

Well Stimulation Techniques for Geothermal Projects in Sedimentary Basins

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1 Introduction

1.1 Objective of this technical overview

Existing and new geothermal wells can suffer from disappointing injectivity and productivity. Sometimes the initial good performance is deteriorating with time for various reasons, while in other cases wells in low permeabilities require a treatment right from the start.

In the oil and gas industry over the years a number of different treatments to improve the performance have been developed ranging from acid treatments to large hydraulic fracturing treatments. Some of these treatments can be applied straight away in geothermal wells, others need adaptation to the special situation in geothermal applications. The application of the correct well stimulation technique in an optimum manner will help to establish and maintain the maximum energy capacity of geothermal wells.

This overview can be used as technical guidelines, aiming to provide operators of geothermal doublets and their consultants with the tools to select the right stimulation techniques for an optimum performance of geothermal wells. The technical guidelines are mainly focused on proven stimulation techniques: matrix acidizing and hydraulic fracturing. The scope of this report is discussed in 1.3.

Many geothermal operators will not have an exhaustive expertise in their own organisation like some big oil & gas operators do. This also accounts for the specific expertise on stimulation of geothermal wells. These technical guidelines will not replace these experts, though it will add extra input to discuss and understand the techniques and it will help making final decisions. For final detailed designs, decisions on investments, operational working plans and during the operational and monitoring phases of stimulation activities it is strongly advised to work together with experts and contractors who are used to work with these techniques and have knowledge of the related industrial standards, legislation and QHSE.

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1.2 Well Stimulation in general

What is well stimulation and for which purposes can it be used?

The primary goal of well stimulation is to increase the productivity of a well by improving the connectivity between the reservoir and the inflow zone of the well. Three main stimulation techniques are involved:

- removing or bypassing near-wellbore damage, typically in production zone <1m around the well (e.g. removing filter cake and fines using acids) and/or;
- increase the contact area with natural low permeable reservoirs (e.g. increasing the effective wellbore radius using fracking and/or;
- increase the natural low permeability of the reservoir close to the well (e.g. open and enlarge pores in carbonates using acids);

Well stimulation techniques are used to improve the flow in:

- well screens or perforations;
- gravel pack around well screens or perforations;
- near-wellbore reservoir (assumed <1m around wellbore diameter);
- reservoir.

Most common techniques to stimulate wells in the deep well industry (e.g. oil & gas and geothermal over 500m) are chemical treatment using acids and mechanical treatment using fracs.

Generally the following techniques are no subject of well stimulation, though these techniques can improve or help starting the production: routine well cleanout work, well maintenance like removing scaling or treating corrosion in tubing, routine removal of formation damage due to drilling prior to completion, backwashing of injectors, etc.

1.3 Scope of this technical overview

1.3.1 Why technical?

The guidelines in this document are written as technical recommendations for methods and techniques to stimulate geothermal wells in the most effective way.

These technical guidelines are not meant to be an obligatory standard for the sector. They are also not obligatory or restrictive in any way, both not

juridical and legislative. Methods or programs described in these technical guidelines do only contain the technical aspects and are not representing the working programs as needed for authorities to start the stimulation activities.

1.3.2 Which techniques?

This report will give an overview of existing, commonly used and proven techniques for the oil and gas industry that are also applicable to the geothermal industry and specific technical guidelines for the application of these stimulation techniques. These include:

- matrix stimulation (acidizing)
- hydraulic fracturing
- acid fracturing

Some other stimulation techniques will be described briefly.

1.3.3 Technical limitations of the guidelines

This report is written specifically for the application of stimulation of geothermal doublets in permeable reservoirs and do not address the use of stimulation in hot dry rock projects. In non-permeable reservoirs the fracturing techniques are not used for improving the contact area with a permeable reservoir, but will create highly permeable channels itself in the formation.

The technical guidelines in this report are also not specifically meant for the purpose to make a pathway to high permeable fault zones at a big distance from the wellbore using fractures. In this context it should be realized that this can only work in case of reverse faulting. Fractures tend to grow parallel to normal faults and will not connect up with normal faults.

1.3.4 For who?

This report is specifically written for operators, consultancies and contractors in the geothermal industry.

1.3.5 For which purposes to be used?

The parties as mentioned above can use the technical guidelines in this report for:

- a technical consideration using a stimulation technique and select one in specific;

-
- a preliminary design for these stimulation techniques;
 - Assessments on stimulation proposals/designs.

This report is technically orientated. It will give technical guidelines for:

- identifying whether stimulation is the right solution for the selected case;
- selecting the best stimulation technique and design.

The technical guidelines in this report are mainly focused on the stimulation technique itself, though it will also discuss most important operational and environmental aspects that are related to the techniques.

Important aspects are for example:

- well design issues: qualitative comments will be given on design parameters that need to be taken into account for a well that will be stimulated (pressure, dimensions, etc.);
- effects on well(integrity) because of stimulation: corrosion, erosion, high pressures causing packer movement and ballooning;
- job execution in general: general information about the needed preparations, location, HSE-aspects.

The technical guidelines in this report are not to be used for:

- making a comprehensive detailed stimulation treatment design or job execution program. This should be done by stimulation specialists, usually together with the contractor;
- Well design, well completion or drilling programs: these technical guidelines are not meant to aim on the well design, completion or drilling programs itself. It will only give qualitative comments on these aspects related to the stimulation techniques;
- cost calculations/consideration: prices or costs are not included in these technical guidelines. Though of course the consideration to use one or the other technique will not only depend on the technical part as described in these technical guidelines, but should always be considered using financial consequences: treatment costs vs. operational benefit. A preliminary design that results from these technical guidelines could be used to get first estimates on the treatment costs from service companies.

1.3.6 Other techniques?

There are less commonly used techniques applicable in the geothermal industry. These techniques will be described in less detail. Furthermore the technical guidelines provides a framework to identify further development needs for the longer term.

1.3.7 Legal aspects of stimulation

As already stated in 1.3.1, these technical guidelines are not meant to be guidelines for legislative purposes.

In most countries the authorities have issued documents dealing with the rules and regulations with respect to well stimulation, specifically fracturing. In the Netherlands SodM (Staatstoezicht op de Mijnen) has recently issued an inventory of fracturing (including acid fracturing) in which the controlling role of SodM is explained. In Germany fracking permits are arranged by state authorities (Bergamts). The state Lower Saxony has issued several documents specifying the conditions under which fracturing might be allowed. In the UK the DOE (Department of Energy) is the controlling authority.

For Dutch purposes a summary of the Dutch regulations is given in ref. 1. In appendix VIII procedures and working plans needed to start the stimulation programs in the Netherlands are given.

1.3.8 References

1. Staatstoezicht op de Mijnen, Ministerie van Economische Zaken, Resultaten inventarisatie fracking. De toepassing van fracking, de mogelijke consequenties en de beoordeling daarvan, Februari 2016.

2 Description of the main types of treatments

There are many ways to stimulate the productivity/injectivity of a well. The most widely used techniques are:

- A. Chemical methods (matrix treatments)
 - a. Matrix acidizing (acid treatments)
 - b. Treatment using solvents
 - c. Treatment with bleach
- B. Mechanical methods
 - a. Hydraulic fracturing
 - b. Explosive fracturing
 - c. Re- and additional perforating
- C. Combined mechanical/chemical methods
 - a. Acid fracturing
 - b. CFA (closed fractured acidizing) treatments
- D. Radial drilling or jetting (fishbone/radial drilling). These relatively new techniques have been described adequately by TNO (see ref. 8).
- E. Thermal methods
 - a. Cold water injection
 - b. Heat stimulation
- F. Acoustic methods

The methods are shortly discussed in the paragraphs below. The technical guidelines will be focused on the most common used stimulation techniques: matrix acidizing and hydraulic fracturing.

2.1 Chemical methods

2.1.1 Matrix Acidizing

Matrix acidizing is the original and simplest well stimulation treatment. Matrix acidizing is a relatively cheap technique, is less complicated to design and execute and the treatment has limited impact on its direct surroundings.

Matrix acidizing aims at the removal of impairing material near the wellbore by injection of acid – at pressures below fracturing pressure – into the porous matrix of the reservoir. It is applied in both sandstone and

carbonate reservoirs, but the methods, objectives and mechanism for each type of rock are completely different.

The objective of conventional sandstone acidizing is to restore permeability of the formation to its original, undamaged condition by removal (dissolution) of formation fines, clays, etc. from the near-wellbore area. Damage removal is accomplished by injection of acid, mostly mixtures of HCl and HF.

In carbonates, matrix acidizing not only provides opportunity to remove damage from the vicinity of the wellbore, but it also tends to increase near-wellbore permeability by acid dissolution and enlargement of pore throats and the creation of flow channels (wormholes), which bypass formation damage. Matrix acidization in carbonates is usually carried out with HCl only, and it is a much more straightforward process than sandstone acidizing.

2.1.2 Treatment with solvents

Acid is often defined as a solvent for the clogging material although actually it will chemically react with the clogging material, for example scaling (salts, carbonates) resulting in water soluble reaction products. In essence the actual solvent for the reaction products is the water, which will be produced or injected to remove the reaction products from the damaged zone.

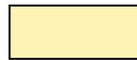
In some cases however the near-wellbore area can be clogged with specific material that could be dissolved without an aggressive chemical reaction like acid. Geothermal wells can for example be polluted with oil related products that origin from the reservoir (heavy oil residues) or from drilling activities (pipe dope, grease, etc.). The injection of solvents can be used to dissolve these oily residues. The solvent with the dissolved residues can be produced back and disposed of.

The treatment depends on the type of material that clogs the well. Table 1 shows a solvent selection chart.

| | Aromatic solvent | Kerosene/diesel | Alcoholic solvent | Mutual solvent | Surfactant |
|---------------|------------------|-----------------|-------------------|----------------|------------|
| Wax | | ✓ | | | |
| Asphaltene | ✓ | | | | |
| Emulsions | | | | ✓ | ✓ |
| Scale/sludge | | | | ✓ | |
| Waterblock | | | ✓ | ✓ | ✓ |
| Pipe dope | ✓ | | | | |
| Oil based mud | ✓ | | | | |
| Paint, etc. | | | | | |



Preferred



Reasonable



Poor

Table 1 Solvent selection chart

There is not much literature on typical solvent treatments that are used for near-wellbore damage. It should always be checked that the solvents will not affect the reservoir or chemistry of the water in a negative way and even increase near-wellbore damage.

2.1.3 Bleach

Some impairment, e.g. bacterial slime in water injectors, but also water soluble polymers (HEC, CMC, etc.) can be removed by strong oxidising agents, such as hypochlorite or bleach. These products can, besides degrading the polymers, also remove other potential impairing materials present in the near-wellbore region. The drawback of these materials is, however, that since they are strong oxidative chemicals, specific safety precautions need to be taken.

2.2 Mechanical treatments

2.2.1 Hydraulic fracturing

Compared to matrix acidizing hydraulic fracturing is an expensive technique, is quite complicated to design and execute. The treatment will have a higher impact on its direct surroundings.

Hydraulic fracturing is successfully applied in low to moderate permeability reservoirs, whereby the productivity is improved through effectively increasing the contact area with the surrounding reservoir or, in other words: increasing the effective wellbore radius. It can be applied in almost any formation. In sandstones a granular material - sand in its simplest form – is used to keep the fracture open after the treatment. In carbonate reservoirs acid fracturing (a combination of fracturing and treatment with acid) can be used (see 2.3.1).

In “propped hydraulic fracturing” a clean fluid, called a “pad”, is pumped at high pressure to initiate the fracture and to establish propagation. This is followed by a viscous fluid mixed with a propping agent or proppant (“slurry”), further extending the fracture and at the same time filling the fracture. A two-wing fracture is created.

The proppant, transported by the frac-fluid, is placed inside the fracture to prevent it from closing after the treatment. The fluid chemically breaks back to a lower viscosity and flows back out of the well, leaving a highly conductive flow path for reservoir fluids. The propped fracture can be from tens to several hundred meters long, and it usually has a width of some 5-35 mm, thus increasing the effective wellbore radius. As a result the production rate of the well will increase. Depending on the formation permeability and the presence of damage in the frac-reservoir passage itself, the productivity improvement may be tenfold or more.

Hydraulic fracturing is currently the most widely used process for stimulating oil and gas wells, and MHF (Massive Hydraulic Fracture = large fracture) treatments have played a significant role in developing otherwise uneconomical tight/shale gas reservoirs.

Hydraulic fracturing can also be used for bypassing the near-wellbore damage using small size fracs (5-25m) instead of mainly focusing on increasing the contact area with the surrounding reservoir.

The Skinfrac technique is developed, primarily intended to bypass near-wellbore damage, for which an extra wide, proppant-filled, relatively short hydraulic fracture is created. In unconsolidated reservoirs, where sand production is a potential problem, the Skinfrac technique can be a good alternative for sand control purposes: the reservoir is fractured with a screen in place, followed by a gravel pack operation. Such technique is also called Frac&Pack and is particularly of interest for geothermal wells (see chapter 10).

2.2.2 Explosive fracturing

Explosives have been used with some limited success as a well stimulation method. More commonly used are propellants, which could be viewed as a slow explosive, with the reaction taking place in milliseconds rather than microseconds. It is often combined with perforating to create deeper and more effective perforations. It is offered commercially under the trade names STIMTUBE or STIMGUN. It is primarily used to by-pass near-wellbore damage.

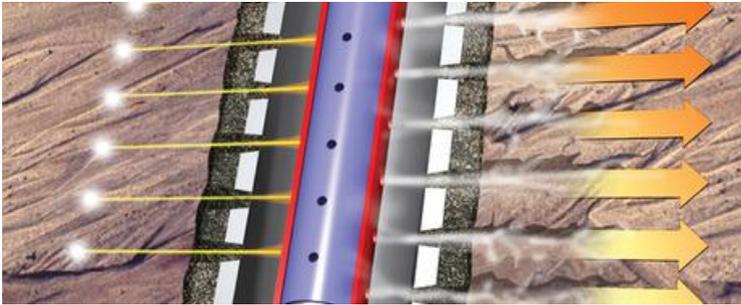


Figure 1 StimGun (site Baker Hughes)

2.2.3 Re- and additional perforating

Strictly following the definition of well stimulation – making sure that the connection between wellbore and reservoir is not the bottleneck for production - re- and additional perforating may be considered as a method to stimulate a well. Obviously this is only applicable to cased and perforated completions.

2.3 Combined mechanical/chemical methods

2.3.1 Acid fracturing

Acid fracturing is similar to propped hydraulic fracturing. In essence the proppant stage is replaced by an acid flush. It is only applicable to carbonates as they are soluble in acids. The most common acid is hydrochloric acid, but under certain conditions also organic acids such as formic or acetic acid is also used. The advantage over propped hydraulic fracturing is that it is operationally less risky. However, it is generally less effective because the conductive length of the fracture is usually shorter than for a propped fracture of similar fluid volumes.

2.3.2 CFA (closed fractured acidizing) treatments

CFA entails injection of acid at a relatively low rate and just at the fracture closing pressure of the formation. It is applied in highly naturally fractured reservoirs or immediately following an acid fracturing treatment.

2.4 Radial drilling or radial jetting

Again following the strict definition of well stimulation new technologies such as radial drilling or radial jetting may be seen as well stimulation methods. Though it can also be seen as drilling techniques or (small) side tracks, though mostly uncased. It was decided that these technologies will not be described in these technical guidelines. Instead the reader is referred to the following publication: TNO 2015 R10799, Final report, Radial drilling for Dutch geothermal Applications, Date 24 July 2015, author(s) E. Peters, J.G. Veldkamp, M.P.D. Pluymaekers, and F. Wilschut.

2.5 Thermal methods

2.5.1 Cold water injection

The fracture closing pressure, which in principle is equal to the minimum in situ stress, varies with temperature of the formation by about 0.5 bar/ °C or 8 psi/°F. As a result most water injectors around the world are, sometimes inadvertently, actually fractured. This has often a strong stimulation effect as long as the water injection is maintained at the same level. Since no provisions are made to keep the fractures open the stimulation effect disappears when the pressure drops below the (lower) fracture pressure. In geothermal project the same effect may occur, but regulations often prohibit injection above the fracture pressure. If it is allowed it constitutes a good method to increase the capacity of a geothermal project.

2.5.2 Heat stimulation

Some chemical methods have been developed to create heat downhole to (re-) dissolve wax and grease or to reduce the viscosity of heavy oils. These methods are in general less applicable to geothermal doublets. Likewise electrical heaters have been developed in the oil industry, also not really suitable for geothermal applications.

2.6 Acoustic methods

At the turn of the century several research institutes renewed the attention to the development of acoustic stimulation methods. A brief overview is shown in Table 2. Some of these technologies could be very suitable for geothermal wells that are completed with wire-wrapped screens.

High frequency sonic waves, especially ultrasonic waves have been used in many industrial applications to remove contaminants like dirt, oil, and grease from parts immersed in fluids. An obvious extension of this application is the removal of wellbore impairment by exposing it to high frequency acoustic waves. Although the concept is old, successful large-scale application of acoustic well stimulation is not common. Successes have been claimed in Russia, but these are difficult to substantiate.

Greater understanding of the technology's applicability and limitations are essential in order to design effective downhole acoustic tools and guide successful field implementation, i.e. the technology needs more research and development.

| Technology | Application | Success |
|------------------------------------|---|---|
| Low frequency waves | Higher permeability deep damage removal | Success claimed in Russian oilfields |
| Audible sound - "downhole whistle" | Prevention of scale formation | questionable |
| High frequency sound | Mud cake removal, very near-wellbore damage | Successful trials in USA and Middle East |
| Pulsed Power | Screen cleaning | Very effective in laboratory test; No field experience. |

Table 2 Acoustic tools for well stimulation

2.7 References

1. Portier, Sandrine. "Review on Chemical Stimulation Techniques in Oil Industry and Applications to Geothermal Systems," 2007.
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4. Jose Gil Cidoncha., "Application of Acoustic waves for reservoir stimulation" SPE 108643.
5. Fred van der Bas, Eric de Rouffignac, et al (Feb 2004). "Radial Near-wellbore Stimulation by Acoustic Waves" SPE 86492.
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7. Frash, L.P. Gutierrez, M.S. and Hampton, J.C., "Experimentation with Hydraulic Impulse Stimulation in a Scaled Enhanced Geothermal Systems Reservoir" American Rock Mechanics Association, ARMA 13-166.
8. TNO 2015 R10799 | Final report, Radial drilling for Dutch geothermal Applications, Date 24 July 2015, author(s) E. Peters, J.G. Veldkamp, M.P.D. Pluymaekers, F. Wilschut.

3 Differences between geothermal and oil & gas wells

3.1 Differences & comparisons

As indicated, the oil and gas industry uses a set of well established guidelines that will be applicable to geothermal wells as well. However there are a number of differences between oil & gas and geothermal energy that need special attention:

Fracturing in geothermal and shale gas industry

The frac techniques in the shale gas industry are far more intensive than techniques used for geothermal applications in sedimentary basins, although the basic techniques may be similar:

- **Frac length:** frac length for geothermal projects in sedimentary basins will be in the order of 10 to 300m. Even very small fracs (frac&pack or minifracs) could be preferable if the stimulation is used to bypass the skin around the borehole. In shale gas the aim often is to open up an existing network of microfracs. As a result the frac length for shale gas production can be more than 1000m.
- **Fluid volumes:** the fluid volumes used in (remedial) matrix treatments of geothermal projects are limited to about 50 – 75 m³ of acid or less. The volumes used in fracturing of geothermal wells are normally in the order of 500 m³ or less per fracture. This is considerably less than the volumes used in shale gas and shale oil, where volumes of 2500 m³ or more per fracture are quite common.
- **Number of fracs:** in shale gas often a large number of fracture treatments per well are performed (around 10), whereas in geothermal doublets the general norm is one or two with a maximum number of three or four per well.
- **Exploitation:** during exploitation the gas pressure in fractured shale gas wells will decrease and therefore production capacity will decrease. As a result these shale gas wells have a limited lifetime of one or several years. After its lifetime a new well needs to be drilled, including the needed fracturing activities. This is in

contrast to geothermal wells that are meant to produce for 15 to 30 years or even more.

The application of frac techniques in the geothermal industry can be compared to the smaller standard fracture techniques in the regular oil & gas industry (not for shale gas applications). The environmental and safety effects are proven to be minimal:

- Staatstoezicht op de Mijnen (legal authority of Economic Affairs in the Netherlands) just published an evaluation on regular oil & gas fracking activities in the Netherlands (252 wells and 338 fracs since 1950, ref.1). The conclusion is that no harmful effects have occurred.
- In a German study (30 hydraulic frac operations and 26 chemical stimulations, ref. 2) of the Umweltbundesamt (environmental authority in Germany) it is concluded that in compliance with existing rules, the installation of monitoring equipment as well as following the state-of-the-art scientific and technological expertise a detraction of the groundwater as a result of hydraulic fracturing or chemical stimulation in deep geothermal reservoirs can be ruled out. Moreover, the probability of perceptible seismic events can be minimized by an appropriate monitoring system in combination with an immediate response system and reaction plan.

Even though the intensity of frac activities in the shale gas industry is high compared to regular oil & gas or geothermal applications, effects in this industry will be minimal if activities apply to the industrial standards & rules and legislative restrictions, if monitoring is done and if state of the art technology is used. A recent evaluation of the environmental impact of shale gas activities in Germany has been done by the Bundesanstalt für Geowissenschaften und Rohstoffe (BGR, see ref 3.)

Temperature

The temperature in geothermal projects, more specifically in the producing wells, may be higher than in oil or gas fields. Fluids, proppants, etc. may need to be adjusted to the higher temperatures. Since the temperature in the producer is higher than in the injector the treatments need to be adjusted. Fluids and other materials may be different.

Treatment fluid composition

The matrix treatments are often done with 15% hydrochloric acid (carbonate reservoirs) or a mix of 9 -13 % hydrochloric acid and around 1% hydrofluoric acid (sandstone reservoirs). A small number of additives may be used, of which the most important one is the corrosion inhibitor to protect the metal tubulars in the wells.

Hydraulic fracturing fluids are normally water based with a small number of additives to provide the right properties for fracturing. The most important one is a gelling agent which often is based on guar gum, a natural product. Nowadays the industry has developed frac fluids that are entirely based on ingredients used in the food industry. Reference 1 gives a good overview of the composition of frac fluids.

Reservoir fluid chemistry

The reservoir fluid is always water (or steam). Standard additives added to stimulation fluids are often aimed at specific issues related to the presence of oil or gas and need to be replaced with other additives or could be left out, e.g. additives to make oil less viscous.

However some of the oil recovery techniques could also be used to clean damage zones in geothermal wells, if damage is caused by oil-related products (asphaltenes, oil residues).

Flows

Oil is produced for 10 to 10.000 barrels per day (0,06-60 m³/h).

The water flow needed for geothermal purposes depends on its temperature. For low to medium (~50-150 °C) geothermal purposes it is common to inject/produce 50 up to 400 m³/h continued flow or even more. For high enthalpy geothermal systems (>150 °C) steam is produced from 10 up to >100 tons/h.

Investment versus gains

Stimulation of wells can be quite expensive. To make the stimulation feasible, the return of investment should be positive. This means that the well should be more productive for a longer period of time.

For oil and gas the extra productivity will have a higher impact on the return on investment than for geothermal water. The amount of energy (MWh) per extracted m³ for oil and gas is much higher than for geothermal water or steam.

Specific set up with respect to well configuration

In low/medium enthalpy geothermal projects we are dealing with at least two wells (on doublet) per project. As a result optimum stimulation would often involve treatment of two wells. In principle this will reduce the cost per well, but the total cost of stimulation can be higher. To increase the cost effectiveness of stimulation in geothermal doublets, methods of both matrix treatments as well as fracturing need to be simple as possible.

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4 Well and Reservoir terms and definitions

4.1 Productivity

The primary target of stimulation is enhancement of the productivity (see 1.2).

The productivity is defined as the production/injection rate divided by the drawdown/injection pressure at reservoir depth.

The rest of this chapter addresses some terms and definitions in more detail. It will help to quantify changes in the productivity and whether these are caused by damage between well and reservoir. It will also allow the calculation of the potential improvement in productivity or injectivity.

4.2 Injection/production rate Q

The absolute injection and production rate (in m^3/h) as such are not an indicator for well stimulation. However, a decline in injection/production rate with time is a sign of gradual plugging of the near well formation or screen if present.

4.3 Drawdown, permeability and production rate

Drawdown is defined as the Reservoir pressure minus the flowing bottom hole pressure. Without damage around the well the resistance to flow and thus the drawdown is determined only by the permeability of the reservoir (assuming a simple vertical well). With damage there is an extra pressure drop caused by the lower permeability in the damage zone (Figure 2).

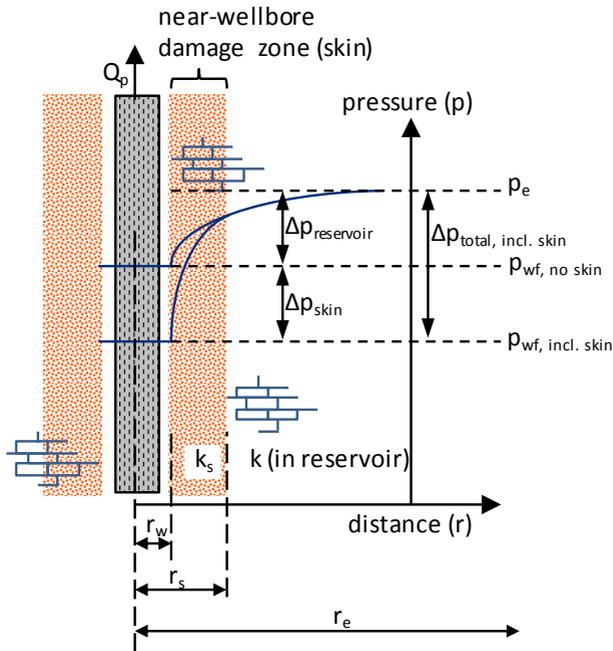


Figure 2 Extra pressure drop during production, because of near-wellbore damage

The permeability is a measure for the ability of the formation rock to transport liquids through the pores. The concept is first developed by Henry Darcy in 1865. The unit for permeability, Darcy, is defined using Darcy's law.

A familiar expression of the Darcy's law (for steady-state and in a radial reservoir) is:

$$Q = \frac{2\pi kh(p_e - p_{wf})}{B\mu \ln\left(\frac{r_e}{r_w}\right)}$$

The stabilised flow of a slightly compressible fluid of constant compressibility into a vertical or deviated well, completed over the entire producing interval in a bounded radial reservoir, is given by the semi-steady state equation (SI units)

where

-
- k: reservoir permeability,
 - r_e : drainage radius (circular reservoir assumed),
 - r_w : wellbore radius,
 - h: reservoir height,
 - p_e : far field reservoir pressure,
 - p_{wf} : flowing bottom hole pressure,
 - μ : the reservoir fluid viscosity.
 - B: so-called formation volume factor, is a correction factor for the difference in volume of the reservoir fluid under reservoir pressure and temperature conditions and at standard conditions. For water it can usually be taken as 1.

4.4 Productivity Index (PI) and Injectivity index (II)

The performance of a well is defined as the production or injection index: flowrate per unit of drawdown.

$$PI = Q_p / \Delta p$$

$$II = Q_i / \Delta p$$

$$\Delta p = p_e - p_{wf}$$

where Q_p and Q_i is the production and injection rate and p denotes pressure.

This is the absolute performance of a well. A high PI or II implicates that a small amount of energy is sufficient for realizing the needed production or injection flow (m³/h).

