

EFFECTIVENESS OF FLUOBORIC ACID ON TREATING
FINES MIGRATION IN SANDSTONE FORMATION

by

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14352

Dissertation submitted in partial fulfillment of the requirements for the
Bachelor of Engineering (Hons) (Petroleum)

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the

Petroleum Engineering Programme

Universiti Teknologi PETRONAS

In partial fulfillment of the requirement for the

Bachelor of Engineering (Hons)

(Petroleum Engineering)

Approved by:

(Noor Ilyana Ismail)

Project Supervisor

CERTIFICATION OF ORIGINALITY

I hereby verify that this report was written by me, Mohd Khairul Azree Bin Abdul Aziz (14352). I am responsible for the work I have been submitted in this project, the work have that had been done is my own except as specified in the references and acknowledgements.

(MOHD KHAIRUL AZREE BIN ABDUL AZIZ)

ABSTRACT

There are many technologies have been introduced to find efficient and cost effective ways to prevent fines migration in the sandstone formation. Fines that able to migrate are usually the main contribution to the reduction of well's permeability by clogging the pore throat of the rock. Further fines migration also can cause screen erosion and failure. It is important to control fines migration in the producing well as it contributes to a lot of problem. Huge interest on fluoboric acid in oil and gas industry has raised the question how fluoboric acid can stabilize formation clays while improving the permeability properties.

This work focusses on how effective the fluoboric acid stabilize the clay in the sandstone formation. An experiment was set up to show the effectiveness of fluoboric acid in treating fines migration in the sandstone formation. The sand pack was saturated with different concentration of hydrofluoric acid and a high concentration (2500 ppm) of mixed formation fines was flown through the sand pack to simulate migrating fines and finally, the effluent was collected and analysed. From the study, as concentration of hydrofluoric acid is increased, the collected effluent are becoming clearer. This is due the high amount of HF molecules leads to higher concentration of hydrofluoric acid causing stabilized undissolved fines to be obtained. Another experiment was conducted to measure the amount of effluent collected and turbidity reading for 5% and 7% concentrations to identify the optimum concentration to dissolve the fines as the volume of the formation fines solution increases. It turns out that 7% concentration of hydrofluoric acid gives low reading of turbidity as the volumes increases up to 200 ml.

This project can be considered as one of the well stimulation techniques to improve the productivity of the producing well. It is very much related to the current conditions of the wells that are reducing in formation permeability because of the fines migration and deposition results in high positive skin near the wellbore.

ACKNOWLEDGEMENT

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CHAPTER 1

INTRODUCTION

1.1 Background of study

There are four factors that contributed to the development of the petroleum system which includes reservoir rocks, source rocks, trap and permeable layer. Reservoir rocks usually are rock that contains petroleum and have both porosity and permeability. Reservoir rocks are dominantly sedimentary such as sandstones and carbonates. Other minerals such as clay can be found in the sandstone, for example: authigenic clays, such as kaolinite, illite, smectite and chlorite, and also the silicates, such as quartz, silica and feldspar, and carbonates, such as calcite, dolomite and siderite (Belcher *et al.*, 2010). **Figure 1** shows the fundamental components of sedimentary rocks.

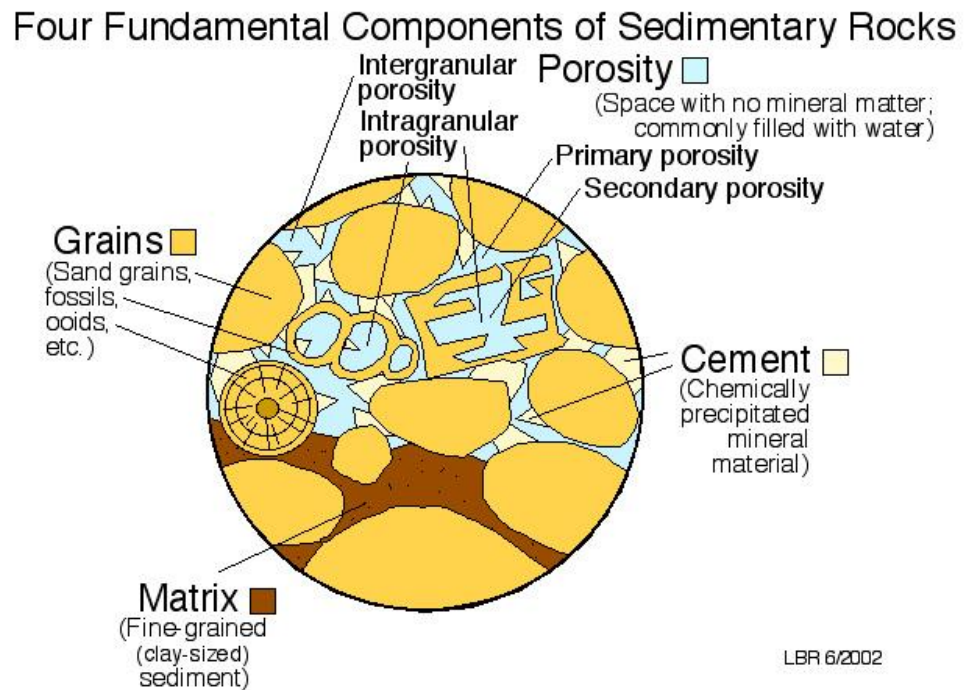


Figure 1: Components of sedimentary rocks (Railsback, 2014)

According to Kotlyar *et al.* (1993), depending on grain size, minerals or fines are classified as colloidal fines ($< 2 \mu\text{m}$), which are subjective by Brownian diffusion and electric double-layer effects, and the non-colloidal fines (2 to $40 \mu\text{m}$), which are exaggerated by hydrodynamic forces. Clays are acknowledged as hydrous silicates of aluminum. Their configurations are based on tetrahedral layers of silica-oxygen and octahedral layers of aluminum-hydroxyl.

