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# How to Prevent and Avoid the Induced Seismicity from the Water Disposal Process

Author(s): Sáchica J. A., Usuriaga, J. M., Quintero, Y. A., Ecopetrol S.A.

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**Abstract**
The induced's seismicity phenomenon has been one of the most controversial events in recent years, especially in the hydrocarbon industry. Among the activities related to these events is the disposal injection of wastewater. Various studies have been developed to characterize this phenomenon. However, very few of these have directed actions towards the root cause of these events.

This study was developed by analyzing various areas where this phenomenon has occurred, concluding that there are various tools that prevent and eliminate its materialization. The analysed tools are categorized from different views. First, the analysis focuses directly on the structural and mechanical areas from a regional perspective, second from a local view where the focus is directed toward the storage reservoirs of the fluid to be disposed of. Third and finally, the focus is on the injection's process feasibility, both in the short and long term.

The regional perspective incorporates probabilistic studies of fault reactivation through which the fact of destabilizing a fault under the stress behaviour can be analysed by simulating the planned operating conditions on the system's mechanical conditions. The local view included other tools, such as water distribution through selective injection and the implementation of a rigorous process for selecting suitable flow units for fluid confinement. The injection process contains fluid-fluid and rock-fluid compatibility studies which are fundamental tools to prevent or reduce the effects of injectivity losses.

The results of the study allowed us to conclude that the operation of water disposal by injection is a safe process if it is executed rigorously, under the implementation of the tools exposed here. This study was developed by a multidisciplinary team with the aim of giving it the most complete approach possible.

**Keywords** Water Disposal, Induced Seismicity, Fault Reactivation.

## Introduction

The oil and gas industry requires water to operate but it also produces water. From construction to transportation, with the refining and production stages being the ones that require the most water, especially in the latter more when waterflooding projects are executed, although many times these are developed with the same production water, which makes them closed-cycle projects. In the case of implementing Multistage Hydraulic Fracturing in the well-completion, this generates return fluids (flowback) that must also be properly managed on the surface.

For the management of production waters (Colombia's oil-water ratio is around 14 barrels of water per barrel of oil produced, but there are oil fields whose ratio exceeds 30 barrels of water per barrel of oil produced), and wastewater, whether from subsoil processes such as completion or surface processes, there are different techniques for its management or disposal that range from injection, or reinjection (when they return to the same producing reservoir), reutilization (use of water in the same sector and process), reuse (supply of water to other sectors and processes), or mechanical evaporation, among others.

The implementation of each technique depends on various conditions, such as the quality of the water to be disposed of, the regulations of the area where the project is developed, the balance between the water required and the water produced, the ecosystem of the area of operations, and the availability of confining receptor reservoir units among the most important.

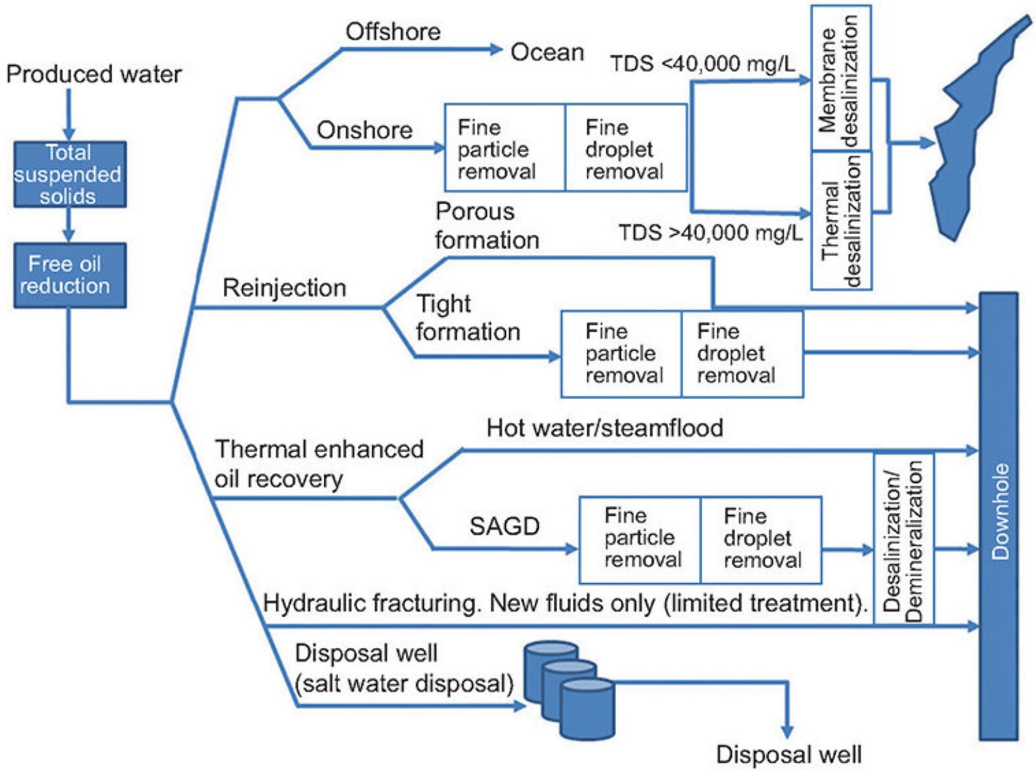


Figure 1. Process of produced water management. Source: Journal of Petroleum Technology (2015)

Production water is called saltwater when it exceeds total dissolved solids above 600 ppm (EPA), exceeding the recommendations of entities such as the World Health Organization (WHO) to be used as drinking water or local standards to be used as irrigation water.

In many oil and gas-producing regions, considerable amounts of fluids such as saltwater are produced along with oil and natural gas. Much of that saltwater is injected into oil reservoirs during secondary and enhanced oil recovery operations to force additional oil out of the rocks, and to maintain a pore-pressure balance within the rock formation. In places, however, substantial amounts of saltwater are injected into deep subsurface rock formations via disposal wells. In some locations, wastewater disposal operations correlate with increased seismicity. Though many of these seismic events are too small to be felt by most people, some have been widely felt and have caused damage. In most areas of active oil and gas operations, wastewater injection thus is the focus of induced seismicity prevention, rather than hydraulic fracturing. In the future, due to concerns about greenhouse gases and climate change, increased injection of $CO_2$ could also require careful management in relation to induced seismicity (AASG, 2015).

Earthquakes, whose pattern is known as seismicity, occur when the strength of a mass of rock, or frictional resistance between adjacent bodies of rock, is exceeded by stresses. A fault is a fracture where rock bodies have moved relative to each other. Earthquakes occur when rock ruptures or if adjacent rock bodies slip relative to each other along a fault. Whether rocks on either side of a fault will be displaced relative to each other depends on the fault's orientation, the natural stresses on the fault, the properties of the faulted rocks, and the nature of fluids in the pore spaces of rocks surrounding the fault. Numerous faults have formed in the geologic past, although many do not continue to slip because the shearing stresses on the fault no longer periodically exceed the frictional strength of the fault.

As long as the stress on a fault is less than the frictional strength of the fault, there is no relative motion along the fault. However, where a fault is oriented so as to be susceptible to slipping, and is near a critical state of stress, an increase in pore fluid pressure in the surrounding rock can reduce the friction holding the fault in place, thus potentially triggering an earthquake. Injection of fluid into the subsurface may cause such an increase in pore pressure, reducing friction, allowing fault movement, and potentially inducing earthquakes. Aside from the characteristics of the faults, several factors affect whether injected fluids will induce seismicity, including the distance between a fault and an injection well, permeability of the strata surrounding the fault, and the volume and rate of injection. The potential for induced seismicity following subsurface liquid waste disposal has been recognized for some time. One early, well-known instance occurred when waste from chemical manufacturing was injected at the Rocky Mountain Arsenal near Denver in the early 1960s (AASG, 2015).

Earthquakes associated with human activities are referred to as induced or triggered (as opposed to natural) seismicity. They include both small events that cannot be felt, but are measureable by sensitive instruments, and larger events that may be felt and that can cause damage (National Research Council, 2013). Determining whether a single earthquake is natural or induced can be extremely difficult, in part because fluids may be injected in areas where earthquakes occur naturally. In some situations, however, it is possible to correlate fluid injection with an increase in the frequency and/or magnitude of earthquakes (AASG, 2015).

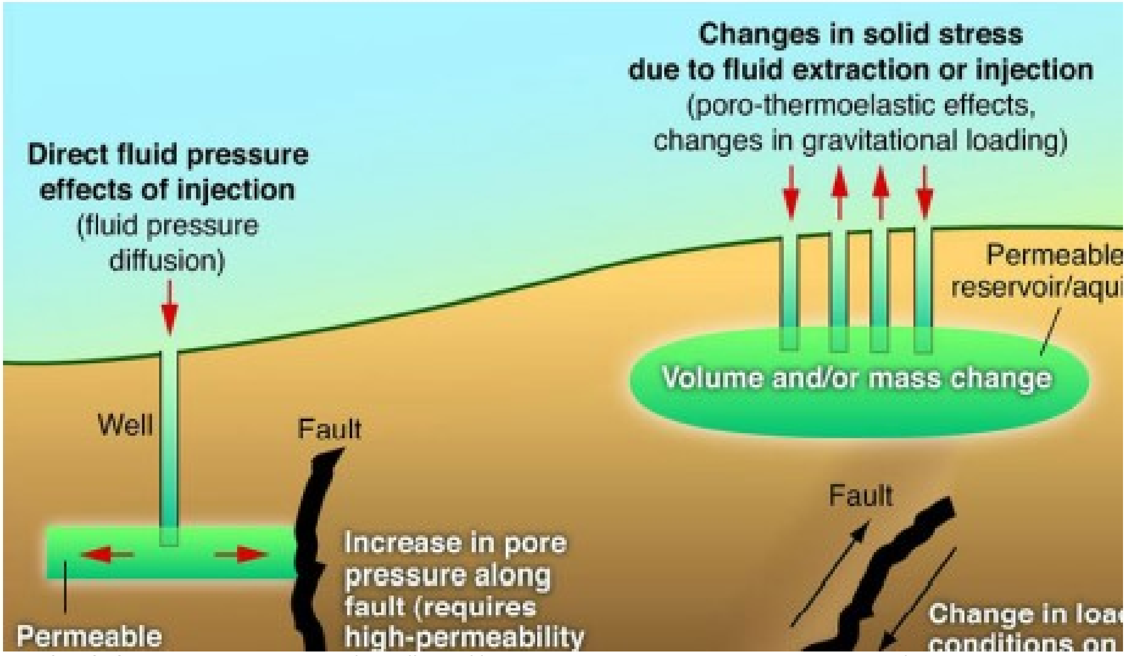


Figure 2. U.S. Geological survey drawing of the effects of fluid injection and withdrawal can have on nearby faults.