4.5 Well Inflow Quality Indicator - WIQI

Shell introduced the term Well Inflow Quality Indicator - in short WIQI – in the nineties of the last century in an attempt to find a simple method to quantify the performance of an existing well. It is defined as follows:

$$\begin{aligned}
 WIQI &= \left(\frac{Q}{\Delta p}\right)_{actual} / \left(\frac{Q}{\Delta p}\right)_{ideal} \\
 &= PI_{actual} / PI_{ideal} \quad \text{for production wells and,} \\
 &= II_{actual} / II_{ideal} \quad \text{for injection wells}
 \end{aligned}$$

It is actually a relative parameter to define the performance of the well. The ideal PI or II is based on the expected “natural” permeability of the reservoir. Without near-wellbore damage the WIQI equals one. A value less than one indicates that there is a restriction to flow in the near-wellbore region, whilst a value over one means that the well has in fact been stimulated for instance by fracturing. The difficulty is that it is very often not clear how accurate the value of the reservoir permeability actually is.

Nevertheless the WIQI should always be based on the reservoir permeability determined by a pressure build-up or fall-off test.

4.6 Skin factor S

Reservoir stimulation deals with well productivity. As a result, a successful stimulation first requires accurate identification of parameters controlling well productivity and the determination of whether or not stimulation can improve production. This is therefore the very first step of the stimulation job design. Darcy’s law as described in 4.3 in its simplest form is adequate to study the issue.

To be able to use it for further identification, we should include the degree of damage. The skin factor is an expression for the degree of damage. It is defined as the Hawkins relation:

$$S = \left(\frac{k}{k_s} - 1\right) \ln \frac{r_s}{r_w}, \text{ where}$$

- k is reservoir permeability
- k_s is the permeability of zone where the skin is present
- r_s skin radius (circular reservoir assumed),
- r_w is wellbore radius,

In essence the skin factor S is a dimensionless expression for the extra pressure drop (Δp) required to have certain production or injection rate in the ideal situation. The skin factor can be determined in a number of ways. The most common methods are:

-
- Multi-rate tests
 - Transient well tests (pressure-build-up analysis)

Including S in the inflow equation results in the following expression for the production well:

$$Q = (2\pi k\mu(p_e - p_{wf}) / (B\mu \ln(\frac{r_e}{r_w}) + S)$$

References 2 – 6 describe some methods to determine S specifically for geothermal wells. The most commonly used tests involve shutting in the production well (or injection well) and monitoring the pressure for some time. Ideally the pressure should be the measured bottom-hole pressure, although the bottom-hole pressure can also be calculated from the pressure at surface. The latter introduces some uncertainties due to compression and/or temperature effects.

From the relation above it is apparent that at the same permeability, the pressure drop decreases with the natural logarithm of the distance from the well, i.e. the pressure drop within the first meter is roughly the same as in the next ~two and a half, ~six, etc.

If the permeability of the near-wellbore zone is reduced significantly, the largest portion of the total pressure gradient is consumed within the very near-wellbore zone. Similarly, recovering or even improving this permeability may lead to a considerable improvement in the well's production or injection.

4.7 References

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5 Work process for selection & design of well stimulation treatments

The following technical work process needs to be followed for preparing and executing the well stimulation.

1. Candidate selection
 - Improving new wells or existing wells
 - Skin analysis – separating skin caused by damage from other sources of skin
2. Treatment selection
 - Defining cause of damage
 - Identifying suitable treatments
3. Preliminary treatment design:
 - Fluids and additives recommendation
 - Placement and diversion method
 - Pumping schedule
 - Flow (diversion) simulation modelling
 - Design evaluation
4. Execution of the well stimulation job
 - Final detailed design
 - Work plan
 - Permits
 - HSE
5. Post-job analysis
 - Productivity improvement
 - Re-run flow simulation
 - Long-term, short-term analysis / monitoring

In these technical guidelines no financial considerations are included. Nevertheless, typical financial go-no go milestones for the process could be chosen after the process steps: candidate selection, treatment selection, and preliminary treatment design.

- After the candidate selection the difference in productivity before and after the treatment can be estimated and therefore the extra benefits after improving the wells can be estimated.
- After the treatment selection the monetary investment of the selected treatment can be roughly estimated.

- After the Preliminary treatment design, the work can be tendered and costs for the well stimulation job can be determined.

Figure 3 depicts the sequence and details of these elements and their mutual dependence.

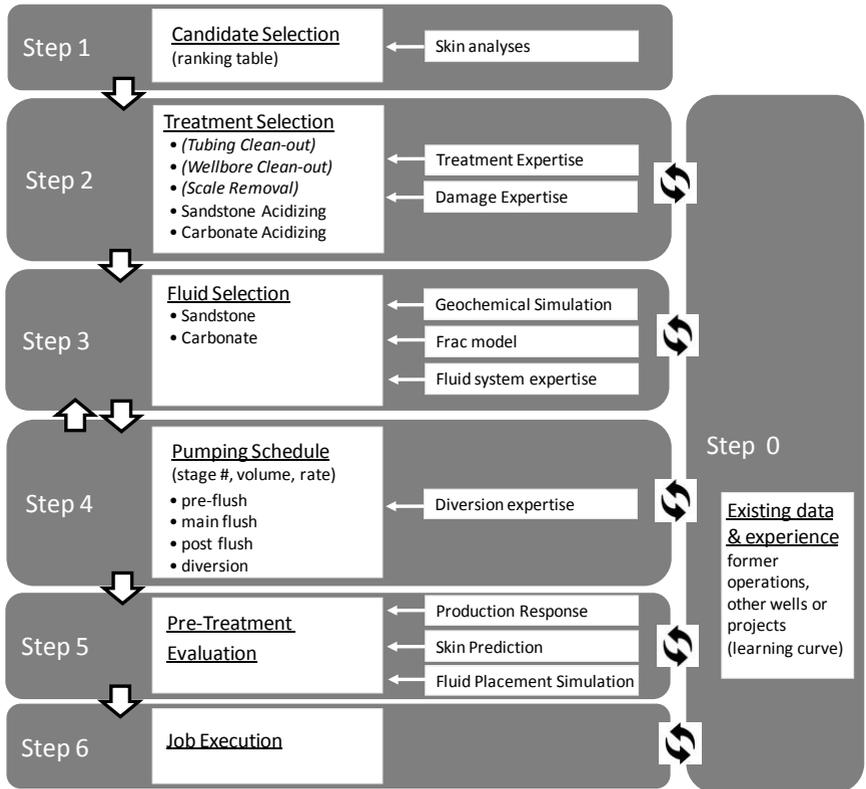


Figure 3 Workflow for selection and design of well stimulation treatments

5.1 Step 1 Candidate selection

The candidate selection could account for two situations:

- improving the productivity of existing wells because of suspected damage;
- improving the productivity of new or existing wells by effectively improving the “natural” permeability.

Improving existing wells because of suspected damage

In time, well productivities could decrease because of clogging mechanisms in the near-wellbore zone (near-wellbore damage). Also the productivity of newly drilled wells could be less than expected because of near-wellbore damage e.g. by blocking drilling fluids remnants. When considering well stimulation the following damage analyse should be worked out.

For candidate selection the existing data should be analyzed and parameters should be calculated:

- Measure the actual PI/II
- Determine the permeability of the reservoir
- Calculate the ideal PI/II
- Calculate the WIQI
- Calculate Sdam (skin due to wellbore damage)
- Whether the wells are a candidate for well stimulation depends on: the expected improvement which is reflected by the WIQI. If $WIQI < 0.9$, the treatment could affect the well productivity significantly.
- the expected damage which is reflected by the Sdam. If $Sdam > 5$, the treatment could affect the well productivity significantly.

Improving existing or new wells focusing on improving the “natural” permeability

Operators can also consider to improve the well performance by creating artificial, additional permeability (effectively improving the “natural” permeability).

In that case the “natural” PI or II should be calculated, followed by the expected improvement in PI or II. The expected PI after well stimulation should be significantly higher than the “natural” PI.

It is mainly a financial consideration whether the well is a candidate for well stimulation: does the extra production/injection after the well stimulation justify the extra investment.

Sand control

If sand production is expected in new wells or if sand control is a problem in existing wells, the well could also be considered to be a well stimulation

candidate, as a Frac and Pack treatment (also known as skinfrac treatment) could solve this problem.

Skin or damage analyse

The analysis of the damage is focused on:

- quantifying the skinfactor (S);
- defining which part of the skin is related to near-wellbore damage (S_{damage}).

Using the terms and definitions as described in chapter 4 the skinfactor (S) can be calculated after performing specific well tests. It should be considered by reservoir specialists if (simplified) analytic models can be used or if more difficult 3D or 4D modelling is required in this stage. This depends on the complexity of the reservoir e.g. variation of specific the reservoir parameters (temperature, depth of top/bottom reservoir, thickness of reservoir and/or permeability and well trajectory) as also the existence of sealing or non-sealing faults but also on the availability of data e.g. production data and well test data.

After determining the total skin, it should be analyzed which part is related to the near-wellbore damage. Skin is in fact the sum of a series of components that together make up the skin factor determined in a pressure build-up test (as described in Chapter 5.6). This is often overlooked and S_{total} is used for the decision to stimulate a well. This may lead to unsuccessful treatments. For instance treating a well with an insufficient number of perforations or a limited completion interval, will not have the desired result.

Figure 4 Skin components shows the most common skin components.

Again, it is important to realize that only the damage skin can be removed or bypassed by stimulation. All other components are not affected by stimulation. In geothermal wells the turbulence skin is insignificant. Further details on Skin analysis are given in Appendix II.

$$\begin{aligned}
 S_{\text{total}} = & \\
 & S_{\text{dam}} \quad \text{skin caused by damage} \\
 & + S_{\text{perf}} \quad \text{skin caused by perforation} \\
 & + S_{\text{turb}} \quad \text{skin caused by turbulation} \\
 & + S_{\text{dev}} \quad \text{skin caused by deviation} \\
 & \text{skin caused by gravelpacks} \quad + S_{\text{gravel}} \\
 & \text{skin caused by stimulation} \quad + S_{\text{stim}} \\
 & \text{skin caused by natural fracs} \quad + S_{\text{fiss}}
 \end{aligned}$$

Figure 4 Skin components

5.2 Step 2 Treatment selection

The first choice that has to be made is whether to treat the well with acid or carry out a fracture treatment as the main and most common treatment techniques used in the conventional well stimulation market. The procedure is shown in Figure 5 and Figure 6 for existing and for new wells.

The basic principle is that low permeability reservoirs need a fracture treatment, not an acidizing treatment. There are a few exceptions:

- If the reservoir height is limited, say, less than 10 m a fracture may be a waste of materials because a fracture is likely to grow out of the zone. The only option then becomes an acidizing treatment.
- If the damage is insoluble or the formation is incompatible with acid a (small) fracture may be more effective.

Acidizing is a good stimulation method in moderate to high permeability reservoirs, which show substantial damage (skin) in the near-wellbore region. The damage is removed by injecting acid below fracturing pressure. The impairment may originate from drilling or completion operations, for example due to the invasion of drilling or completion fluids,

or it may be caused by the production process (or in case of injection wells, by the continuously injected fluids), for example by oil residues or moving fines. Hydraulic fracturing is successfully applied in low to moderate permeability reservoirs, whereby the productivity is improved from effectively increasing the wellbore radius. It can be applied in almost any formation, although commonly in carbonate reservoirs acid fracturing is applied.

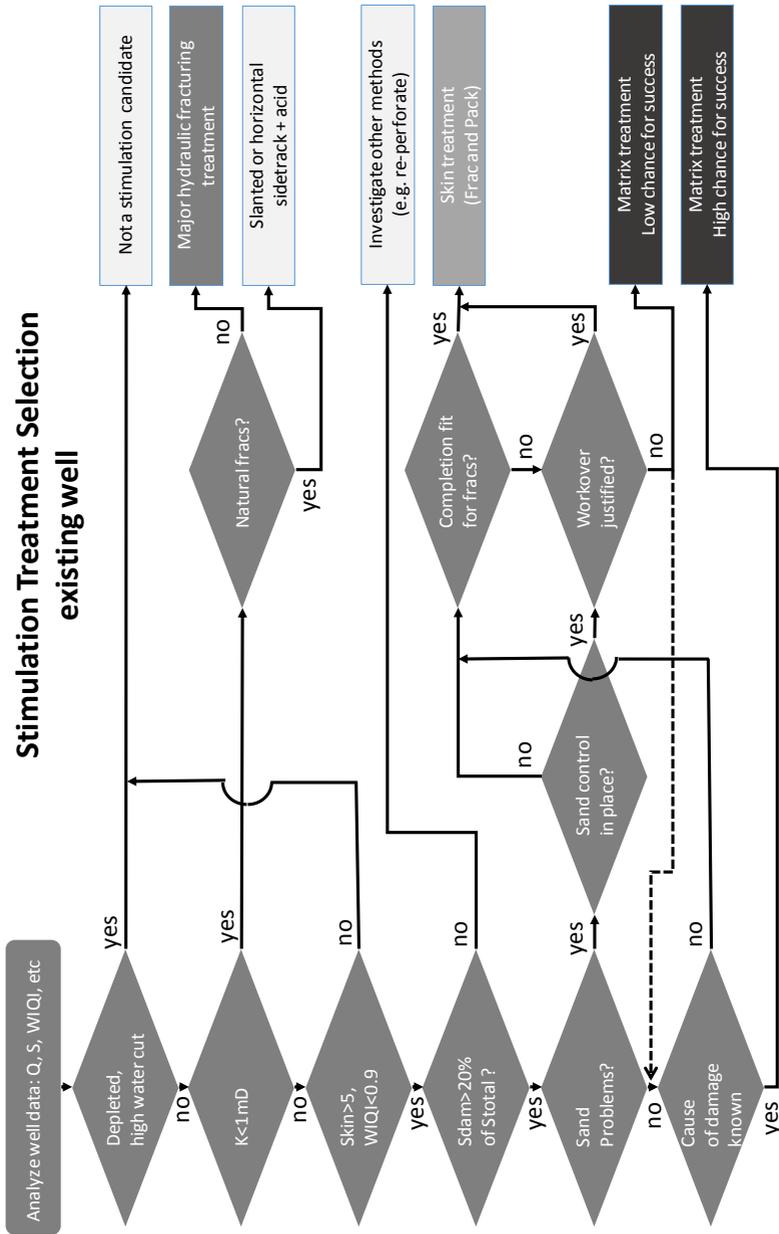


Figure 5 Candidate selection chart for existing wells

New wells

To improve the capacity of new wells that will be developed, it can be decided to use stimulation treatments on beforehand. In Figure 6 a typical stimulation treatment selection chart for new wells is given. It is assumed that drilling and completion methods that will be used for new wells are optimal, so no skin/wellbore damage is foreseen (different from existing wells, Figure 5). For the new wells the stimulation is only used to improve the “natural” permeability and therefore the capacity of the well. Which stimulation technique will be used depends mainly on the permeability of the reservoir and is then decided on beforehand.

Two different scenarios for new wells:

- After drilling and testing the capacity of a new well could be worse than expected. In this case the selection chart for an existing well (Figure 5) should be used, because the skin/wellbore damage could be the reason of the capacity reduction.
- If a specific drilling mud is used, it could be concluded on beforehand to remove it using an acid treatment. This treatment is actually focused on an optimal drilling & completion method instead of improving the “natural” permeability (first decision step in Figure 6 is “no”).

Stimulation Treatment Selection new well

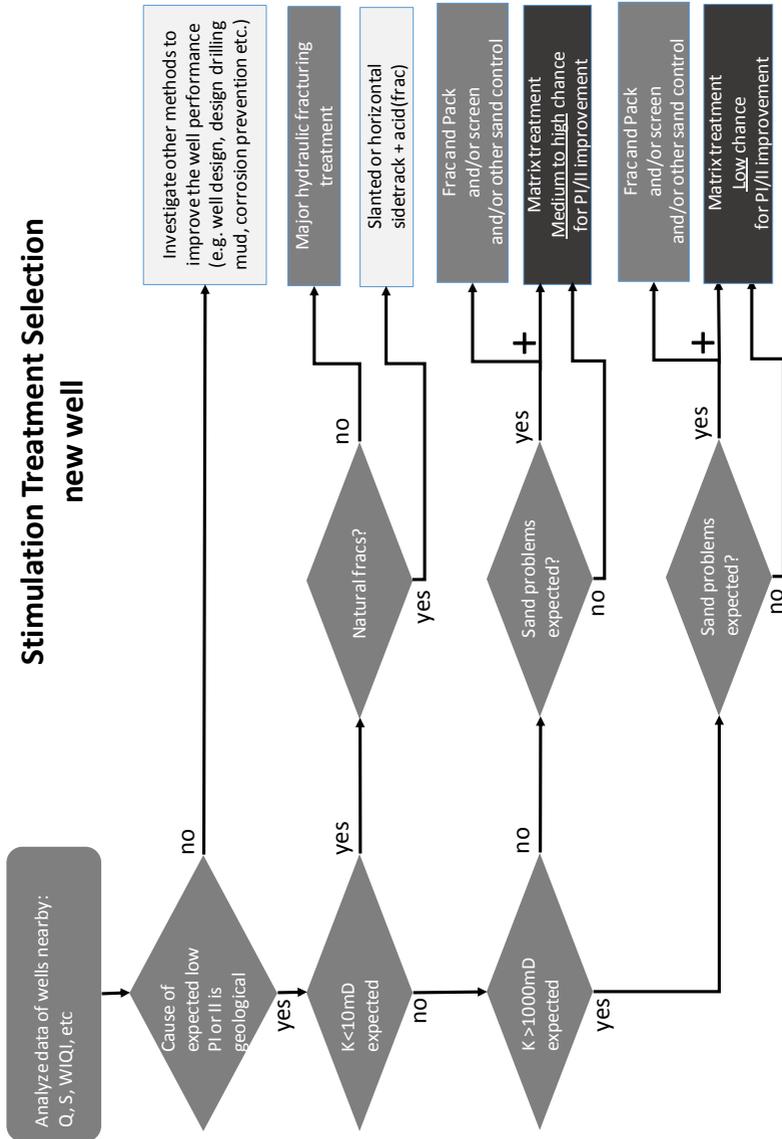


Figure 6 Candidate selection chart for new wells

5.3 Step 3 & 4 Preliminary treatment design

This topic is discussed in detail in chapters 6, 7 and 8 for each type of treatment. It involves:

- fluids and additives recommendation
- pumping schedule
- (diversion) simulation modelling

In fact this is an iterative process. If, after the modelling step the results are not satisfactory the process goes back to re- formulate a pumping schedule, followed by a next round of modelling.

5.4 Step 5 Treatment design evaluation

Before executing the treatment and finalising on the design it is useful to evaluate the potential benefits of the treatment. For matrix acidizing this can be done by assuming that the damage skin becomes zero or slightly negative.

5.5 Step 6 Execution of the well stimulation job

The operational aspects are detailed in Chapter 12.

5.6 Step 0 Existing data & experience - learning curve

At most steps it is important to include experience and information from projects and well treatments in the area, perhaps from other operators. Also make sure that when executing a treatment that the results and experience – both positive and negative – is properly documented for future treatments.

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6 Preliminary design: Matrix treatment sandstones

Matrix acidizing is the oldest well stimulation technique with the first treatment carried out in 1895. Matrix acidizing design has been more like an art than a science up to the mid-seventies of the last century. Perhaps as a consequence the success rate was rather poor. Studies were undertaken to gain a better understanding of the processes involved. Nowadays proper design criteria have greatly improved the success of matrix acidizing. A clear distinction has to be made between carbonates and sandstones. The design involves the following steps:

6.1 Sandstone reservoirs

1. Identification of the damage
2. Selection of the type of acid
3. Selection of the placement technique
4. Pumping schedule

6.2 Identification of the damage

In principle, formation damage can be classified according to the process or operation which caused it to develop, viz. induced and natural damage:

- Damage related to drilling, completion and workover operations, (induced damage).
- Damage as a result of fluids lost to the formation during specific operations, such as (re)perforation, stimulation, gravel packing, etc., (induced damage).
- Damage caused by produced fluids, or in case of injection wells, by the continuously injected fluids, (natural damage).

Induced damages include:

- plugging by entrained particles, such as solids or polymers in injected fluids
- wettability changes caused by injected fluids or oil-base drilling fluids
- acid by-products
- iron precipitation
- bacteria
- water block

-
- fluid/fluid and fluid/rock incompatibility

Natural damages include:

- fines migration
- swelling clays
- water-formed scales
- organic deposits, such as paraffins or asphaltenes (perhaps not very common in geothermal wells, but not impossible)
- mixed organic/inorganic deposits
- emulsions

6.3 Selection of the type of acid

In sandstone formations, acid treatments aim to remove near-wellbore flow restrictions and formation damage. The goal of these treatments is to return the near-wellbore area to its natural condition. Usually, wellbore damage is caused by drilling or completion operations, fines migration, clay swelling or polymer plugging. To select an optimized fluid system for effective stimulation, the type of damage and the formation mineralogy must be known.

Appendix I shows common types of damage and a general indication of a suggested cure.

A typical minimum-step acid treatment in sandstones consists of injection of three sequential flushes, viz.:

1. A preflush, consisting of HCl or organic acid, to condition the formation by displacing water from the wellbore and connate water from the near- wellbore region and to dissolve any calcium carbonate and iron carbonate or oxide.
2. The main flush, which is usually a mixture of HCl and HF in various concentrations. Also mixtures of HF and organic acids are applied.
3. An after flush, to displace the spent acid and the reaction products deep (3 to 5 ft, 1 –1.5 m) into the formation, and to restore the wettability of the formation.

The success of sandstone acidizing treatments is based on the fine-tuning of the acid formulation to the mineralogy of the formation and the nature of the damage.

6.3.1 Sandstone mineralogy

Sand (quartz) is the main component in sandstone reservoirs. Sand grains are cemented by silicates (clays and feldspars) and/or carbonates. Quartz (SiO_2) has a stable structure and a relatively low specific surface area compared to clays and feldspars. This makes the rate of dissolution of quartz in hydrofluoric acid slower than that of clays and feldspars.

Clays and feldspars are in essence a chemical mix of oxides built into a single molecular or crystalline structure. Feldspars have a three-dimensional network structure with SiO_4 -4 and AlO_4 -4 tetrahedral. The structure of feldspars is similar to that of quartz, except some of the silicon atoms have been replaced by aluminum.

Clays are siliceous materials like silica and feldspar, but their structure is quite different. Clays have a plate-like structure. The most familiar types of clay are kaolinite, montmorillonite (smectite), illite and chlorite.

Kaolinite is a clay where the silica tetrahedral sheet is linked with the octahedral alumina sheet by shared oxygen. Kaolinite is a non-swelling clay because hydrogen bonds that fasten the two layers are strong enough to prevent water penetration between them.

Montmorillonite (smectite) is a 2:1 clay in which one alumina sheet is sandwiched between two silica sheets. Water and other polar molecules can penetrate into the layers and cause swelling. Water can increase its volume by up to 600%, significantly reducing permeability. If montmorillonite clay occupies only the smaller pore throats and passages, it will not be a serious problem; if it occupies the larger pores and especially the pore throats, then it is capable of creating an almost impermeable barrier to flow if it swells.

Illites have a structure similar to that of montmorillonite. Their layers are composed of two silica sheets sandwiching the alumina sheet. In the illites, some silicon atoms are replaced by aluminum. Potassium ions are positioned between the layers to balance the electrical charge. Illites are non-swelling clays; no water can penetrate between the layers because they do not have an expanding lattice.

Chlorite is a clay that can release iron during acidizing, which precipitates at pH > 2, and may cause formation damage.

Sandstone formations may also contain carbonate minerals. The most common carbonates are calcite, dolomite, siderite and ankerite.

Mixtures of HF and HCl are usually applied for sandstone matrix acidizing, since they can dissolve feldspars and clays. However, a major concern in the acidizing of sandstones, is damage caused by (re)precipitation of acid-mineral reaction products. In acidizing sandstones with HF, the formation of some insoluble side-reaction products is unavoidable. Table 3 shows the most common precipitation reactions:

| Reaction | Precipitate(s) |
|-------------------------------------|--|
| HF + carbonates (calcite, dolomite) | Calcium and magnesium fluoride (CaF ₂ , MgF ₂) |
| HF + clays, silicates | Amorphous silica (orthosilicic acid) (H ₄ SiO ₄) |
| HF + feldspars | Sodium and potassium fluosilicates (Na ₂ SiF ₆ , K ₂ SiF ₆) |
| HF + clays, feldspars | Aluminum fluorides (AlF _n ³⁻ⁿ) Aluminum hydroxides |
| HF + illite clay | Na ₂ SiF ₆ , K ₂ SiF ₆ |
| Spent HF + formation brine, | Na ₂ SiF ₆ , K ₂ SiF ₆ |
| HCl-HF + iron oxides and iron | Iron compounds |
| HF + calcite (calcium carbonate) | Calcium fluosilicate |

Table 3 Damaging HF reactions in sandstones

However, the degree of damage they cause to the well productivity depends on the amount and location of the precipitates. These factors can be controlled, to some extent, with proper job design.

6.4 Treatment fluid selection

Once it has been determined that acid-removable formation damage is present, and the treatment is mechanically feasible, the proper acid type, acid volume and acid concentrations must be determined.

Traditionally, the majority of acidizing treatments of sandstones have been carried out with a standard mixture of 12% HCl and 3% HF (regular mud acid, RMA), irrespective of the chemical nature of the formation damage and formation mineralogy. In recent years, however, the trend has been towards the use of lower strength HF solutions, e.g. 6% HCl + 1.5% HF (half-strength mud acid, HMA), see below.

6.4.1 Acid preflush

The main purpose of an acid preflush is to remove carbonate minerals from within 2 ft (0.6m) from the wellbore. HF acid reacts with carbonates, such as calcium carbonate and magnesium carbonate, to form insoluble calcium and magnesium fluorides. If a separate brine displacement stage is not employed, the acid preflush also serves the purpose of displacing formation water from the main HF acid stage. Spent HF acid will further react with sodium, potassium and calcium ions in formation water, to form insoluble precipitates that can severely plug the formation.

The standard preflush consists of 5-15% HCl, plus additives of which the corrosion inhibitors are the most important. Organic acids, such as acetic and formic, can also be used, also in combination with each other, or in combination with HCl. Organic acids are especially useful in high-temperature applications, because they are less corrosive than HCl and might require lower concentrations of corrosion inhibitors. Corrosion inhibition is especially important when the well is completed with high alloy steels for instance as used in wire wrapped screens.

6.4.2 Main acid

The purpose of the main acid stage is to dissolve siliceous particles that are restricting near-wellbore permeability, plugging perforations or gravel packs. As stated before, a trend has developed in recent years toward the use of lower strength HF solutions. Research and field results suggest that for most sandstone formations, the optimal ratio of HCl to HF is 9:1, and therefore nowadays mixtures like 13.5% HCl + 1.5% HF are often used

for sandstone matrix treatments. The benefits of lower concentration HF solutions are a reduction in damaging precipitates from the spent acid and less risk of de-consolidation of the formation around the wellbore. Lower HF concentrations react much slower with sand. This slower reaction allows the HF to use more of its dissolving power on such targeted damage sources as clays and feldspars, while spending less on sand.

The new HCl/HF systems have as main purpose to prevent or minimize:

- Na- and K- Fluosilicate precipitation,
- Aluminum scaling.

In essence, the composition is a balanced compromise between maximum dissolution and minimum secondary precipitation.

From all naturally occurring clays, chlorite is probably the most difficult one with respect to acidizing. It usually contains calcium, magnesium and iron(III). As a result, upon dissolution it is very sensitive to precipitation of calcium and magnesium fluoride and ferric hydroxide. Formations containing chlorite should therefore be treated with low concentrations of hydrofluoric and hydrochloric acid. Alternatively, hydrochloric acid may be replaced by acetic acid in these cases

Some of the new fluid systems (without their proprietary additives) are given in Table 4.

| Fluid | Advantages |
|-------------------------|---|
| 13.5/1.5% HCl/HF | This acid formulation is the fluid of choice when the mineralogy is unknown. It offers maximum dissolving power with minimum secondary precipitation and prevents |
| Retarded HCl/HF | This formulation is a retarded system that removes deep damage caused by fines and swelling clays. It also helps prevent fines |
| 9/1% HCl/HF | This acid with low HF content, is compatible with formations high in feldspars and illite. It also helps prevent fines migration. |
| Organic/HF | This organic acid system is compatible with HCl- sensitive minerals. It can also be used in high temperature applications. |
| 12/3% HCl/HF "Mud acid" | This acid uses a high HF concentration to remove silica scale from high temperature |
| HCl only | This acid should be used whenever the carbonate content is higher than 15%. |

Table 4 Sandstone acidizing systems

In Appendix III a generic fluid name cross reference list of matrix acidizing fluids and additives is given.

