. Such a component exists on the market however, because the product has been seldom used under geothermal conditions, testing is necessary to prove that:

1 The equipment can reliably be operated at more than 6000m rigless in a large diameter completion.
2 What is the maximum allowable deviation for this equipment to be operational?
3 Can this equipment be operated after some years at geothermal downhole conditions?

Because it was initially planned to operate this equipment with slickline, there was a necessity to prove the concept before running this equipment. After the idea was discussed and modelled, it was decided to switch from slickline operation to wireline tractor and stroker operation (see paragraph 6.2), therefore only item 3 in the above list remains an open question.

So far, the kind of test that would be needed for the Haute Sorne project is pending. Should the system be run in a different project with slickline operations, additional testing might be undertaken. So far two providers have been identified that could offer large bore sliding sleeves compatible with geothermal projects and available to be mounted on a 7” completion string:

Baker Hughes’ CM U/D™ sleeve, this equipment can be manufactured with a 5.875” ID, thus offering very little resistance to flow. It is an on/off type of equipment

Welltec® Flow Valve, offers a large 6.184” ID and can be mounted in its single choke version as a 2 position on/off device. Other versions include the dual flow sleeve that offers three positions: fully closed, fully opened and a choked position restricting the flow to thief zones. For more flow control, additional chokes can be used, up to four plus a fully closed position (Figure 24: Example of a WFV Welltec® variable choke sleeve. Courtesy of Welltec®).

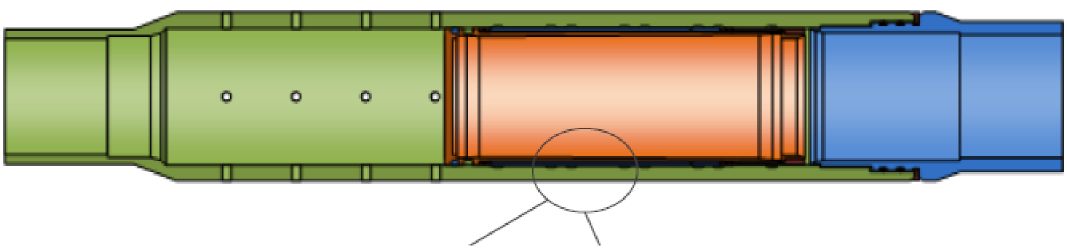


Figure 26: Example of a WFV Welltec® variable choke sleeve. Courtesy of Welltec®

Currently, the equipment available on the market has not been qualified to meet deep geothermal requirements. The Baker Hughes equipment is currently rated 150°C (300°F) for the 7” version and the Welltec® equipment has been qualified for 135°C only. Therefore, the selected equipment will have to potentially be modified and tested to ensure its long-time operability above 150°C and up to the Haute-Sorne maximum temperature of 180°C.

8 Real-time downhole monitoring

EGS creation is associated with large fluid injection(s) known as the stimulation phase. These injections are the source of two major concerns:

1. Induced seismicity associated with injection into active faults
2. Proper placement of the designed treatment to ensure its efficiency

During the life of the geothermal project that can last several decades, water circulation will cool down portions of the reservoir at a different pace.

To monitor and mitigate these effects and take the appropriate measures in a timely fashion, monitoring the geothermal well through its construction and life is desirable.

Geothermal wells primary monitoring purposes are:

1. Understand seismicity and take preventative actions
2. Ensure efficient stimulation
3. Monitor injection and production profile
4. Understand downhole temperature behaviour with time
5. Monitor well integrity

With the advance of fibre optic technology what seemed to be a distant dream a few years ago is becoming reality, provided a few developments are undertaken.

Only twenty years ago the early attempts using conventional telecom fibres for distributed temperature measurements were introduced. Today, high temperature fibre optics have been developed and distributed acoustic surveys are being run. The technology is improving by the day as research on the fibre itself (Palit S. et al. 2012, and Paulsson B. et al, 2014), but also on the surface electronic equipment for data acquisition and interpretation via elaborate software is advancing. The fibre-optic technology is still in its infancy, and we can envision the days when it will be difficult to justify not having a fibre-optic installed inside a wellbore for permanent monitoring.