According to Gabriel *et al.* (1983) and Ezeukwu *et al.* (1998), fines migration (which are silt and clay) was documented in oil and gas industry as a difficulty in hydrocarbon wells from reservoirs. These occurrences are due to the flowing of fines in wellbore area that been caused by automated dispossession instead of clay diffusion as an outcome of ionic shock. During production and workover operations, this formation fines can migrate. The formation fines can migrate once a critical flow rate is reached, when water intrudes the reservoir or two-phase flow (oil/water) exists. Fines migration can take place during workover or during completion because of fluctuations in water salinity and/or high drawdown during a well test. Severe plugging will occur and thus, reduces the permeability on the porous medium (Muecke, 1979).

The purpose of this project is to study the effectiveness of fluoboric acid (retarded acid) which has the capability to permanently stabilize formation clays thus increase the permeability of the formation. The experiment was conducted based on the concentration of the hydrofluoric acid and turbidity of the effluent collected at the end of the run. Next, another experiment was conducted to identify optimum concentration of hydrofluoric acid by increasing the volume of formation fines solution. Fluoboric acid slowly hydrolyzes with water in the formation to generate hydrofluoric acid, which cause deep, live acid penetration. As the outcome of the treatment, stabilized undissolved fines are obtained. This project will determine the effectiveness of the fluoboric acid in treating fines migration in the formation.

1.2 Problem Statement

Fines become a problem when they swell or detach from the pore wall and migrate through rock matrix with produced fluids. There are no restrictions for the fines to travel with fluid into the formations. As the distance of the fluid and the wellbore decreases, it will gain huge amount of velocity. The fines will then accumulate near the wellbore when they reach the fluid or gas stream at a critical velocity. This causes the fines to clog the pore throats, plugging the pores and thus, reduces the rock permeability. Extremely high positive skin completions are the result of these non-stop fines migration and accumulation near the wellbore. Contained plugging and hotspots with high velocity could ensue when the fines travel into a pre-packed screen, causing screen erosion and failure. In addition, formation fines incursion into proppant packs can cut the permeability and disturb the well production.

Huge interest on fluoboric acid in oil and gas industry has raised the question how fluoboric acid can stabilize formation clays while improving the permeability properties.

1.3 Objective

1. To compare the turbidity of effluent collected with different concentration of hydrofluoric acid.
2. To compare the turbidity reading for the optimum concentrations with increasing volume of formation fines solution.

1.4 Scope of Study

1. Conducting research and finding information related to fines migration
2. Conducting research and finding information related to fluoboric acid.
3. Conducting experiments to examine all the objectives by using laboratory approach.

1.5 Feasibility of the Project within the Scope and Time Frame

This project is relevant to the author's field of study since it focuses in one of the areas in Petroleum Engineering. In this project, the author examine the effectiveness of fluoboric acid on treating fines migration in sandstone formation. This is very essential since formation fines invasion lower the permeability and affects the production performance.

The project is feasible since it is within the scope and time frame. Besides, this project requires some equipment to operate which are readily available at the university Lab (Block 14 and 15). The author conducted the lab experiments by following the procedures cautiously.

CHAPTER 2

LITERATURE REVIEW

2.1 What are Formation Fines?

Solid particles that tight-fitting to pore walls in rocks are called as fines. According to Miranda *et al.* (1993) and Muecke (1979), these particles are produced “in situ” or due to field operations. When these particles unattached from the grain surface, they are spread and flow over the porous medium towards very small pore spaces, where they build up. This describes fines migration. When this happen, severe plugging will occur and will reduce the permeability in the porous medium.

Kotylyar *et al.* (1993) and Byrne *et al.* (2014) mentioned that subjected on grain size, minerals or fines are ordered as colloidal fines ($< 2 \mu\text{m}$), which are swayed by brownian diffusion and electric double-layer effects, and the non-colloidal fines (2 to 40 μm), which are exaggerated by hydrodynamic forces.

The following are examples of fines: authogenic clays, such as kaolite, illite, smectite and chlorite, and also the silicates, such as quartz, silica and feldspar, and carbonates, such as calcite, dolomite and siderite. Kotylyar *et al.* (1993) stated that it is well known that clays are hydrous silicates of aluminum. Their structure is based on tetrahedral layers of silica-oxygen and octahedral layers of aluminum-hydroxyl.

Authigenic clays are the commonest clays in the reservoirs, since they form in pore spaces. These minerals are small, and they have a layer structure and large surface area. Therefore, they tend to react very fast with the fluid entering the porous medium. If the fluid contacting these minerals is not compatible with the type of clay in the reservoir, a 2% of clay will be enough to plug or damage the formation. Therefore, injected fluids should have the same concentration and composition as the original brackish solution in the formation or, if this is not possible, they should contain cations contributing to fine stabilization (Baptist and White, 1957).

The type of authigenic clay which has the highest probability of migrating through the porous medium is kaolinite, because there is a 1:1 ratio between its tetrahedral and octahedral layers, which are also electrically neutral. Therefore, charges can only result from the breakage of crystal edges or dissociation of the H⁺ bonded to the structural cations.

The structure of kaolinite has (OH)⁻ radicals and, therefore, a hydrogen bridge is created. This bridge keeps layers tightly together. This link facilitates the formation of large units, and it also prevents the formation of interlayer water. Consequently, there is no expansion of its structure, which can come loose and easily move due to effects related to the ionic concentration of the medium (Grim, 1953).

The structural formula is $\text{Al}_2(\text{Si}_2\text{O}_5)(\text{OH})_4$.

Smectite or montmorillonite is made up of one octahedral layer between two tetrahedral layers, which implies a 2:1 ratio, where the end tetrahedral layers and one (OH)⁻ layer make up the structure of a unit. In the structure of smectite, water or other polar molecules may cause clay swelling. When the mineral is dehydrated, this separation depends on the size of the interlayer cation or the organic compound and its geometry. **Figure 2** shows the microscopic electronic photo of kaolinite and smectite plugging the pore volume while **Figure 3** shows the thin-section photomicrograph of pore-filling kaolinite and scanning electron microscope (SEM) micrograph of pore-occluding kaolinite from a seal zone.