6.4.3 Over flush

The over flush (or after flush) is an important part of a successful acidizing treatment. It has several purposes:

- to displace non-reacted mud acid into the formation;
- to displace mud acid reaction products away from the wellbore;
- to remove oil-wet relative permeability problems caused by some corrosion inhibitors;
- to re-dissolve HF precipitates, if an acidic after flush is used.

Typical over flushes for mud acid treatments are:

- water containing 3 to 5% ammonium chloride;
- weak acid (5 to 10% HCl or organic acid);

-
- nitrogen (in the producer wells only and only following a water or weak acid over flush).

Production wells should be put on production immediately after the treatment. In that case, the after flush volume should be at least the same as the main HCl/HF volume. When wells have to stay closed in for some time (which is not desirable), the after flush volume should be at least twice the HCl/HF volume to displace the reaction products to a distance where their influence is less (3 to 5 ft (1 – 1.5 m) radial penetration). A large over flush is necessary to prevent the near-wellbore precipitation of amorphous silica. At formation temperatures of 95 °C or higher, amorphous silica precipitation occurs when the mud acid is being pumped into the formation. The precipitate is somewhat mobile at first, but may set up as a gel after flow stops. If it is kept moving by over flushing, it is diluted and dispersed far enough from the wellbore to where it has a less harmful influence.

In injection wells injection should also start as quickly as possible. An ammonium chloride spacer is needed to prevent contact between the last mud acid flush and the injection water to avoid precipitation of sodium fluorosilicates and calcium/magnesium fluorides.

Instead of having an over flush, the well can also be back flushed (producing). Advantage of back flushing is that the produced water can be analysed and no precipitation in the reservoir at some distance of the well will take place. In practice back flushing is scarcely done. There are some main considerations not to do this:

- to back flush the well, one needs to be sure that the pumping equipment will work. If delays occur, serious damage can be caused because of precipitation in the near-wellbore zone;
- If a back flush is used, the produced water needs to be stored and disposed.
- In contradiction to the common theory it is experienced that flow paths in the reservoir during injection are not always similar to flow paths during production. Therefore there is a risk of not back flushing parts of the reservoir where chemicals are injected.

6.5 Other acidizing formulations

The fluid systems mentioned above usually cover the vast majority (> 90 %) of fluid systems selected for sandstone matrix acidizing. However, a number of other fluid systems can also be considered, depending on the mineralogy and field conditions/experiences. These are briefly mentioned below.

BH Sandstone Acid

This acid contains an organic acid (phosphonic acid), which produces a delayed reaction on clay minerals, significantly slowing the HF acid reaction rate. This minimizes de-consolidation of the formation in the wellbore area by spreading the acid reaction over a larger area. The result of this is a (claimed) deeper damage removal and a higher production increase over conventional, retarded HF acidizing methods. However, until now these claims have not been substantiated.

Organic mud acid

This system has basically three advantages:

- it causes less corrosion,
- it minimizes sludge formation,
- it causes no clay instability.

Such a system is particularly suited for high-temperature wells (90 to 150 °C), for which pipe corrosion rates are an issue. However, some of these fluids can produce severe secondary precipitation with Ca/Mg ions (calcium glycolate and citrate). So, depending on the composition of the injection water the systems might be less suitable for geothermal wells.

Alcoholic mud acid

Alcoholic mud acid formulations are a mixture of mud acid and isopropanol or methanol (up to 50 %). The main application is in low-permeability dry gas zones and is less suitable for geothermal wells.

Fluoboric acid

This acid, also known as Clay Acid (developed by Schlumberger), does not contain large amounts of HF at any time and thus has a lower reactivity. However, it generates more HF, as HF is consumed, by its own hydrolysis. Therefore, its total dissolving power is comparable to a more regular

mud acid solutions. Fluoboric acid solutions are often used as a preflush before treating formations sensitive to mud acid; this avoids fines destabilization and subsequent pore clogging. They are also used as a sole treatment to remove damage in a sandstone matrix with carbonate cement or in fissures that contain many clay particles. Fluoboric acid may be of use when the sandstone contains potassium minerals, to avoid damaging precipitates and in the case of fines migration owing to its fines stabilization properties.

6.6 Treatment design considerations

A sandstone acidizing design procedure consists of a number of steps to be taken. Typical treatment design aspects of sandstone matrix acidizing are briefly discussed in the following paragraphs.

6.6.1 Typical job stages

In a sandstone acid treatment, the following stages are distinguished:

Tubing/wellbore cleanup

Wellbore cleanup is commonly used to remove scale, paraffin, bacteria or other materials from the tubing, casing or gravel-pack screen. The injection string (production tubing, drill pipe or coiled tubing) should be cleaned (pickled) prior to pumping the acid treatment. The pickling process may be multiple stages, consisting of solvent and acid stages. An acid pickling job of tubing/casing can be done by simply spotting 3.5 m³ of 15-20% HCl down the (coiled) tubing and up the annulus.

Non-acid preflush

A water displacement stage, consisting of 5% NH₄Cl solution can be considered to displace formation water containing bicarbonate and sulfate ions. Typical volumes are 0.6 to 1.2 m³/m.

Acid preflush

The standard preflush, to dissolve carbonate minerals in the formation, consists of 5-15% HCl, plus additives. Typical volumes are 0.6 to 1.2 m³/m. However, as a minimum, the preflush should penetrate the same distance as the HCl/HF mixture.

If formations do not have much solubility in HCl, operators have tended to leave out acid in the preflush and use brine instead. However, this is not a

good idea, since the HCl preflush performs the vital function of cation exchange, which prepares the mineral surfaces for the HF mixture. The cation exchange must otherwise be done by the HCl portion of the HF mixture, which raises the pH of the acid system and induces the precipitation of silicate complexes.

Damage removal system (HF)

The main acid phase is commonly a mixture of HCl/HF as discussed above. Volumes may range from 25-200 gal/ft (0.3 -2.4 m³/m) or more (see also next section). If these volumes were applied in horizontal wells, extremely large volumes would be necessary, which may not be feasible, because of associated logistics, cost and pump times. Therefore, for horizontal wells in sandstone formations, stage volumes of 10 to 20 gal/ft (0.12 to 0.24 m³/m) are more common.

Over flush

The over flush displaces the HF acid stage away from the wellbore, thereby ensuring that precipitation reactions that inevitably take place, will occur well away from the near-wellbore region, where the effect on productivity will be insignificant. The over flush normally consists of 5% NH₄Cl, with typical volumes of 25-100 gal/ft (0.3 – 1.2 m³/m), and displacing the main fluid stage more than 3 ft (1 m) away from the wellbore.

In extremely water-sensitive formations, nitrogen might be an effective over flush.

Diverter stage

A diverter stage can then be followed by a repetition of the above steps, if required. Diversion will be discussed in more detail below.

6.6.2 Rates and volumes

Different opinions exist about how fast acid should be injected during a matrix treatment. In a significant number of cases, stimulation fluids are pumped at the highest injection rate possible, without exceeding formation fracturing pressure (MAPDIR technique of Paccaloni). Very high success rates in numerous field treatments have been obtained with this method. The success of Paccaloni's "maximum Δp , maximum

rate” procedure may be due to improved acid coverage throughout the interval of formation exposed. Also damage by precipitates from the acid/formation reaction is minimized. Therefore, Paccaloni’s MAPDIR procedure is recommended, unless there is specific field evidence that another method is better.

The maximum allowable injection rate into a vertical and horizontal well that does not fracture the formation, is given in Appendix III. Since this rate is directly proportional to the length of a horizontal well, maximum injection rates are significantly higher in a horizontal well than in a vertical well, completed in the same formation.

In Table 5 recommended main acid treatment volumes for regular mud acid (3% HF) are summarized, which should be considered as rules of thumb only.

| Permeability | Formation temperature | | |
|---------------------------|-----------------------|------------|------------|
| | < 65 °C | 65-120 °C | > 120 °C |
| k < 20 mD*) | 100 gal/ft | 50 gal/ft | 50 gal/ft |
| 20 < k < 100 | 150 gal/ft | 100 gal/ft | 100 gal/ft |
| k > 100 mD | 200 gal/ft | 150 gal/ft | 100 gal/ft |

**) Consider fracturing for low permeabilities!*

Table 5 Guidelines for the main acid (HF) volume as rule of thumb

Although 1.5% HF has half the dissolving power of 3% HF, doubling the volume of 1.5% HF will not produce the same results, because lower HF concentrations react much more slowly with sand. This slower reaction allows the HF to use more of its dissolving power on such targeted damage sources as clays and feldspars while using less dissolving power on sand. Table 6 shows the different HF concentrations and volumes that will give a comparable performance.

| HF concentration | Volume gal/ft |
|------------------|---------------|
| 3% | 100 |
| 1.5% | 150 |
| 1% | 200 |
| Retarded HF | 200 |

Table 6 HF acid volume guidelines

6.6.3 Additives

Although proper fluid selection is critical to the success of a matrix treatment, it may be a failure if the proper additives are not used. Additives are added to the different stages of a treatment to prevent excessive corrosion, sludging and/or emulsions, provide a uniform fluid distribution, improve clean-up and prevent precipitation of reaction products. Additive selection is primarily dependent on the treating fluid, the type of well, bottom hole conditions, the type of tubulars and the placement technique.

Since there is a large number of additives available, which may be different for various contractors, the choice of additives to use can be rather difficult. It is pretty much the domain of the service companies. Additives are always required, but it is important that only necessary additives be used. Although additives are designed to improve the success of stimulation treatments, they can also have a negative effect. For instance, surfactants used to keep fines in suspension can cause emulsion problems. Corrosion inhibitors are often cationic surfactants that may have a tendency to change the wettability of the formation resulting in a (temporary) reduction of the permeability to water.

Of all the additives, a corrosion inhibitor is the only one that should **always** be applied. Also, a sequestering agent, for the prevention of iron hydroxide precipitation is often required. All other additives should only be used, if there is a demonstrated need for them.

6.7 References

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7 Preliminary design of matrix treatments in Carbonates

7.1 Carbonates

Matrix acidizing in carbonate is essentially different from that in sandstones. In carbonates the rock matrix is readily soluble in most acids and there are no negative side reactions causing secondary precipitates.

Another technique that is frequently used in carbonates is acid fracturing, which will be discussed in Chapter 8.

Carbonate rocks have been created by chemical and biological processes in a water environment. Dissolved carbonates can re-precipitate when mixed with water from other sources. Marine animal life often plays an important role in creating carbonate rocks (shells, skeletons, etc.). Subsequent reactions can cause recrystallization. This is instrumental in the formation of dolomite, for instance. The presence of iron may then result in the formation of siderite (FeCO_3).

Limestones are composed of more than 50% carbonate minerals; of these, 50% or more consist of calcite and/or aragonite which are both CaCO_3 . A small admixture of clay particles or organic matter imparts a grey colour to limestones, which may be white, grey, yellowish or blue in colour.

Dolomites are rocks which contain more than 50% of the minerals dolomite [$\text{CaMg}(\text{CO}_3)_2$] and calcite (plus aragonite), with dolomite being more dominant. Dolomitization of carbonate rocks, i.e. the replacement of calcite by dolomite, involves a contraction (an increase in porosity) of about 10-12%, if the reaction proceeds as follows:



However, subsequent precipitation of carbonates in pores may also destroy (part of) the porosity formed as a result of dolomitization. Figure 7 shows a schematic classification of carbonates as a function of their composition.

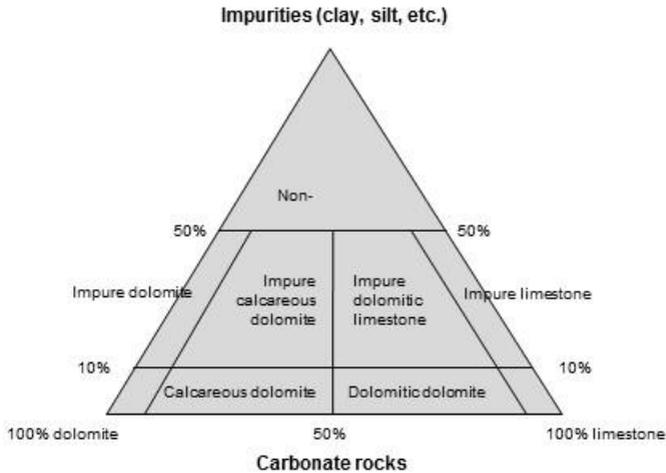


Figure 7 Carbonate rocks

7.2 Porosity/Permeability

Porosity of carbonates is of a different nature than the intergranular porosity of sandstones. Primary porosity in limestones includes openings between the individual constituent particles of detrital carbonate rocks and openings within the skeletal and protective structures of sea animals and within the tissue of algae. Secondary porosity in carbonate rocks includes fractures due to contraction of sediment during consolidation or because of mineralogical changes, or resulting from crustal movements, from leaching in general, or intercrystalline pores produced by dolomitization.

Well-defined porosity/permeability relationships generally do not exist for carbonate reservoirs. This is mostly due to the different nature of porosity and permeability in carbonates (e.g. vuggy, fractured porosity vs. intergranular porosity in sandstones). Moreover, although the permeability of many limestone and dolomite reservoirs is very low, their productivity is often considerably higher than one would expect from the permeability of the cores, because of the fractured nature of many of these rocks.

Whilst in sandstone the dominant improvement mechanism is the dissolution of formation impairment, in carbonates the mechanism is by-

passing the damaged zone by dissolution of the rock. The dissolution of carbonate rock often creates so-called “wormholes” as shown in Figure 8.

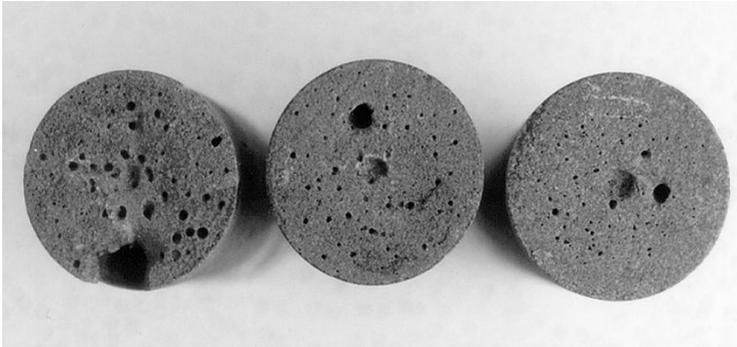


Figure 8 Wormhole formation in a core flow test.

Instead of uniform dissolution of the rock, acid creates wormholes that can be up to a meter deep. There has been a lot of study on the mechanism of wormhole formation. In principle, the longest wormholes are created at a certain optimum pump rate. Below this rate the wormhole length rapidly decreases. However at higher rates the wormhole length decreases only slowly. As a practical approach it is again best to pump at the highest rate without fracturing (see Figure 9).

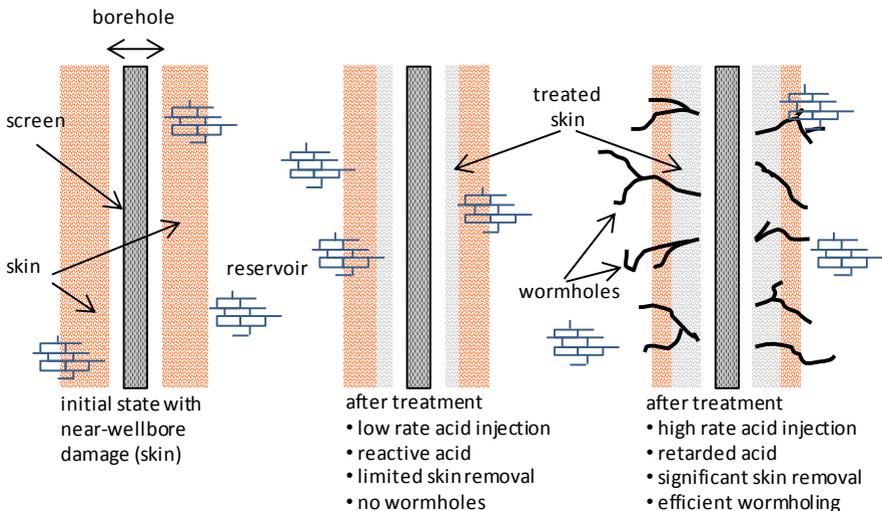


Figure 9 Optimum conditions for wormhole formation

Also the type and concentration of acid affects the wormhole length. Solutions with very reactive acids will just have limited effect on the near-wellbore -damage (skin). Retarded acids will be more effective in removing skin and in forming wormholes up to a greater distance from the borehole.

7.3 Carbonate treatment selection

In carbonates there are a number of ways to treat the well with acid depending on the type of damage and formation rock. Table 7 shows a treatment selection chart. For completeness sake it includes the use of massive hydraulic fracturing which does use proppant rather than acid.

| Type of rock damage | Acid wash/soak | Matrix treatment *) low & high volume | | CFA **) | Acid frac | MHF ***) | Worm-holes required |
|---|----------------|--|-----|---------|-----------|----------|---------------------|
| Plugged perforations | X | X | | | | | No |
| Shallow damage, no vugs or fracs | | X | (X) | | | | No |
| Shallow damage, vugs or fracs | | X | (X) | | | | (Yes) |
| Deep damage, no vugs or fracs | | | X | | | | Yes |
| Deep damage, vugs or fracs | | | X | X | (X) | | Yes |
| Deep or shallow damage, low permeability with natural fracs | | | | X | X | (X) | No (n.a.) |
| Deep or shallow damage, low permeability no natural fracs | | | | | X | X | n.a. |

*) low volume: 0.2-0.4 m³/m, 15% HCl; high volume: 1.2-2.0 m³/m, 15-28% HCl

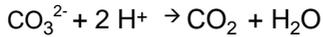
**) CFA: Closed Fracture acidizing

***) MHF: Massive Hydraulic Fracturing

Table 7 Treatment selection chart for matrix treatment of carbonate formations

7.4 Selection of the type of acid

Although a wide variety of carbonates is found in nature, their reaction with HCl - and other, organic acids - is governed by a simple ionic reaction:



Apart from the possible formation of ferric hydroxide (due to the pick-up of iron from the tubing) there are no complicating precipitation reactions, as is the case in sandstones.

Hydrochloric acid, the most commonly used acid in carbonate stimulation, is ordinarily supplied in concentrations of 32 – 36%. In well treatments, its normal strength is 15% by weight, but the use of a higher concentration of 28% by weight has also become more popular, in particular for dolomites, and shallow, low temperature carbonate formations.

Organic acids, viz. acetic acid (CH_3COOH), and formic acid (HCOOH) are weakly ionised, slow-reacting acids and they are used in acidizing carbonates primarily in wells with high bottom hole temperatures (above 120 °C), thus causing significantly lower corrosion rates, or for conditions where prolonged reaction times are required. For field use acetic acid solutions are normally diluted to 15% or less. At concentrations greater than 15%, one of the reaction products, calcium acetate, can precipitate. Similarly, the concentration of formic acid is normally limited to 15% because of limited solubility of calcium formate.

The most commonly used acid is hydrochloric acid. Hydrochloric acid solutions can be blended with either formic or acetic acid. Formic and acetic acids can also be blended together.

In general hydrochloric acid is the preferred acid. Only at higher temperatures organic acids may be used to reduce corrosion. The chart below (Table 8) can be used in case of naturally fractured carbonates.

| Formation | | Fractures | |
|-----------|---------------------------------------|---------------------------------------|---|
| | Open or filled with calcitic material | Filled with siliceous fines | Filled with mud remnants, etc. |
| Calcite | HCl (10-15%) | HCl (10-15%) + silt suspending agents | HCl (10-15%) + silt suspending agents, small volume |
| Dolomite | HCl (10-15%) | HCl (28%) + silt suspending agents | HCl (28%) + silt suspending agents, small volume |

Table 8 Treatment selection chart for matrix treatment in naturally fractured carbonates

The influence of high temperatures on the design, execution and performance of acid stimulation treatments in carbonates is perhaps more drastic than the effect of high pressures. Reaction rates are faster, resulting in a limited penetration depth of live acid. To combat this, retarded acids may have to be applied, such as:

- Emulsified (acid-in-oil) acid, with a recently developed high-temperature emulsifier surfactant mixture, which is stable to temperatures up to 180 °C.
- A combination of organic acids (acetic and formic acid), which have extended reaction times, possibly in combination with a high-temperature, high molecular-weight polymer gelling agent.

Alternatively, cool-down preflushes could be applied. A drawback of this procedure is that substantial amounts of water may have to be injected, which in geothermal wells may not be a problem.

Corrosion of tubulars at high temperatures is much more severe than at low temperatures. Being a chemical reaction, the corrosion rate doubles every 10 °C temperature increase whilst most current commercial inhibitors start to decompose at temperatures above 100 – 120 °C. However, corrosion inhibition systems are available that protect tubulars up to 180 °C. The common way to combat this higher corrosion is to add

high (excessive?) concentrations of corrosion inhibitors and intensifiers. Also cool-down flushes will help to reduce the corrosion problems. However, it should be borne in mind that return acid, although spent, is hot and still very corrosive, and it should therefore contain sufficient corrosion inhibitor. Unfortunately, corrosion inhibitors tend to stay behind in the formation. Therefore, an overdose might be required to compensate for loss of inhibitor through adsorption in the formation. Over displacement of the acid (in case of a matrix treatment) will alleviate the problems. In any case, it is strongly recommended to include corrosion tests with (simulated) spent acid in the corrosion testing program.

The use of organic acids can also be considered to reduce corrosion problems in high-temperature applications. The blends can be designed so that the dissolving power is equivalent to HCl, with significantly reduced corrosion rates. Although the base acid cost for a formic/acetic acid is normally about twice that of HCl, inhibition costs are generally less.

7.5 References

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8 Placement/diversion techniques

8.1 Why placement & diversion techniques?

Placement strategy and diversion techniques are important steps in the design of a matrix stimulation treatment. The goal of these considerations is how to obtain a uniform penetration of the treating fluid throughout the entire section and/or into each natural fracture system. If complete zonal coverage is not achieved, full production potential cannot be realized. While the stimulation of horizontal wells, in principle, is not different from that of vertical wells, as far as selection of candidates and treatment fluids is concerned, unique problems arise in these wells with respect to the placement and diversion of a treatment.

Determination of the proper fluid placement method is a key factor in acid treatment design in both sandstones and carbonates. More often than not, some method of placing or diverting acid is required to distribute acid across the zone or intervals of interest. The problem of fluid placement is magnified in horizontal wells because of the length of the interval. Damage, depending often on fluid-rock interactions, may be unevenly distributed along the length of the interval. Also, the natural reservoir permeability may vary considerably, with substantial contrasts. In such an environment, matrix stimulation tends to remove or bypass the damage that is easiest to reach, and the fluid invades the zone where it is least required. To achieve full damage removal, acid must be diverted to the sections that accept acid the least – those that are most damaged. There are various placement and diversion techniques available for matrix acidizing, viz.:

- mechanical methods,
- chemical diverter techniques,
- diversion with fluids,
- pumping strategy.

In a lot of treatments, particularly in long horizontal hole sections, combinations of the above methods are being used, like coiled tubing for placement in conjunction with foamed fluids for diversion.

8.2 Mechanical methods

These techniques use mechanical means to isolate a particular zone for injection, or selective placement of stimulation fluids. Mechanical

placement methods are usually more reliable than other techniques, albeit at high costs. A further disadvantage is that they are not applicable to gravel-packed wells and wells where zonal isolation does not exist through effective cementation of the production casing (bad cementation, horizontal wells completed as open hole or with slotted liner).

8.2.1 Packers and bridge plugs

Complete zonal isolation can be obtained in a perforated completion by packing-off a section of the completion interval, for instance by a combination of a retrievable packer and bridge plug, or a straddle assembly. This effective method is very expensive, however, and may require a rig. A more appropriate means of hydraulically setting and retrieving such tools is with the use of coiled tubing. The perforation intervals should include blank sections to allow setting of packers.

A coiled tubing-conveyed, inflatable, selective injection straddle packer assembly has been developed, (the Inflatable Straddle Acidizing Packer tool, ISAP), by Baker Hughes. This tool can be used for through-tubing selective stimulation jobs through casing perforations, and for open-hole selective stimulation jobs. The straddled length is 5 m. It can be used for:

- acid stimulation of specific intervals with optimum volumes of fluid,
- treatment of highly inhomogeneous formations.

When hydraulically inflatable packers are used as a straddle tool, it is possible to treat three intervals (below, between and above the packers) without moving the completion. Although this is an effective means of obtaining excellent control on coverage, it is expensive and time consuming.

For horizontal wells, which frequently have been completed as open hole completion with slotted liner, external casing packers (ECPs) may help improve wellbore fluid placement by compartmentalizing the annulus. However, the optimum ECP position for remedial treatments should be known already when the completion is designed, which is clearly not practical. When zonal segmentation is provided by slotted liner with ECPs, each segment (500 ft long on average) must be treated with retrievable

packers set opposite to the casing packers to prevent treating fluid migration along the wellbore behind the slotted liner.

An isolation method has been developed, in which non-elastomeric sliding sleeves replace the slotted pipe between the ECPs. With the use of coiled tubing and hydraulically actuated tools, the sliding sleeves can be manipulated for selective treatments in long horizontal wells. Whilst in principle many ECPs could be used to deal with the uncertainty in the optimum position, their number is usually restricted to avoid deployment problems and to reduce initial well costs.

8.2.2 Coiled tubing (CT)

Coiled tubing (CT) is a very useful tool for improving acid placement. The use of coiled tubing is often considered for the placement of matrix treatment fluids in horizontal wells, both in cased and open hole completions. The combination of employing coiled tubing and a (temporarily cross linked) gelled acid or foam as a diverting agent, has proved effective in carbonate formations in horizontal wells.

Coiled tubing can be used to spot fluids along the zone, while drawing or reciprocating the tubing along the zone of interest. Other CT-based methods in matrix acidizing of horizontal wells involve either circulating up the CT/tubing annulus, or bull heading acid or an inert fluid along this annulus. Combining coiled tubing with straddle packer assemblies for selective zone placement is a standard method for improving zonal coverage. Moreover, the use of CT with a jetting tool provides an excellent means of establishing direct communication of the acid with the formation face in long open hole sections. This can be very effective for the removal of mud filter cake or for the cleaning up of installed screens.

8.2.3 Ball sealers

Ball sealers are small rubber-lined plastic balls. They are available in a density range of 0.9 – 1.4 g/cm³. Ball sealers with densities less than 1.0 are called buoyant ball sealers or floaters. Ball sealers with specific gravity greater than water or acid are called sinkers, for obvious reasons. Newer, conventional ball sealers are of the floater or neutral density variety. Older, conventional ball sealers are of the sinker variety.

Ball sealers can be used in both acidizing and fracturing treatments. This diversion method has been successfully applied both in vertical and horizontal perforated wells. However, in horizontal wells, ball sealer efficiency is influenced by hole angle, ball density, injection rate, perforation orientation, density and number. In horizontal wells, neutral buoyancy balls should be used, if at all.