The type of surveys that are currently acquired via fibre-optic are DTS (Distributed Temperature Sensing) and DAS (Distributed Acoustic Sensing)

DTS:

Using a multi-mode fibre-optic, DTS provides a temperature distribution along the fibre. A laser light is sent through the fibre. The temperature of the fibre modifies the intensity of the backscattered light in a particular frequency (the anti-stokes component of the Raman bands).

A DTS can effectively monitor selective injection of the stimulation treatment, help determine injection and production profiles, provide information on well integrity, measure geothermal reservoir temperature depletion.

DAS:

Strain modifies the refractive index in the fibre. The Rayleigh backscattered light component is analysed and translated into an acoustic survey. Backscattered light frequency, mode and intensity can be analysed in terms of flow nature and seismic events.

This type of utilisation is fairly new, but lots of research is on-going and promising results have been published, especially with regards to using DAS as a seismic monitoring tool (Parker T et al. 2014).

A DAS can help monitoring seismicity during drilling and stimulating in the field, can give acoustic indication on selective injection of the stimulation treatment, help determine injection and production profiles through noise listening, and may provide permanent seismic monitoring during the plant operation. Alternatively, Paulsson Inc. provides downhole sensors that can transmit seismic information through a fibre optic.

8.1 The benefits of real time downhole monitoring for EGS optimisation

A DTS can effectively monitor selective injection of the stimulation treatment, help determine injection and production profiles, provide information on well integrity. In case the zonal isolation system is not efficient, when a previously stimulated zone is again stimulated, the stimulation engineer can decide on whether continuing the operation or aborting the stage and switch to a different zone. This simple monitoring would allow a more efficient use of the time. It might also prevent the injection of a too large stimulation volume in a single zone.

A DAS can help monitoring seismicity during drilling and stimulating in the field. It can give acoustic indication on selective injection of the stimulation treatment, thus help determining here again the quality of the zonal isolation system. Additionally, a DAS could help locating the seismic cloud for a better determination of the EGS volume and position. This information might critically affect the trajectory of the second well. It might also help reducing the seismic risk by providing data to the traffic light system.

A DAS could also help monitoring the seismicity during drilling and stimulating of the second well, thus providing even more data to the scientist and modeller working on EGS projects.

Alternatively to DAS, Paulsson Inc. provides downhole sensors that can transmit seismic information through a fibre optic

8.2 Downhole permanent monitoring

A permanently installed DTS can effectively help determine injection and production profiles, provide information on well integrity, measure geothermal reservoir temperature depletion. On the same token, a DAS could also help monitoring the production/injection profiles throughout the life of the geothermal project, through noise listening.

Since the well is equipped with selective sleeve, these could be manipulated through a wireline and tractor operation to rearrange the flow profile when necessary thus then optimizing the power production over a longer period.

It is worth noting that a fibre-optic has been tested in Soultz-sous-Forêt EGS project where its value has been recognised for temperature profile measurement (DornstädterJ, et al. 2007). Schlumberger has also tested the fibre for VSP acquisition in GRT-1 well at Rittershoffen, results of that research project have not been published yet.

8.3 The wellbore installation difficulties and possible solutions

To benefit from fibre optic technology, two scenarios are currently used:

8.3.1 Temporary/well intervention type of survey:

Fibre optic can be run like a wireline intervention, either with a wireline unit, slickline unit, coiled tubing or semi-rigid coil-able rod (speciality by Ziebel). This type of intervention is used to get a specific survey at a specific time in the life of the well. In the scope of EGS construction, that would mainly mean data acquisition during the stimulation phase. Later on, punctual surveys could be run through mobilisation of the equipment when need is identified.

8.3.2 Permanent installation, wellbore monitoring:

Fibre-optic can be installed permanently, either strapped outside a casing string and cemented in place, or attached to the completion string and connected to surface equipment through a wellhead penetration.