One of the main questions to be answered is: Do all wastewater disposal wells induce earthquakes? According with studies the answer in No. For instance in the United States of more than 150,000 Class II injection wells, roughly 40,000 are waste fluid disposal wells for oil and gas operations (27%). Only a small fraction of these disposal wells have induced earthquakes that are large enough to be of concern to the public (USGC, 2022). The program called UIC developed by the EPA has the mission to control hazards related with water activities and other related. EPA regulates the construction, operation, permitting, and closure of injection wells used to place fluids underground for storage or disposal.

Another question is: Are earthquakes induced by fluid-injection activities always located close to the point of injection? The answer is No. Given enough time, the pressure increase created by injection can migrate substantial horizontal and vertical distances from the injection location. Induced earthquakes can occur 10 or more miles from injection wells. Induced earthquakes can also occur a few miles below injection wells (USGC, 2022).

Various studies explain the process that is generated by inducing seismicity. The fluid that is injected at depth is sometimes hydraulically connected to faults. When this happens, fluid pressures increase within the fault, counteracting the frictional forces on faults. This makes earthquakes more likely to occur on them. An analog to this system is an air hockey table. When an air hockey table is off, the puck does not move readily, but when the table is on, the puck glides more easily. Raising fluid pressure within a fault is like turning on an air hockey table (USGC, 2022).

The scope of this paper is associated with how to prevent or mitigate the event of generating induced seismicity that could affect communities. In this case the following question arises: Is it possible to anticipate whether a planned wastewater disposal activity will trigger earthquakes that are large enough to be of concern? Currently, there are no methods available to do this in a definitive sense. However, different studies has developed methods to help us determine whether injection activities might cause induced earthquakes and rule out other injection activities that are unlikely to induce earthquakes, but we cannot say either with certainty (USGC, 2022).

In the case of USGC enumerate different conditions that increase the likelihood of inducing earthquakes. These include:
1. Presence of a fault.
2. Stresses acting on the fault favorable to slip.
3. A pathway for the pressure increase from injection to interact with the fault.
4. High injection rates and/or rapid changes in injection rate.
5. Injection occurring within or close to very hard rocks at depth, known as crystalline basement.

The USGS has developed models to forecast induced earthquake rates on a regional scale using what we know about injection on a regional scale.

One approach to prevention of induced seismicity is a traffic light protocol that has been developed in association with enhanced geothermal systems. Under this system, operators have a green light to continue injection as long as earthquakes do not occur above a specified level. Under a yellow light, which prevails if seismicity above certain levels occurs, operators must slow injection rates and take additional precautions. They must stop injection under a red-light scenario if associated seismicity does not stop or slow adequately after precautions are taken. In some states, this sort of protocol has been applied to induced seismicity caused by wastewater disposal associated with oil and gas production. In addition, states are developing best practices designed to reduce the risk of induced seismicity, including avoiding fluid injection near known faults, and more frequent monitoring of injection pressures, volumes, and duration. Enactment of these and other mitigation protocols requires coordination between industry, government, and the research community. These protocols, best practices, and monitoring, conducted on a well-coordinated basis by public and private groups including state geological surveys, are thus directed at further assessment of the risk of induced seismicity associated with fluid injection, and minimization of that risk in order to prevent felt and, in particular, damaging induced earthquakes (AASG, 2015).

Through the methodology used in this study together with the application case, the best practices developed in multiple water injection projects developed in the world will be compiled, and from these the activities that may be critical in the eventual process are selected.

**Methodology**

In the case study, using the risk analysis methodology, we will define the limit event as the generation of induced seismicity at levels that affect the communities or the environment, the latter being the undesired consequence. Although the presence of a failure indicates that the probability of risk increases, there are more factors that cause the limit event to be reached. Within these factors are grouped all those that do not allow optimal performance of a water disposal system by injection.

When the documented cases of induced seismicity are observed in detail, these characteristics can be found that accompany the poor performance of the injection system (their order does not depend on the criticality of the variable):

1. Injection in reservoirs or storage rocks with poor petrophysical properties (porosity, permeability).
2. Injection in thin layers with poor natural barriers.
3. Injection by linear flow.
4. Injection of fluids incompatible with the fluids and rock of the storage reservoir.
5. Accumulation of high volumes of fluids confined in the same storage reservoir.

Based on the 5 previous points, and including the fault reactivation analysis, an analytical and experimental methodology was proposed to determine how efficient a water disposal process can be through reinjection and therefore prevent the generation of induced seismicity.

In the case of points 1 and 2, it was proposed to make a review based on reservoir analysis, specifically from the petrophysical analysis associated with different types of storage rock and the factors that influence their performance to allow intergranular fluid. Of course, the presence of clay minerals that can react against the injection of fluids can also cause flow restriction, so it would be closely related to points 3 and 4.

**Experimental Analysis.** One of the most important experimental tools is the displacement tests known as “coreflooding”, which allows the injection of fluids through the reservoir to be recreated at the laboratory level under various premises considered. From the implementation of premises adjusted to the reality of the injection project, the behavior of the experimental work and its escalation will be more precise, which allows generating decision-making with greater confidence. This technique allows to compare the efficiency of different formations before the injection process and in the same way to take corrective measures to improve it.

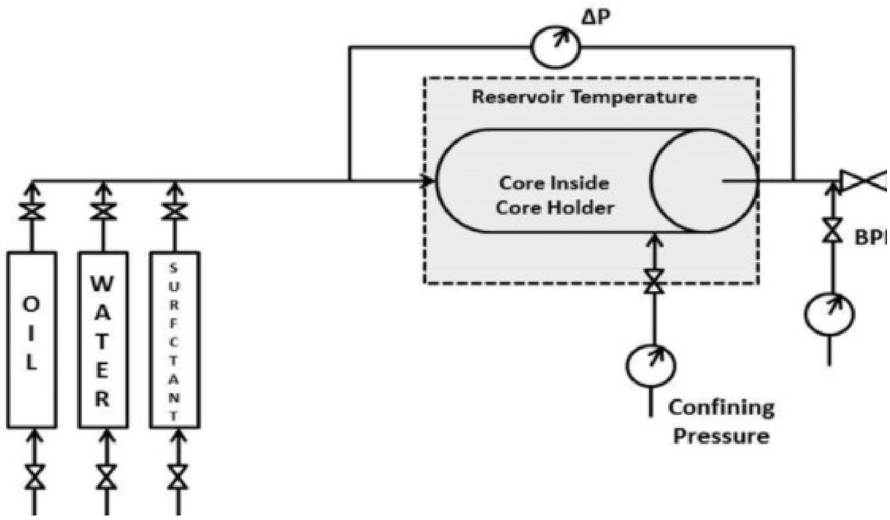


Figure 3. Desplazamiento o Coreflooding. Fuente. Alameri, W., et al. (2014)

The two inputs that must be carefully selected are the rock in which the displacement process will be carried out and the fluid itself to be displaced. The latter is often unknown, especially for projects that start from the pilot stage, so in these cases an additional effort must be made by implementing various techniques to generate synthetic fluids that best represent the future fluid to be handled.

The methodology implemented for the theoretical-experimental study to obtain the necessary technical considerations for the injection of water is proposed in three stages, first, understand the reservoir storage formation and their storage fluid (formation-water), second, plug-formation selection and mineralogy analysis, and third, coreflooding test and formation damage evaluation. It could be included critical rate evaluation and stimulation if this can be considered necessary.

**Analysis of Fault Reactivation.** The fault reactivation process can occur due to changes in the effective stress condition present in the fault planes, which can be generated by an increase in the total loads and/or by variations in the pore pressure of the saturating fluids which may be in proportion to the increase/reduction or in response to the effect of fluid injection/production rates (Zhu et al., 2017). When the pore pressure increases in the reservoir, the effective normal stress in the fault plane decreases, and consequently the fault reactivates and slips (Figure 4A). Eventually, due to the increase in pore pressure, the effective normal stress decreases to zero and the fault opens (Figure 4B). Both phenomena are undesirable, since hydrocarbon fluids can migrate from the reservoir to other porous layers, generate seismic activity and/or cause fluid leaks to the surface.

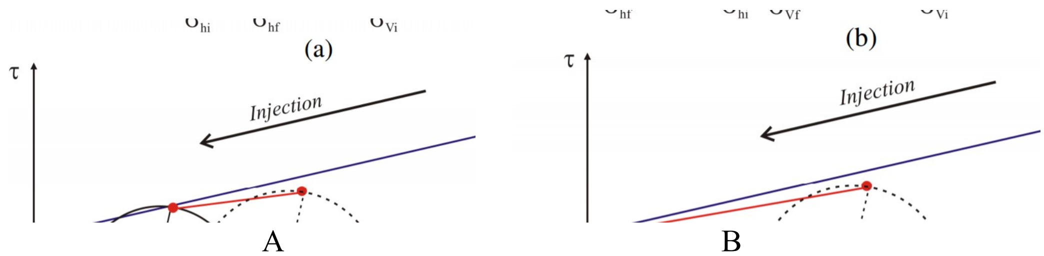


Figure 4. Reactivación de plano de falla por inyección de fluido (A) por cizalla y (B) por tensión. Fuente, Nacht et al., 2010.

Fault reactivation can occur in situations where the pore pressure change is localized in the vicinity of a fault, causing the increase in pore pressure to also increase the slip tendency of the fault.