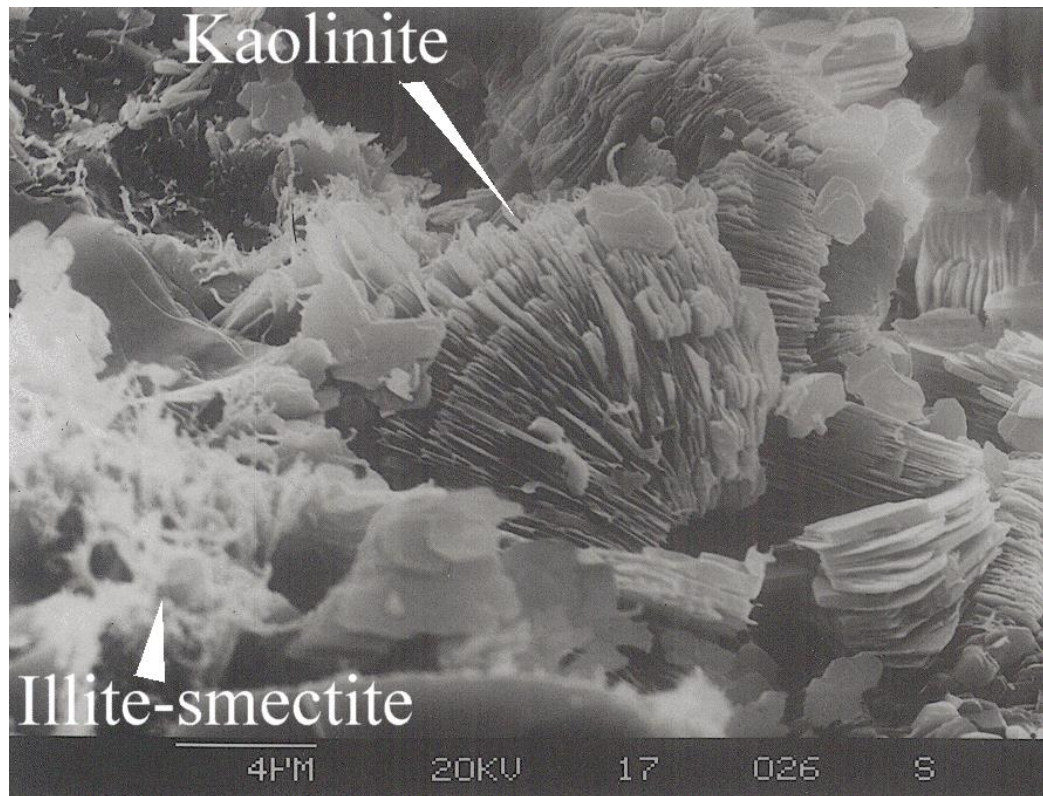


Figure 2: Microscopic electronic photo of kaolinite and smectite plugging the pore volume (Debra *et al.*, 1997)

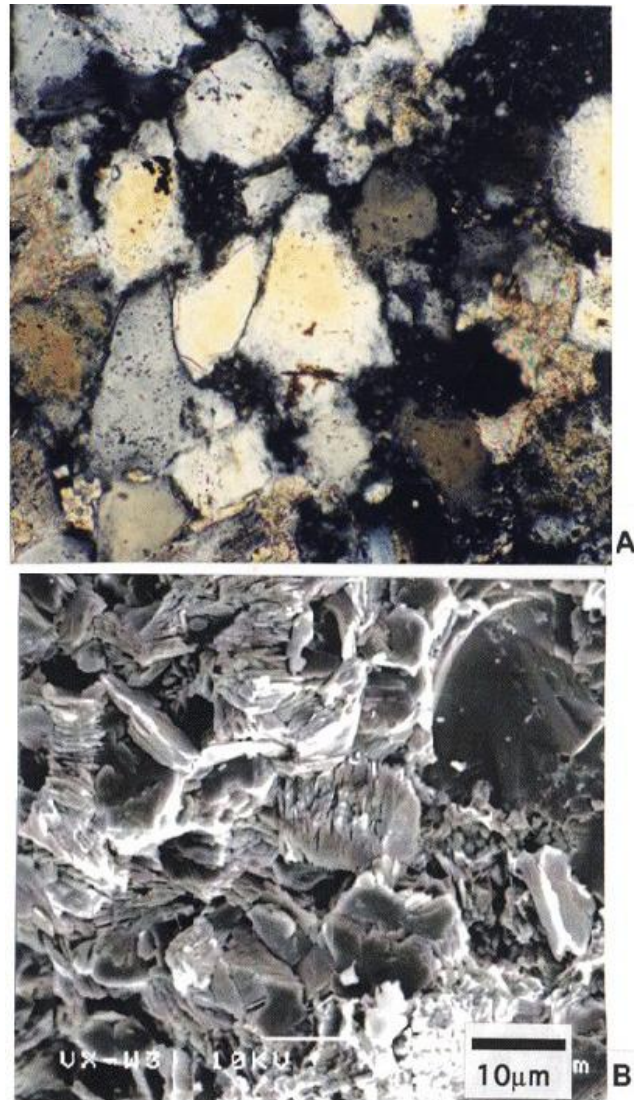


Figure 3: A. Thin-section photomicrograph of pore-filling kaolinite. B. SEM micrograph of pore-occluding kaolinite from a seal zone (Searchanddiscovery, 2014)

Isomorphic replacement takes place in these minerals. The Mg^{++} ions replace some octahedral Al^{+++} ions, which results in an excess negative charge in this structure. The cell charge is satisfied by the cations which are outside the layers. There is a significant cations exchange capability (90 to 150 meq/100 g), which will result in clay swelling if there is contact with water having low salt concentrations (Neasham, 1977).

Its structural formula is: $Al_4(Mg)(Si_8O_{20})(OH)_4H_2O$

Illite, as smectite, has a 2:1 ratio, but unlike the latter, some tetrahedral silicon ions are replaced by Al⁺⁺⁺, and the resulting charge is neutralized by interlayer potassium ions.

2.2 Fine migration mechanism

Gabriel and Inamdar (1983) mentioned that generally, fine migration takes place in two consecutive stages. During the stage, particles come loose due to their sensitivity to fluids (chemical effect) and, during the second stage, they are carried away by the fluid (physical effect).