The action of ball sealers is based on the idea that the balls are carried along with the stimulation fluid towards a perforation, which they will subsequently shut off. In order for the balls to seat, the fluid velocity needs to be sufficiently high. As a guideline, the following values have been used: 3 bpm in a 4.5" casing, 4 bpm in 5.5" casing and 7 bpm in 7" casing. The perforations should be of a consistent size, round and free from burrs. A rule of thumb for selecting ball size to achieve an adequate seal is that the ball diameter should be about 1.25 times the perforation diameter. Ball sealers require a pressure differential of 100 – 200 psi to seat efficiently. This should be kept in mind when planning the number of perforations to be balled, and the treatment pump rate. In order to compensate for non-seating balls, the number of balls to be used is usually 10 – 20% higher than the number of perforations believed to be taking fluid.

Water-soluble balls, constructed from collagen, have also been developed. This eliminates a range of potential problems, such as the possibility that the balls will remain down hole where they can make drilling out plugs difficult, failure to unplug during flow back in low pressure reservoirs.

Also relatively new on the market are biodegradable ball sealers. These are made of animal protein material that degrades at certain temperatures. With biodegradable ball sealers, there is no danger of plugging, recovery failure, or loss to the sump. These conveniences come at a higher price. However, it may be worth it, especially in more complex completions or those containing permanent down hole tools. The practical temperature limit of biodegradable ball sealers is probably about 95 °C which makes them less suitable for some geothermal wells. However, the temperature limitation not be an issue for short treatments of injection wells.

8.3 Chemical diverter techniques

Chemical diverters, which are materials insoluble in acid, but highly soluble in water or hydrocarbons, have been used either to form a thin, low-permeability filter cake at the formation face, or to reduce the injectivity of high-permeability zones or perforations, with the injection of a viscous polymer plug. The first technique has been found to be more effective and can provide faster clean-up. It has prevailed over the viscous slug technique.

Diverting particulates must be soluble in either the production or injection fluids. Having acted as diverters, they should allow a rapid and complete clean-up. Diverting agents can be classified, according to their particle size, as bridging agents or particulate diverters.

8.3.1 Bridging and plugging agents

These diverting agents consist of relatively large-size particles, ranging from 10/20 to 100 mesh (2 to 0,15 mm). They are used as diverters in carbonate formations, where natural fractures are common. However, their effectiveness is limited by the relatively high permeability of the cakes they create. When effective diversion is required in fractured zones, a slug of bridging agent is injected first, followed by the treating fluid containing a diverting agent.

Bridging agents are: inert materials such as silica sand; water-soluble bridging agents, including rock salt and benzoic acid; oil-soluble resins (OSRs), naphthalene flakes and beads made of wax-polymer blends, obviously less applicable in geothermal wells.

8.3.2 Particulate diverters

These are characterized by very small particle sizes, well below 0.004 in. in diameter. Both water-soluble (fine grade of benzoic acid, or salts) and oil-soluble (blends of hydrocarbon resins) particulate diverters are available (not suitable in geothermal applications). Sodium containing solids (salt, sodium benzoate, etc.) should never be used as a diverter in hydrofluoric acid (HF) treatments, or before HF treatments, since it may lead to sodium fluosilicate precipitation.

8.3.3 Recommendation

The various types of chemical diverter do not require zonal isolation to work. However, their main disadvantage is that, if they are not removed

by the produced fluids, they can cause impairment too. In most cases clean-up is rather slow. Many cases of slow clean-up after diverted acid stimulation treatments may be attributed to the diverter not (rapidly) dissolving in the back-produced fluids.

8.4 Horizontal wells

In vertical or deviated wells, completed in sandstone formations as cased and perforated completions, matrix acidizing with HCl/HF mixtures is a common practice. However, in horizontal wells, such remedial matrix acidization is not commonly done in sandstones, as is evident from the lack of reporting on this topic in the open literature. Also, most of the acid treatments in horizontal wells, and reported in literature, pertain to wellbore cleanouts and matrix treatments in carbonates, with HCl only. See for more details Chapter 10.

8.5 Pumping schedules

After selecting an acid recipe and a diverting method (if applicable) a pumping schedule can be formulated. Pumping schedules for matrix treatments are in general rather simple. Figure 10 shows a typical schedule for a carbonate acid treatment. Note: the chemicals have Halliburton trade names, but the function is given in-between brackets. For sandstone a similar schedule would be given with an additional flush of an HF/HCl mixture after the first HCl flush.

Summary – Fluids

| No. (#) | Description | Fluid Name | Total Volume (m ³) | Average Coverage (gal/ft) | Fluid Additives |
|------------------------|---------------------------|-----------------------------------|--------------------------------------|---------------------------------|---|
| 1 | Aqueous Non acid preflush | Fresh Water with Friction Reducer | 4.97 | 20.0 | 0.2 % SGA-III (friction reducer) 0.1 % Losurf 300M (surfactant) |
| 2 | First acid mainflush | 15% HCl | 24.34 | 98.0 | 0.5 % HC-2 (Fines suspension agent) 0.1 % HAI-OS (Corrosion inhibitor) 1% CLA-STA FS (Clay stabiliser) 2.99506 kg/m ³ FERCHECK A (Iron control agent) 0.1 % Losurf 300M (Surfactant) 0.2 % SGA-III (friction reducer) |
| 3 | Non acid overflush | Fresh Water with Friction Reducer | 0.99 | 4.0 | 0.2 % SGA-III (friction reducer) 0.1 % Losurf 300M (Surfactant) |
| 4 | Displacement | Fresh Water with Friction Reducer | 5.32 | | |
| Total Volume of Fluid: | | | 35.62 | | |

Figure 10 Typical pump schedule for a carbonate acid treatment

8.6 References

1. Kalfayan, L.J. “The Art and Practice of Acid Placement and Diversion: History, Present State and Future.” SPE124141. New Orleans (USA), 2009.



9 Preliminary treatment design: hydraulic fracturing

In the geothermal world two types of fracturing techniques can be distinguished: classical tensile fractures that are being propped and shear fracs or water fracs that are self propping. We will be dealing with tensile propped fracs in this overview and in this chapter. On the other hand shear fracs are being applied frequently in geothermal projects. Many EGS projects (Soultz, Newberry) rely on shear fracs. However, in The Netherlands the naturally present shear stress is in general not high enough to be able to create shear fractures. Also, shear fractures are especially useful in very hard materials like granites, and less so in sandstones.

9.1 Introduction

At this point it is worthwhile to realize that by hydraulic fracturing, the well productivity is increased by altering the flow pattern in the formation near the wellbore from one that is radial, with flowlines, converging to the wellbore, to one that is linear with flow to a conductive fracture that intersects the wellbore. For this to be successful, however, the fracture must be much more conductive than the formation. To obtain such a high-permeability fracture, a highly permeable proppant pack is required of some 50 - 500 Darcy.

Since its inception, hydraulic fracturing has developed from a simple low-tech, low-volume, low-rate fracture stimulation method to a highly engineered, complex procedure that is used for many purposes. Fracturing treatments typically have varied in size from the small (e.g. 10 m³ or less) mini-hydraulic fracturing treatments, to the deeply penetrating massive hydraulic fracturing (MHF) treatments, which now exceed 1 million gal (3.8 x 10³ m³) fracturing fluid and 3 million lbs. (1.4 x 10⁶ kg) of propping agent.

The application of hydraulic fracturing is generally limited to low-permeability reservoirs (e.g. < 1 mD for gas reservoirs and < 20 mD for oil/water reservoirs). The fracture conductivity corresponding to the typical fracture widths achieved is not sufficient to effectively stimulate medium and high permeability reservoirs. However, a technique has been developed in more recent years, primarily intended to bypass near-

wellbore damage, for which an extra wide, proppant-filled, relatively short hydraulic fracture is created. This technique, called Skinfrac, uses a limited volume (some 600 bbl or 100 m³) of fracturing fluid, and some 10,000-100,000 lbs (5-50 tons) of proppant, using an aggressive pumping schedule, in which the proppant reaches the fracture tip at an early stage of the treatment, preventing the fracture from growing further (tip screen-out, TSO, design). The fracture is then further inflated and filled with proppant. In unconsolidated reservoirs, where sand production is a potential problem, the Skinfrac technique can be a good alternative for sand control purposes: the reservoir is fractured with a screen in place, followed by a gravel pack operation. Such technique is also frequently called Frac&Pack, or FracPack and is particularly of interest for geothermal wells.

Hydraulic fracturing a well is not without some risk. A fracture treatment may fail because of unintended communication with neighbouring reservoir zones. Furthermore, mechanical failures can occur, including leaking packers, casing or tubing leaks, or communication of fracturing fluids behind poorly cemented casing. Other causes of failure include the inability to complete the treatment due to high treatment pressure, or poor proppant transport (screen-out). Incompatibility of the fracturing fluid and additives with the reservoir rock or fluids can lead to severe reservoir damage. When selecting candidates for hydraulic fracture treatment, a careful candidate and treatment selection procedure is therefore of paramount importance, to avoid any of the above problems.

9.2 Design Steps Hydraulic Fracturing

Two basic steps in the fracturing design process are:

- The selection of fluids and
- The selection of proppants.

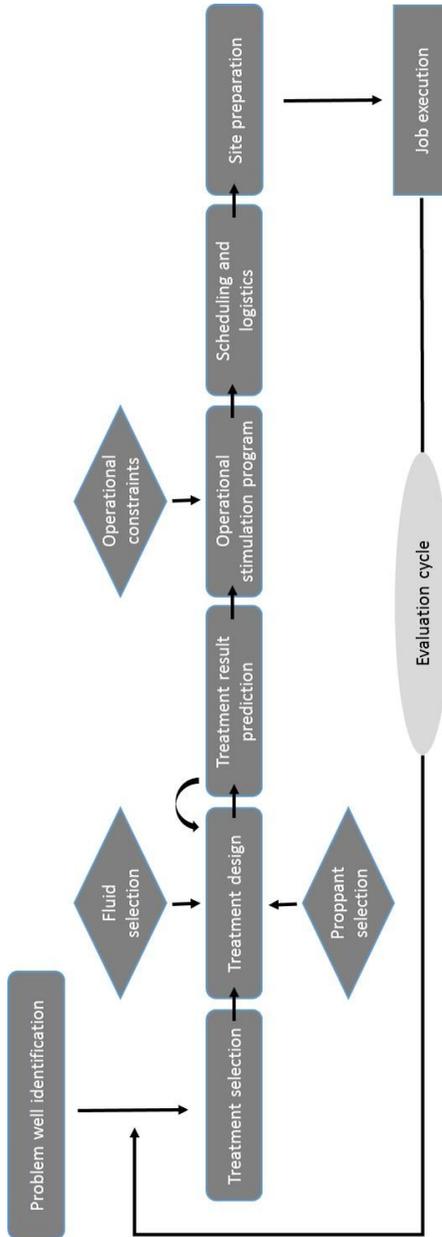


Figure 11 Fracturing treatment design process

9.3 Fluid selection

A hydraulic fracturing fluid for geothermal applications needs to combine a number of, sometimes conflicting, properties. While traveling down the well the viscosity should be relatively low to avoid an excess of friction. During the time it creates the fracture the viscosity should be high to increase the efficiency and to carry the proppant into the fracture. Upon terminating the treatment the fluid should lose its viscosity to allow easy flow back (in a producer) or easy (re-) start of injection. Furthermore, a fluid should be compatible with the formation rock and should not pose a threat to the environment.

To combine all these requirements in a single fluid formulation is not easy but the oil and gas industry has succeeded in formulating fluids that come very close. The following fluid types are used:

- Water-based gels
 - linear gels
 - crosslinked gels
- Gelled hydrocarbons
- Foamed fluids
- Emulsions
- Visco-elastic surfactants

Of these only the water based fluids are applicable in geothermal projects.

Linear gels include agents known as guar or cellulose derivatives that are biodegradable. The substances are polymeric, which are used to thicken the water for better proppant transport. Guar gum is nontoxic and is a food-grade product commonly used to increase the viscosity of foods such as ice cream. Cross-linked gels are an improvement to linear gels providing greater proppant transport properties (see Figure 12).

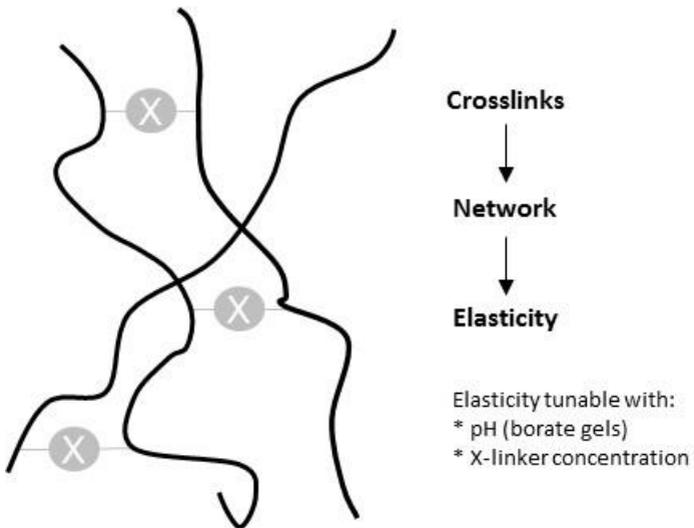


Figure 12 Principle of cross-linked gels

Cross-linking reduces the need for fluid thickener and extends the viscous life of the fluid. Metal ions such as chromium, aluminum, and titanium have been used to achieve the cross-linking. Nowadays boron is the most commonly used cross-linker. Cross-linked fluids require breaking agents to reduce the viscosity for flow back. Breakers are additives of acids, oxidizers, or enzymes. Foamed gels use bubbles of nitrogen or carbon dioxide to transport proppant into fractures. The inert gases can reduce the amount of fluid required for fracturing by up to 75%. Potassium chloride is sometimes used as a thickening agent for water-based fracturing fluids. Polymers in hydraulic fracturing fluids can provide an excellent medium for bacterial growth. The bacteria can secrete enzymes that break down gels and reduce viscosity, which translates to poor proppant placement. Biocides are added to inhibit microbial action. Leak-off is the action of fracturing fluids flowing from the fracture through the fracture walls into the rock matrix. Leak-off can be controlled by viscosity (cross-linking) and by adding bridging materials such as 100 mesh sand, soluble resin, or other plastering materials. Pumping of stimulation fluids can occur at maximum rates in which friction from high-viscosity fluids requires significant horsepower. Friction reducer additives are used to minimize energy requirements and primarily consist of latex polymers. Borate cross-linked fluids can be used up-to about 160 °C. Some titanium or zirconium cross linked gel could be used up to about 170 -190 °C. If necessary the near-wellbore formation can be cooled down somewhat, but the effect might be limited and could create well integrity issues, see also chapter 12.

However, although crosslinked HPG (Hydroxy Propyl Guar) systems can be pumped into deep, hot reservoirs, severe shear degradation occurs when the fluid is crosslinked at surface and then pumped at high rates down the tubulars. Since viscosity may thus be lost permanently downhole, delayed crosslinked frac fluid systems lower pumping friction because of the lower viscosity in the tubing. Thus, the use of delayed crosslink fluids yields a higher ultimate viscosity downhole and a much more efficient use of available horsepower on location.

Table 9 shows an overview of the most used gelled fracturing fluids

| Cross linker | Gelling Agent | pH range | Temperature °C |
|-----------------|------------------|----------|----------------|
| B, non-delayed | guar, HPG | 8-12 | 20 - 150 |
| B, delayed | guar, HPG | 8-12 | 20 - 150 |
| Zr, delayed | Guar | 7-10 | 65 - 150 |
| Zr, delayed | Guar | 5-8 | 20 - 120 |
| Zr, delayed | CMHPG, HPG | 9-11 | 95 - 190 |
| Ti, non-delayed | guar, HPG, CMHPG | 7-9 | 40 - 165 |
| Ti, delayed | guar, HPG, CMHPG | 7-9 | 40 - 165 |
| Al, delayed | CMHPG | 4-6 | 20 - 80 |
| Sb, non-delayed | guar, HPG | 3-6 | 15 - 50 |

Table 9 Fracturing fluid systems

In addition to this list also foamed fluids might be used in some cases.

Figure 13 is an example of a selection spreadsheet incorporating the most important criteria.

Appendix IV lists the most common commercially available frac fluids for use in geothermal wells

| Fracturing fluid selection | | | | | | | | | |
|---|-----------|---------------|------|---------------------|----|--------------------|----|-------|----|
| | | Type of fluid | | | | | | | |
| | | Linear gel | | X-linked gel Borate | | X-linked gel Metal | | Foam | |
| Well profile | | score | | score | | score | | score | |
| Permeability | (example) | | | | | | | | |
| > 50 mD | 0 | 1 | 0 | 5 | 0 | 4 | 0 | 3 | 0 |
| 1 - 50 mD | 0 | 2 | 0 | 5 | 0 | 4 | 0 | 3 | 0 |
| < 1 mD | 1 | 4 | 8 | 4 | 8 | 4 | 8 | 3 | 6 |
| Reservoir pressure (bar) | 400 | 1 | 3 | 2 | 5 | 2 | 5 | 3 | 8 |
| Tubing ID (inch) | 3.95 | 5 | 9 | 4 | 7 | 4 | 7 | 2 | 3 |
| Temperature @ | 150 | 1 | 0 | 3 | 20 | 4 | 20 | 1 | 0 |
| Rate the importance/ likelihood of the following factors (scale 1 to 5)*: | | | | | | | | | |
| Proppant pack damage | 5 | 3 | 8 | 4 | 10 | 2 | 5 | 4 | 10 |
| Use of Resin Coated Proppants | 5 | 5 | 13 | 4 | 10 | 2 | 5 | 4 | 10 |
| Fracture containment | 4 | 5 | 8 | 2 | 3 | 2 | 3 | 2 | 3 |
| >8 ppg proppant | 5 | 2 | 5 | 5 | 13 | 4 | 10 | 1 | 3 |
| Safety/ environmental risks | 4 | 5 | 8 | 3 | 5 | 4 | 6 | 3 | 5 |
| Costs | 5 | 2 | 3 | 3 | 2 | 3 | 2 | 4 | 1 |
| Total score | | | 62 | | 82 | | 71 | | 48 |
| Summary | | Score | Rank | | | | | | |
| Linear gel | 62 | 3 | | | | | | | |
| X-linked gel (Borate) | 82 | 1 | | | | | | | |
| X-linked gel (Metal) | 71 | 2 | | | | | | | |
| Foam | 48 | 4 | | | | | | | |
| *) 1 = not important/ unlikely, 5 = very important | | | | | | | | | |

Figure 13 Typical fracturing fluid selection overview

9.4 Proppant selection

The purpose of proppant is to maintain a conductive flow path for the reservoir fluid after the treatment. Like fracturing fluids there are many proppants available. The main types are given in Figure 14: sand and ceramics, like sintered bauxite.



Figure 14 Types of proppants:sand and sintered bauxite

In addition all these proppants can be coated with resin to reduce the tendency of proppant back production.

The selection of type and size of proppant, hinges on two criteria:

- proppant strength (crushing), and
- proppant size.

As to proppant size, the most commonly used size is 20 - 40 mesh (0.84 - 0.42 mm). Depending on the conditions, other sizes can also be selected, with relatively larger sizes being selected for the softer, and more permeable rock types. When selecting relatively large-size proppant, it should be ensured that the perforation tunnel must have a cross-sectional area that allows proppant passage without bridging (6 - 7 times the proppant diameter). Moreover, fracture width at the wellbore must also be large enough to accept the initial stages of proppant. It is generally required that the ratio of fracture width to maximum proppant diameter be at least $2\frac{1}{2}$ to 3.

In addition all proppants can be coated with resins to reduce the tendency to proppant flow back, which is especially an issue in gas wells. But also in

the producing side of doublets it could cause problems (like pump failures).

Table 10 & Table 11 summarizes the main selection criteria:

| Estimated Closing Stress | | |
|------------------------------------|---|--|
| <275 bar (< 4000 psi) | 275-550 bar (4000-8000 psi) | >550 bar (>8000 psi) |
| Sand Resin coated sand | Resin coated sand Intermediate strength proppant | Intermediate strength proppant High strength proppant |

Table 10 Selection proppant type based on estimated closing stress

| Permeability | Soft rock (BHN<1000 bar) | Hard rock (BHN>1000 bar) |
|---------------------|------------------------------------|------------------------------------|
| > 20 mD | 10-20/16-20 mesh | 10-20 mesh |
| 1-20 mD | 20-40 mesh | 10-20/16-20 mesh |
| < 1mD | 20 - 40/40 - 60 mesh | 20-40 mesh |

Table 11 Selection size of proppant based on permeability and BHN (BHN=Brinell Hardness)

There are many proppant manufacturers that all produce similar types of proppants.



Figure 15 Commercial proppants

In general proppants are not bought straight from the manufacturers but form an integral part of the fracturing package provided by the service companies.

9.5 Fracture design and execution

The calculation of a detailed fracture treatment design usually follows the following steps:

1. Estimate the desired fracture length ideally on the basis of a reservoir engineering study
2. Determine the total required fluid volume

-
3. Determine the pad volume (usually 30-40% of the total fluid volume)
 4. Design the proppant addition schedule

Determining the treatment schedule is the last, and most essential, step in a fracture stimulation design. As indicated above, treatment scheduling consists of selecting a pad volume, a slurry volume to follow the pad, and a proppant addition schedule, specifying the proppant concentrations to be used. The pad stage opens the fracture at the wellbore, and extends the fracture ahead of the proppant laden stages. As the fracture extends the total volume of fluid loss increases. As a result the rate of propagation, when pumping at a constant rate, decreases. Therefore, the fracture tip propagates slower than the proppant laden stages. Ideally, the treatment should be designed to end, when the proppant laden fluid reaches the fracture tip, where it will then quickly dehydrate and screen out. Continuing pumping after that point will increase the pressure causing the width of the fracture to increase without further propagation of the fracture. This is known as a Tip screen out design.

The complete recommended procedure is as follows:

1. Collect the necessary input data. Probably the most sensitive input parameters are the stress profile, Young's modulus (E) and the fluid-loss coefficient. While the E-modulus may be determined from core samples, the latter two parameters can only be obtained from a minifrac test. The stress profile is often derived from sonic logs.
2. Run a frac design programme¹ for a most likely stress regime and fluid-loss value. In a new field, where experience and uncertainties associated with the design data have not been fully established, it is advisable to design a rather conservative treatment with a relatively large pad volume and a moderate maximum proppant concentration.
3. For planning purposes with the contractor, select the most likely pumping schedule, based on, for instance, information from other wells. Also, compare designs provided by the stimulation

¹ Several design programs are commercially available: MFrac (Baker Hughes), Fracpro (Stratagen and RES), Gohfer (Stimlab), Stimplan (NSI) and others.

contractor with designs obtained with the design programme used.

4. Screen the treatment with the service company – hydraulic fracturing is a complex operation that requires good coordination of all parties involved.
5. Carry out a minifrac (just) prior to the main fracturing treatment, to confirm estimates of in-situ stress, fracture overpressure and fluid-loss coefficient. Revise treatment design **on-site**, if necessary.

9.6 Required Input data

A good design requires knowledge on a large number of input parameters. Table 12 shows an overview of the most essential data.

| Input Parameter | Source | Purpose | Importance for frac design |
|---|----------------------------------|--|----------------------------|
| Reservoir | | | |
| Porosity | Lab tests on cores, logs | Production modelling, stiffness calculations | minor |
| Compressibility | Lab tests on cores, PVT analysis | Production modelling | minor |
| Reservoir pressure | Build up | Stress calculations | Important |
| Permeability/ leak-off coefficient | Lab tests on cores, logs | Fluid loss, Production modelling | Very Important |
| Reservoir fluid viscosity | PVT analysis | Fluid loss, Production modelling | minor |
| Gross and net pay | Logs | Production modelling, frac size calculations | medium |

| Rock mechanics | | | |
|--|---|---|-----------------------|
| Poisson's ratio | Lab tests on cores, logs | Fracturing pressures and geometry | Important |
| Young's modulus | Lab tests on cores | Fracturing pressure and geometry | medium |
| Fracture toughness | Lab tests, field calibration | Fracturing pressure and geometry | minor |
| In situ Stress profile | Logs (DSI) + calibration with field and core tests | Fracturing pressure and geometry | Very important |
| Well completion | | | |
| TVD/MD | Drilling/completion reports | Wellhead Treatment pressures | Important |
| Well trajectory | Deviation survey | Wellhead Treatment pressures | Important |
| Perforations and interval | Drilling/completion reports | Wellhead Treatment pressures, fracture initiation, geometry | Very important |
| Tubing and casing configuration | Drilling/completion reports | Wellhead Treatment pressures | Important |
| Restrictions (e.g. SSSV) | Drilling/completion reports | Wellhead Treatment pressures | minor |
| Frac Fluid | | | |
| Rheology (incl. Cross- linking) | Lab tests, Stimulation contractor handbooks | Wellhead Treatment pressures, Fracture geometry, Fluid optimization | Important |
| Compatibilities (rock, proppant, reservoir fluids, drilling and completion fluids) | Lab tests, Stimulation contractor handbooks | Fluid optimization | Important |
| Density | Lab test | Wellhead Treatment pressures | Important |

| Proppant | | | |
|---------------------------------|--|---|-----------------------|
| Density | Lab test | Wellhead Treatment pressures, proppant settling | Medium |
| Size | Lab test | Proppant pack Conductivity, Proppant back production | Important |
| Material (incl. Coating) | Stimulation contractor handbooks, lab tests | Proppant pack Conductivity, Proppant back production | Very important |

Table 12 Typical overview of input data for a hydraulic fracturing design

Below is a summary of the most important parameters and their influence on the fracture design and geometry.

9.6.1 Permeability and leak-off coefficient

Accurate fluid-loss data are essential to a good hydraulic fracture design. In principle the higher the permeability the higher the fluid loss is, but other factors also play a role. The major stimulation contractors have compiled data, measured under a variety of conditions, in their design manuals. Although these data may be used in some cases, it is preferred to measure, specifically the fluid-loss coefficient, under in-situ conditions, i.e. during a minifrac treatment prior to the main fracturing treatment. The procedure of such a minifrac treatment is described in Appendix V. If such a minifrac is not feasible, the fluid-loss coefficient could be measured on core samples, using samples of the actual materials (i.e. mix water, breaker, cross linker).

Ideally, the value for fluid-loss coefficient should be as low as 0.002 ft/1/min for hard rock. If the fluid-loss coefficient exceeds a value of 0.005 ft/1/min, a different fluid with better fluid-loss characteristics should be chosen, if possible. Fluid-loss additives should only be used if the fluid loss exceeds the value of 0.005 ft/1/min for the preferred fracturing fluid. For softer rock and Tip Screen Out treatments, these criteria can be relaxed somewhat.

9.6.2 In-situ stress level and profile

The in-situ stress is the local stress in a given rock mass at depth. The three principal stress components of the local state of stress, which are typically compressive, anisotropic and non-homogeneous, are the result of the weight of the overlying rock (overburden), burial history, pore pressure, temperature, rock properties, diagenesis, tectonics and viscoelastic relaxation. In addition, drilling, production and fracturing itself can also alter some of these parameters, thereby changing the local stress field.

For most sedimentary basins, the three principal stresses will be different, with the vertical principal stress, σ_1 , which equals the weight of the overburden, being the largest, and two unequal horizontal stresses, σ_2 being the intermediate horizontal stress, and σ_3 being the minimum horizontal stress (see Figure 16). The vertical, or maximum stress component, can usually be obtained from the integration of a density log. If such a log is unavailable, as a rule of thumb, a vertical stress gradient of 1.0 psi/ft is generally a good approximation for this stress component. For the magnitude and orientation of the in-situ horizontal stresses, actual measurements are required to provide an accurate quantitative description, for which a number of methods are available, which will be discussed later.