Fibre-optic can also be injected into a dedicated control line (1/4” in.) installed during the well construction (that technology is patented by Schlumberger).

When a completion is designed to receive a fibre and has to be run in two parts (lower and upper completions) such as in the Haute-Sorne project, then a wet connector is needed. Both optical (permanent system) and hydraulic (pumped-in case) wet-mates (wet connectors) are available on the market. These parts are though relatively expensive, especially the optical wet-mate.

Installations can be either single ended or double ended, the double ended fibre, provided successful placement, allows for more corrections in the signals analysis. It is also worth noting that the current pumped-in technology must be double ended to be retrievable because it is also “pumped out”. Pulling the fibre out is not feasible as it will break during the operation. Pumping out is the safest way of recovering the fibre. Therefore, a retrievable fibre-optic permanently installed is done through a double ended control line.

Another way of installing a fibre after well construction is by conveying it through a coiled tubing that is suspending into the wellbore. The system has to be retrieved if a pump is to be installed or before performing any kind of well intervention.

8.3.3 Installation in Haute-Sorne

When investigating more closely the permanent installation issues, it appeared that it is more complicated than anticipated as discussed hereafter. The installation hurdles are still unresolved for the Haute-Sorne project.

The lack of a robust solution might lead to using this technology only during the stimulation operations; possibly kept in the well for the drilling and stimulation of the second well, but is unlikely to provide permanent information during the plant operation. These difficulties are explained hereafter in more details.

In Haute Sorne, the well design calls for a 7” completion liner hung at around 4900m in a 9 5/8” cemented liner (Figure 25: Casing prognosis for the Haute-Sorne geothermal well).