According to the restrictions in information available in the study area, the modeling of the fault reactivation potential was approached from a probabilistic point of view, where for each input parameter a most probable value and a sampling window were selected in accordance. with the geomechanical information available in each of the formations. Subsequently, the 2D fault model was built for each formation taking into account the interpreted surfaces. Subsequently, the result obtained for each fault system is integrated into a single graph of accumulated probability, where the probability of reactivation of the orientations identified in the structural model and of the orientation of greatest sensitivity is presented, in Figure 5 it is shown schematically. the flow of this methodology.

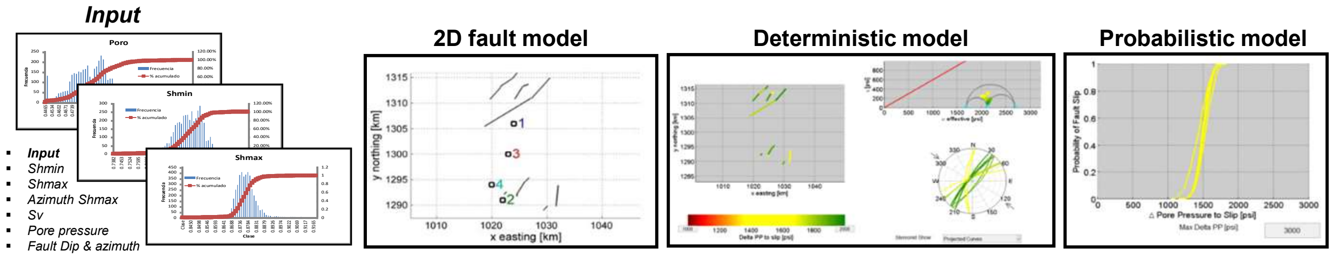


Figure 5. Metodología potencial de reactivación de fallas

For the implementation of this workflow, it was carried out in the FSP tool (Walsh et al., 2017; Walsh and Zoback, 2016), which was developed by the Induced and Triggered Seismicity group of Stanford University.

**Application**

Regardless of the process being executed, be it injection, reinjection or fluid disposal, the most important variable is injectivity. Of course, everything starts on the basis of a formation that is competent enough to store fluids, however, the injection flow and the injection pressure will depend on the injectivity. To ensure, improve or maintain injectivity, one of the fundamental topics to be analyzed is compatibility between fluids. Regardless of the size of the flow units and their petrophysical properties, this compatibility variable can affect injectivity, drastically reducing it and even degenerating it completely.

The following figure represents the best practices to select a suitable formation or unit and maintain a constant and prolonged injectivity, including the distribution of the injected fluids. Before analyzing the probability of fault reactivation, it should be considered to start implementing these good practices within the disposal process.

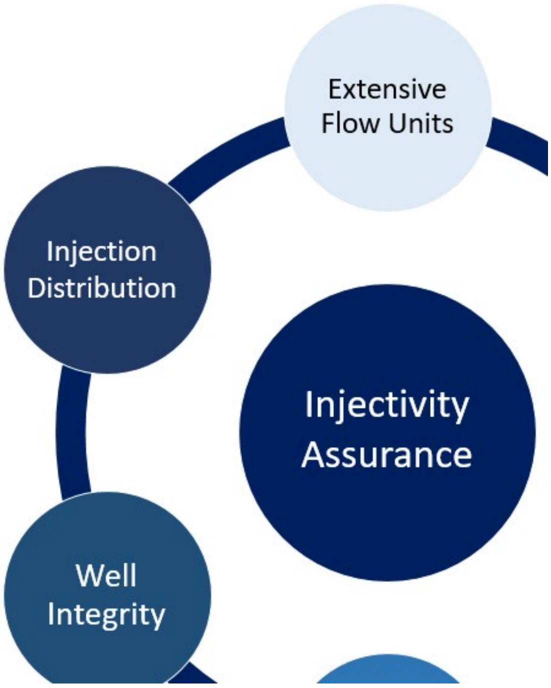


Figure 6. Steps to ensure water injection in disposal process.

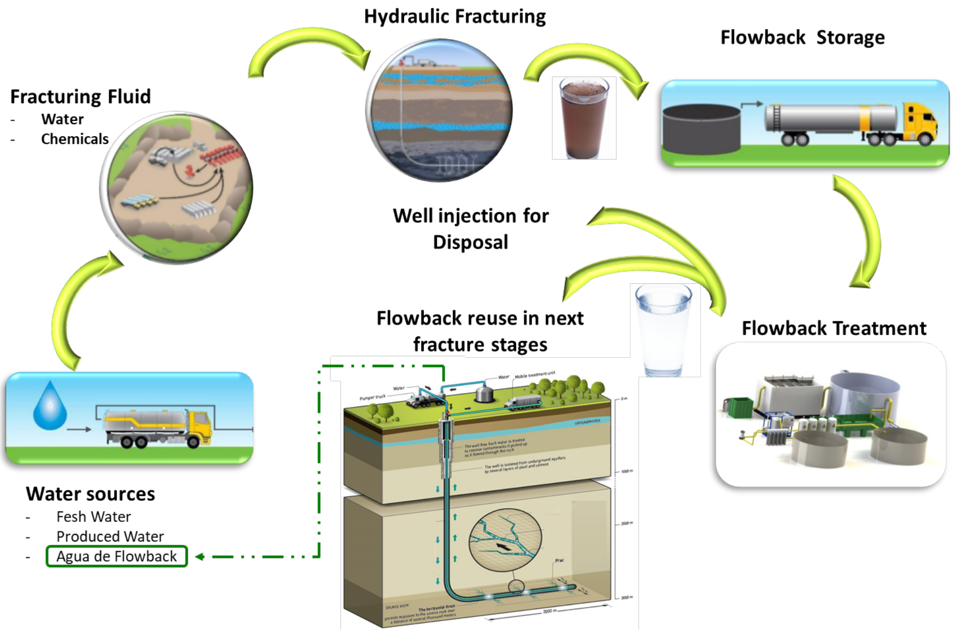


Figure 7. Water cycle in hydraulic fracturing operations and water reuse and disposal. Source: Modified from EPA 2015.

**Site Description.** The Middle Magdalena Valley basin recently celebrated 100 years of commercial production. Its history in exploration and exploitation of hydrocarbons allows it to implement all that acquired knowledge, for the development of reserves and resources that this same Basin has. The first commercial hydrocarbon field in Colombia was Infantas, discovered in 1918 in the Middle Magdalena Valley Basin. In the following decades, other fields were discovered, among the most important La Cira, Casabe, Provincia, Bonanza, Llanito, Gala, Galán, Lisama, Tesoro, Nutria, Tisquirama, San Roque, Payoa, Las Monas, Cocorná and Velasquez. In the Cira Infantas, the first water injection project in Colombia was developed in 1957, so this process is well known in the basin under study (Castro R., 2010).

The Middle Magdalena Valley basin is geomorphologically located along the central portion of the valley crossed by the Magdalena River, between the Eastern and Central Cordilleras of the Colombian Andes, covering an area of 32,000 km2. It includes part of the departments of Boyacá, Santander, Cundinamarca and Antioquia, among others (Figure 8).

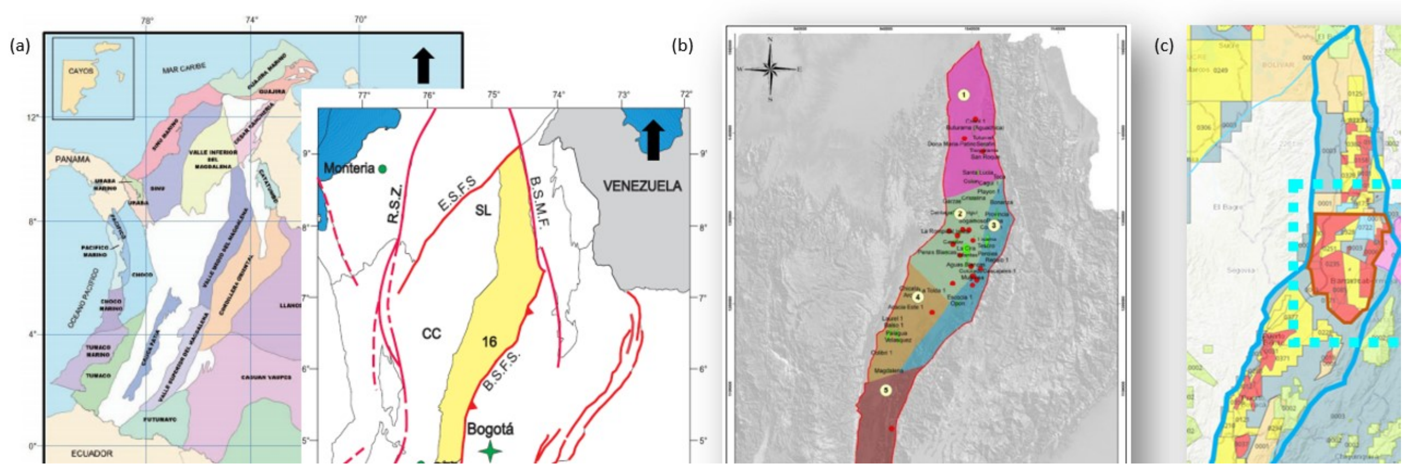


Figure 8. Localización de la Cuenca del Valle Medio del Magdalena. Barreto et al., 2007.

The central part of the basin is very interesting from the point of view of resources and reserves, as shown in the previous figures. For this reason, this type of analysis becomes more important. The hydrocarbon-producing formations are part of the Paleocene. The Lisama, Esmeraldas, La Paz, Mugrosa and Colorado Formations are the main sources of the more than 6 Billion oil discovered in the Basin's history. These formations rest on deposited Members of Cretaceous origin, whose formation characterized as source rock (Figure 9).