The chemical effect takes place when an incompatible fluid enters the formation, through the rock or the connate water. Then, the particles are set into motion and/or clays swell. This last result is structural because water is absorbed between the layers due to the cation exchange capability. Therefore, clays swell and fill part of the porous volume. The result is permeability reduction.

The breaking loose of fines from pore walls depends on the total potential energy of interaction between fines and the grain surface, which is the summation of all forces acting between the grain and the fine particle, i.e: electrostatic forces, repulsive Born forces, Van der Waals forces and dispersion or Hamaker forces. The relative importance of any of these forces will depend on ionic concentration in the medium (Sharma *et al.*, 1985).

The following are some factors affecting this chemical process:

- the ionic strength of the medium,
- the pH between the flowing fluid and
- the particle, temperature and electric conductivity.

The physical effect takes place when the particles which are loosely adhered to grain surfaces are carried away by the dragging force of flowing fluids. In this situation, the most significant influence is exerted by hydrodynamic forces, which become increasingly strong as particle size increases.

Hydrodynamics forces are the result of the motion of a fluid on the surface of a certain body or particle, when it passes through the gravity center of the particle, along the flow line, stated by Jumikis (1983) in his book entitled "Rock Mechanics."

The physical effect is influenced by flow rate and the viscosity of the flowing fluid.

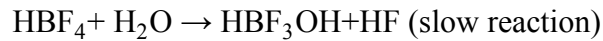
Regardless of the type of mechanism taking place, the result is the reduction of formation permeability due to plugging of pore throats.

2.3 Fine migration control

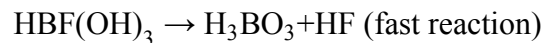
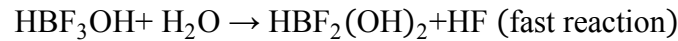
The studies conducted in 1978 by Thomas from Dowell Division, (Thomas & Crowe, 1981) showed that one of the most effective matrix treatments to permanently control migratory clays was a system of retarded acid based on fluoboric acid.

When fluoboric acid hydrolyzes (ie. connate water), it produces hydrofluoric acid, which may react with the alumina layers of clays, and the result will be a borosilicate film, which is capable of permanently stabilizing formation clays (Thomas and Crowe, 1981).

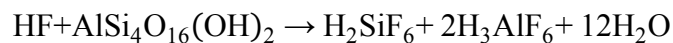
Flouboric acid reacts deeper into the formation. It can hydrolyze first and then reacts with silicates. The chemical reactions taking place are the following:



(flouboric acid)+(water)→(hydroxyflouboric acid)+(hydrofluoric acid)



Then, hydrofluoric acid will react with formation clay. The chemical reaction taking place is the following:



(hydrofluoric acid)+(kaolinite)→(fluosilicic acid)+ (fluoaluminic acid)+(water)

When the fluoboric acid hydrolyzes, it can produce 4 moles of HF per mole of the HBF that was initially present (Kunze and Shaughnessy, 1983). This HF is capable of reacting with silicates. The first reaction is generally slow which results from the final reaction and it bonds and stabilizes clays in the formation.

2.4 Proppant sand

From the beginning of fracturing in the late 1940's natural materials such as mined sand particles have been used to prop the created hydraulic fractures. Proppant is essential in hydraulic stimulation treatments. Proppants are used to maintain fracture-flow capacity after completion of a hydraulic fracturing treatment (Kothamasu *et al.*, 2012). The amount of proppant used, the manner in which it is placed in the fracture, and the properties of the material itself all play a vital role in maintaining productivity throughout the life of the well (Martinez *et al.*, 1987).

All of the properties of proppant – mainly roundness, size distribution, and resistance to crush under the influence of closure stress, grain-size distribution and proppant density – can affect the resultant fracture conductivity. Conductivity of a propped fracture is one of the most important factors that directly affect well productivity, along

with the propped fracture area, reservoir permeability, and drainage radius (Montgomery *et al.*, 1985). To be able for the fines to migrating out towards the wellbore, the conductivity of the propped fracture must be higher. In this parametric study, a constant 20/40 sand is used since 20/40 sand give a better distribution of sizes. Generally, proppant with larger grain size generate greater proppant pack permeability under low stress conditions.

Based on the literature, proppant size controls proppant embedment (Gao, 2012), proppant conductivity, porosity, and permeability (Beckwith, 2011) (Cohen *et al.*, 2013) (Terracina *et al.*, 2010) (Ali, 2010) (Alramahi, 2012), closure stress tolerance (Cohen *et al.*, 2013) (Terracina *et al.*, 2010) (Gao, 2012), and flowback problem (Edelman, 2013).