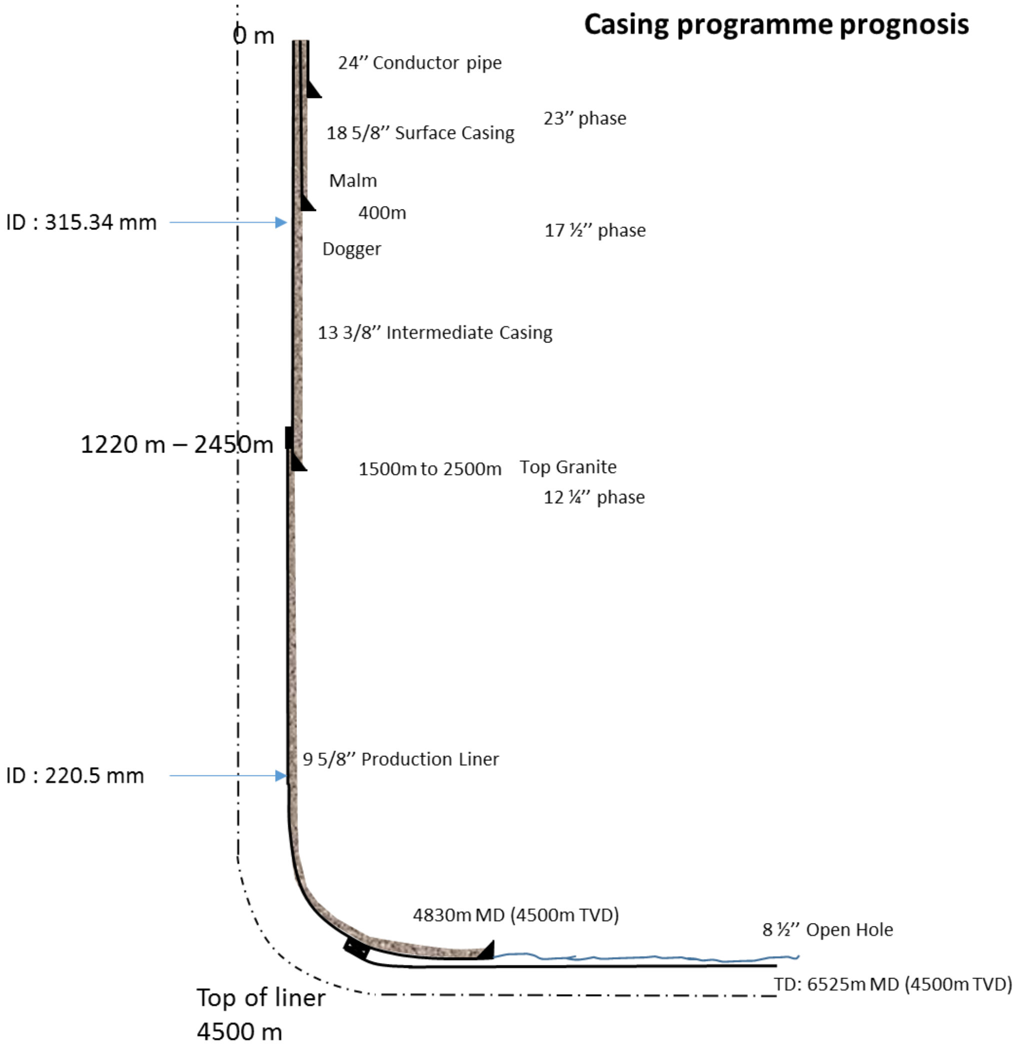


Figure 27: Casing prognosis for the Haute-Sorne geothermal well

As depicted in **Error! Reference source not found.**, the completion liner will be designed to section the open hole drain into 30 isolated intervals that will be stimulated individually through mechanically operated sliding sleeves.

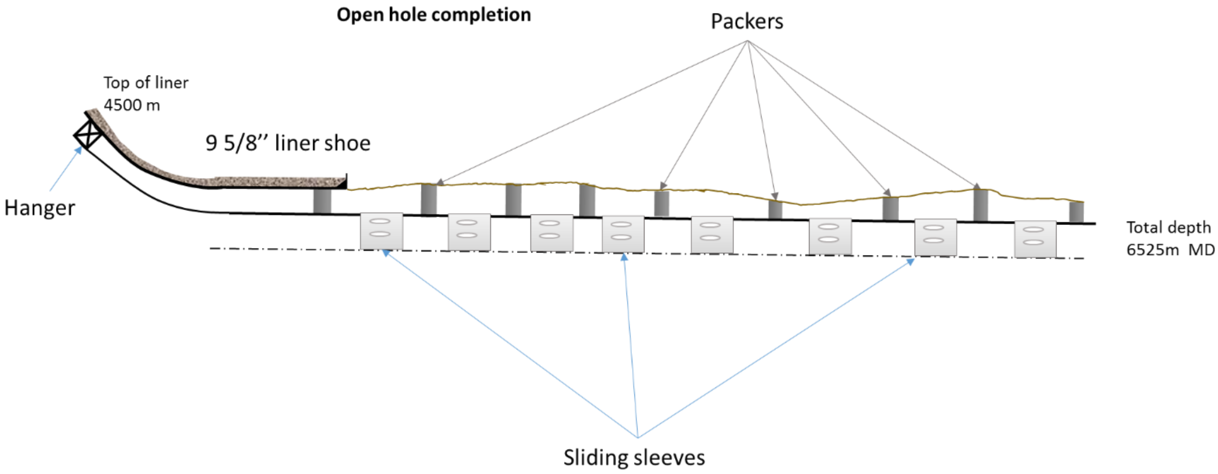


Figure 28: Haute-Sorne completion liner system

Normally, the completion liner is run with a running tool that sets the liner hanger. In the Haute-Sorne case, as shown in Figure 27: In Haute-Sorne, a 7" tie-back is installed to protect the casings and cement sheaths during the stimulation phase., a 7” tie-back would then be run to protect the casings and cement behind from the potential high pressure, during the stimulation operations.