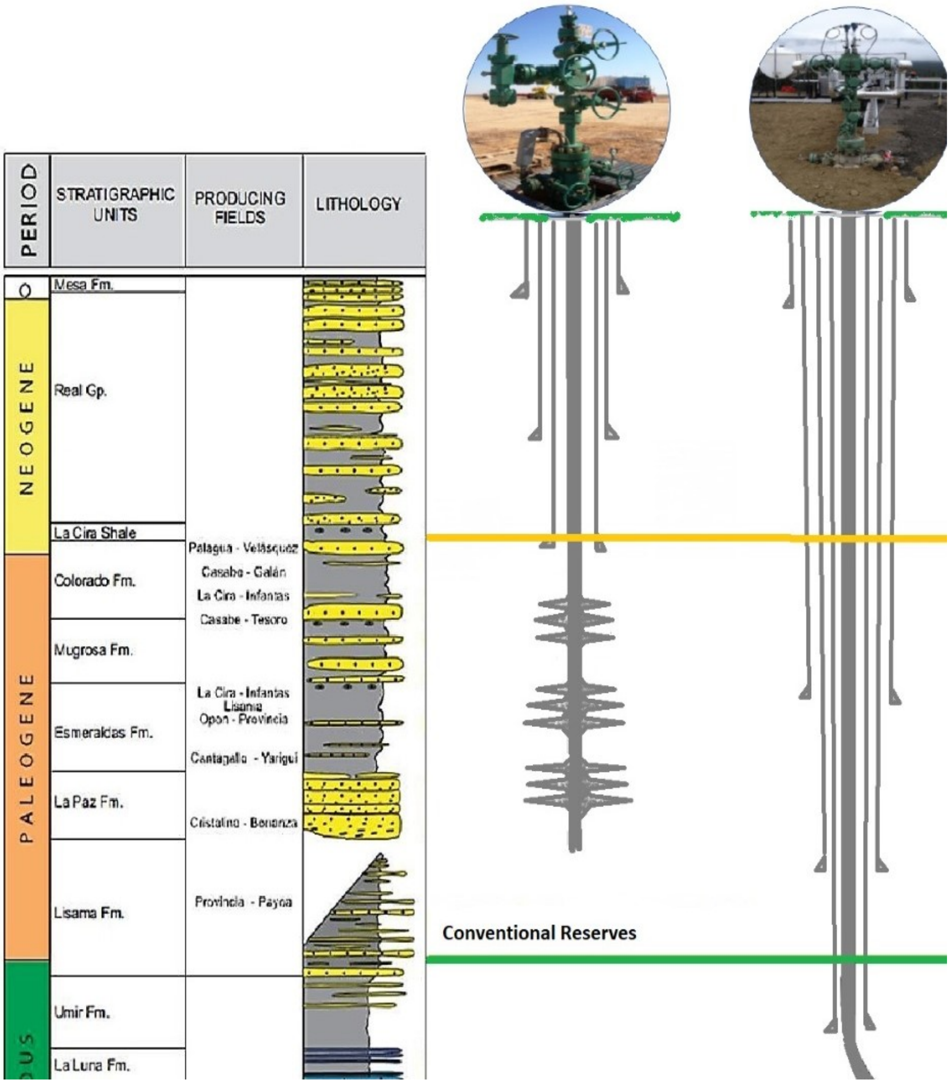

Figure 9. Stratigraphic column reference modified from Vargas 2012

To date, several water disposal projects have been developed that include injection, reinjection and wastewater disposal processes. Some initially used water from surface sources, other projects chose to use water from underground sources, and other projects have used water from hydrocarbon production processes or return water. To date, more than 5 large-scale projects associated with this type of process have been developed in the Basin, and about 8 pilots with scalability potential (Figure 10).

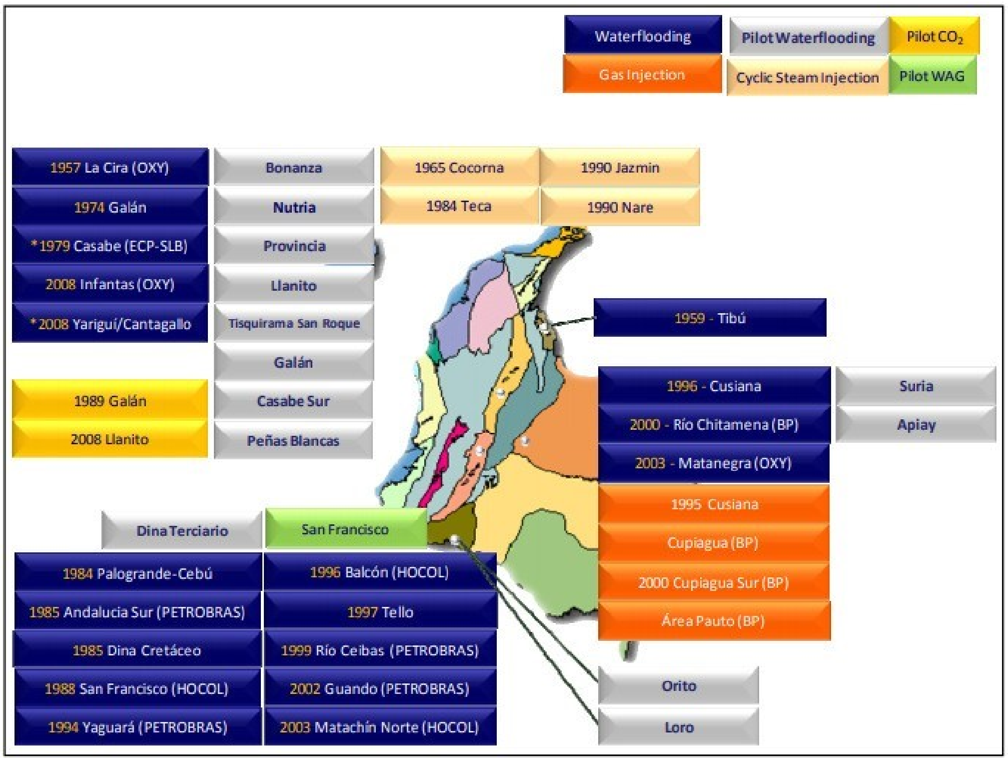


Figure 10. Conventional oil fields in Colombia (Castro et all, 2010).

To date, no seismic knots associated with this type of process have been detected in the study basin, which in some way represents the competition of the formations subject to injection. The main units exposed to this type of process have been Colorado and Mugrosa. The following Figure represents a cut in a northwest-southeast direction, in which the interesting continuity of these Paleogene formations represented in pink and orange colors can be evidenced. These formations present a diverse variety of petrophysical properties, but the main ranges in the areas of interest are composed of competent properties that offer productivity and at the same time injectivity, however, a key part of the analysis is found in the management of the critical rate as well as in fluid rock compatibility due to the presence of clays in its porous medium.

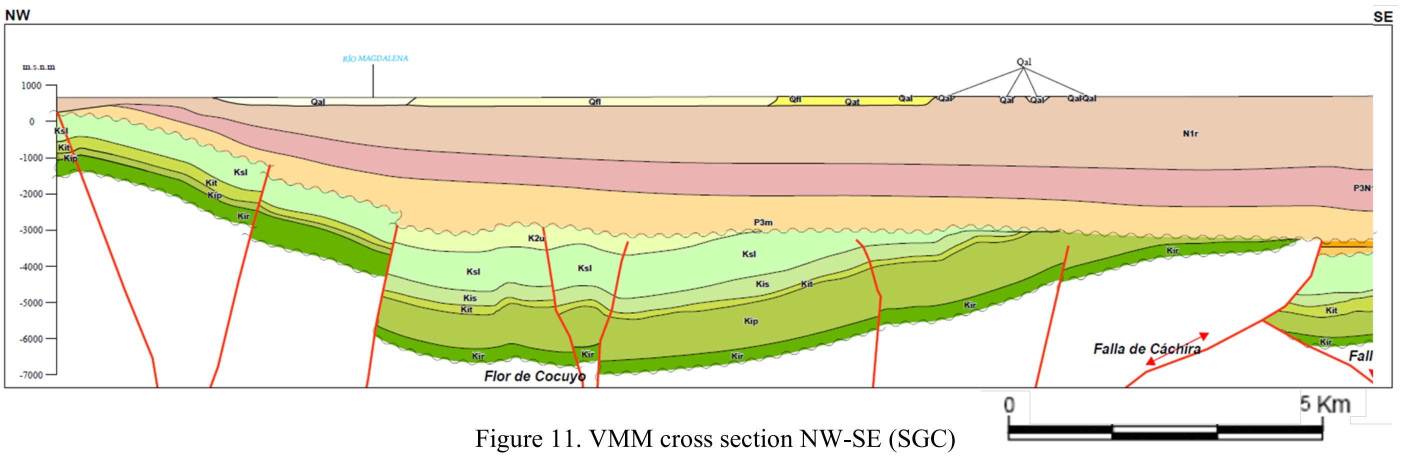


Figure 11. VMM cross section NW-SE (SGC)

**Experimental implementation.** The process applied in the experimental part is described below, following the steps mentioned in the methodology focused on the Valle Medio del Magdalena basin.

**Stage 1:**

- Review of the physicochemical composition of the water-formation in the storage units or formations.
- Definition of the physicochemical composition scenarios of the waters to be injected in terms of the content of total dissolved solids (TDS) and ions that cause the precipitation of inorganic scale.
- Carrying out the simulation of the encrusting tendency of the different scenarios (theoretical) of the composition of the water to be injected at the injection temperature and pressure conditions.
- Adjustment of the critical ion composition limit parameters to prevent problems associated with the precipitation of inorganic scale.
- Theoretical analysis of rock-fluid compatibility (Scheuerman-Bergersen Guides. SPE 18461, 1990).

**Stage 2:**

- Definition of the formations and intervals of interest for the injection of return water separated from the flowback.
- Review of the mineralogy of the formations or defined intervals to evaluate the criticality of the injection depending on the composition of the return water separated from the flowback.
- Selection of plugs or cores of the formations of interest to carry out displacement tests in coreflooding.

**Stage 3**

- Execution of coreflooding tests to evaluate: Critical rate, Sensitivity of formations to saline shock and formation damage generated by the injection of flowbacks (synthetics of the defined composition).
- Evaluation of stimulation treatments for remediation of possible formation damage caused by flowback injection.