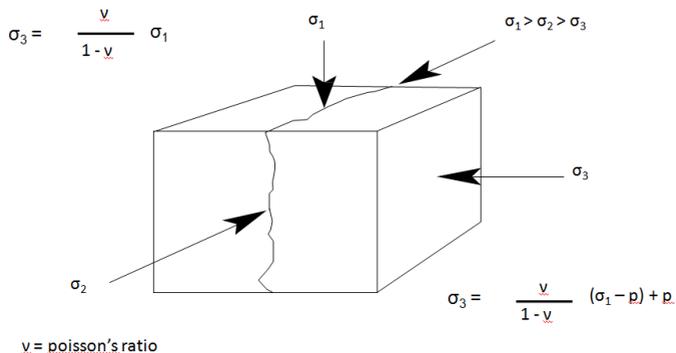


Figure 16 Fracture orientation is controlled by in-situ stress field

The in-situ stresses control the fracture orientation (vertical or horizontal and the azimuth of the fracture plane), vertical height growth and containment, surface treating pressures, proppant crushing and embedment. Fractures are generally planar and oriented perpendicular to the minimum in-situ stress (Figure 17). For horizontal wells, if drilled perpendicular to the minimum horizontal stress, the created fracture will thus be longitudinal. If the horizontal well is drilled parallel to the minimum horizontal stress, the created fractures are expected to be perpendicular to the horizontal well, i.e. transverse fractures will be created. For horizontal wells and (highly) deviated wells drilled in an intermediate direction relative to the direction of the in-situ horizontal stresses, non-planar fracture geometry may be created near the wellbore.

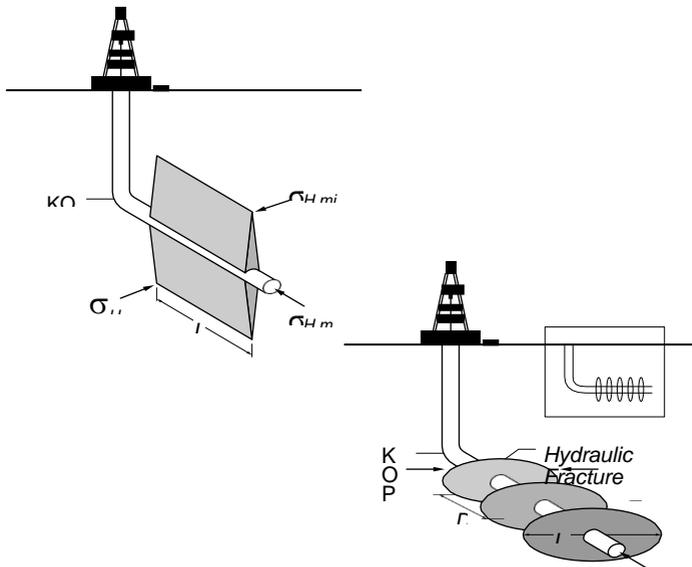


Figure 17 Fracture orientation

9.6.3 Fracture geometry

A hydraulic fracture grows primarily in the vertical and horizontal direction, having a width which is much smaller than these dimensions. Given a single uniform formation, a fracture would develop radially, i.e. equally in both directions (penny- shape). However, vertical lithology contrasts are the rule and at some stage the top or bottom part of the fracture will sense a change in environment. Usually, the growth in the vertical direction

decreases compared to the horizontal growth. This is called (vertical) containment. Figure 18 shows a side view of a fracture developing from radial to more rectangular, illustrating fracture containment.

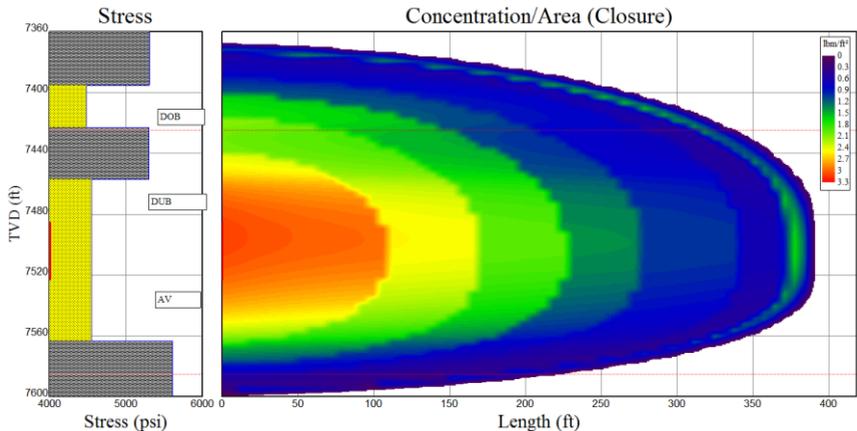


Figure 18 Fracture containment

Predicting the fracture geometry in terms of fracture length and height is crucial, if the height constraints apply e.g. to avoid fracture growth out of the zone of interest. Often, the fracture length required from a production improvement point of view, can only be obtained if there is containment.

There are several parameters that can lead to containment. The most important is (a contrast in) the in-situ stress. The containment depends on the magnitude of the in- situ stresses relative to the fracturing pressure.

Apart from variations in in-situ stress, fracture containment is influenced by other formation parameters as well:

- Young's modulus (stiffness), E . A larger E value in adjoining layers, helps containment and gives a narrower fracture width.
- Poisson's ratio, ν , which is directly related to the horizontal confining stress generated by vertical loading. A high value of ν helps containment.
- Permeability contrast. When a fracture runs into a zone of high leak off, it may become impossible for the fracture to penetrate that zone.

Often, contrasts in in-situ stresses and elastic properties are interrelated and occur simultaneously. A simple rule of thumb is that a stress contrast of more than 1000 psi (7 MPa) acts as a stress barrier and causes the fracture to be contained.

The fracture geometry can be influenced in the completion stage by selective perforating. For instance, if a fracture encounters a barrier at the top of the interval, the fracture length could be maximized by positioning the perforations in the bottom of the reservoir.

9.6.4 Fracture propagation and Net pressure

The fracturing fluid pressure must exceed the minimum in-situ stress in order to generate fracture width. Indeed, the fracture width is proportional to the pressure in excess of the minimum in-situ stress. This excess pressure is called net pressure.

Two main processes contribute to net pressure. The first one is fluid friction: pressure is required to squeeze the fracturing fluid through the fracture. The second one is fracture propagation: energy, i.e. pressure, is required to generate new fracture area.

In field applications, the net pressure tends to be quite independent of fracture length. This indicates that it is dominated in many cases by fracture propagation rather than by fluid friction. Net pressures typically range between 1 and 10 MPa (145 and 1450 psi). The fracture propagation component of the net pressure can be estimated from analysis of the pressure behaviour during a minifrac test.

9.7 Pumping schedule

Once the fluid and proppant selection has been made and the input data have been obtained pumping schedules can be made. Since there is still quite some uncertainty with respect to stress and fluid-loss, often a series of pumping schedules are made. In any case at this stage the design is of a preliminary character. It is primarily made for planning purposes with the service company.

A final pumping schedule will be made on-site after a number of test injections, often referred to as the Datafrac or Minifrac.

Figure 19 shows an example of a pumping schedule generated using MFrac.

INPUT SURFACE TREATMENT SCHEDULE

| Schedule Type | | | | Surface | | | | |
|--|-------------------|--------------------------------|------------------|------------|------------|-----------|----------------------|--------------------|
| Wellbore Fluid Type | | | | D003 | | | | |
| Fraction of Well Filled | | | | 1 | | | | |
| Recirculation Volume | | | | 0 | (U.S. gal) | | | |
| Stage No. | Slurry Rate (bpm) | Stage Liquid Volume (U.S. gal) | Stage Time (min) | Stage Type | Fluid Type | Prop Type | Prop Conc. (lbm/gal) | Prop Damage Factor |
| 1 | 37.739 | 23775 | 15 | Pad | DS T35 | 0001 | 0 | 0 |
| 2 | 37.739 | 8321.4 | 5.4401 | Prop | DS T35 | S022 | 1 | 0.5 |
| 3 | 37.739 | 8321.4 | 5.6301 | Prop | DS T35 | S022 | 2 | 0.5 |
| 4 | 37.739 | 8321.4 | 5.8202 | Prop | DS T35 | S022 | 3 | 0.5 |
| 5 | 37.739 | 5943.9 | 4.293 | Prop | DS T35 | S022 | 4 | 0.5 |
| 6 | 37.739 | 5943.9 | 4.5645 | Prop | DS T35 | S022 | 6 | 0.5 |
| 7 | 37.739 | 5943.9 | 4.8361 | Prop | DS T35 | S022 | 8 | 0.5 |
| 8 | 37.739 | 5943.9 | 5.1076 | Prop | DS T35 | S022 | 10 | 0.5 |
| 9 | 37.739 | 3328.6 | 2.1 | Flush | D003 | 0001 | 0 | 0 |
| Fluid Type: DS T35 - SLB Thermofrac 35 | | | | 72515 | (U.S. gal) | | | |
| Fluid Type: D003 - WF130, 2% KCl w/ No Breaker | | | | 6821.7 | (U.S. gal) | | | |
| Proppant Type: 0001 - No Prop, Slug, ... | | | | 0 | (lbm) | | | |
| Proppant Type: S022 - HyperProp G2 @250 deg F | | | | 2.1636e+05 | (lbm) | | | |

Figure 19 Typical pumping schedule

9.8 Final design and execution

Just prior to the execution of the fracture treatment a minifrac or datafrac is carried out. The purpose of the minifrac, sometimes also called calibration frac, or fracture- efficiency test, is threefold.

- to establish the FCP (Fracture Closure Pressure) of the pay zone only
- to measure the overpressure, Δp_o ,
- to determine C_t , the total fluid loss coefficient.

These field calibrated parameters are derived prior to the main fracture treatment, to allow optimization of its design. Although downhole data is preferred during a minifrac test, accurate surface pressure recording can be used as well. The digital surface pressure data can be entered into a minifrac evaluation package, usually part of one of the frac design programs mentioned earlier, e.g. MinFrac in MFrac.

9.9 Acid fracturing

9.9.1 Acid fracturing in general

Acid fracturing is a well stimulation process in which either acid alone (usually HCl), or a viscous nonreactive fluid (the pad fluid) consisting of linear or cross- linked guar based fluid preceding the acid, is injected into

a carbonate formation at a pressure sufficient to fracture the formation. As the acid flows along the fracture, portions of the fracture face are dissolved. Since flowing acid tends to etch the fracture walls in a non-uniform manner, conductive channels are created which usually remain open when the fracture closes. When straight acid is used without a pad fluid, the fracture will generally be short and narrow, since the rate of fluid loss for acid is very high, due to its high reactivity with the carbonate rock. If a viscous pad is used, a relatively long and wide fracture will be formed, which will begin to close as the acid is injected, thereby etching the fracture walls to create conductive channels.

The basic principles and objectives of acid fracturing are the same as for propped fracturing treatments in sandstones. In both cases the goal is to produce a conductive fracture with sufficient length to allow more effective drainage of the reservoir. The major difference is how fracture conductivity is achieved. In propped fracturing treatments, sand or other propping agent is placed in the fracture to prevent closure when pressure is released. Acid fracturing basically relies on non-uniform etching of fracture faces to provide the required conductivities. Acid fracturing can only be applied when the reaction rate between acid and the rock is fast and complete, i.e. currently only in carbonate reservoirs using HCl, possibly combined with organic acids. However, occasionally treatments have been successful in some sandstone formations, containing carbonate-filled natural fractures.

Acid fracturing is not generally recommended for formations that are less than 80% soluble in acid, the preferred solubility is greater than 90%. However, if acid solubilities are between 75 and 85%, and cores are available, special laboratory tests can be used to determine whether to apply acid fracturing or propped fracture treatments, by analysing the differential etching patterns and flow capacity values generated in these tests. Fracture conductivity tests are discussed later in this document.

The success of an acid fracturing treatment is determined by two characteristics of the fracture formed by the acid reaction:

- Effective fracture length
- Conductivity of the fracture

These characteristics are briefly discussed below.

The effective fracture length is controlled by the acid fluid-loss characteristics and the acid spending during its travel down the fracture.

Excessive fluid loss can severely limit fracture growth. Wormholes formed by the preferential reaction of acid through large pores of the rock are the main mechanism by which excessive fluid loss occurs. In general acid fluid-loss additives are not being used extensively because of lack of performance and cost limitations. Most common techniques for fluid loss control involve the use of a viscous pad preceding the acid. Often multiple stages of nonreactive viscous pad are being used, which are designed to enter and seal wormholes created by the acid stages. The nonacidic pad can be a crosslinked, gelled water, that has some tolerance to a low-pH environment. By using alternating acid and gel stages, leak off into wormholes is controlled.

Fine particulate material can also be added to the pad stages in aid of fluid-loss control. Such material fills/bridges the wormholes and natural fractures. The most commonly used material is 100-mesh sand, usually added at a concentration of 120-360 kg/m³. Rock salt can also be considered for this purpose.

Acid fluid loss can also be reduced by gelling or emulsifying the acid itself. This method of control has become widely used since the development of more acid- stable thickening agents, such as xanthan biopolymers and certain surfactants. Gelled or emulsified acid systems have viscosities several times higher than straight acid, thus making it unnecessary to use viscous pads in some cases.

The use of foamed acids can be one of the most effective methods for controlling acid fluid loss. Fluid-loss control is further enhanced by the use of a viscous pad preceding the foamed acid. However, foaming the acid does reduce the effective amount of acid available for etching, since there is less acid present per unit volume injected. As a result, 28% HCl should be used in preparing the foamed acid to maximise the amount of acid available for fracture etching.

As to the acid spending in the fracture, the acid spending rate usually depends on the rate of acid transfer to the wall of the fracture, and not on the acid reaction kinetics. As a result, the flow rate of the acid in the fracture and the fracture width are major factors in controlling acid spending. As an illustration of the importance of fracture width, an increase of fracture width from 0.1 to 0.2 inch results in an increase in acid penetration distance from 120 to 177 ft. Further factors of importance to acid spending are volume of acid used, acid concentration, the formation temperature and the composition of the formation.

Various materials and treating techniques have been developed for controlling the acid spending rate. These are quite similar to those used for fluid-loss control, but their action is quite different. One of the most common methods involves the injection of a viscous nonreactive pad preceding the acid. The pad reduces the acid spending rate by increasing the fracture width and cooling of the fracture surfaces.

Emulsification is also a commonly used means of retarding the acid spending rate, like in matrix acidizing. Oil-outside emulsions are the most common, because the external oil phase physically separates the acid from the reactive carbonate surface. Gelled acids can also be used in acid fracturing treatments, and they are usually considered to be retarded. However, some controversy exists in the literature, where it is stated that in reality the amount of retardation provided by the increased acid viscosity is probably small, and gelling the acid may actually accelerate the acid reaction rate under flowing conditions, thought to be due to improved transport of reaction products from the carbonate surface by the more viscous acid. On the other hand, comparable tests performed under conditions simulating leak off into the fracture face, showed that the acid reaction rate was reduced as a result of the gelling agent depositing a filter cake on the surface of the fracture.

9.9.2 Fracture conductivity

Acid must react with the walls of the fracture to form a channel that remains open after acid fracturing treatment. Flow channels can be formed as a result of an uneven reaction with the rock surface or preferential reaction with minerals heterogeneously distributed in the formation. The conductivity of the fracture is determined by the volume of rock dissolved,

the roughness of the etched rock surface, rock strength and closure stress. If the reaction rate is too high, then the acid will tend to spend excessively at or near the wellbore, resulting in poor conductivity closer to the tip of the fracture. High reaction rates can also result in too much rock volume being dissolved, which may not necessarily lead to higher conductivities once the fracture closes, especially in soft carbonates. On the other hand, if the reaction rate is too slow, then the amount of rock dissolved may be insufficient to prevent fracture closure.

Various techniques and materials have been developed, aimed at maximising fracture conductivity. The technique most commonly used involves the injection of a viscous pad ahead of the acid. The presence of this higher viscosity fluid in the fracture promotes viscous fingering of the thinner acid which follows. This selective acid flow also increases penetration distance and tends to create deep channels with good conductivity. Propping agents have also been used in acid fracturing treatments to obtain higher conductivities.

9.10 Closed fracture acidizing (CFA)

On a number of occasions, e.g. in fractured carbonates, or soft chalks after an (acid) fracture treatment, the resulting fracture conductivity may be too low for a sustained higher productivity. This can be due to the etched fracture face being too smooth, or it softens with acid, or the formation strength is insufficient to prevent closure due to the overburden pressure.

The CFA procedure has been developed as an alternative solution to the problem of fracture closure which sometimes results from standard acid fracturing. This procedure consists of the injection of a low viscosity acid at a pressure just below the fracture closure pressure. Acid flows out into the closed fracture, which still forms a preferential flow path for the acid, thereby rapidly dissolving much more of the formation than if it were flowing in an open fracture. This is due to the very high surface over volume ratio of the closed fracture, as was discussed earlier in this document. This causes a wormhole type penetration of the acid along the original fracture plane. Since only a small portion of the overall fracture face will be dissolved into relatively deep channels or grooves, the remaining unetched fracture face can hold these channels open under

very severe formation closure conditions, without completely collapsing the etched channels. This is especially beneficial in chalk formations.

The CFA technique is also applicable in previously fractured formations, as re-treatment, possibly even after several years, and in naturally fractured formations, in which case wormholes will then be formed along the natural fracture plane.

9.11 AcidFrac software application

Several acid fracturing models have been developed since 1970. The purpose of such calculations is to obtain the acid-etched width, length and conductivity of the created fracture. To calculate the amount of rock dissolved, an acid reaction model must be used to calculate the amount of acid spent. Acidfrac design is included in all commercial software packages.

9.12 References

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10 Completion aspects

10.1 Horizontal wells

Horizontal wells can be classified into four categories, depending on their turning radius (see Figure 20). Turning radius is the radius that is required to turn from the vertical to the horizontal direction. These categories are the following:

Ultrashort-radius

An ultrashort-radius horizontal well or drain hole has a turning radius of 1 to 2 ft; build angle is 45° to 60°/ft. The length of these boreholes is limited to 100-200 ft, drilled from existing vertical holes and left as an open hole completion. It is possible to drill several drain holes, like bicycle spokes, at a given depth.

Short-radius

Turning radius is 20 to 40 ft; build angle is 2° to 5°/ft. Short-radius drain holes are limited to hole sizes ranging from 4¹/₂ to 6¹/₂". Their advantage is that the critical direction drilling portion of the well is accomplished rapidly. The usual length of these drain holes is around 600 ft, with a maximum of about 1000 ft. These wells can be completed as an open hole or with slotted liners.

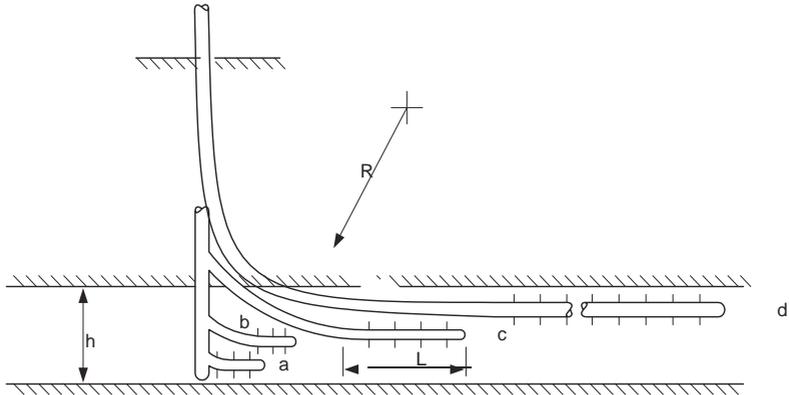
Medium-radius

These wells have a turning radius of between 150 and 1000 ft; build angle from 8° to 20°/100 ft, and hole sizes range up to 12¹/₂".

Long-radius

Long-radius horizontal wells have a turning radius of 1000 to 3000 ft; build angle is 2° to 6°/100 ft, with horizontal drains over 5000 ft, no known vertical depth limitation and no known hole-size limitation, although most drains are 8¹/₂".

Many directional wells are drilled with two build-up sections. This is often the case when the wells come back to the same surface location and most of the targets are displaced horizontally some distance away from the surface location.



- | | | |
|------------------------|------------------|-------------------------|
| a) Ultra short radius, | $R=1-2$ ft, | $L=100-200$ ft |
| b) Short radius, | $R=20-40$ ft, | $L=100-800$ ft |
| c) Medium radius, | $R= 300-800$ ft, | $L=1000-4000$ ft |
| d) Long radius, | $R>1000$ ft, | $L=1000-over 10.000$ ft |

Figure 20 A schematic of different drilling techniques

Stimulation of horizontal wells

Many of the stimulation techniques applied in vertical wells can also be used in horizontal wells. Stimulation methods for horizontal wells range from simple acid washes, matrix stimulation, massive hydraulic fracturing and acid fracturing. Stimulating horizontal wells has, however, its unique problems, which relate to the placement or diversion of the treatment.

When a matrix stimulation treatment is required, the placement of acid over the entire wellbore is the key to the success of the treatment. The problem here is that typical zones to be treated are an order of magnitude longer in horizontal wells than in vertical wells. The specific acid volumes (i.e. the volume of acid per unit length of treatment interval) conventionally used in vertical wells ($0.6-2.5$ m³/m) would not be economical in horizontal wells. Moreover, the treatment duration also has to be kept limited for practical operational reasons and to avoid corrosion problems. The specific acid volume will therefore normally be significantly lower in horizontal than in vertical wells. Furthermore, the placement of stimulation fluids over the treatment interval tends to become less uniform with increasing interval

length, whilst existing techniques to improve placement in vertical wells are not always suitable for use in horizontal wells.

Full matrix acidization of horizontal wells in sandstone formations is not normally done for a number of reasons, the most important one pertaining to the near impossibility of zonal coverage with the three required flushes, viz. preflush, main flush and over flush. Since bull heading (injecting the fluid in the well from the well head top down) the treatment results in inefficient zonal coverage, the use of coiled tubing is normally recommended. However, a mud acid treatment in which the coiled tubing is retrieved while pumping fluids, cannot be done effectively, since after the main flush the over flush should be pumped immediately, so that the precipitation products remain in flow, away from the wellbore, as explained earlier. When pumping mud acid, while retrieving the coiled tubing, there is a time interval before the coiled tubing can pump the over flush into a particular interval. During that time, near-wellbore precipitation of amorphous silica may have occurred, resulting in severe and permanent formation damage.

Other considerations for not carrying out full-size mud acid (or other HCl/HF mixtures) treatments in horizontal sandstone wells relate to the large volumes of fluid required, and the inherent extremely high cost of fluids and rig time. Therefore, the vast majority of acid treatments of horizontal open hole completions in sandstone formations pertain to the removal of filter cake solids on initial completion, with an acid soak.

The use of particulate diversion material for matrix acidizing treatments in long horizontal open holes would require so many diverter stages, that such treatment would become prohibitively expensive. As a rough estimate, the diverting agent on its own would cost about € 5,000 for every 50 m of open hole section. In such a case, the preferred diverting technique consists of pumping viscous banks or foam into sections of high fluid intake.

When wells are drilled in reservoirs where hydraulic fracturing or acid fracturing is required (e.g. low permeability, layered reservoirs), the fracture orientation is dependent on the in-situ stress field, i.e. the fracture may be transverse, longitudinal, or it can be complex with multiple

fractures initiated at the borehole, reorienting itself as they propagate from the wellbore, parallel to the preferred fracture plane (perpendicular to the minimum horizontal stress). Because of the dependence of fracture orientation on well direction with respect to the stress field, the possibility of fracturing a horizontal well must be considered before the well is drilled. Moreover, fracturing a horizontal well may also dictate how the well should be completed, i.e. cemented and cased or open hole. Both cased and cemented and open hole completions are candidates for fracture stimulation. However, cementing is generally required for multiple fracture treatments and for zonal isolation. The cemented pipe allows individual intervals or stages to be isolated or sealed off. Nevertheless, several methods are available and applied in practice for placing multiple fractures in open hole completions.

10.2 Horizontal well completions

10.2.1 Type of completion

Many factors will influence the completion design of a horizontal well. Some of the most important aspects which will influence the design are:

- sand control requirements,
- zonal isolation and selectivity requirements,
- future stimulation requirements,
- operational and workover requirements.

The success of a horizontal completion depends on balancing equipment selection and installation with reservoir development objectives, formation parameters and costs. In horizontal wells it is necessary to pay more attention to details, to ensure successful first-trip equipment installation.

The main types of horizontal well completion are:

- barefoot completions,
- open-hole liner completions,
- cased-hole completions.

Some of the significant features of the different completion types are shown in Figure 21.

10.2.2 Barefoot completions

A barefoot completion is one in which the horizontal reservoir section stays uncased and no liner or screens are run. This type of completion is

the most attractive in terms of cost, but carries the risk of hole failure. As a result, it is found more often in carbonate reservoirs than in sandstones. Additionally, it is difficult to stimulate open-hole wells and to control their injection or production along the well length.

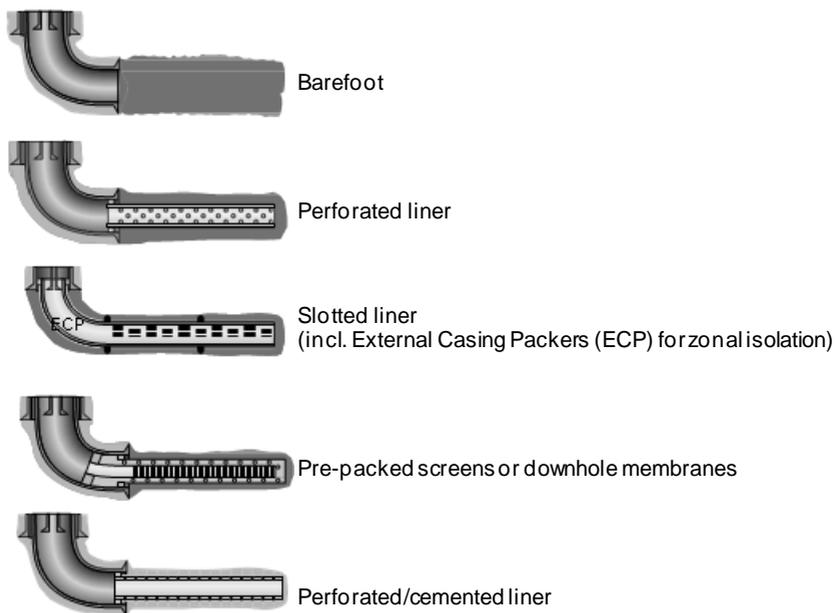


Figure 21 Horizontal hole completions

10.2.3 Open-hole liner completions

In this type of completion, the horizontal well section is completed with uncemented liners or screens. With the exception of pre-perforated liners, these completions are always run because of either sand control or zonal isolation requirements.

Pre-drilled liners

Completions using pre-drilled, uncemented liners offer nothing more than a future logging conduit. They prevent an unconsolidated formation from completely filling the wellbore.

Slotted liners

While by far the most cost effective method, the capabilities of slotted liners in open-hole completions are limited. Slots are cut parallel to the longitudinal axis and uniformly distributed around the circumference of the liner, whilst retaining the liner's mechanical integrity. However, the slots are susceptible to plugging with formation fines, corrosion products and precipitates during installation and production. Slotted liners are applied, primarily, in coarse-grained formations with low production rates and low sand-producing tendencies.

Wire-wrapped screens (WWSs)

These have around up to 20 times the inflow area of an equivalent slotted liner. The main drawback of WWSs is that they are generally more costly which, in view of long completion intervals, result in significant upfront expenditure. As with slotted liners, the use of WWSs should be limited to low erosion risk applications.

Pre-packed screens (PPSs)

A PPS is a second line of defence against sand production, but also adds a barrier to production. Their use should be restricted to conditions that demand assurance against erosion, and special precautions should be taken to ensure that they are installed correctly and to minimise their effect on production rates. PPSs plug more rapidly than WWSs, because the pore throats of the gravel are much smaller than wire spacing of WWSs.

Further sand exclusion can be achieved with Stratapac downhole membranes (a screen consisting of multiple and independent layers of a

permeable stainless steel composite material, sandwiched between a perforated base pipe and an external armoured cage), and gravel pack completions. Gravel packing horizontal wells is not generally recommended, although in the US this method is frequently used.