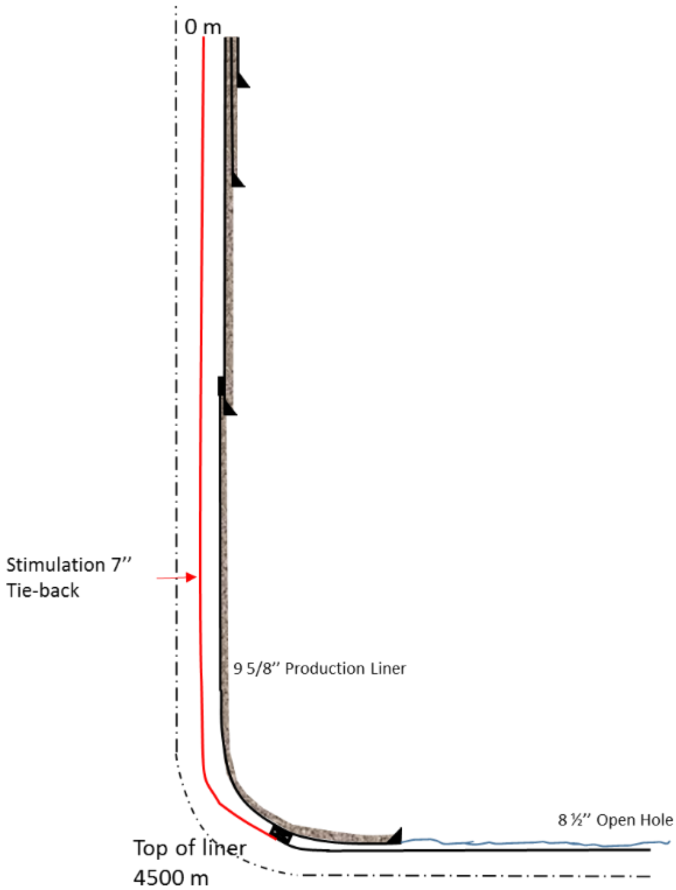


Figure 29: In Haute-Sorne, a 7" tie-back is installed to protect the casings and cement sheaths during the stimulation phase.

That tie-back would later be retrieved to use the full wellbore internal diameter during the plant operation, thus reducing the losses induced by friction pressure.

As previously stated, because this kind of completion is designed to be run in two parts (liner and then temporary tie-back), a wet connector is needed. These either optical or hydraulic wet-mates even though expensive are on the market. However, besides their cost, the current wet-mates available have 2 features that makes them unsuitable for Haute-Sorne:

1 They have been designed for 5 ½” and less completion strings.
2 Their internal diameter cannot accommodate the shifting tool necessary to manipulate the 7” sliding sleeves located below.

In the absence of wet-mate, other solutions have to be looked at.

Of course the temporary installation remains an option. In this case, the fibre could be conveyed after well construction through a coiled tubing that would be suspended into the wellbore. The wireline option can only be used in punctual surveys, because the horizontal nature of the drain requires either a tractor or a coiled tubing to run the fibre. In any case, the system has to be retrieved if a pump is installed or when a well intervention is required.

8.3.4 A new semi-permanent installation for Haute-Sorne

Because there is no suitable wet connector on the market, the alternative might consist in conveying the monitoring system with a completion string that would be run in a single operation with the tie-back. That suppose a number of specifications:

1 The liner hanger can accommodate the fibre
2 The liner hanger can be set with the tie-back connected
3 The tie-back and liner can be run together and the top joint can sustain the weight
4 The tie-back can be retrieved and safely severe the fibre optic during that operation.

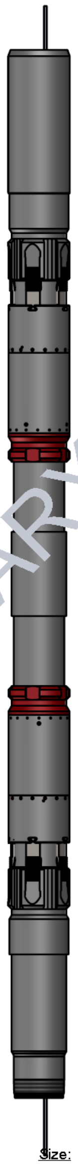


Figure 30: Example liner hanger to accommodate the fibre optic, courtesy of GOT.