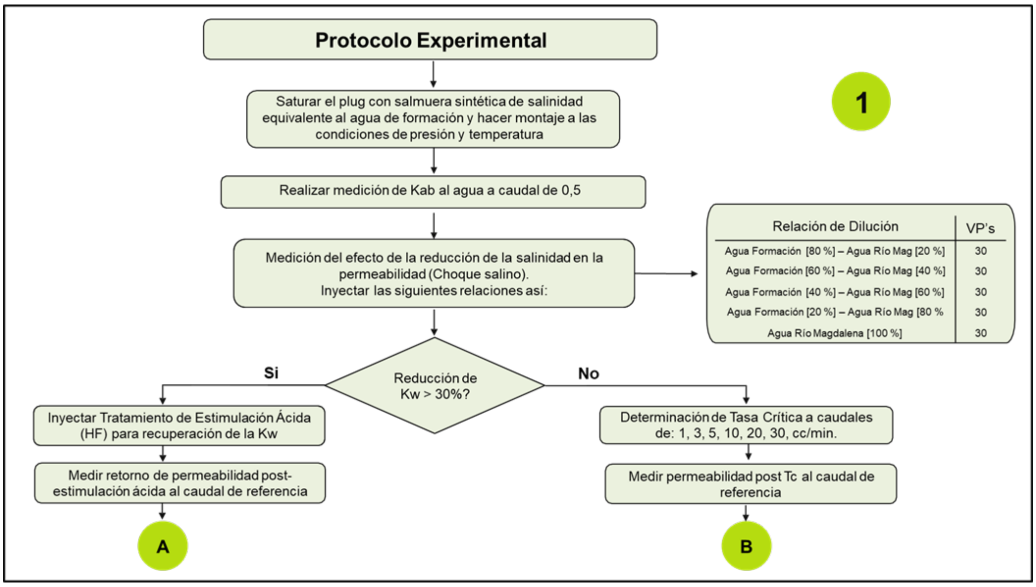


Figure 12. Step 1 - Core flow protocol test. Source: Usuriaga, J., et al. 2021.

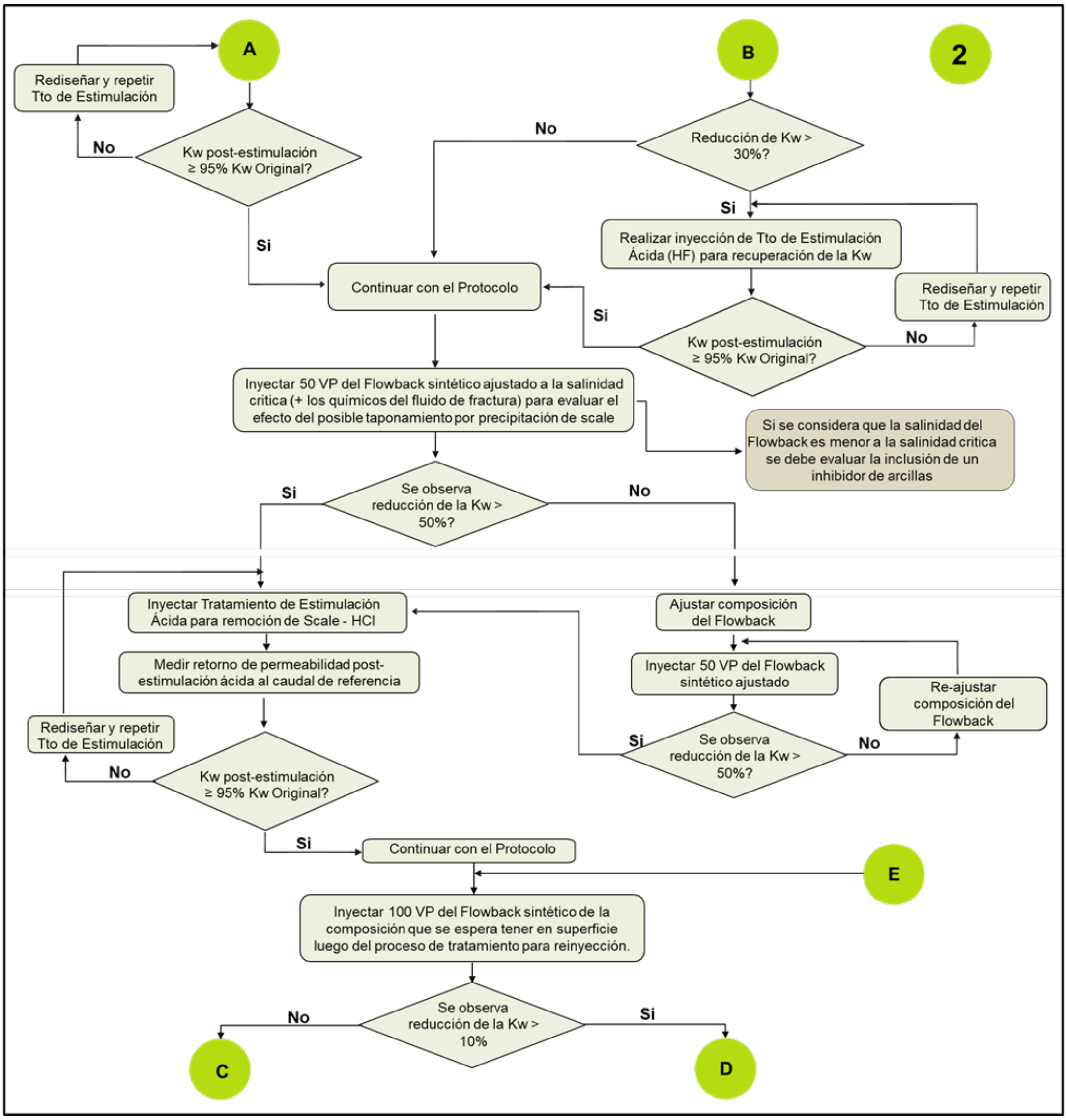


Figure 13. Step 2 - Core flow protocol test. Source: Usuriaga, J., et al. 2021.

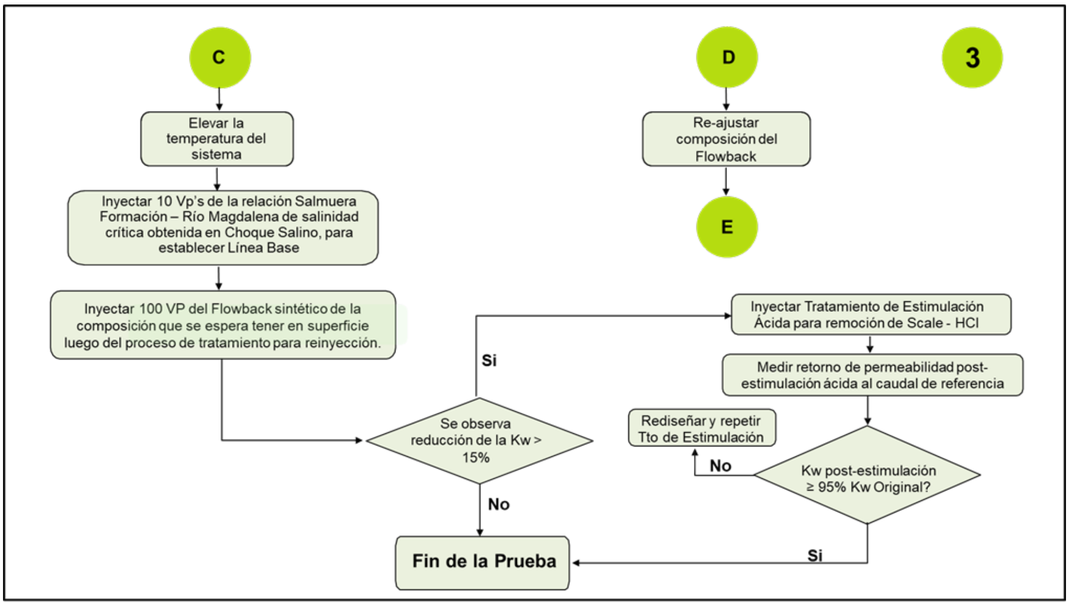


Figure 14. Step 3 - Core flow protocol test. Source: Usuriaga, J., et al. 2021.

The definition of the fluid to be injected as mentioned above is a very critical variable. For example, in the case of application of a study like this one towards the injection of return water from a Hydraulic Fracturing Multistage process, the methodology must include the type of Fracture Fluid that will be implemented, its chemical components, and its interaction with the reservoir rock where return water will be injected. Figure 15 presents the different fracturing fluids used in the United States. It can be seen how the proportion of fluids used changes from basin to basin, so the number of variables to take into account is important. To recreate the return fluid generation process, a digestion process is implemented with the aim of diluting part of the rock matrix in the fluids analyzed at the temperature of the medium to obtain the composition with the least possible uncertainty.