A latest development on sand exclusion in horizontal open holes is expandable sand screens (ESSs). New tools have been developed to ensure more complete expansion of the screens and to make screen expansion easier. The ESS system, which is not cheap, should be faster and easier to install than a gravel pack.

Liners with partial isolation

This can be achieved with external casing packers (ECPs), which are installed outside the slotted liner to divide a long horizontal wellbore into several small sections. The method provides limited zonal isolation, which can be used for stimulation or production control along the well length. However, the optimum ECP position for remedial treatments already has to be known when the completion is designed. Whilst in principle many ECPs could be used to deal with the uncertainty in the optimum position, their number is usually restricted to avoid deployment problems and to reduce initial well costs.

10.2.4 Cased hole completions

The majority of horizontal wells in the oil and gas industry are completed either barefoot or with uncemented liners. However, despite higher costs, the use of cased and cemented completions has increased because of the flexibility gained in production techniques and reservoir management.

Thus, cemented and perforated liners are installed to:

- facilitate zonal isolation,
- monitor and control fluid production/injection,
- initiate hydraulic fracture treatments.

Main questions surrounding cemented and perforated liners are the quality of the cement bond and the effectiveness of perforating the horizontal wellbore.

10.3 Gravel-packed wells

This section presents a discussion on maximising gravel-packed well productivity through tailored stimulation methods. In a gravel pack, the most critical areas for impairment, and hence for stimulation, are:

- the screen
- the perforations, if present
- the gravel
- the gravel/sand interface
- the near-wellbore formation

In practice it is often difficult to determine the exact location of the damage. Ideally, one should aim at developing stimulation treatments that can simultaneously remove damage from many locations. Even when a stimulation treatment is designed to deal with a specific identified form of impairment, care should be taken that the procedure employed does not negatively influence the remainder of the gravel-packed well.

10.3.1 The screen

A remedial treatment based on a soak with a fluid that can dissolve the plugging material, should restore the flow capacity of the screen. The preferred method is to spot the acid with coiled tubing at the bottom of the well and subsequently pulling up the CT while pumping. This will ensure coverage of the entire screen and, hence, maximise the chance of establishing inflow across the total length. To avoid possible adverse reactions in the pack or formation, treatment volume should not exceed the capacity of the completed section of the wellbore by more than, say, 1 – 2 m³.

The fluid should:

- dissolve the plugging material,
- be compatible with the gravel and formation, and
- be non-aggressive to the combination of carbon steel and high-quality steels used in the screens.

10.3.2 The perforations

Many publications on both laboratory and field studies indicate that perforations in gravel-packed wells are often responsible for poor well performance. Frequently encountered problems are:

- Perforations contaminated with debris, paint, pipe dope, etc.

-
- Perforations filled with precipitates from incompatible completion brine and formation fluids.
 - Contamination with mud remnants.
 - Perforations filled with formation sand/gravel mixtures.

The first three types of impairment can occur prior to the actual placement of gravel. In that case they are treated best before gravel packing. For this purpose, five commonly used techniques are available:

- Perforation washing
- Back surging
- Pre-gravel pack acidization
- Underbalanced (tubing conveyed) perforating
- Pre-packing of perforations

The latter two techniques aim at prevention of damage, and as such fall outside the scope of this document.

Perforation washing is generally considered to be an effective way of removing any impairing material from the perforations. Perforation washing should be done with a clean, non-damaging (compatible) fluid. Circulation rates should be 2 to 3 bbl/min. Care should be taken with strongly laminated sands, to prevent mixing of sand and shales.

Back surging is another method to clean perforations prior to gravel packing. Usually, back surge tools are designed such that the perforated interval is exposed to a reduced pressure for a short period (see Figure 22).

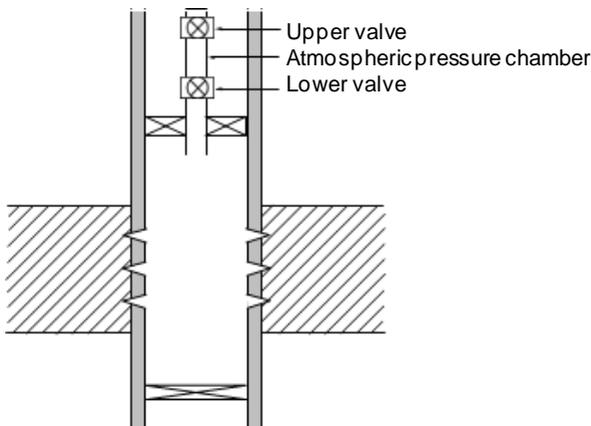


Figure 22 *Cleaning perforations using back surging*

Pre-gravel pack acidization is in principle also a good method to obtain clean perforation tunnels. However, severe potentially negative effects, such as fines generation, secondary precipitates, emulsions, etc. may nullify the effect of the acid, especially when post-acid/pre-pack well clean-up is not feasible. On the other hand, it has proven its use in removal of lost circulation materials, such as graded calcium carbonate, or in removal of perforation debris. To minimise negative effects, the pre-gravel pack acid job should be limited in size such that essentially only the perforation area is treated, i.e. total volumes should be limited to 0.08-0.16 m³/m (10-20 gal/ft).

10.3.3 The gravel

Assuming that the correct size of gravel has been placed, the bulk of the gravel usually does not create a significant reduction in productivity, provided that the gravel is clean and free of dirt, cement dust, etc., i.e. the gravel should satisfy the API requirements for good quality gravel. Occasionally, intermixing with e.g. shales from other zones due to poor placement techniques, has been reported. Depending on the nature of the contamination, treatment with HCl or HF/HCl can alleviate such problems. Such a treatment would also help in case dirty (off-spec) gravel has been applied. If iron pick-up from the tubulars (rust, scale) is suspected, it is advised to add a sequestering agent to the acid, specifically when HCl alone is used. Normally 10-20 kg/m³ of citric acid will suffice. The treatment volume should be geared to the approximate volume of the gravel pack. If the size of the gravel is too large and formation sand has invaded the gravel pack, a similar treatment with HF/HCl may have some effect. If, on the other hand, the gravel size is too small, stimulation would not have an appreciable effect on productivity. A re-gravel packing treatment under fracturing conditions, "Frac&Pack", could be considered.

10.3.4 The gravel/sand interface

Two main problems may occur at the gravel/sand interface:

- Just prior to and during the placement of the gravel pack, the formation may be stirred up. Remixing of sand, shale, feldspar, etc., creates a new surface of reduced permeability. This defect is best cured by an acid treatment, using an appropriate mix of HF and HCl.

-
- Incompatible fluids can create an impaired zone at and/or near the formation face (filter cake). The effect is intensified if the fluids contain solids or if the viscosifier leaves a residue behind (e.g. poorly mixed, unsheared and unfiltered, partly broken Hydroxyethylcellulose, HEC).

Subject to the type of damage, usually an HCl treatment will alleviate the problem. If the impairing solids are due to precipitation, 15% wt HCl is suggested. If, however, the problem is related to the presence of polymer (HEC) residue, lower concentrations of, say 2-3% wt HCl should be used. But be aware that HEC breakdown by strong acids creates a significant amount of insoluble residue. Alternatively, treatments with enzymes (if reservoir temperature is less than 65 °C) or hypochlorite may be applied. Laboratory tests should be carried out to establish the applicability of a particular treatment.

Again, the volume of the treatment should be restricted to the zone to be treated, say, 1.1 times the volume of the pack. To promote complete coverage of the zone, a diverting agent that filters out at the formation face (i.e. particles that are small enough to travel through the pack) may be used. Also, gelled acid or foam may be applied.

10.3.5 The near-wellbore formation

The formation rock near the wellbore may have been damaged during drilling, cementing, perforating and preparing the well for gravel packing. As such, gravel packed wells do not differ from perforated wells, but it is more difficult to direct the stimulation fluids to the impaired region in gravel packed wells, than it is in conventionally completed wells.

10.3.6 Summary

Table 13 below, shows a gravel pack stimulation selection scheme based on the above discussion.

As in any acid stimulation treatment, a number of additives is required to combat a number of side-effects inherent to the use of acid. In relation to gravel packing, special attention should be given to corrosion aspects. Often screens are manufactured using high-alloy steels. Particularly, the points where the screen is welded to its support, are sensitive to corrosion.

Currently available corrosion inhibitors are in principle designed for use in normal steels, although most contractors claim that they are also effective in high-alloy steels, albeit in higher concentrations. Service companies should be requested to carry out corrosion tests, using the steels applied in the well. As a rule of thumb, it is suggested to use twice the concentration of corrosion inhibitor recommended for normally completed wells.

| Most likely location of damage | Preferred treatment |
|---|--|
| <u>Screen, slotted liner</u> | Acid/solvent soak |
| <u>Blocked perforations</u> Perforation debris, precipitates, etc. Formation sand/gravel mixtures | Back surging Perforation washing Pre-gravel pack acidization Post-gravel pack acidization, with small volume HF/HCl, spotted or diverted |
| <u>Gravel</u> Contamination with shale, etc. Gravel too large Gravel too small | HF/HCl post-gravel pack acidization HF/HCl post-gravel pack acidization Squeeze pack or |
| <u>Gravel/formation interface</u> Remixing of sand, shale, feldspar Solids Polymer residue (HEC) | HF/HCl 15 %w HCl 3 %w HCl, enzymes or |
| <u>Near-wellbore formation</u> | Various matrix treatment techniques, as applied in normally completed wells important) |

Table 13 Gravel pack stimulation selection scheme

11 Other methods – future

Matrix acidizing and hydraulic fracturing form the bulk of all stimulation treatments carried out in the oil and gas industry. There are a few other stimulation methods that may be very well suited for geothermal wells. Some have been around for some time and are available on a commercial basis. Unfortunately some of these technologies, although around for many years, have not been very well developed. Further development is required. We will briefly discuss the following techniques:

- Sonic/ultrasonic sound stimulation (ref. 7 - 10)
- Heat stimulation
- Explosive/propellant fracturing

11.1 (Ultra) Sonic stimulation

The application of sound waves to stimulate wells has been around for more than 50 years. The technologies range from application of intensive low frequency waves (down to 1 Hz) to ultra sonic frequencies (20,000 Hz or more). The successes have not been overwhelming. Often the production improvement was relatively short-lived. Nevertheless some technologies, offered on a commercial basis, might be useful for mitigation of very near-wellbore damage and especially for screen cleaning.

A special technology that is in its infancy and needs further development is the Pulsed Power technology. High energy shock waves created by electric discharge (sparks) cause dislodging of dirt trapped in screens for instance. A diagram is shown in Figure 23.

Laboratory trials have shown excellent potential of this technique (ref. 8) for mud cake removal and screen cleaning. The development was interrupted due to a downturn in the oil industry some 10 years ago. Since many of the geothermal doublets are completed with wire-wrapped screens this technique would be ideally suited for the maintenance of these wells.

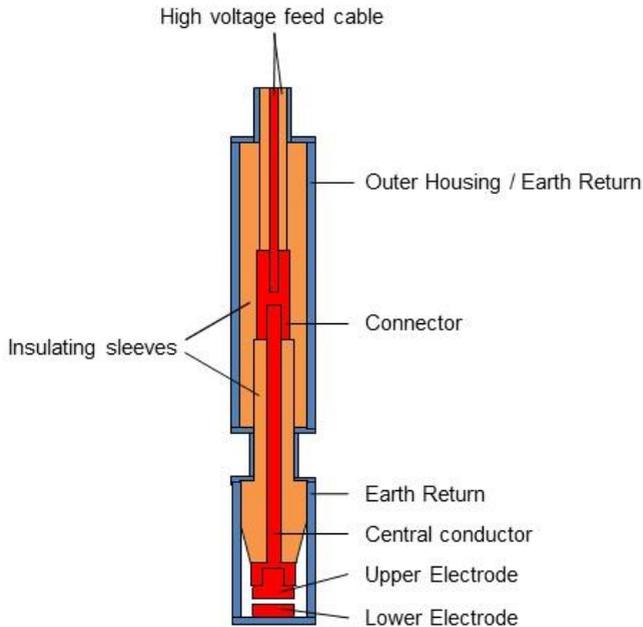


Figure 23 Schematic of the radial acoustic source

11.2 Heat stimulation

Application of heat generated by exothermal chemical reactions has been proposed and actually applied in a number of wells to remove oily residues. Also electric heating and steam injection has been used. In general it has not been very successful and applicability in geothermal wells is limited, except for the removal of oily residues ("Schmoo") from screens.

11.3 Explosive fracturing

The use of explosives has been experimented with in oil wells, but successes have been limited perhaps with the exception of the use of propellants in combination with perforation. These treatments have been used to prevent or mitigate the effects of perforation debris and other impairment. It is commercially available from a number of service companies and smaller companies that specialize on this technology.

12 Operational and environmental

One of the most essential operational considerations for a stimulation treatment, is to verify the **condition** of the well. While well/completion integrity is required for both matrix and fracture treatments, the amounts of fluids and materials pumped under very different pressure regimes, make wellbore considerations for both types of well stimulation treatment also significantly different. The following aspects are particularly important in this respect:

- Cement quality
- Pressure limitations
- Pump rates and fracturing
- Perforations
- Corrosion concerns
- Erosion concerns
- Slim hole completions
- Proppant transport in horizontal pipe

These topics will be briefly discussed in the following paragraphs.

12.1 Cement quality

A critical aspect of wellbore considerations is usually the requirement of a good cement job around the casing or liner to provide zonal isolation. However, a poor cement bond in itself may not be a reason to refrain from stimulation, since the design of the stimulation job can be adjusted to a poor cement bond (e.g. a weaker acid may be used for a matrix treatment, or a proppant slug may be applied prior to a fracture treatment, to screen out a channel/micro annulus in the cement).

12.1.1 Cement evaluation

The primary way to evaluate cement quality has been for many years the cement bond log (CBL, Figure 24), combined with the Variable Density (VDL) waveform. The principle of the measurement is to record the transit time and attenuation of a 20 kHz acoustic wave after propagation through the borehole fluid and the casing wall.

The CBL measurement is the amplitude in mV of the casing first arrival, E1, at the 3-ft receiver (see Figure 24). It is a function of the attenuation

due to the shear coupling of the cement sheath to the casing. The attenuation rate depends on the cement compressive strength, the casing diameter, the pipe thickness and the percentage of bonded circumference. The longer 5-ft spacing is used to record the VDL waveform for better discrimination between casing and formation arrivals. The VDL is generally used to assess the cement to formation bond and helps to detect the presence of channels and the intrusion of reservoir fluids.

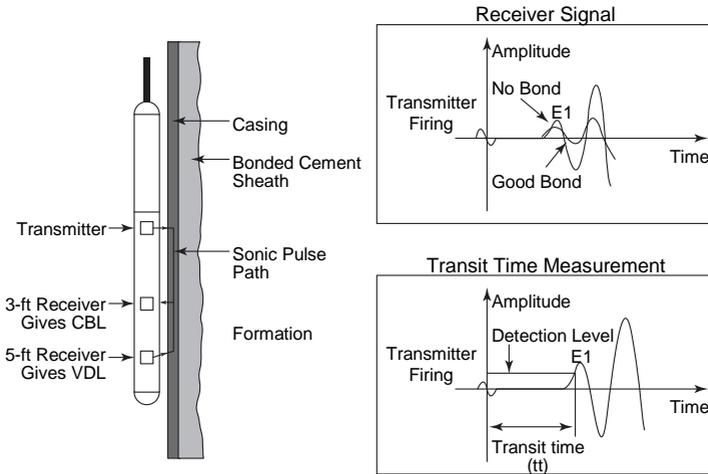


Figure 24 CBL measurement

The Cement Evaluation Tool (CET) was designed to evaluate the quality of cementation in eight directions, 45° apart, with a very fine vertical resolution. While conventional cement bond logging tools measure the attenuation of a sonic plane wave propagating axially along the casing, the CET tool uses the casing resonance in its thickness mode. The ultrasonic transducers, both emitters and receivers, emit a short pulse of acoustic energy and receive the echo from the casing. The reverberation of energy within the casing is controlled by the local acoustic impedance of the mud column, the casing and the cement, or fluid in each sector of the annulus. With cement behind the casing, the decay of the echo is fast due to the larger acoustic impedance of the cement.

In many cases the objectives of a cement quality evaluation are to identify the causes of poor cementation jobs and evaluate repair possibilities.

Often both CET and CBL logs are required, since the CET and CBL-type measurements have different responses in the presence of e.g.:

- a micro annulus (a small water gap between casing and cement, generally caused by releasing the pressure inside the casing before the cement is set),
- thin cement sheets,
- gas or air,
- heavily corroded casing.

In many ways the two measurements complement each other. The need for an interpretation method using both measurements has been identified, and a computer interpretation program (CEQL) is now available at the wellsite.

Cement Evaluation Logs require economic justification, as does any other logging device. Many times Bond Logs are run routinely as a part of completion operations, with justification being that the Gamma Ray-CCL recordings are required for perforation depth control, and the CBL-VDL and Δt curves are recorded at the same time at small additional cost.

12.2 Stimulation treatments

In principle, **hydraulic fracturing** requires a good cement bond. However, when a fracturing treatment is being considered, the first requirement is that there should be no danger to the well integrity. If safety and/or environmental rules would be violated, the fracturing treatment should not be carried out. The second rule is that fracturing into non productive layers should be avoided. Finally, an uncontrolled, high, leak off of fracturing fluids may adversely affect the fracture geometry, and fluid leak off should be reduced by adding fluid-loss material to the fluid system.

Likewise, the success of **matrix treatments** may be affected in case of a poor cement bond, since acid may leak off behind casing. However, in general, the well integrity is not at risk, due to the much lower pressures at which the stimulation fluids are being injected.

In both cases, however, the design of the treatment should be adjusted to minimize the risks. For a fracturing treatment, slugs of a fine mesh

proppant could be used to shut off a micro annulus. However, this carries the risk of (partially) plugging of the perforations. In case of a matrix treatment, a less aggressive acid formulation (lower concentration, weaker acid) is advised, not to further weaken the cement bond.

12.3 Pressure limitations

During well stimulation, but particularly during fracturing, a well will be exposed to much higher pressures than during production or normal injection, thereby possibly exceeding the allowable pressure rating of completion components. Moreover, net fracture initiation and propagation pressures for transverse fractures in horizontal wells may be 1000 to 5000 psi greater than the initiation pressures for longitudinal fractures. Ideally these higher pressures must be considered during the selection of the well completion equipment.

Pressure limitations may be due to the wellhead equipment, the tubulars as well as packers. Also, cooling down by cold fracturing fluids will cause forces in the completion, which can lead to ballooning, failure of (older) tubing, unseating of packers, etc. Therefore the well condition needs to be verified, by using dedicated software. Alternatively, most vendors of well equipment can give advice on this subject.

In critical cases, the use of a wellhead isolation tool, or tree saver, can protect a Christmas tree at the wellhead from damage and the possible failure that results from exposure to high pressure, corrosive fluids or abrasive proppant-laden fluids. Pressurizing the casing-tubing annulus may also alleviate the problems to some extent. Also heating of the fracturing fluid may help in some cases, although it is stressed that most fracturing fluids have a limited temperature stability. Modern water-based fracturing fluids, i.e. borate crosslinked fluids, can be used up to 170 °C. In most cases, however, the design has to be adjusted (pump rate, fluid selection, etc.) to allow fracturing in critical situations.

12.4 Stimulation operations with coiled tubing

Coiled tubing (CT) has been increasingly used for matrix acidizing and fracture stimulation operations over the past few years. CT is especially helpful for acidizing long intervals in horizontal wells, by allowing spotting successive acid and diverter stages throughout the open interval, while

withdrawing the CT, thereby ensuring good coverage of the entire producing zone.

Fracturing through coiled tubing has been applied in recent years in western Canada, to carry out multistage fracture treatments in relatively shallow gas sands. To overcome the friction constraints of coiled tubing fracturing, a viscoelastic surfactant (VES) fracturing fluid can be employed if the temperature allows it. In these cases, the coiled tubing protects the wellbore tubulars from excessive pressures encountered during fracturing. Coiled tubing is used in a very unusual manner for a steel product. The bending and unbending cycles that occur when the pipe is spooled on and off a reel and over the guide arch, may cause permanent deformation and damage in the pipe material. In order to estimate how much longer a CT string will last before the risk of a fatigue failure becomes too high, CT fatigue-tracking models have been developed, and computer programmes are available with all major contractors.

While CT applications are now being performed at greater depths and at greater extended and horizontal reaches (> 20,000 ft) and higher wellhead pressures (>10,000 psi), a good understanding of the operational limits of CT is required. Main parameters that determine the lifetime of a CT string are:

- bending cycle fatigue,
- pressure/depth history,
- acid exposure (strength, volume/duration),
- exposure to H₂S,
- mechanical damage.

Electronic data acquisition systems that typically record depth, speed, circulation pressure, wellhead pressure and weight, are now common. A record of the use of a CT string is also kept in a CT journal, which should be consulted before using the CT in a stimulation job.

12.4.1 Corrosion of coiled tubing

Stimulation and well cleanout acids used in coiled tubing jobs require special care to avoid aeration. Corrosion rates can increase by up to 5-7 times due to aeration. The largest danger of aeration occurs from exposure of coiled tubing to air between coiled tubing runs and between

job locations, even though the acids used are de-aerated. Spent acids are also more corrosive than fresh acids, since they are hotter and because of oxygen pickup and deterioration of the inhibitor. When acid cleanouts are enhanced with gas, such as during nitrified acid descaling, increased corrosion rates and loss of inhibitor effectiveness can result from more turbulence and slug behaviour of the acid inside the tubing. Actual corrosion is expressed in terms of weight loss during the entire treatment. The allowable weight loss for coiled tubing due to corrosion is less than 0.03 lb/ft².

12.4.2 Pump rates and fracturing

In matrix acidizing, both sandstones and carbonates, stimulation fluids are often injected as fast as possible, below the fracturing limit (MAPDIR, Maximized Pressure Differential and Injection Rates method, introduced by Paccaloni). In sandstones this is thought to avoid the creation of precipitates near the wellbore and to extend the radius of live-acid penetration, while in carbonates this would allow wormholes to form and propagate. The method is also meant to assure acid placement in all zones during matrix stimulation treatments, without using any diversion technique. It allows a decrease of pumping time and minimizes the risk of treatment failure caused by low pumping rates. A drawback of the method is that it results in more acid than is necessary, being pumped into high-injectivity intervals. In addition, the benefits of this method are being reduced when the attainable bottom hole pressure is less than the desired value, because of limitations in surface pressure or pumping capacity. Maximum, non-fracturing, injection rates for matrix treatments for both vertical and horizontal wells are briefly discussed in Appendix IV.

Generally high injection rates should be considered in hydraulic fracture treatments, because of increased treatment efficiency resulting from decreased fluid-loss time and increased fracture width. Higher rates also directly improve proppant transport capabilities because of an increase in slurry velocity relative to proppant fall rates and a reduced pumping period, leading to less time for proppant fall and less viscosity degradation.

However, the size of the treating tubulars and the corresponding friction pressure typically limit the injection rates as a result of tubing or wellhead

pressure ratings. The increase in surface pressure increases the horsepower requirement and cost.

12.4.3 Fracturing fluid friction pressures

The loss of energy due to friction between the wellhead and the zone to be stimulated, can reach high values depending on pump rate, size and length of the tubulars, proppant concentration and rheology of the fracturing fluid. High friction pressures may restrict the pump rate in order to avoid excessive wellhead pressures, and this could hinder optimal treatment. Commonly, the flow regime in the tubulars during a fracturing treatment is turbulent. Figure 25 shows the friction pressures of water in tubulars of different diameter up to pump rates of 6.4 m³/min (40 bbl/min). The addition of soluble polymers to the water reduces the friction pressures. These polymers also increase the apparent viscosity, which is essential to create wider fractures and to transport the propping agents into the fracture.

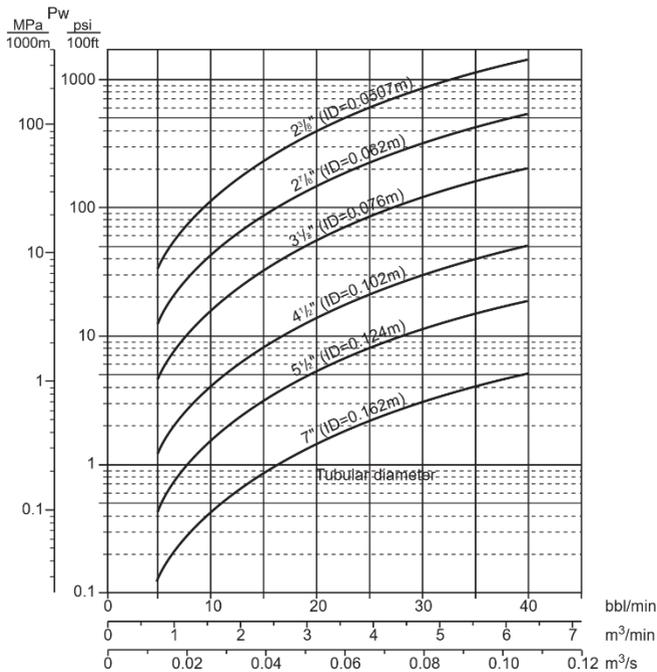


Figure 25 Friction pressure vs. Pump rate for water

12.4.4 Power requirements fracturing treatments

In a fracturing job, the wellhead treating pressure, P_{tr} , is given by:

$$P_{tr} = P_p - \Delta P_h + \Delta P_f$$

where P_p = fracture propagation or breakdown pressure, ΔP_h = hydrostatic pressure drop and ΔP_f = friction pressure drop.

The treating pressure and the injection rate, Q_i , are related directly to the power demand. In HHP (Hydraulic Horse power) this relationship is:

$$HHP = Q_i P_{tr} / 40.8$$

in field units.

This equation predicts the theoretical requirement, but has to be corrected for the pump efficiency.

The number of pumps available for the job should be able to provide at least this power plus whatever additional capacity is warranted in the event of breakdown or other mechanical problems. The power requirement is an important item for the contract with the service company, since it determines the number of pumps.

12.5 Perforations

The perforation policy followed during the completion phase of a well will have a significant effect on the success and quality of a subsequent stimulation treatment. The objective of perforating for **fracturing** is to choose perforating parameters that minimize near-wellbore pressure drops during both the fracturing operation and production. Some of these near-wellbore effects are perforation friction, multiple competing fractures and fracture tortuosity caused by a curved fracture path. Effective **matrix** treatments require communication through all, or most of the perforations. Insufficient open perforations could result from improper perforating practices, poor perforation cleanup or ineffective formation breakdown procedures.

For stimulation operations, the order of importance of the geometrical factors for perforating is:

1. perforation diameter,
2. shot density,
3. perforation phasing and orientation,
4. perforation length.

The following guidelines are applicable with respect to perforating.

12.5.1 Fracture stimulation: perforation diameter

The flow of fracturing fluid through perforations will create a pressure drop between the wellbore and the fracture. This frictional pressure drop is governed by the flow rate, fluid density, number of perforations and the perforation diameter, as follows:

$$\Delta P \propto C \frac{Q^2}{n_p^2 d^4}$$

where Q is the flow rate, n_p the number of perforations in contact with the fracture, d the perforation diameter and C a proportionality constant, including the orifice discharge coefficient, fluid density and viscosity. As the flow through a perforation is highly turbulent, fluid viscosity hardly plays a role.

Big hole charges and high shot densities will reduce the pressure drop across the casing and limit shear degradation of polymer fracturing fluids. In hydraulically fractured wells, perforation length is less important.