The liner hanger

A European oilfield tool company was contacted to design a liner hanger that could accommodate a wire or control line on the outside while maintaining a sufficient internal diameter for the sliding sleeve shifting tool (Figure 28: Example liner hanger to accommodate the fibre optic, courtesy of GOT.).
This is possible by eliminating the seals of the liner hanger, and providing a grove to locate the fibre and run the fibre or cable between the hanging dogs.
A severing system has still to be added to the design. This system would be composed of blades that would severe the cable when rotation the seal assembly before pulling the tie-back. This type of cutting device is already an existing feature on similar tools.
The absence of seals is not a real issue in a geothermal well. In case an additional seal is desired in the 7" liner and 9 5/8" annulus, an additional swell packer can be run below the hanger.
The internal diameter of the hanger is 130mm (5.12 in.) that can accommodate a retractable key shifting tool. There is even a high expansion shifting tool on the market (HEST) by Caledyne that has a maximum OD of 72.3mm and that can expand into a 5.95" (151mm) profile).
The settings of the system is performed with hydraulic pressure after running a wireline plug to isolate below the setting ports. The plug is retrieved after setting the hanger to recover access to the liner below. Therefore, item 2 above is fulfilled and item 4 is also taken into account. The cutting mechanism would though have to

be tested on surface with the selected cable to ensure a safe operation when the tie-back is pulled out.

Running the liner and tie-back in a single run

A computer simulation (WellPlan) was run to validate the concept of running the liner and tie-back in a single run.

It appears that the liner could be run to bottom, but at a reduced speed (20m/min maximum) below 3900m (i.e. when entering the deviated section) to prevent helical buckling. The maximum hook load would be 200 metric tons, thus not exceeding the rig capacity. In case that the liner would need rotation to reach bottom, the standard BTC connections cannot be used. However, including torque rings in these BTC connection would allow that operation to be safely undertaken, providing actual fluid data and friction coefficient match the simulation values. In any case, rotating the liner and running string with the cable strapped around and a cutting device including in liner hanger still has to be carefully looked at. The option of rotating that string should be only considered as a back-up option in case the liner cannot reach bottom otherwise.

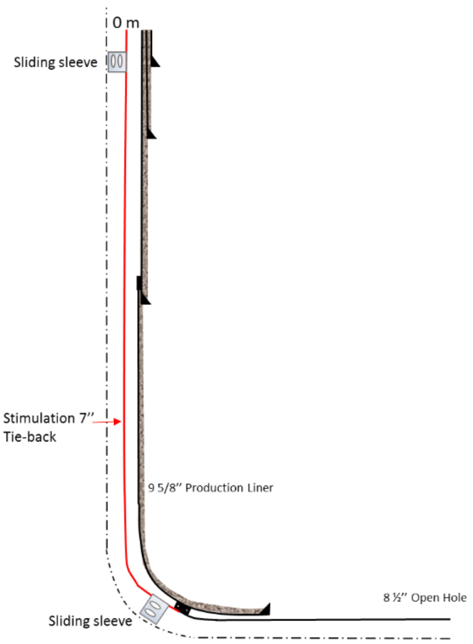


Figure 31: Injector well design to keep the measurement signal for the life of the project.

Keeping the fibre operational as long as feasible

In the Haute-Sorne producing well, a pump will have to be install. To run a pump capable of lifting water at the specification rate (75l/sec or more), the full 13 3/8" internal diameter is needed. Therefore, the 7" tie-back will have to be retrieved and the sensor cable will be lost.

In the injector well, if the signal is deemed useful over the life of the project, a simple modification can be incorporated in the tie-back design to limit its impact on friction losses. By incorporating a sliding sleeve in the tie back above the liner hanger, both the 7" tie back internal and annular spaces can be used for injection (Figure 29). At the top, the injection line can either be connected on surface to both inner and annulus spaces, or a sliding sleeve can also be incorporated at the top. With this configuration, at the expense of limited friction that can be easily compensated by the injection pumps, a permanent monitoring of the injection well can be achieved. It is also worth mentioning that manipulating sleeves to redistribute the flow in case of a thief zone is easier achieved in the injector well.

9 Alternative solutions for future EGS applications

Today, the Haute Sorne pilot and demonstration project calls for multi-zonal stimulation. When HDR project become better known, alternative to improve the reliability of EGS can be contemplated. Here below is a non-exhaustive list of options that may be part of future energy solutions.