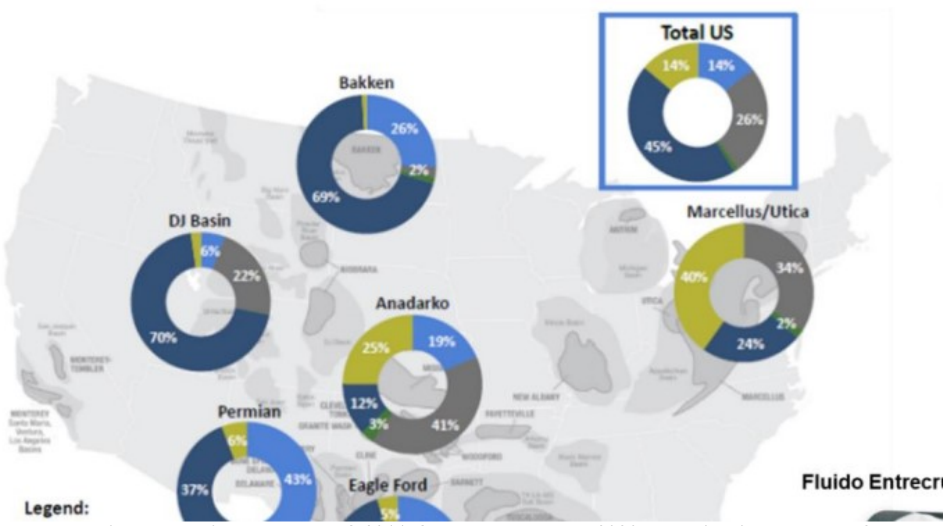


Figure 15. Main types of Fracturing fluids used in U.S 2014. Source: Usuriaga, J. 2020 – Modified from Pacwest Consulting Partners

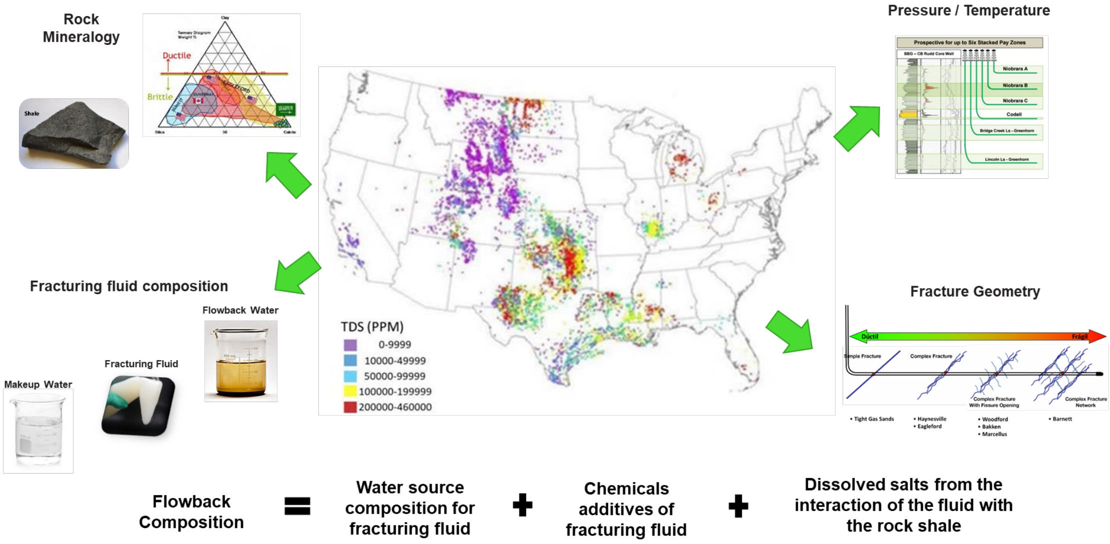


Figure 16. Variables on which the composition of the flowback depends. Source: Modified from SPE-199993-MS.

In the case of a wastewater recovery or disposal process, the complexity may be less since there may be greater knowledge of the water to be used, however, synthetic fluids can also be analyzed, especially where there is a strong interaction of these with the porous medium. For example, in the case of a new recovery project, the water sources are subjected to displacement analysis to evaluate their compatibility with the medium found in the reservoir, or the storage rock itself, which is known as compatibility. fluid-fluid or rock-fluid.

The application of the study has taken about 3 years in which the entire process has been analyzed. A fundamental part has been the generation of synthetic return waters where an attempt has been made to recreate most of the variables. The experimental part of this application is based on being able to develop displacement tests from these so-called synthetic return waters.

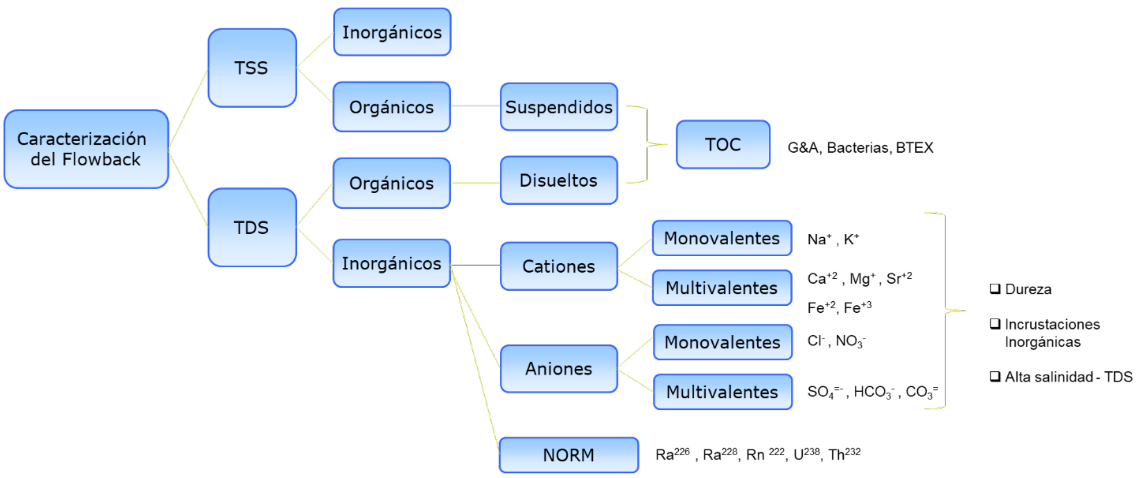


Figure 17. Main flowback components. Source: Usuriaga, J. et al. 2021.

The biggest challenge is related to trying to simulate the behavior of the Return Water of a Hydraulic Fracturing process. For this purpose, the digestion process was implemented, ensuring four duly selected rock samples of Cretaceous age. These were placed in contact with 500 mL of fracture fluid with a probable formulation in liter-capacity Schott glass flasks at the temperature of the source rock. Each of the samples was subjected to a pretreatment by acid digestion with the aim of simulating the effect of the pumped acid preflush prior to the fracture operation, which mainly dissolves the calcareous fraction of the rock and has a significant effect on the increase of the concentration of some ions in the return water.

The procedure for the samples that were subjected to acid pretreatment was as follows: The amount of rock sample was put in contact with hydrochloric acid-HCl at 15% in a ratio of 0.5 mL per gram of rock. Subsequently, the mixture was taken to the oven for 45 minutes at reservoir temperature, after which the 500 mL of fracturing fluid with the previously selected formulation were added.

Figure 18. Rock samples of La Luna Formation used to prepare a synthetic flowback on a laboratory scale.

Once the fracturing fluid was added to the 4 samples (with and without acid pretreatment), the samples were stirred to ensure homogenization of the system. Subsequently, the samples were placed in an oven at reservoir temperature for 30 days. After 30 days, the samples were removed from the oven and the aqueous fraction was removed (flowback) and the analysis of the physicochemical composition of the samples was performed. Synthetic flowback was obtained for various Cretaceous units.

With the information collected from the digestion tests, the displacement tests were started with different types of fluid, starting from 100% fresh water, up to 100% return water, with the aim of evidencing the types of formation damage that occur. they can present as they are the saline shock, and the generation of encrustations, including a critical rate analysis.

The fluids are generated through various ranges of water enriched with calcium, magnesium, barium, iron, bicarbonate and sulfate ions, to increase their encrusting tendency, simulating a probable composition in accordance with the literature and what was recorded in the tests to obtain the laboratory-scale flowback.

The case in the Mugrosa formation is presented below, as it was previously exposed, the most important formation of the oil system of the basin under study. To evaluate the saline shock, dilutions of the synthetic brine equivalent to the Mugrosa formation water (TDS 55034 mg/L and 54822 mg/L NaCl equiv) were made with water from the Magdalena River (STD 321 mg/L and 168 mg/L NaCl equiv) in different ratios until observing a reduction in permeability. A critical salinity of around 11099 mg/L corresponding to the mixture (20% formation water + 80% Magdalena River water) was determined. During the injection of 100% water from the Magdalena River (TDS 321 mg/L and 168 mg/L NaCl equiv) a reduction in permeability of 34% was recorded, after the injection of 6 porous volumes.

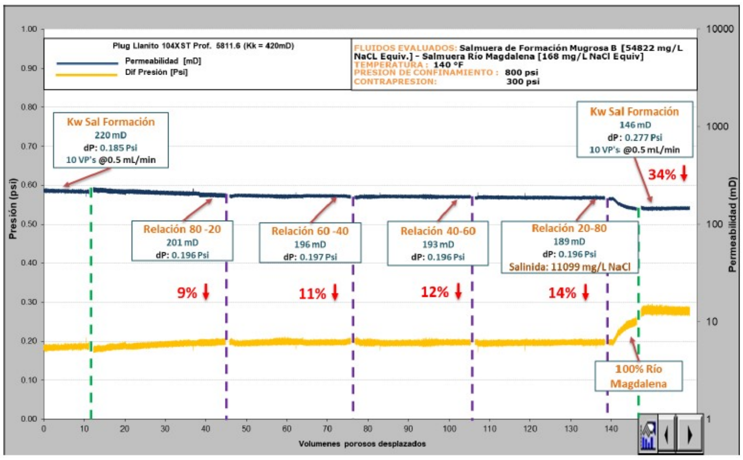


Figure 19. Mugrosa formation sensitivity to salinity reduction effect. Source: Usuriaga, J. et al. 2021.

Subsequently, to evaluate the critical rate, synthetic brine was injected at flow rates of 1, 3, 5, 10, 20, 30 mL/min. The evaluation showed that the rock sample (plug) presented a critical rate at a flow rate between 10 and 14 mL/min, as evidenced in the analysis of the trend line Q Vs dP type Darcy. The measured post-critical rate permeability represented a 61% reduction from absolute water permeability (baseline).

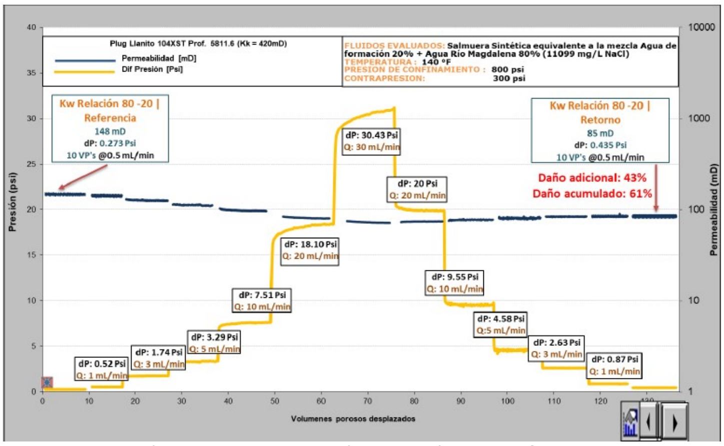


Figure 20. Determination of critical rate injection of Mugrosa formation. Source: Usuriaga, J. et al. 2021.