12.5.2 Perforation phasing and orientation

The orientation of a hydraulically created fracture will be perpendicular to the direction of the minimum horizontal stress, and will not be affected by the orientation of a perforation. If the perforation tunnel happens to be oriented along this minimum horizontal stress, a fracture will initiate at the base of the perforation tunnel and perpendicular to the tunnel. The fracturing fluid may then be required to travel through the micro annulus between the casing and the borehole to the base of the fracture, as shown schematically in Figure 26. This will result in an increase in fracture initiation pressure and other near-wellbore tortuosity related problems,

such as a premature screen-out. The use of phased perforation guns will limit this phenomenon, as there will always be a set of perforations likely to be in communication with the fracture. Therefore, the recommended phasing in vertical wells is 120° or better (down to 45°; Phasing is the angle between the perforations; phasing of 120 degrees means 3 perforations on the circle of the casing).

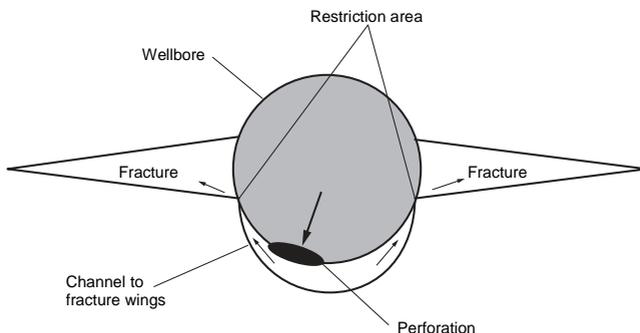


Figure 26 Pinch point caused by rock-casing annulus

12.5.3 Perforation interval and shot density

The recommended perforation density is a minimum of 4 shots/ft for 120° phasing, while for 45° phasing a higher shot density (12 shots/ft) is recommended.

12.5.4 Horizontal wells

In horizontal (or highly deviated) wells, special perforation schemes are used to ensure that the communication between the fracture and wellbore is optimized, thereby minimizing multiple fractures.

Circumferential or peripheral perforating

This perforation phasing should be used, when transverse fractures are expected, i.e. when the horizontal well is drilled parallel to the minimum horizontal stress (see Figure 27). Perforating a 1 m interval at multiple phase angles (“360°”) phasing with a shot density of 15 to 25 shots/ft, should promote that only a single fracture is created at the location being perforated.

Axial perforating

This perforation scheme should be used for designs in which a longitudinal fracture is to be initiated, i.e. in wells drilled perpendicular to the minimum horizontal stress (Figure 27). In this design, the high and low sides of the wellbore are perforated (180° phasing). It may even be preferable to cut slots along the high and low sides of the casing. The spacing and number of perforations should ensure that the desired treatment interval is covered and that each perforation will take fluid during the treatment. If primarily upward growth of a longitudinal fracture is expected, the well should be perforated with 0° phased perforations, placed at the top of the wellbore. Blank sections should be left in between perforated intervals if multiple longitudinal fractures are required.

For both above perforation schemes, for optimum results perforations should be oriented to within 15° of the preferred fracture plane.

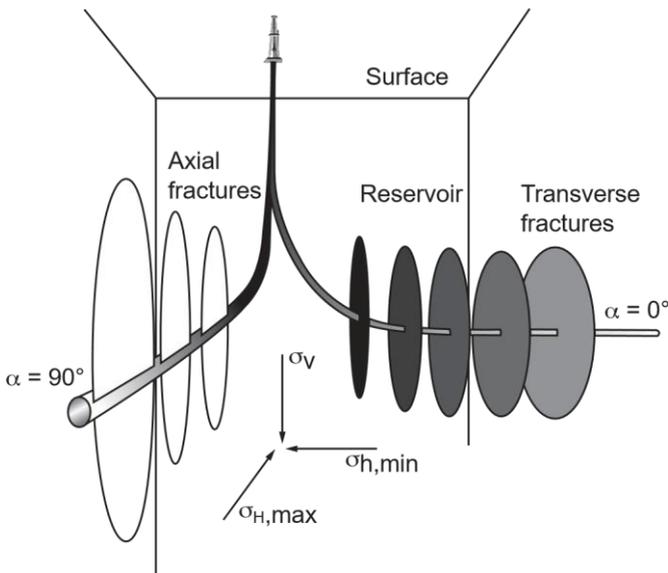


Figure 27 Longitudinal (axial) and transverse fractures

Arbitrary perforating

If the preferred fracture plane is unknown, or if a randomly oriented perforating gun is used, 60° phasing is recommended. With 60° phasing,

two diametrically opposed perforations will always be within 30° of the preferred fracture plane.

If the perforations are spaced closely enough, and they are not aligned with the preferred fracture plane, overbalanced perforating will create small fractures at each perforation. These fractures will initiate and link up along the axis of the wellbore, before reorienting into the preferred fracture plane. This may lead to a smoother fracture surface, which minimizes proppant flow restrictions during the treatment.

12.6 Erosion concerns

As to erosion concerns in fracturing treatments, the size of the high-pressure pipe, called treating iron, used on a treatment, is dictated by both the anticipated rates and pressures. Smaller lines have a higher maximum treating pressure limitation than the larger sizes. The velocity of the fluid should be limited to 45 ft/s to minimize excessive erosion of the iron. Pumping above these rates for any prolonged period of time can erode the treating iron and thereby lower the effective working pressure that the iron could be exposed to before a catastrophic failure would occur. If the design treating rates exceed the rate limits of the iron's size, then either a larger iron must be used, or multiple lines must be laid to the wellhead.

Another suggested empirical relation to maintain erosion control of surface treating iron is that all slurry-laden fluids should be restricted to flowrate values equal to the following equation:

$$Q_{max} = 2(ID_{pipe})^2$$

with ID in inches, and Q in gal/min.

It should be noted that this flow restriction is directed towards protecting frequently used fracturing treating lines from significant erosion by sand or proppant slurries. If the fluid being pumped is not sand or proppant laden (i.e. pad or displacement fluids), then no upper restriction is applied.

12.7 Matrix stimulation

In matrix treatments it is important to promote an even distribution of the stimulation fluids around the wellbore, which can be particularly difficult to achieve in long, horizontal wellbores. An even distribution of fluids is best achieved by a high shot density, a proper phasing – 120° or better – and

perforations of equal length. The latter implies that every effort should be taken to ensure that perforation guns are properly centralized, specifically in highly deviated or horizontal holes. Application of a high shot density should be balanced against the constraints this puts to effective diversion. It almost certainly precludes, for instance, the use of ball sealers.

12.8 Corrosion concerns

Corrosion is a concern in all acid stimulation operations. As with any chemical reaction, the corrosion rate rapidly increases with temperature: each 10 °C increase in temperature will increase the corrosion rate by a factor 2 to 3. Moreover, corrosion inhibitors lose their effectiveness at higher temperatures, causing an extra increase in corrosion rates above 100 to 150 °C.

An important difference between conventional well operations and horizontal wells is the potentially longer duration of acid exposure. This longer exposure is the result of larger volumes and longer pumping times and the slower cleanup of injected fluids from the horizontal wellbore.

Modern corrosion inhibitors can give adequate protection to temperatures up to approximately 100 °C. Carbon steels are easier to protect than high-alloy steels (13Cr, 22Cr, etc.). For protection at higher temperatures, salts with reducing properties (cupro-iodide, potassium iodide, etc.) are added as **intensifiers**. The use of these intensifiers is a concern, however, since their solubility in acid at lower temperatures is sometimes poor. Moreover, they hamper environmentally acceptable disposal of spent acid.

Addition of other additives can have a great impact on the inhibitor performance. The use of silt suspending agents or mutual solvents blended into the acids, for instance, can reduce the corrosion inhibitor effectiveness dramatically.

The use of corrosion inhibitors is **imperative** in acid stimulations. The required concentration, however, depends on the degree of corrosion that can be tolerated. The general guidelines for inhibitor performance are as follows:

-
1. Less than 0.05 lb/ft² weight loss of tubular steel (equivalent to a thickness reduction by 0.001 inch) over the duration of the exposure (exposure times are 2-5 times longer in horizontal wells) as measured with inhibited acid on a coupon of the representative metal at static bottom hole temperature in an oxygen-free environment. Test duration for horizontal wells is typically 24-40 hours, compared to 6-18 hours for conventional wells.
 2. No pitting should occur. Also to be confirmed with coupon testing.

12.9 Site preparation – onshore

Just prior to the treatment, the wellsite needs to be prepared for the treatment. The equipment of the stimulation company has to be rigged up. In many cases, also “third party” equipment needs to be on location, such as logging tools, wireline rig, coiled tubing unit, etc. The various stimulation equipment should be rigged up such that other equipment can easily be installed, when required. If a service rig is on location, equipment should be spotted out of the fall line of the rig mast. Care should also be taken to place the high-pressure pumping equipment, where personnel will not be exposed to the fluid end of the pump. If equipment for N₂ or CO₂ is on location, it should be spotted at least 20 m from other equipment and the wellhead.

12.9.1 Matrix treatments

The equipment needed for matrix treatments is, in general, fairly simple. The main items required are:

- Storage vessels for acids, solvents, etc.
- Low-pressure suction lines and manifold.
- Blending equipment for “on-the-fly” addition of additives, such as surfactants, sequestrants, diverting agents, etc.
- A number of high-pressure pump units, at least one more unit than is strictly required for the treatment (based on horsepower requirements).
- High-pressure line to the wellhead (treating iron).
- Adequate measurement and control equipment, such as pressure sensors, flow meters, densitometers, recording equipment, etc.

² 0.03 lb/ft² for Coiled Tubing

- Waste disposal tank(s) or similar facilities (see also chapter on environmental aspects).

In Figure 28 a schematic equipment layout is shown for a matrix stimulation treatment.

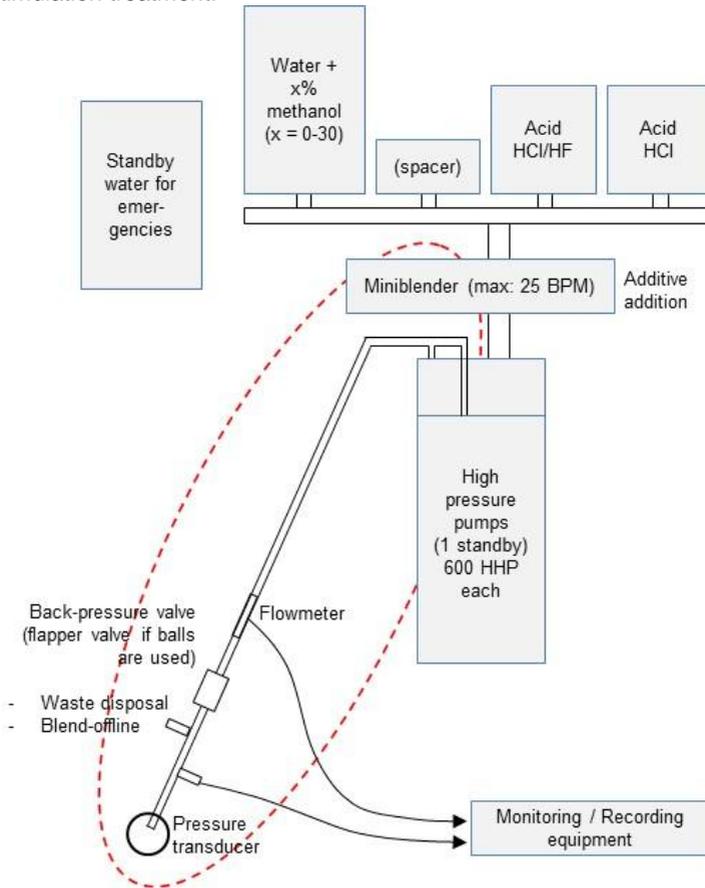


Figure 28 Typical land lay-out of matrix acidizing equipment

12.9.2 Fracture treatments

For fracture treatments, similar equipment as for matrix treatments is installed; however, due to the different nature of the treatment, more pump units and additional storage space for proppant are required. Also, mixing equipment is more complicated and robust in view of the use of abrasive

proppant and higher pump rates. The main items for a fracturing treatment, are the following:

- Wellhead isolation tools (tree saver), if required.
- Treating iron, the size of which is dictated by both the anticipated rates and pressures. The treating iron should not have welded seams or exposed threaded connections.
- High-pressure pumps. These should be spotted close enough to the blender so that the discharge pumps on the blender can easily feed slurry at a sufficiently high net-positive-suction head to the intake manifolds of the pumps.
- Blending equipment.
- Proppant storage and delivery.
- Measurement and control equipment, such as pressure transducers, densitometers, rate sensors, data acquisition and process control computer systems.

Site layout and preparations

Large hydraulic fracturing operations require a large plot space to allow all the equipment to be placed on-site at suitable distances from the wellhead. Site preparation should take place well before mobilization of the contractor to ensure that equipment requirements can be catered for. For example, if large silos are used to store several hundred tons of proppant, the ground below the silos may need to be compacted.

A pre-job site inspection should be arranged, so that the service company personnel can view the layout and equipment placement can be decided upon. Any piece of equipment that may be a source of fire, should be positioned well away from the wellhead. Depending on the local situation, the area of the storage tanks may have to be diked and planked. An open path to the wellhead and off location should be kept. It is also recommended to keep an open path to the storage tanks, in case any fluids need to be hauled to or from the location after rigging up. Moreover, a path should be kept clear behind the pump trucks to allow a tank truck to supply the pump units with gasoline during the job, if necessary. For a large treatment, it is recommended to measure the dimensions of the wellsite and to make a scale drawing of the location with the pumps, blenders, tanks, etc. indicated. Such a scale drawing, of which an outline is given in Figure 29, will facilitate planning, organization and logistics.

Government requirements and many other requirements can then conveniently be checked, if such a scale drawing is available.

The frac tanks are usually the first to arrive on location. Ideally, tanks should be lined (epoxy coated) and steam cleaned, to prevent iron from contaminating water and interfering with proper gelation and crosslinking of fracturing fluids. If this is not feasible, the tanks that are available, should at least be steam cleaned. Tanks that arrive at location should have the hatches open, and be inspected visually to ensure their cleanliness and to certify the integrity of linings (if applicable). To further ensure stimulation fluid cleanliness, all transport tanks should be cleaned in the same manner. If fluids are to be heated, make sure that the heating coil is clean and not rusty. Clean this coil, if necessary, with 5% HCl to remove all rust.

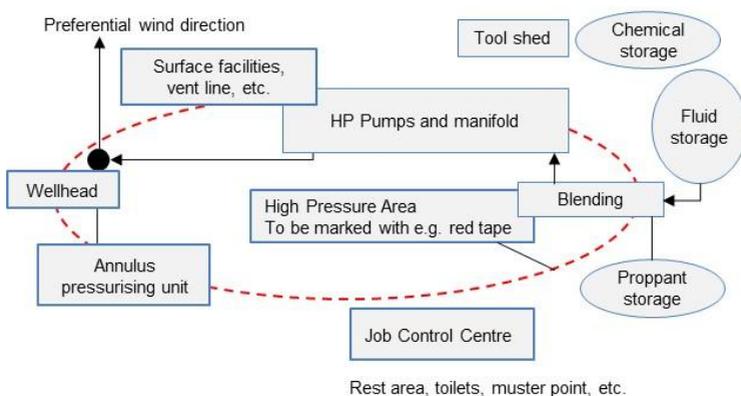


Figure 29 Recommended stimulation equipment lay-out

Backup requirements

Equipment needs vary with the type of job and its design. However, as a rule of thumb, the following excess equipment for backup, in case of failures, is recommended for fracture treatments:

- 10% excess tank and storage capacity.
- 50% backup on power.
- 20-50% backup on pumps, depending on the number of pumps.
- sufficient (e.g. 50%) backup on blenders and instrumentation.

As job size and complexity increases, more backup equipment, specifically pumps, is required. Some pump trucks have two pumps, but only one power source for both. Check to make sure that the stimulation contractor understands that backup means both in pumps and in power.

A recommended set-up for the equipment layout is shown in Figure 29. The actual distances between the various pieces of equipment, including lines and wellhead, should take account of local HSE requirements and legislation. The contractor should supply drawings of the equipment layout with respect to the site dimensions. Appendix VI shows a general layout checklist. The HSE guidelines are discussed in Appendix VII.

12.9.3 Additives and fluids for fracturing

There are a variety of different additives used in fracturing fluids. Because the make-up of each fracturing fluid varies to meet specific needs for a well, it is not possible to provide a single amount or volume present of each additive. However, based on the volume of water that is used in making a fracturing fluid, the concentration of these additives is low (ca. 1%).

SodM (Dutch authority for mining) has published a list of additives that is/can be used during frac activities (ref. 1). This list is given in Table 14.

| General component name | Examples of the specific components that are used | Function |
|------------------------------|---|--|
| Proppant | Sand / ceramics | Prevents the frac from closing and therefore improves and maintains the flow |
| Gel-polymers | Natural organic macro molecules (guar gum) | Improves the transport of the proppant; the fluid is used as carrier for the proppant |
| Gel stabilization components | Sodium Chloride | Supports the gel |
| Biocides | Glutaraldehyde | Prevents growth of bacteria |
| Gel breakers | Acids and/or oxidants | Decrease the viscosity; after settlement of the proppants the fluids can easily be produced to surface again |
| Cross-linkers | Borate salts | Increases viscosity to improve injection of proppants in fracs |
| Acids | Citric, formic, acetic, hydrochloric acid | Preventing precipitates (metal oxides) and dissolution of minerals |
| Fluid-loss-additives | Sand / fine silt | Preventing losses to the formation |
| Lubricants | Polymers, poly-acrylamides | Reducing friction during pumping the fluids |
| Surfactants | Alcohol ethoxylates | For supporting a low surface tension between rock and fluid to optimize pumping frictions |
| pH stabilizer | Sodiumcarbonates/ potassiumcarbonates | Maintaining the pH (buffering) |

Table 14 Additives used for frac activities

The fluids can be classified according to the German WGK classification system, see Table 15.

| Class | Hazard Potential |
|--------------------------|------------------------------|
| “nicht wassergefährdend” | Not Hazardous (was WGK 0) |
| 1 | Slightly hazardous to water |
| 2 | Hazardous to water |
| 3 | Extremely hazardous to water |

Table 15 German WGK fluid classification

Nowadays most fluids meet the requirements for a German WGK -1 classification. For comparison swimming pool water falls under same classification. Service companies are also working to develop even more environmentally friendly fluids that will meet the former WGK 0 classification.

The American Petroleum Institute (API) has issued a series of guidelines for fracturing fluids related to the environmental impact of hydraulic fracturing (see references).

Standard proppants have in general no impact on the environment. In some areas the disposal of (uncured) resin coated proppants is subject to limitations.

12.9.4 Seismicity during frac activities

Another effect of fracturing might be the occurrence of light seismicity. This is only applicable to fracturing in tectonically active areas, where a fracture can act as a trigger mechanism for an earthquake in faults that are critically stressed. In tectonically relaxed areas there is minimal risk of noticeable earthquakes; they stay well below $M=1$ on the Richter scale. Fracturing has been applied for the last 70 years, also in the Netherlands, without incidents related to the environment. According to a recent SodM publication. SodM also addressed this in a recently issued an inventory of potential risks of hydraulic fracturing (ref.1).

For all cases the seismic risk should at least be assessed. The seismic risk has to be excluded and if needed mitigated. At medium risks it is very

common to work with “traffic light systems”, where seismic events are monitored and if certain levels are exceeded the frac operation program will be adjusted.

12.9.5 Integrity of sealing formations

FracS are made in the more permeable formations (reservoir). On top of these formations other formations are present. Some are also permeable, but some are also more or less impermeable. These sealing formations (e.g. claystones, salt layers etc.) do prevent the exchange of reservoir fluids from one to the other reservoir (cross contamination).

When fracS are engineered, the risk of opening the sealing formations on top of the target reservoir should be assessed as this could lead to cross contamination of the reservoirs and loss of containment during the frac activities. It is of greatest importance that this will be prevented for the more shallow reservoirs that could be used for drinking, irrigation or production water, now or in the future. In most industrial standards and legislative norms the maximum frac pressures are defined.

12.10 References

1. Staatstoezicht op de Mijnen, Ministerie van Economische Zaken, Resultaten inventarisatie fracking. De toepassing van fracking, de mogelijke consequenties en de beoordeling daarvan, Februari 2016.
2. API HF1: hydraulic fracturing operations integrity guidelines
3. API HF2: water management for hydraulic fracturing
4. API HF3: mitigating surface impact associated with hydraulic fracturing
5. API hydraulic fracturing info sheet
6. Potential Direct Environmental Effects of Well Stimulation , California Council on Science & Technology



Appendix I

Causes of formation damage and their cure

| Operation | Causes of formation damage | Accelerating factors | How to cure the damage |
|---------------------------------|---|---|--|
| 1. Drilling | mud filtrate invasion mud solids invasion sealing of pores and flow tunnels by the trowelling action of the bit, drill collars and drill pipes plugging by rock cuttings | high permeability formation water-based mud abrupt reduction in salinity drilling with high water loss bentonite mud strongly over pressured drilling high solids mud | backflush acid wash, matrix acidizing |
| 2. Running casing and cementing | plugging/blockage of pore space by mud or cement solids filtrate invasion chemical reactions with cement additives and spacers | high-permeability formations | deep perforations matrix acidizing, acid wash |
| 3. Perforating | plugging of perforations and formation with debris compaction of pores around perforations | use of low performance or expendable guns perforate overbalanced in drilling mud | backflow acidizing |
| 4. Running completion string | plugging by solids from completion fluids and diverting agents filtrate invasion dissolution of rock cementing material | overbalanced conditions with damaging completion fluids improper bridging materials high-permeability formation uncleaned wellbore and production equipment | acid treatment solvent wash same as for drilling |
| 5. Production | finer movement clay migration condensate and water blockage deposits of salt crystals, wax, and paraffins hydrate and emulsions forming | high production rates pressure decrease communication with water zones poor gravel-packing or sand-control measures | acidizing chemical treatments |

| | | | |
|-------------------|---|--|--|
| 6. Gravel packing | invasion of filtrate from gravel-pack slurries invasion of solids and contaminations mixing of gravel with formation sand plugging by diverting | variation of permeability along the producing interval non-uniform sand clay-rich sand | acidizing (through the gravel pack) replace the gravel pack |
| 7. Acidizing | insoluble precipitates iron precipitation in the wellbore plugging of solids cored from the tubing | incompatibility between acid, acid additives and formation materials damaging diverting agents large variations in permeability | - re-acidize with proper additives |
| 8. Fracturing | plugging by formation fines or damaged by gelled frac fluids | poorly designed frac | soak with a gel breaker |
| 9. Workover | residual cement plugging plugging by wireline loosened iron scale or paraffin from tubing plugging by metallic particles resulting from casing repair operations damaging workover fluids damaging bridging materials | operate at overbalanced conditions high-permeability formation large variation in permeability uncleaned wellbore use of corrosion inhibitors or emulsion breakers | acid stimulation chemical treatment |



Appendix II

Definitions of skin components

1. Skin due to partial perforation

$$s_p = \left(\frac{1}{h_{pD}} - 1 \right) \ln \frac{\pi}{2r_D} + \frac{1}{h_{pD}} \ln \left[\frac{h_{pD}}{2 + h_{pD}} \left(\frac{A - 1}{B - 1} \right)^{1/2} \right]$$

where

$$h_{1D} = h_1/h, \text{ with } h_1 \text{ is interval from top reservoir upto perforation}$$

$$h_{pD} = h_p/h, \text{ with } h_p \text{ is interval of perforated reservoir}$$

$$A = \frac{1}{h_{1D} + h_{pD}/4}$$

$$r_D = \frac{r_w}{h} \left(\frac{k_v}{k_h} \right)^{1/2}$$

$$B = \frac{1}{h_{1D} + 3 h_{pD}/4}$$

Reference:

http://petrowiki.org/Fluid_flow_with_formation_damage#Incompletely_perforated_interval

2. Skin due to gravel packs between well and perforation

$$s_{gp} = \frac{khL_g}{2nk_{gp}r_p^2}$$

- n is number of perforations open
- L_g is length of flowpath through gravelpack
- k_{gp} is permeability of gravelpack
- r_p is radius of perforation tunnel

Reference:

http://petrowiki.org/Fluid_flow_with_formation_damage#Incompletely_perforated_interval

3. Skin due to perforating

$$s_{dp} = \left(\frac{h}{L_p n} \right) \left(\ln \frac{r_{dp}}{r_p} \right) \left(\frac{k}{k_{dp}} - \frac{k}{k_d} \right)$$

- S_{dp} is the perforation damage skin
- L_p is length of perforation tunnel
- r_{dp} is radius of damaged zone around perforation
- r_p is radius of damaged zone around the wellbore
- k_{dp} is permeability of damaged zone around perforation
- k_d is permeability of damaged zone around wellbore

Reference:

http://petrowiki.org/Fluid_flow_with_formation_damage#Incompletely_perforated_interval

4. Skin due to deviation

This almost always applicable in geothermal projects with doublets. The following empirical formula can be used.

$$s_{\theta} = - \left(\frac{\theta'_w}{41} \right)^{2.06} - \left(\frac{\theta'_w}{56} \right)^{1.865} \log \left(\frac{h_D}{100} \right)$$

where

$$\theta'_w = \tan^{-1} \left(\sqrt{\frac{k_v}{k_h}} \tan \theta_w \right)$$

$$h_D = \frac{h}{r_w} \sqrt{\frac{k_h}{k_v}}$$

- θ_w is the deviation angle from a vertical well

Reference:

http://petrowiki.org/Fluid_flow_with_formation_damage#Incompletely_perforated_interval

5. Skin and the factor k_f/k_v

In a number of these equations the term k_f/k_v appears. Unfortunately this not always very well known. With respect to the skin due to partial perforation the effect is limited since k_f/k_v is under the log sign, but to calculate the skin factor for deviation it becomes more essential to know the correct value for k_f/k_v .

6. Skin and the factor k/k_s

To calculate the damage skin the above values need to be subtracted from the total skin as determined from a pressure build up test. Alternatively the damage skin could be calculated using the Hawkins relation.

$$s_{dam} = \ln\left(\frac{r_s}{r_w}\right)\left(\frac{k}{k_s} - 1\right)$$

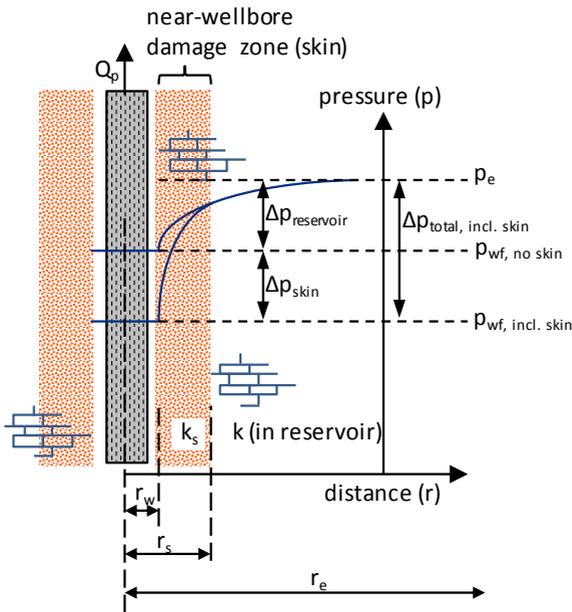


Figure 30 Effect of near-wellbore damage zone on flowing bottom hole pressure (p_{wf})

Figure 31 illustrates how the skin factor varies with the damage ratio, k_d/k , and damage zone radius, r_d ($\approx r_s$), for a vertical well with a radius of 0.0762

m. These variables determine the magnitude of the skin factor and control the well productivity. For instance, a reduction in permeability to less than one tenth of the initial value within 0.45 m of the wellbore axis results in a skin factor of approximately 18.7.