9.1 Multi-drain

Used in the oil and gas, a multi-lateral well can increase the number of natural fractures intersected from a single larger mother bore. The multi–zonal completion can then be run into these drains, thus increasing the stimulation options. Challenges are of course many ahead, but they are not impossible to solve. The following paragraph can also be considered as potential solutions or approach towards a multi-drain project.

9.2 Short radius drilling

Short radius drilling would certainly prevent running sophisticated large bore equipment into the drains because of the high dog leg severity. However, this can be an alternative to current stimulation technique. Short radius from a mother bore could intersect many natural permeable features to achieve the desired flow rate. The question of drilling in small diameter at a decent rate in crystalline rock needs to be resolved. Some projects are currently investigating technologies that could help.

9.3 Jetting

The oil and gas industry has used water and sand jetting to create fishbone wells. Jetting from the wellbore to create small diameter penetrations into sand formations has worked. However, jetting into crystalline rock with sufficient penetration is still to be proven.

The Thermodrill project of the Horizon 2020 programme aims at developing a tool that combines water jetting and conventional rotary drilling. Simulation and experiments run by the Thermodrill team show that extremely high pressure is necessary to jet into crystalline formation, namely granite. This would be a serious limitation for the technique. The team has not found evidence that using garnet particles in the jet would improve the cutting process.

It is difficult, under these circumstances to perceive short term advances in jetting that could be used to produce an EGS in crystalline formation anytime soon. However, the SURE project, also in the scope of the H2020, but focussing on using radial water jet drilling (RJD) to enhance geothermal wells' performances may prove otherwise. However, that project is more targeting sedimentary and magmatic rock.

9.4 Exotic drilling techniques multi-branching

Spallation, plasma and laser drilling are still being developed in an attempt to reduce drilling costs by speeding up the rock destruction process. These technologies were initiated some time ago, mostly in the US for oil and gas drilling (Maurer W.C. et al, 1980). Research is still being performed (Bazargan M. et al, 2016 and Meier T., 2016) and might find some application (Potter R.M. et al. 2010), but lots of interrogations on how to economically apply these technologies are still pending (Meier T., 2016).

However, instead of focussing on drilling large borehole thus competing with conventional relatively "low cost" rotary drilling these technologies might find better applications in EGS development, for multi-branching wells or creating fishbone geothermal wells that is inaccessible to conventional drilling technologies. One of the main issues would then lay on the ability to steer the drilling system in the desired azimuth and deviation angle.

9.5 Stimulating while drilling

Stimulation while drilling might be the ultimate grail of EGS. New material compatible with the drilling process might be discovered that would temporary block the newly stimulated zone to:

1. Allow post stimulation drilling and cuttings to be returned to surface thus preventing the well to load up and ultimately losing the drilling assembly.
2. Prevent the damage of the stimulated zone by infiltration of damaging drilling fluid and solids that would render the stimulation inefficient for later industrial use.

Isolation of the open hole section to selectively stimulate a zone of interest has also its own challenges, as discussed in paragraph 4) with the additional requirement of being incorporated within a drill stem.

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11 Glossary

BHP	Bottom Hole Pressure
BHT	Bottom Hole Temperature
BHST	Bottom Hole Static Temperature
BS-1	Basel 1 well
CT	Coiled Tubing
CTU	Coiled Tubing Unit
DAS	Distributed Acoustic Sensing
DHM	Deep Heat Mining
DLS	Dog Leg Severity
DTS	Distributed Temperature Survey
ECP	External Casing Packer
EGS	Enhanced (or Engineered) Geothermal System
GES	Geo Energie Suisse AG
GVL-1	Glovelier 1 well
HDR	Hot Dry Rock
HEST	High Expansion Shifting Tool
MD	Mesured Depth
NPV	Net Present Value
RJD	Radial Jet Drilling
SAGD	Steam Assisted Gravity Drainage
S/L	Slickline
TCP	Tubing Conveyed Perforator

TD	Total Depth
UCS	Unconfined Compressive Strength
W/L	Wireline
WOC	Wait on Cement

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