CHAPTER 3

METHODOLOGY/ PROJECT WORK

3.1 Project Work

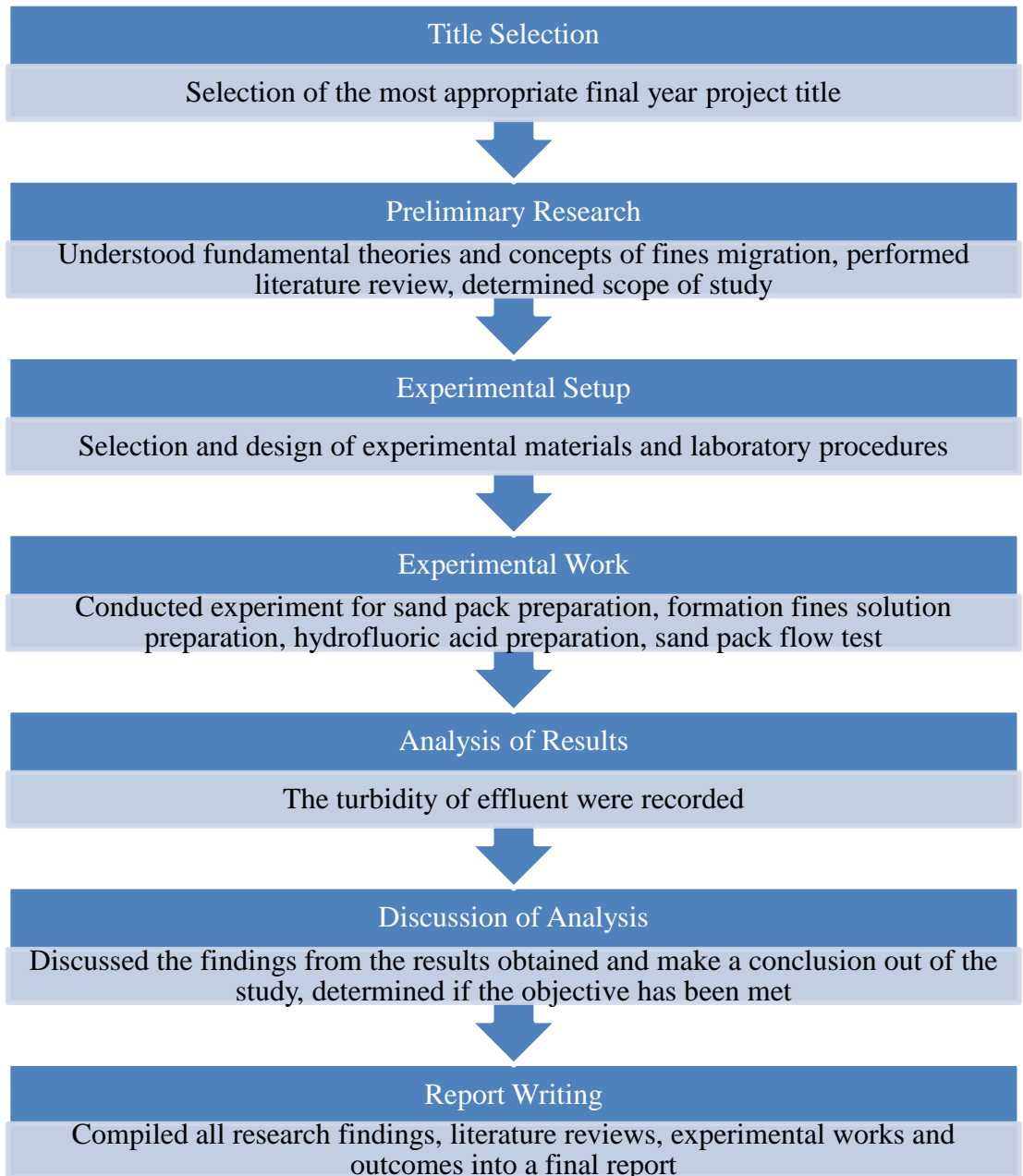


Figure 4: Project Activities Flow

3.2 Research Methodology

Research is a method taken in order to gain information regarding the major scope of the project. The sources of the research cover the handbook of acid stimulation, e-journal, e-thesis and several trusted links. As the project is a laboratory based, the experimental procedure is being designed carefully to ensure the safety as well as to get the required result.

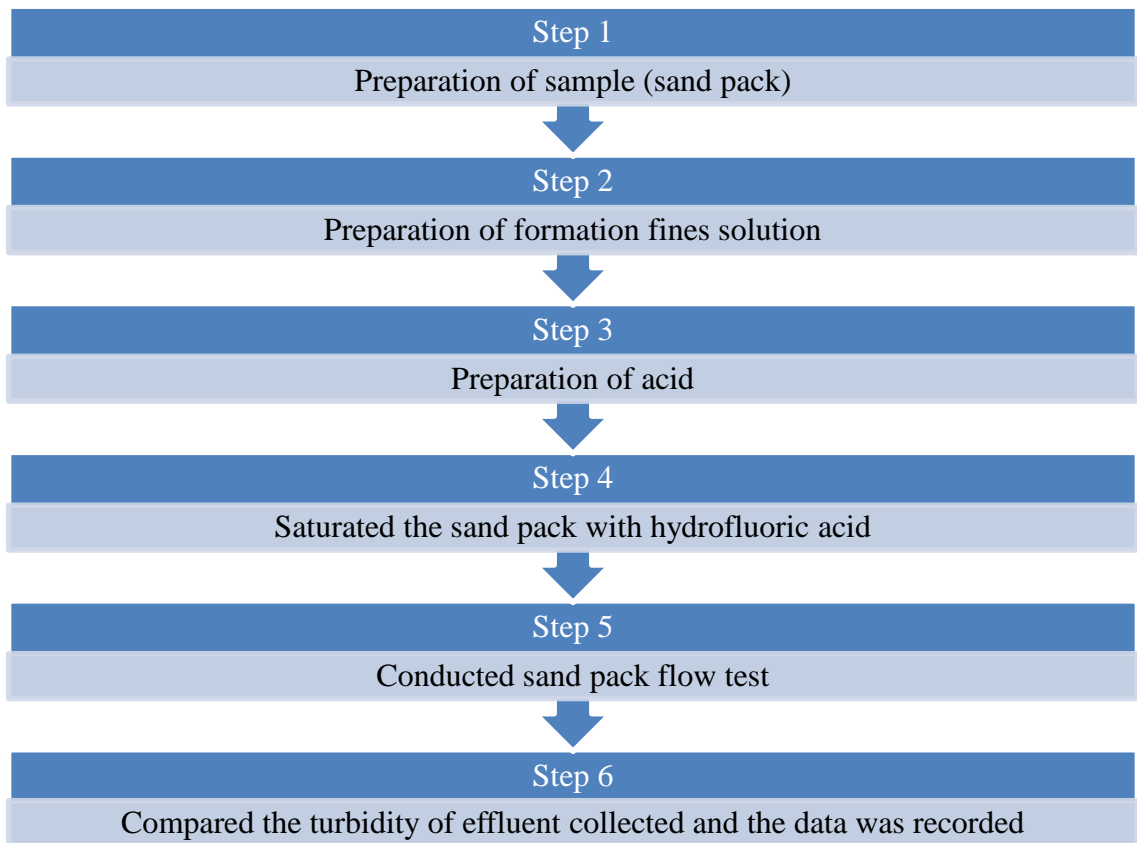


Figure 5: Experimental Procedures

1. Sand pack preparation

The sand that was used in this experiment is artificial sand. It is used as a decoration in an aquarium. The reason for this is to imitate the artificial sand with proppant sand since the artificial sand has similar shape and size and the medium have high conductivity for the fines to pass through it. The sample is then sieved by using the sieving unit. The API standard for 20 - 40 sand is to use a 16 sieve for the coarse grains and a 40 sieve size which is measured by "US Mesh Size." That is 0.0469 inch/1190 microns (1.190 mm) and 0.0265 inch/420 micron (0.420 mm). That would give a better distribution of sizes since a 20 - 40 proppant has a grain diameter range from 0.0331-0.0165 in. and a median grain diameter of 0.0248 in. (630 microns) (Belcher *et al.*, 2010). This is a very controlled figure as all commercial proppants are sieved thoroughly to keep them within this range. Next, the sample needs to be washed and dried in the oven at temperature of 150 °C.