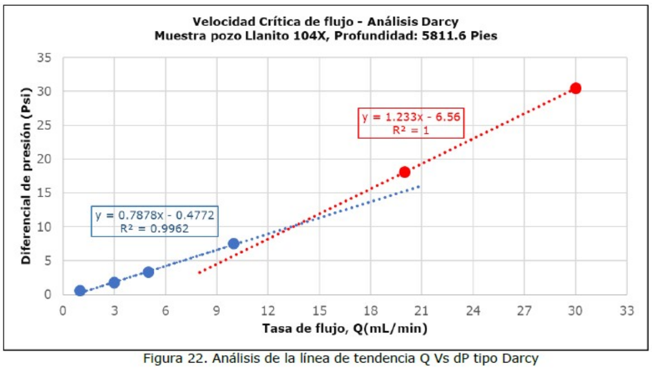


Figure 21. Trend line analysis Q Vs dP Darcy type on the Mugrosa formation. Source: Usuriaga, J. et al. 2021.

Once the plug had deteriorated as it had been affected by the critical rate, a sequence of HF-acid stimulation treatments was injected to remove the formation damage caused by clay swelling and fine migration, obtaining a recovery of the absolute permeability. to water by 95% from baseline.

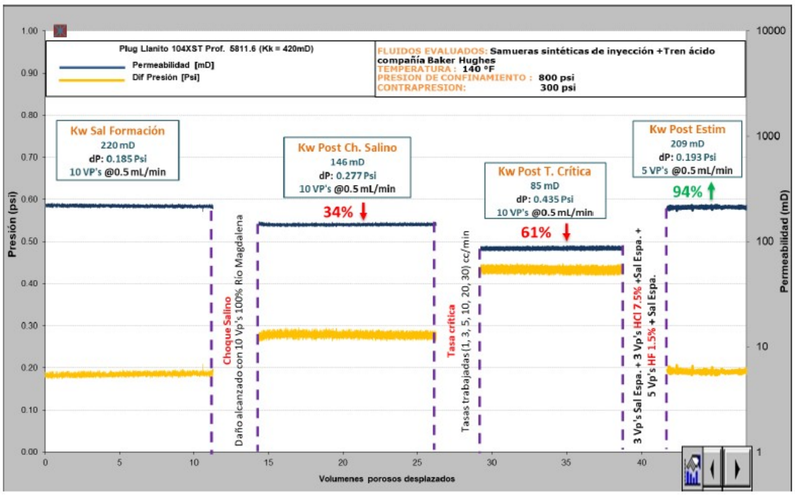


Figure 22. HF acidizing treatment injection to remove damage due to fines migration in Mugrosa formation. Source: Usuriaga, J. et al. 2021.

To define and analyze formation damage due to scale generation, 100 VP of synthetic flowback was injected to assess the effect of composition on plug permeability. Two flowback composition scenarios were evaluated; The first consisted of a synthetic flowback with the theoretical physical-chemical composition probably expected to which the surface treatment process was carried out to reduce the concentration of total suspended solids and oils; with which a reduction in water permeability greater than 40% was recorded as a consequence of the precipitation of inorganic scales (mainly $CaCO_3$) in the porous medium.

With its permeability recovered, the second process was carried out by injecting 100 PV of previously treated flowback, simulating the treatment scenario, in this case reducing the concentration of the main ions that cause scale precipitation. It was observed that at a temperature of 140 °F, after the injection of the 100 VP, the reduction in permeability was only 6%. Subsequently, the temperature of the experiment was increased from 140 °F to reservoir temperature to simulate the effect of temperature on the injection of the same flowback composition.

After 100 Vp's injected from the flowback with lower ion concentration at reservoir temperature, a variation or reduction in water permeability of 23% was observed, going from 211 mD (reference) to 149 mD. This means that the same composition of the flowback, but at a higher temperature, induces the progressive precipitation of inorganic scale in the porous medium of the rock, which is evidenced in the slow and gradual reduction of permeability.

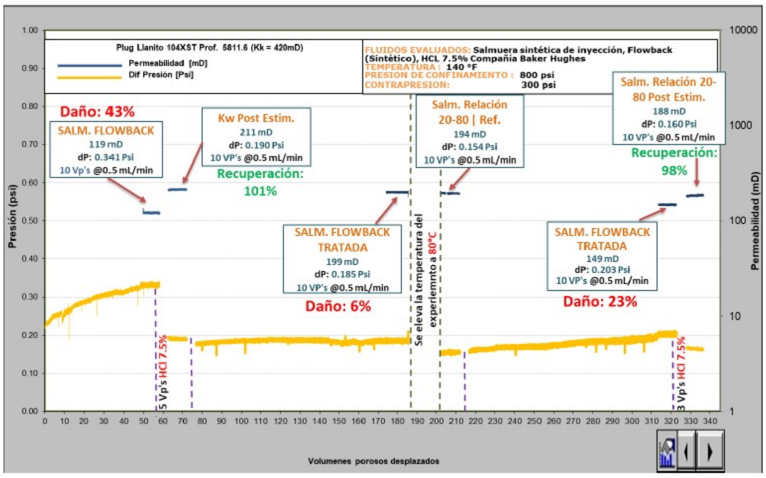


Figure 23. After treatment flowback composition effect on Mugrosa formation permeability. Souerce: Usuriaga, J. et al. 2021.

Finally, and after the injection of the flowback, an acid-base stimulation treatment of HCl 7.5% was injected, with which a permeability recovery of over 95% was achieved. To corroborate that the 23% reduction in water permeability observed during the flowback injection in the second process at reservoir temperature was caused by the precipitation of inorganic scale in the porous medium, the injection of 3 volumes was carried out again. porous HCl acid treatment at 7.5% with which a restoration of 98% of the permeability with respect to the base line was achieved.

**Probabilistic and Deterministic Fault Reactivation Application.** As a first step, the values that will be used for the modeling of each formation are selected, in this case the most probable value of each parameter, as well as the sampling window of each parameter according to the information of the available 1D geomechanical model, with which random scenarios will be generated for the probabilistic model. Table 2 shows the values corresponding to each of the three formations.

| Formación | Sv, psi/ft | | Shmin, psi/ft | | SHmax, psi/ft | | Pore pressure, psi/ft | |
|---|---|---|---|---|---|---|---|---|
| | Most likely | ± | Most likely | ± | Most likely | ± | Most likely | ± |
| A | 0.967 | 0.0028 | 0.805 | 0.0169 | 0.876 | 0.0065 | 0.499 | 0.0274 |
| B | 0.976 | 0.0063 | 0.8142 | 0.02 | 0.8821 | 0.0058 | 0.5457 | 0.031 |
| C | 0.978 | 0.0016 | 0.813 | 0.03 | 0.8805 | 0.0126 | 0.5832 | 0.0463 |

**Table 1.** Geomechanical model values by formations, Rubio 2021.

Subsequently, the 2D fault models are built for each of the formations, taking into account only the faults or fault sections that cut at least 50% of the formation to be analyzed, additionally for faults that presented significant changes in their azimuth, the plane is subdivided in order to preserve that difference independently. Figure 24 shows the fault model built for each of the formations analyzed.

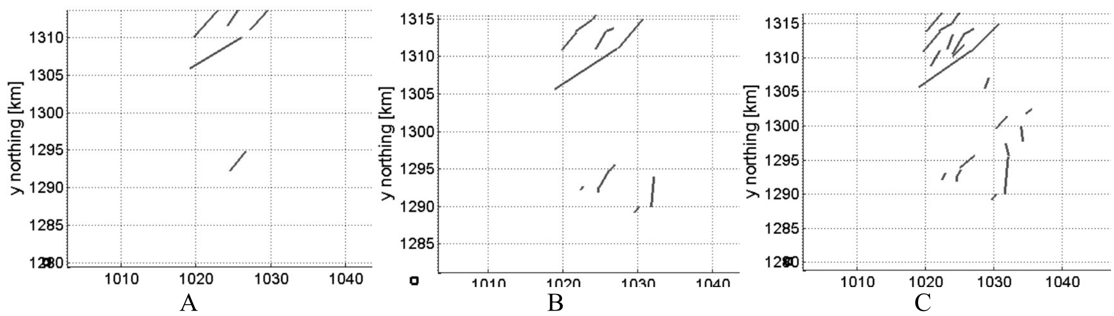


Figure 24. 2D fault model for formations A, B, and C.

As a first approximation, the critical pressure increase value is estimated using a deterministic analysis, where the input value for each parameter is the most probable, obtaining for each formation the result shown in Figures 25 to 27.

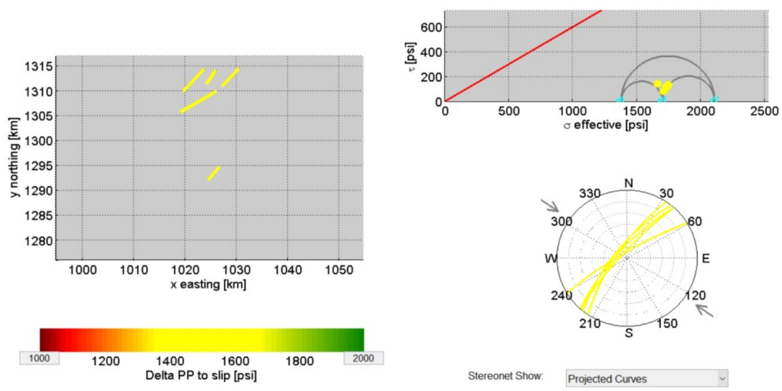


Figure 25. Deterministic result, formation A.