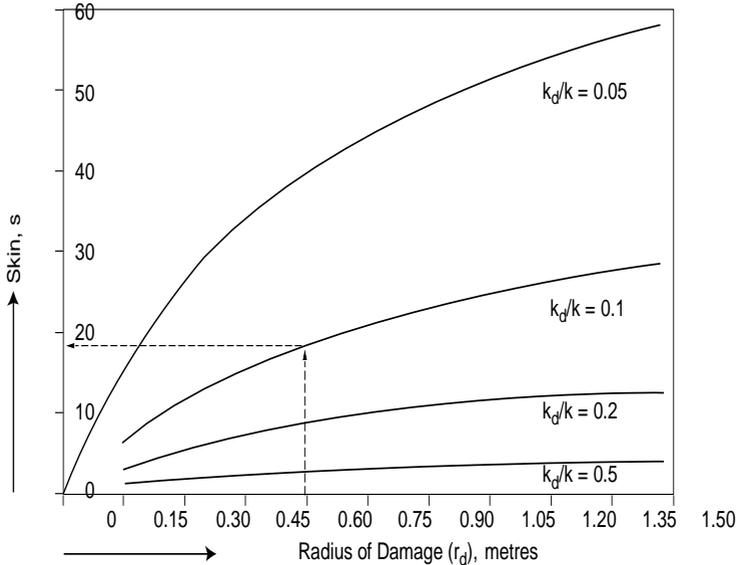


Figure 31 Relation skin (S), radius of damage (r_d) and damage ratio k_d/k ($k_d \approx k_s$ & $r_d \approx r_s$)

7. Flow Efficiency & Production Improvement Factor

To assess the impact of damage on well productivity in vertical wells, we can relate the skin factor S , to the ratio of the damaged to undamaged well production rates Q_{actual}/Q_{ideal} , which is referred to as Flow Efficiency (FE) or Well Inflow Quality Indicator (WIFI).

Flow efficiency is related to the skin factor by the following semi-steady state equation:

$$FE = \frac{Q_{actual}}{Q_{ideal}} = \frac{[(\ln) \left(\frac{r_e}{r_w} \right) - 75]}{\ln \left(\frac{r_e}{r_w} \right) - 0.75 + S}$$

For a range of typical values of the drainage radius, r_e , between 200 and 400 m, $(\ln(r_e/r_w) - 0.75)$ can be approximated by 7. This approximation

results from the behaviour of the natural log function. An approximate expression for flow efficiency in terms of skin, can thus be written as:

$$FE = \frac{7}{7 + S}$$

Following this the potential Productivity/injectivity improvement by reducing the skin will be:

$$PIF = \frac{7 + S_{before}}{7 + S_{after}}$$

PIF = Production Improvement Factor

It is important to realize that an acid treatment in sandstones can only take away the damage skin, not the other components. So for instance for a well with a total skin of 21 of which two thirds can be attributed to formation damage, the maximum PIF will be $(7+21)/(7+7) = 2$, not 4!

Appendix III

General fluid name cross reference list

This listing gives trade names of fluids available through Halliburton, Baker Hughes and Schlumberger, corresponding to a list of generic matrix acidizing fluids and additives.

NOTE: there is no implied equivalency between fluids listed by the service companies; trade names shown are the service company's responses to a request to provide the names of their products which best match the generic fluid descriptions.

| Generic Fluid Description | Halliburton Energy Services | Baker Hughes | Schlumberger |
|----------------------------------|---|-----------------------------|-----------------------------------|
| 6% HCl-1.5% HF | 6% HCl-1.5% HF | 6% HCl-1.5% HF | Half strength Mud Acid (H948) |
| 7.5% HCl | 7.5% HCl | 7.5% hydrochloric acid | Regular Acid (7.5%HCl) |
| 10% HCl-1% HF | 10% HCl-1% HF | 10% HCl-1% HF | Custom Blend |
| 12% HCl-3% HF | 12% HCl-3% HF | 12% HCl-3% HF | Regular Mud Acid (H949) |
| 13.5% HCl-1.5% HF | 13.5% HCl-1.5% HF | 13.5% HCl-1.5% HF | Custom Blend |
| 15% HCl | 15% HCl | 15% hydrochloric acid | Regular Acid (15% HCl) |
| 15% HCl with gelling agent | 15% HCl + SGA-HT | Gelled Acid, LT-100, HT-200 | DGA 100, DGA 200, DGA 300, DGA400 |
| 28% HCl | 28% HCl | 28% hydrochloric acid | Regular Acid (28% HCl) (H28) |
| Acetic - HF system | None | Acetic: HF | Organic Mud Acid |
| Ammonium chloride | CLAYFIX 5, 2% Ammonium Chloride, 5% Ammonium Chloride | Ammonium chloride | J285 |
| Aromatic solvent | Paragon | Xylene | A26, P121 |

| | | | |
|--|---|---|---|
| Aromatic solvent that does not contain xylene, benzene, toluene or ethyl benzene | Paragon 100E+ | Envirosol XS | P129 |
| Asphaltenic compatible acid system for acidizing of sandstone and carbonate reservoirs | Carbonate Completion Acid | One Shot Plus | MISCA |
| Biodegradable, non-aromatic solvent | Paragon EA | | P130 |
| CO ₂ conditioning system | Gidley's CO ₂ Conditioner (No competitive equivalent - HES exclusive patent) | | |
| Diesel | Diesel | Diesel | U051 |
| Emulsified acid | Carbonate Emulsion Acid | Emulsified Acid | Super X Emulsion, Super X Emulsion HT, Dowell Acid Dispersion (DAD) |
| Foamed acid | Fines Recovery Acid | Foamed Acid | Foamed acid |
| Formic - HF system | None | Formic:HF | Organic Mud Acid (H954) |
| Gelled acid | Carbonate Stimulation Acid | Gelled Acid, Gelled Acid 100, Gelled Acid 200, Gelled Weak Acid | DGA 100, DGA 200, DGA 300, DGA400 |
| HCl based, iron control acid system (non-H ₂ S environment) | Fe Acid, Double Strength Fe Acid | Ferrotrol Agents | Micellar Iron and Sludge Control Agent(MISCA) |
| HCl-HF system for use in geothermal wells | Silica Scale Acid | BJ Sandstone Acid | |

| | | | |
|--|-----------------------------------|-----------------------------------|--|
| HCl-HF system with surfactant and aluminum scale inhibitor | Sandstone Completion Acid | BJ Sandstone Acid | |
| Hydrochloric acid / ammonium chloride conditioner | CLAY-SAFE H | | |
| Hydroxypropyl guar gelling agent | WG-11 | Hydroxy Propyl Guar Gelling Agent | J347 |
| In-situ gelled acid | Zonal Coverage Acid | | Leak Off Control Acid (LCA), Self Diverting Acid (SDA) |
| Low strength HCl-HF system for use in high feldspar/fines applications | K-Spar Acid | BJ Sandstone Acid | Clay Acid |
| Nitrogen | Nitrogen | Nitrogen | Nitrogen |
| Organic acid | 10% Formic, 10% Acetic | Organic Acid | L001, L036, L400 |
| Organic acid / ammonium chloride conditioner | CLAY-SAFE 5, CLAY-SAFE F | | |
| Organic acid for high temperatures | Hot Rock Acid | Organic Acid | L400, L036 |
| Organic HF system | Volcanic Acid I, Volcanic Acid II | Acetic:HF For | Organic Mud Acid |
| Potassium chloride | 2% KCl | Potassium Chloride | M117 |
| Retarded HF system with surfactants | Fines Control Acid | BJ Sandstone Acid | Clay Acid |
| Seawater | Seawater | Seawater | Seawater |
| Sour well iron control acid system | SWIC Acid, SWIC II | Ferrotrol-HAS + Ferrotrol- | A255 |
| Water | Water | Water | Water |

| | | | |
|---|-------------------------------------|----------------------|------------------------|
| Xylene | Xylene | Xylene | A26 |
| Acid corrosion inhibitor intensifier | HII-124B, HII-124F, HII-500M | Hy Temp I, Hy-Temp O | A201, A153, A179, A281 |
| Additive for use in aromatic solvents to enhance asphaltene dissolution | Targon II | AS-32 + NE-110W | U101 |
| Anionic, anti-sludging surfactant | AS-5, AS-9 | AS-32 | W035 / W60 |
| Anionic, de-oiling, nonemulsifier for aqueous based fluids | Morflo III | NE-110W | |
| Antisulfide-cracking agent | SCA-130 | HS-2 | A255 |
| Broad spectrum, anionic surfactant for aqueous based fluids | NEA-96M | AS-32, NE-110W | F104 |
| Broad spectrum, cationic surfactant for aqueous based fluids | 19N, 20N | LT-17 | F078, M38B |
| Broad spectrum, nonionic surfactant for aqueous based fluids | Losurf 300, Losurf 259, Losurf, 357 | NE-118, NE-940 | F75N, F103 |
| Cationic oligomer for clay stabilization in aqueous fluids | Cla-Sta XP | Claymaster 5C | L055 |
| Cationic liquid friction reducer | FR-28LC | AG-12, Acigel | J507, J313 |
| Cationic, mineral fines and clay stabilizing additive in aqueous fluids | Cla-Sta FS | Claymaster FSC | L042 |
| Ethylene glycol mono butyl ether | Musol | US-40 | U066 |
| Ferric iron reduction system for iron control in sour environments | FERCHEK SC | Ferrotrol-200 or 210 | L63, L58 |

| | | | |
|--|------------------------|-----------------------------------|-----------------------|
| High temperature corrosion inhibitor for use up to 500°F with all strengths of acid and on corrosion resistant alloys | HAI-85M | | A280 / A282 with A281 |
| Hydroxypropyl guar gelling agent | WG-11 | Hydroxy Propyl Guar Gelling Agent | J347 |
| Improved mutual solvent that does not contain EGMBE and is therefore more environmentally friendly | Musul E | US-2 | |
| Micellar surfactant system with foaming and fluid recovery properties for use at 225 °F and below | SSO-21M | LT-32 + Floback-30 | |
| Micellar surfactant system with foaming and fluid recovery properties for use above 225 °F | SSO-21HT | LT-32 + Floback-30 | |
| Mutual solvent composed of a blend of alcohols/ethers for acids | Musul A | US-2 | U100 |
| Nonionic blend of surfactants, dispersants and solvents for use where health, safety and environmental regulations are concerned | Losurf 396 | | F103 |
| Nonionic micro emulsion penetrating agent for use at 225 °F and below | Pen-88M | LT-32 | |
| Nonionic micro emulsion penetrating agent for use above 225 °F | Pen-88HT | LT-32 | |
| Nonionic surfactant dispersant | Sperse-All M, A-Sperse | D-4GB | F040 |
| Nonionic, anti-sludging surfactant | AS-7 | None | W054 |

| | | | |
|--|----------------|--|------------------|
| Nonionic, penetrating surfactant | Pen-5M | LT-32 | F075N |
| Oil soluble non-emulsifying surfactant | Hyflo IVM | NE-118 | F040 |
| Organic acid corrosion inhibitor | MSA-II | CI-20 | A186, A272 |
| Organic acid used for iron control | Fe-1A, Fe-2 | Acetic Acid, Citric Acid | L001, L400 |
| Organic alcohol | Methanol | Methanol, Isopropyl Alcohol | K046 |
| Oxygen scavenger used for iron control | FERCHEK | Ferrotrol-200 or 210 | L058 |
| Sandstone acidizing additive for the prevention of secondary precipitation of aluminum | ALCHEK | BJ Sandstone Acid | |
| Sequestering/reducing and scavenging agent for iron control in acids | FERCHEK A | Ferrotrol-810, Ferrotrol-270 & 271, Ferrotrol-260I | L041, U042, L62 |
| Soluble corrosion inhibitor for use up to 400 °F | HAI-81M | CI-30NF + HyTemp 400 | A270, A280 |
| Soluble, environmentally acceptable corrosion inhibitor for use up to 200 °F | HAI-OS, HAI-NS | CI-27 | A259, A261, A262 |
| Surface tension reduction and fluid recovery surfactant | Superflo III | Inflo-150, Inflo-100 | F075N, F103 |
| Surfactant gelling agent for acids | SGA-1 | AG-10 | J508 |
| Suspending agent/foaming surfactant for acids | HC-2 | FAW-21 | F78, F100 |
| Synthetic, cationic gelling agent for acids up to 400 °F | SGA-HT | AG-12, Acigel | J507 |

| ADDITIONS from Schlumberger | | | |
|---|--|--|---------------|
| Environmentally acceptable anionic anti-sludging agent | | | W060 |
| Environmentally acceptable friction reducing agent | | | J507 |
| Environmentally acceptable organic acid corrosion inhibitor | | | A272 |
| Environmentally acceptable suspending agent/foaming agent for acids | | | F100 |
| Environmentally acceptable, broad spectrum nonionic surfactant for aqueous-based fluids | | | F103 |
| Soluble environmentally acceptable corrosion inhibitor for use up to 400 °F | | | A259 and A282 |

Appendix IV

Maximum injection rate for matrix treatments

The maximum injection rate, $q_{i,max}$, into a vertical well under matrix conditions, is given in the first equation. This equation is a simplified inflow performance relationship; it does not account for transient effects, multiphase flow, or reservoir heterogeneities. The injected fluid is assumed to be incompressible. The effective permeability is the permeability to the injected fluid. The value of maximum injection rate is obtained with the initial skin value, and can therefore be used only as a guideline for determining the initial rate. The equation reads as follows:

$$q_{i,max} = \frac{4.917 \times 10^{-6} kh (g_f H - \Delta p_{safe} - p)}{\mu B \left(\ln \frac{r_s}{r_w} + S \right)}$$

where $q_{i,max}$ is the injection rate in bbl/min, k is the effective permeability of the undamaged formation in mD, h is the net thickness in ft, g_f is the fracture gradient in psi/ft, H is the true vertical depth in ft, Δp_{safe} is a safety margin for the pressure in psi (usually 200 to 500 psi), p is the average reservoir pressure in psi, μ is the viscosity of the injected fluid in cP, r_e is the drainage radius in ft, r_w is the wellbore radius in ft, and S is the skin factor. B is the formation volume factor and has a value of 1 for non-compressible fluids such as water

If the fracture gradient, g_f , is not known, it can be estimated by adding 0.25 psi/ft to the bottom hole static pressure gradient (a good estimate for areas not tectonically active).

The maximum injection rate (in field units) into a **horizontal well** under matrix conditions, can be calculated by using the following equation:

$$q_{i,max} = \frac{4.917 \times 10^{-6} \sqrt{k_h k_v} L (g_f H - \Delta p_{safe} - p)}{\mu B(F)}$$

Where

$$F = \frac{1}{2} \ln \left(\frac{8hB}{\pi r_w (1 + \beta)} \cot \left(\frac{\pi z_w}{2h} \right) \right) + \frac{1}{2} \left(S - \frac{(h - z_w)\beta}{L} \right)$$

$$B = \sqrt{k_h / k_v}$$

Z_w is the elevation of the well from reservoir bottom in ft.

The equations indicate that the maximum injection rate is directly proportional to the length of the horizontal reach of the well, and normally the maximum matrix injection rate in a horizontal well is significantly higher than in a vertical well, completed in the same formation. Furthermore it should be noted, that F is dependent on the skin factor. As skin decreases in a horizontal well during stimulation, the maximum matrix injection rate increases as well.



Appendix V

Minifrac or datafrac Procedure

Step 1: Fracture initiation

Displace the tubing contents with base gel, at the highest possible rate, to initiate a fracture. Do not use step-up rates for breakdown: they exacerbate near-wellbore tortuosity of the fracture.

Step 2: Fracture re-opening (optional)

Resume pumping. Observe the fracture re-opening pressure and continue pumping for 1 min.

Step 3: Step-down test

Pump, while decreasing the pump rate in 5-10 short steps from the maximum rate determined in step 1 (or 2) to ~ 1 bpm (0.16 m³/min), after which the rate is quickly increased to the maximum again for 1 minute followed by a quick shut-down.

Note. Pressure should be stabilized before proceeding with the next rate step.

This test is especially useful to detect any wellbore/fracture entrance problems (tortuosity). Presence of substantial entrance problems may be cured with a proppant slug in the minifrac for instance to help remove tortuosity or other near-wellbore restrictions.

Step 4: Propagation test (optional)

Switch over to crosslinked gel and displace the tubing contents to crosslinked gel at a rate corresponding to a pressure approximately 2000 psi (14000 kPa) below the maximum allowable THP. Monitor pressure variations as the heavy gel reaches the perforations. A continuously increasing pressure may indicate near-wellbore entrance problems.

Warning: with some highly viscous crosslinked fluids, restart problems may occur! If expected, no shut-in should be applied. Proceed to next step.

Step 5: True minifrac test

Pump at the rate corresponding to a pressure approximately 2000 psi (14000 kPa) below the maximum allowable THP (possibly determined in step 4). Keep the rate constant after the crosslinked gel has reached the perforations. The total volume to be pumped should be equal to half the volume of the planned main fracture, with a maximum of 50 m³. Switch

back to base gel and over displace the completion to base gel by 1 m³, still maintaining a constant pump rate. If near-wellbore entrance problems are suspected, based on first observations from the previous steps, in particular during the step-down test (if carried out, step 3), a 1-2 lb/gal (120 – 240 kg/m³) proppant stage should be included. This can be repeated until near-wellbore problems disappear.

Step 6: True minifrac test (repeat)

Repeat step 5, if necessary

After each step:

Shut in instantaneously and monitor pressure decline for a proper analysis.

Appendix VI

Layout checklist

The following checklist covers the essential points. The list pertains to fracturing as well as matrix treatments.

- Layout of the surface lines and connection to the wellhead
- Proper installation of safety measures, e.g.:
 - o Positioning of the contractor location
 - o Relief valves on the lines and annulus (incl. backup valves) to be set at appropriate pressures and checked (depending on the type)
 - o Measures to control possible vibration in the surface lines (chains, etc.)
 - o Proper fencing off of the wellhead area
- Measures to comply with HSE requirements
- Contingency plan in case of premature termination of the job
- Stand-by of circulation equipment (e.g. coiled tubing) to clean out well
- Check quality of equipment, chemicals and materials (incl. stand-by and contingency equipment)
- Make sure that pressure transducers, flowmeters, etc. are properly calibrated
- Sufficient additional materials and chemicals on location
- Supervise pressure testing of lines and surface equipment
- Instruct rig/installation and contractor personnel on the ins and outs of the treatment

Appendix VII

Health, safety and environmental aspects

Introduction

At no time should the safety aspects of a stimulation treatment be compromised. Safety guidelines have been developed from experience, derived from previous incidents. Many of these incidents have had great potential to seriously injure personnel, or damage/destroy valuable equipment. The inherent risk of dealing with high pressures in fracture stimulation treatments can be greatly minimized by following relatively simple safety procedures.

As to safe handling of chemicals (SHOC), especially in matrix treatments, whenever in doubt, the manufacturer's instructions should be consulted for advice on the handling of chemicals. In general, precautions should be taken to avoid skin contact and inhalation and, in any event where contact is possible:

- hands should be washed before eating, smoking or using the toilet,
- food should be consumed in areas free from dust and fumes,
- contaminated clothing should be removed before eating.

Personnel handling acid or caustic substances should wear gloves, boots, face shields and acid/alkali resistant coveralls or aprons.

During all stimulation jobs, there is a risk of splashing or contact with dangerous chemicals. Therefore an emergency shower and/or eye wash facility should be installed within 20 meters.

Basic information on the nature of chemicals handled, precautions to be taken and actions to be taken in the event of a fire, spillage or accidental contact should be available at locations where chemicals are handled and also at first aid stations. Such data is presented on Material Safety Data Sheets (MSDS).

Environmental aspects

The chemicals applied in well stimulation are intended to react or interact with the rock formation and deposits, to create or restore permeability. The resulting formulations are often toxic, give hazardous reaction products (e.g. acid may release H₂S upon contact with pyrite), and corrode completion equipment (wellhead, tubing, etc.). With the increasing awareness, mentioned previously, of the potential environmental impact of

chemical additives, particularly in the marine environment, there is a continuing need to develop more efficient, more environmentally friendly, alternatives.

Acids

Hydrochloric acid (HCl), and mud acid, a mixture of hydrofluoric acid (HF) and HCl, are the most commonly used acids in well stimulation. Both are corrosive, depending on acid strength and formation temperature, but mud acid is more corrosive than HCl alone. It can cause serious “pitting” corrosion, requiring higher levels of inhibitors for protection. However, new HF-based formulations use 10-20 times less hydrochloric acid and have a much higher pH, thus requiring much lower corrosion inhibitor loadings, while still dissolving the same amount of rock. Such systems can also be used for Process Controlled Acidizing, where the acid is actually prepared on-the-fly and immediately pumped into the well. The benefit of such a technique is that the mixing process can be shut down if the job is interrupted for some reason, thus eliminating the need to dispose of unused, pre-mixed acid.

Another approach to reduce the environmental impact of matrix acidizing is to eliminate acidizing altogether, by performing small fracture treatments (so-called Skin Bypass Fracs), instead. The new fracturing fluids that can be used for such treatments, are much friendlier than their predecessors. New fluids based on biodegradable surfactants, or non-toxic crosslinked gels, have replaced some of the earlier organometallic formulations. The latter contained organic complexes of zirconium, titanium and antimony, amongst others.

Corrosion inhibitors

Mechanical failure of surface or subsurface well equipment can lead to high costs and an HSE problem. Virtually all matrix acidizing and acid fracturing formulations are corrosive to steel, and hence require corrosion inhibitors. The early corrosion inhibitors contained materials like arsenic, but these were replaced many years ago by amines, acetylenic alcohols, and more exotic organics. While less toxic than arsenic, these organics are still hazardous. In the past ten years, newer corrosion inhibitors have appeared in which many of the toxic compounds have been eliminated. Thus, materials like polyaromatic hydrocarbons, NPE's (Nonyl Phenol

Ethoxylate), formamide, etc., have been removed from recently developed products. However, acetylenic alcohols and other reactive species still remain.

One approach to minimizing or eliminating the use of toxic corrosion inhibitors is to substitute strong mineral acids like HCl, with organic acids or with systems, based on materials like EDTA (Ethylene Diamine Tetra-Acetic Acid). Such systems have much lower corrosion rates and are easy to inhibit at high temperatures. Another method uses bio friendly enzymes to generate acid in-situ from noncorrosive, biodegradable esters, effectively eliminating corrosion of tubulars and surface equipment.

Adequate corrosion control cannot be achieved under some conditions, without the addition of inhibitor intensifiers. An intensifier, sometimes called an extender, may consist of metal ions, halide ions, or certain organic compounds. The intensifier function is generally to:

- increase the safe contact time available for the treatment,
- allow the inhibitor system to function in strong acid, and
- allow the inhibitor to be used in the presence of chrome alloys.

Corrosion inhibitors and some intensifiers have the well-deserved reputation of being the most toxic products in a service company's chemical arsenal. Formamides and copper salts are good examples of highly toxic materials used in inhibitor formulations. Removal of copper salts is demanded by many regulatory authorities, since they have extreme high toxicity to aquatic life forms. Copper salts can be lethal at concentrations as low as 6 ppm. Unfortunately, these salts have been used as intensifiers for many years. Alternatives have been developed, or are under development, existing of a combination of potassium iodide and formic acid, resulting in a strong positive synergistic effect to produce enhanced corrosion protection in the inhibited system.

General HSE guidelines for stimulation

A stimulation treatment involves the handling, injection and back production of potentially hazardous chemicals. In addition, usually the injection pressures are high. Therefore, HSE requirements are stringent. To ensure a safe and environmentally acceptable execution of a stimulation treatment, the following rules apply:

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1. Design the treatment with chemicals which have the smallest possible environmental impact. For instance, if a sequestering agent is required, citric acid is preferred over EDTA, unless the presence of large amounts of carbonates precludes the use of citric acid.
 2. Apply treatment procedures with the smallest possible impact, whenever possible. For instance, over displace acid into the formation rather than producing back largely unspent acid, if possible.
 3. Make sure that for each chemical used, a SHOC card or a Material Safety Data Sheet (MSDS) is available.
 4. Keep all unnecessary staff off site during pressure testing, pumping, and perforation operations.
 5. Hold a Safety Meeting prior to the treatment, with all personnel on location.
 6. For critical jobs, or with new, relatively inexperienced crews, hold dry-runs on critical operations.
 7. Pressure test all lines prior to the treatment.
 8. Determine the position of all valves and sequences of opening and closing of the valves.
 9. Make sure all lines are secured and anchored.
 10. Check the monitoring equipment prior to the main treatment.
 11. Designate a gathering (“muster”) area to be used in case of an emergency.
 12. Establish an equipment failure contingency plan.
 13. Make sure that adequate (in accordance with the requirements on the SHOC or MSDS cards) first-aid facilities, including qualified personnel, are available on-site.
 14. Establish – prior to the treatment – handling and disposal procedures for chemicals, empty containers and back-produced fluids.

Guidelines on chemicals/materials handling

- All containerized (sacks or drums) chemicals and materials that are to be pre-blended or mixed on-the-fly, will be stored in the area between the blenders and the frac tanks. At initial arrival on location, all chemicals will be stored away from the main site

activity centres, in a designated storage area, as per the location lay-out plan.

- All chemicals and materials should be well marked and easily identifiable. The storage area should be roped off and designated as a no-go area.
- All chemical safety data sheets should be kept in the frac van or job control centre, for easy access. They should also be available in the fluid testing lab and the well test office. It is the responsibility of the Stimulation Engineer, or Fracmaster, to ensure that all his personnel are familiar with the data sheets.
- As per the MSDS for each chemical, all chemical handling should be accomplished utilizing the specified Personal Protective Equipment.
- The designated first aider will be the well test supervisor, who is trained in First Aid, and has all the necessary medical supplies in the well test office. The first aiders shall be identified to the stimulation crew, during the Safety Meeting.

Guidelines on materials/waste disposal

Wastes must be handled in a manner that protects the environment within the area of stimulation operations and complies with all applicable laws and regulations and good housekeeping practices. Waste minimization and recycling programs and practices should be implemented in all stimulation operations to the extent practicable.

The overall philosophy is that minimal storage of waste materials will occur at the stimulation site. All waste is to be transported to a designated disposal site (paper waste and/or scrap dump) at the earliest notice.

Furthermore:

- Used containers (sacks/drums) should first be tallied to ensure stock control.
- The containers should then be moved to the waste collection area.
- Drums will be punctured in the middle or lower section, taking care not to spill residual contents of hazardous materials. This is done to prevent illegal removal and re-use of the drums.

The pumping services contractor shall provide the necessary equipment required for the handling and mixing of toxic materials, as per the recommendations of the chemical safety material datasheets (i.e. overalls, eye guards, eye washers, emergency showers, rubber gloves, ear protectors, and safety boots).



Appendix VIII

Procedures and working plans needed for stimulation activities in NL

The legal framework for stimulation activities in the Netherlands is summarized in the publication of SodM (Staatstoezicht op de Mijnen, Ministerie van Economische Zaken, Resultaten inventarisatie fracking. De toepassing van fracking, de mogelijke consequenties en de beoordeling daarvan, Februari 2016).

Any operator that will be doing stimulation jobs on his geothermal wells is assumed to have an exploration or production permit (opsporings- of winningsvergunning) and will commit to the Dutch Mining law for any activity related to this permit. This also means that the operator will have an organization and HSE-system that is agreed by SodM.

Before a stimulation job is started, the operator needs to inform the authorities (SodM) on this specific activity. The following working plans need to be worked out and procedures to be followed:

- BARM notification (incl. Quantitative Risk Analysis, QRA)
- Permit for disposal of (re)produced water (comply to the WABO permit)
- Technical/operational working plan:
 - o Organisation;
 - o Description of technique and procedures;
 - o Spatial impact;
 - o Storage and disposal of (re)produced water and other waste;
 - o Planning.
- Evaluation of Health, Safety and Environmental aspects related in specific to the stimulation activities (a general HSE-system is already available):
 - o HSE-organisation during the stimulation activities;
 - o HSE risks evaluation, including mitigating measurements;
 - o If necessary HAZID/HAZOP (high pressures, high temperatures) ;
 - o Working plan for chemicals to be used, stored, transported, archived. Prove that is committed to the REACH regulations;
 - o Assessment on induced seismicity, mitigating measurements including a monitoring plan.