2. Formation fines solution preparation

Choose a mixture of several different types of formation fines that generally contain in producing formations and mix it with water to make it a solution of 2500 ppm.

$$1 \text{ ppm} = 0.0001\%$$

Therefore,

$$2500 \text{ ppm} = 0.25\%$$

Those particular fines used included kaolinite, dolomite, and quartz particles. According to Huang *et al.* (2008) the weight percent of the formation fines is determined as 50%, 25%, and 25% respectively.

3. Preparation of Hydrofluoric Acid Solution

In this particular experiment, hydrofluoric acid is used instead of the fluoboric acid. This is because when the fluoboric acid hydrolyzes, it produces hydrofluoric acid, which may react with the alumina layers of clays, and resulting in dissolve clay in the formation. The fluoboric acid reacts deeper into the formation. The concentration of hydrofluoric acid that were used in this experiment is ranging from 1% to 7%. This is because hydrofluoric acid is very corrosive and can lead to completion damage. (Kunze and Shaughnessy, 1983)

The acid solution is prepared based on the formula

$$M_1 V_1 = M_2 V_2$$

All protective equipments must be wear during the experiment to ensure the safety of the people and surrounding.

4. Sand pack saturation with hydrofluoric acid

Then, the sand pack will be saturated with the hydrofluoric acid by flowing the acid through the sand pack from bottom to top to ensure all the pores are saturated with hydrofluoric acid and the reactions are monitored.

5. Sand Pack Flow Test

The sand pack flow test will be conducted to simulate formation fines entering the wellbore. A 2500 ppm of 40 ml of mixed formation fines will flow through each pack to simulate migrating fines and the effluents are collected and analysed.

3.2 Gantt Chart and Key Milestones

Table 1: Gantt chart and key milestones for FYP 1

No.	Detail/Week	1	2	3	4	5	6	7	8	9	10	11	12	13	14
1	Selection of title Meeting with FYP supervisor	■	■	★											
2	Study the factor that cause fines to migrate				■	■									
3	Analysed the formation fines - Why it become a problem				■	■									
4	Analyzed the potential of flouboric acid in matrix treatment					■	■	■							
5	Draft the methodology of the project					■	■	■							
6	Extended proposal submission								★						
7	Proposal defense									■					
8	Prepare detailed methodology										■	■	■		
9	Submission of draft report													★	
10	Submission of Interim Report														★

■ Process ★ Milestones

Table 2: Gantt chart and key milestones for FYP 2

No.	Detail/Week	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1	Project work continues - Lab booking and tools preparation	■	■	■	■												
2	Starts experiment - Sand pack flow test					■	■										
3	Submission of progress report							★									
4	Project work continues - Turbidity measurement								■	■							
5	Pre-SEDEX									■							
6	Submission of draft project											★					
7	Submission of Dissertation (soft bound)												★				
8	Submission of Technical Paper												★				
9	Oral Presentation														■		
10	Submission of Project Dissertation (Hard Bound)																★

■ Process ★ Milestones

3.3 Important dates for FYP 1

Table 3: Important dates for FYP 1

No	Activities	Completion Date
1	Project title selection	09/06/2014
2	Submission of extended proposal	10/07/2014
3	Proposal defence	16/07/2014
4	Submission of interim draft report	11/08/2014
5	Submission of interim report	20/08/2014

3.4 Important dates for FYP 2

Table 4: Important dates for FYP 2

No	Activities	Completion Date
1	Briefing and update progress	01/10/2014
2	Submission of progress report	05/11/2014
3	Pre-SEDEX	19/11/2014
4	Submission of Final Draft / Submission of Technical Paper	10/12/2014
5	Final Oral Presentation / Viva	22/12/2014 – 23/12/2014
6	Submission of hardbound copies	05/01/2015

3.6 Experimental Methodology

3.6.1 List of materials

Some of the materials that will be used for the experiment:

Table 5: List of materials

General name	Description
Sand sample	0.420 mm – 1.190 mm
Hydrofluoric Acid	1%, 3%, 5%, 7% concentrated
Formation fines solution	2500 ppm

Formation fines solution comprises of:

Table 6: Mineral composition of simulated Formation Fines (Huang *et al.*, 2008)

Mineralogy	
Name	Wt. %
Kaolinite	50
Quartz	25
Dolomite	25

3.6.2 List of Equipment

Some of the equipment that will be used throughout the experiment:

1. Sieving unit
2. Cylindrical tube
3. 1000 ml beaker
4. Turbidimeter
5. Spectrophotometer DR2500

3.6.3 Procedures

The experimental work can be divided into five parts which include sand pack preparation, formation fines solution preparation, hydrofluoric acid solution preparation, saturation of sand pack and sand pack flow test.

Preparation of Sand Pack

Clean sand were filled into a cylindrical tube to act as a porous medium for the experiment.