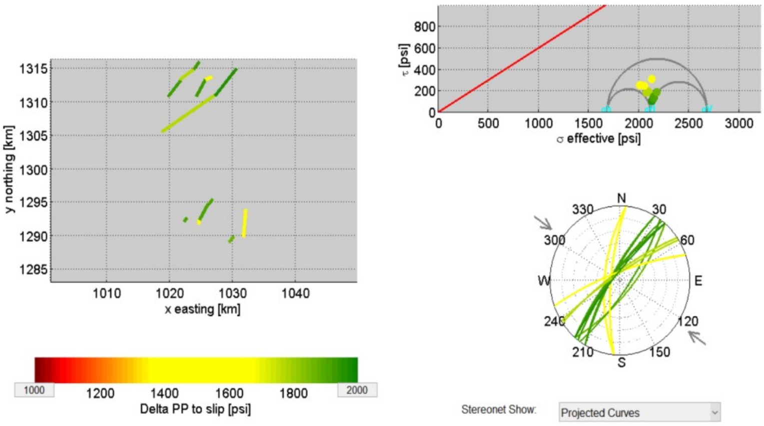


Figure 26. Deterministic result, formation B.

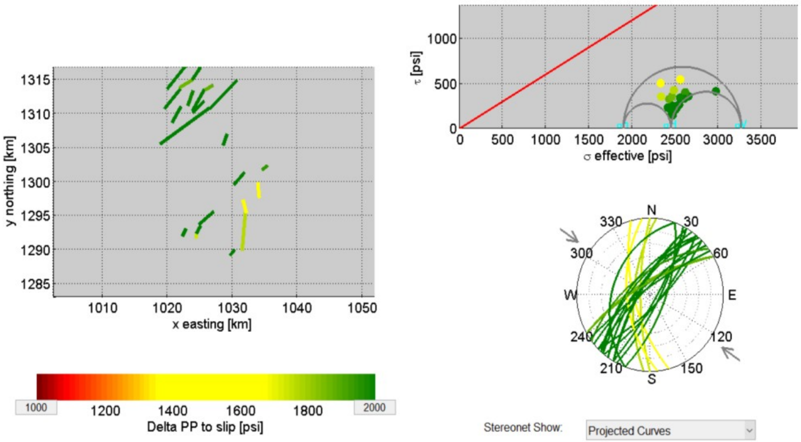


Figure 27. Deterministic result, formation C.

In general, it is observed that the faults are more sensitive to being reactivated at shallower depths, this is due to the fact that their confinement is less, which is evidenced in the location of the Mohr circles of each formation, being the corresponding formation A, which is located further to the left side of the graph, which is reflected in the pressure increase required in the most unstable faults, which would be between 1400 and 1600 psi for formation A, progressively increasing to values above 2000 psi upon reaching formation C .

Next, the probabilistic modeling is carried out, for which the previously selected sampling window values were taken (Tables 2), where the tool generates multiple scenarios using a constant probabilistic distribution for each parameter, constructing a reactivation probability curve for each failure (Figure 28), based on the result of each scenario and subsequently builds a cumulative probability curve for each failure, as shown in Figure 29.

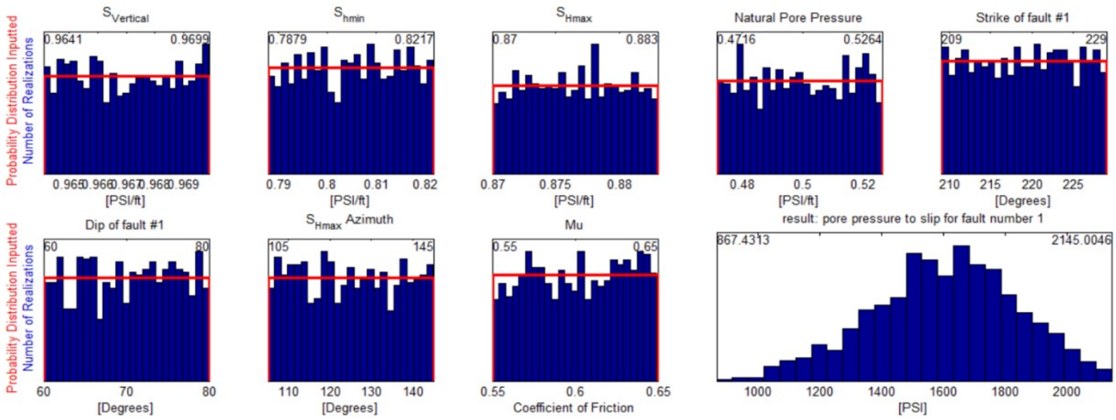

Fig 28. Sampling intervals and frequency result.

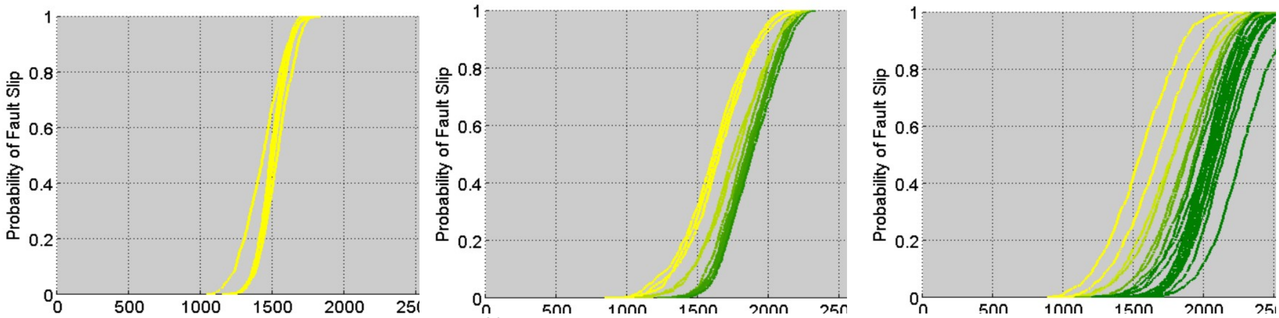

Fig 29. Fault reactivation probability curves.

According to the variability present in the input data, it is possible to identify which of these parameters may have the greatest impact on the estimation of the fault reactivation potential. Figure 30 shows the example of sensitivity analysis for one of the faults located in formation A, where it can be seen that the variables with the greatest impact are the maximum horizontal stress azimuth, the pore pressure gradient and the direction of the fault plane, this same sensitivity configuration was observed in all the faults of the different formations.

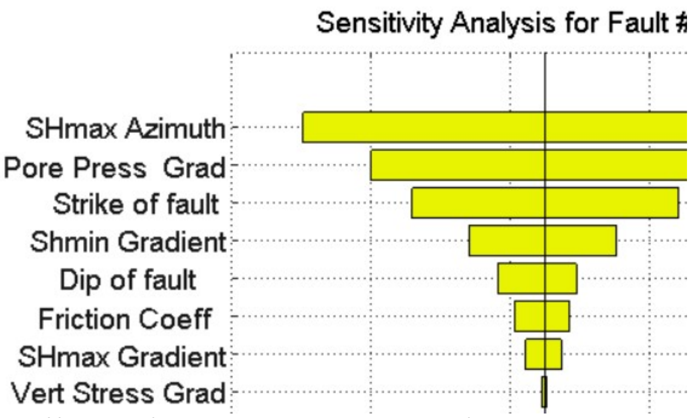

Figure 30. Impact of input parameters in the estimation of the reactivation potential.

For this specific application, the parameters that most impact the result, according to their variability, are related to the initial pore pressure and the angle between the failure plane and the orientation of the maximum horizontal stress.

**Discussion.**
Surely the discussion that this study throws up is to define if with the implementation of all these actions the generation of induced seismicity could be prevented during a water disposal process by means of injection. The answer would be associated with the fact that each of the actions that have been implemented through this methodology are prevention barriers (bow tie methodology), and surely the greater the number of prevention barriers implemented, the lower the probability of reaching the limit event. In the same way, the analysis of the probability of fault reactivation is a barrier that also allows identifying the level of risk to which it is subjected when generating one of these processes in a certain sector. Additionally, as mitigation barriers are the traffic lights for the control of events and whose actions are decisive according to the magnitude of the event, of course all this accompanied by a complete measurement and diagnosis system of the occurrence and a correct monitoring of the process.

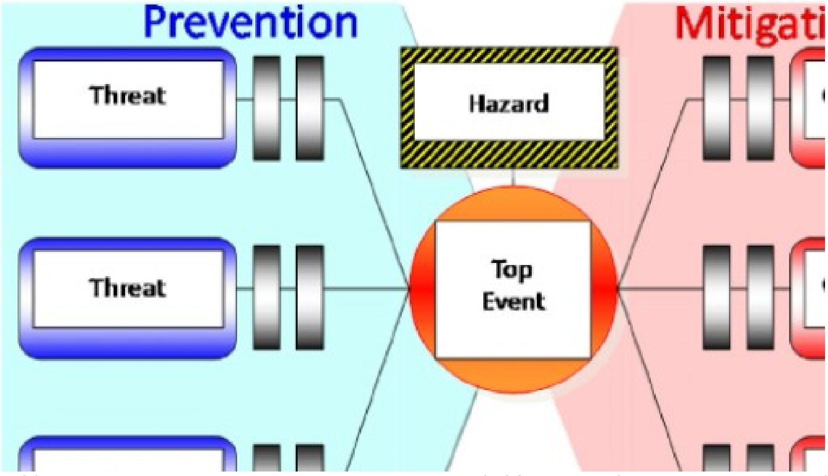

Figure 31. Prevention and Mitigation barriers, Bowtie method (ACS Division of chemical and health safety).

**Conclusión.**
The water disposal processes must be taken with the same technical importance as the other processes that are carried out for the recovery of hydrocarbon resources and reserves. The correct execution of the previous studies for the technical feasibility of the disposal of water through injection requires time and resources, but at the same time it allows to find the shortcomings of the process and allows, at the same time, to generate its optimization. There is no doubt that these tools make it possible to determine that the disposal of water by injection can be a safe process as long as it is done with technical rigor.

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