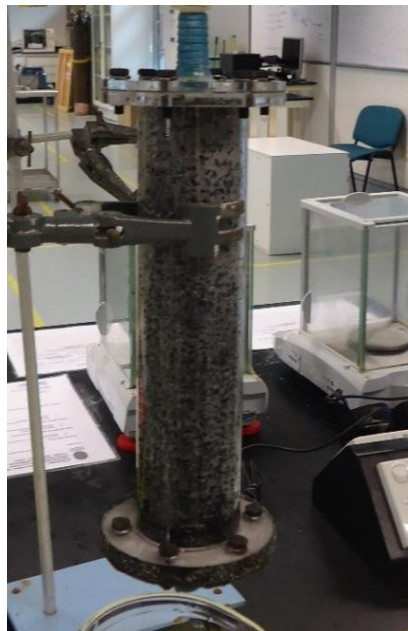


Figure 6: Sand Pack experiment setup

Preparation of formation fines solution

1. Several different types of formation fines were prepared as stated in **Table 4**.
2. The formation fines was mixed and stirred with water to make a solution of 2500 ppm.

$$1 \text{ ppm} = 0.0001\%$$

Therefore,

$$2500 \text{ ppm} = 0.25\%$$



Figure 7: Formation fines

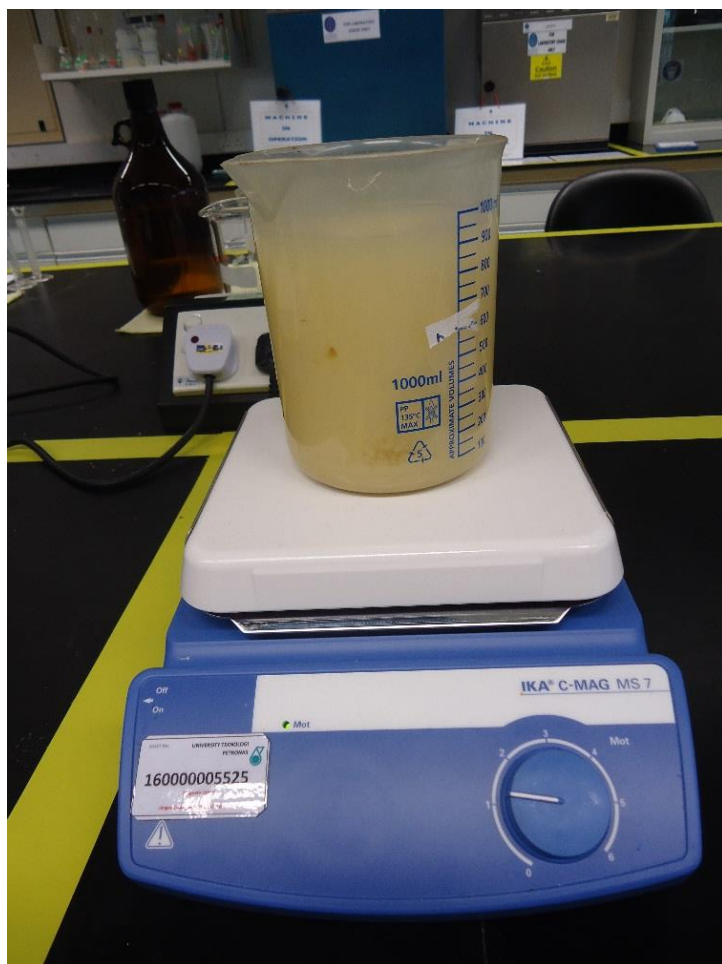


Figure 8: Stirring the formation fines solution

Preparation of Hydrofluoric acid solution

1. Calculation of volume of acid is calculated by using the formula of $M_1V_1 = M_2V_2$. **For instance:**

Volume of hydrofluoric acid (1%)

$$(1)(500) = (37)(V_2)$$

$$V_2 = 13.51 \text{ ml}$$

Volume of distilled water

$$500 - 13.51 = 486.49 \text{ ml}$$

1. Then, the acid were mixed to the distilled water in small doses in the fume chamber.
2. All protective equipments must be wear during the experiment to ensure the safety of the people and surrounding.

Table 7: Summary of concentration preparation

Concentration (%)	Volume of HF (ml)	Volume of distilled water
1%	13.51	486.49
3%	40.54	459.46
5%	67.57	432.43
7%	94.59	405.41

Saturation of Sand Pack

1. The acid were poured into the inlet tube to let the acid saturated the sand pack.
2. The sand pack was left for 30 minutes.

Sand Pack Flow Test

1. The solution of 2500 ppm of 40 ml formation fines was flown into the inlet tube.
2. The beaker was placed at the bottom of the sand pack flow test to collect the effluent.
3. Turbidimeter were used to measure the turbidity of the effluent collected.
4. For turbidity greater than 1000 NTU, Spectrophotometer DR2500 was used to measure the turbidity.

The steps were repeated by using new sand pack with different hydrofluoric acid concentration.



Figure 9: Injecting the formation fines solution into the sand pack



Figure 10: Measuring turbidity using Turbidimeter

CHAPTER 4

RESULT AND DISCUSSION

For this project, it is expected for the turbidity of the effluent to have decrement in the reading as the concentration of the acid is increased. The optimum concentration of hydrofluoric acid to stabilize fines from migrating can be known from the turbidity reading. The data tabulation for the experiment can be seen as follows:

Table 8: Turbidity of effluent

Concentration of HF (%)	Turbidity (NTU)
0%	1550
1%	1000
3%	196
5%	2.17
7%	1.93



Figure 11: Effluent collected (from left: 0%, 1%, 3%, 5%, 7% concentration of HF)

Figure 11 shows a series of bottles consist of effluent collected from left, 0%, 1%, 3%, 5% and 7% concentration of hydrofluoric acid. From the figure, the effluent collected on the left bottle which is 0% concentrated of hydrofluoric acid is very turbid and the effluent collected on the right bottle which is 7% concentrated of hydrofluoric acid is very clear. The turbidity reading indicates the amount of the formation fines in the solution. It is concluded that as concentration of hydrofluoric acid is increased, the fines were almost completely dissolve by the acid as shown by the crystal clear effluent. This is due to the high amount of HF molecules leads to higher concentration of HF causing stabilized undissolved fines are obtained. In contrast, the effluent sample from the untreated sand pack (0% concentrated of hydrofluoric acid) had turbidity very close to the initial fines solution, demonstrating that the fines were able to flow completely through the untreated sand pack.

As shown in **Table 8** above, the turbidity of 5% and 7% concentrated of hydrofluoric acid has a value less than 5 NTU (Nephelometric Turbidity Units). According to Environmental Protection Agency (2014), a solution which have a turbidity reading of 5 NTU and below is considered clean water. Therefore, in this experiment, the 5% and 7% concentrated is the best concentrations to use to control fines migration. Another experiment was conducted to measure the amount of effluent collected and turbidity reading for 5% and 7% concentration to identify the optimum concentration to dissolve the fines as the volume of the formation fines solution increases. A 40 ml formation fines solution is flown into the 5% and 7% saturated sand pack and the effluent is collected. Then, an additional 40 ml of the formation fines solution is flown into the same saturated sand pack and the effluent is also collected. The step continues until the volume of the formation fines reaches 200 ml. The data tabulations for the experiment can be seen as follows:

5% concentration of hydrofluoric acid

Table 9: Turbidity of effluent for 5% concentrated of HF

Volume of formation fines solution (ml)	Turbidity (NTU)
40	2.16
80	2.20
120	4.12
160	10.01
200	12.01

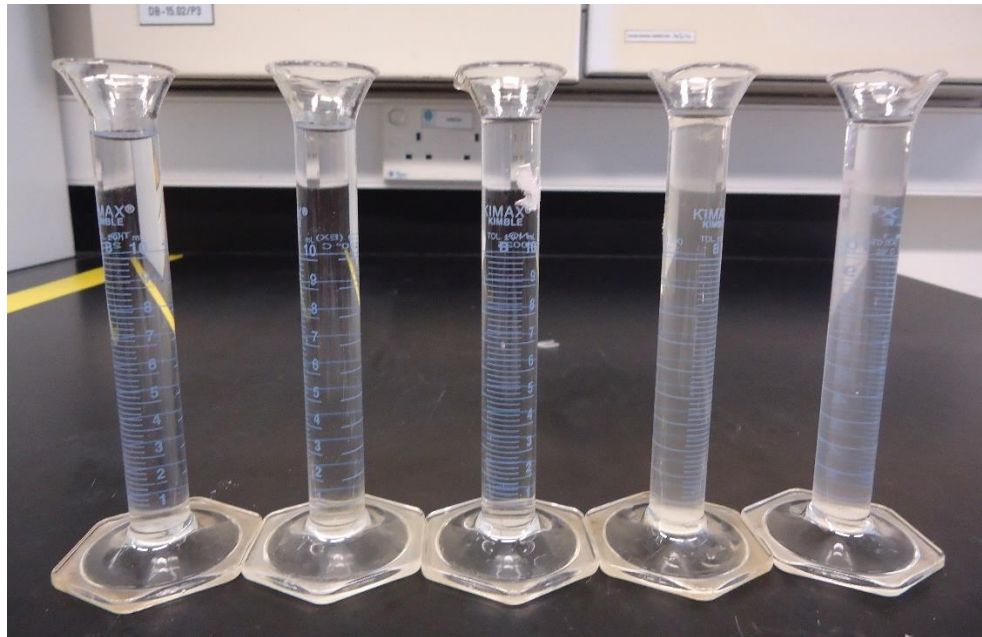


Figure 12: Effluent sample after flowing 2500 ppm formation fines solution through a 5% saturated of HF sand pack

7% concentration of hydrofluoric acid

Table 10: Turbidity of effluent for 7% concentrated of HF

Volume of formation fines solution (ml)	Turbidity (NTU)
40	1.90
80	1.97
120	2.00
160	2.00
200	2.20

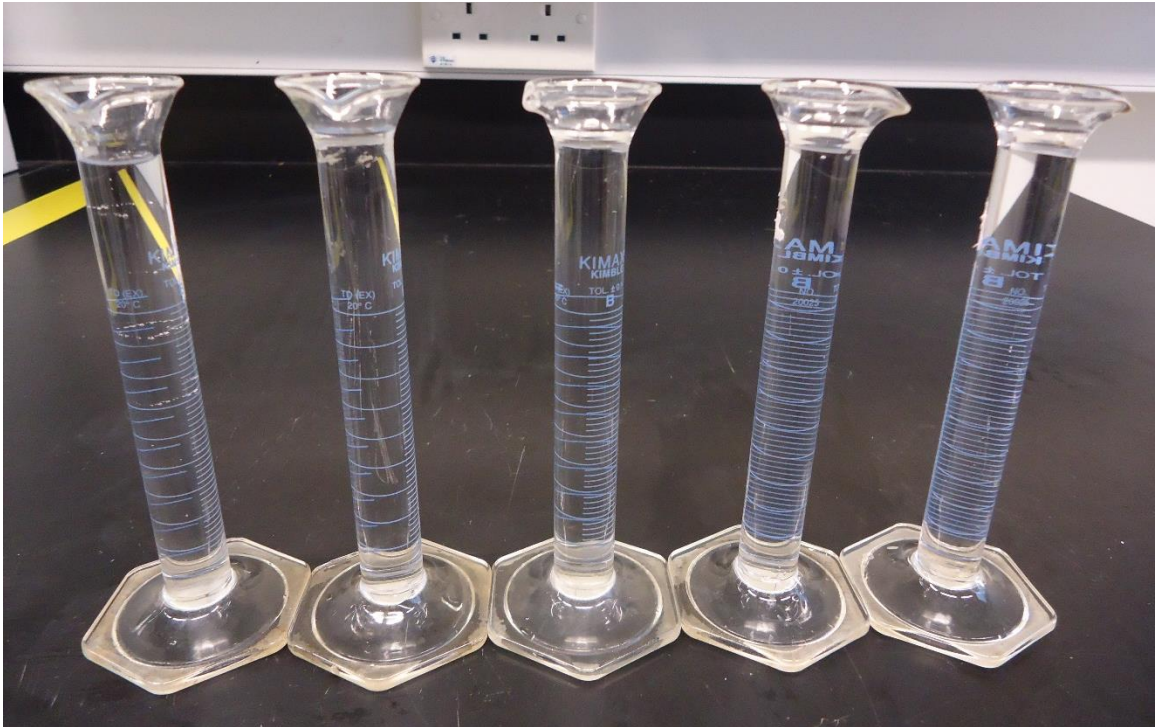


Figure 13: Effluent sample after flowing 2500 ppm formation fines solution through a 7% saturated of HF sand pack

Figure 14 below shows the comparison of turbidity reading versus volume of formation fines for 5% and 7% concentration of hydrofluoric acid.

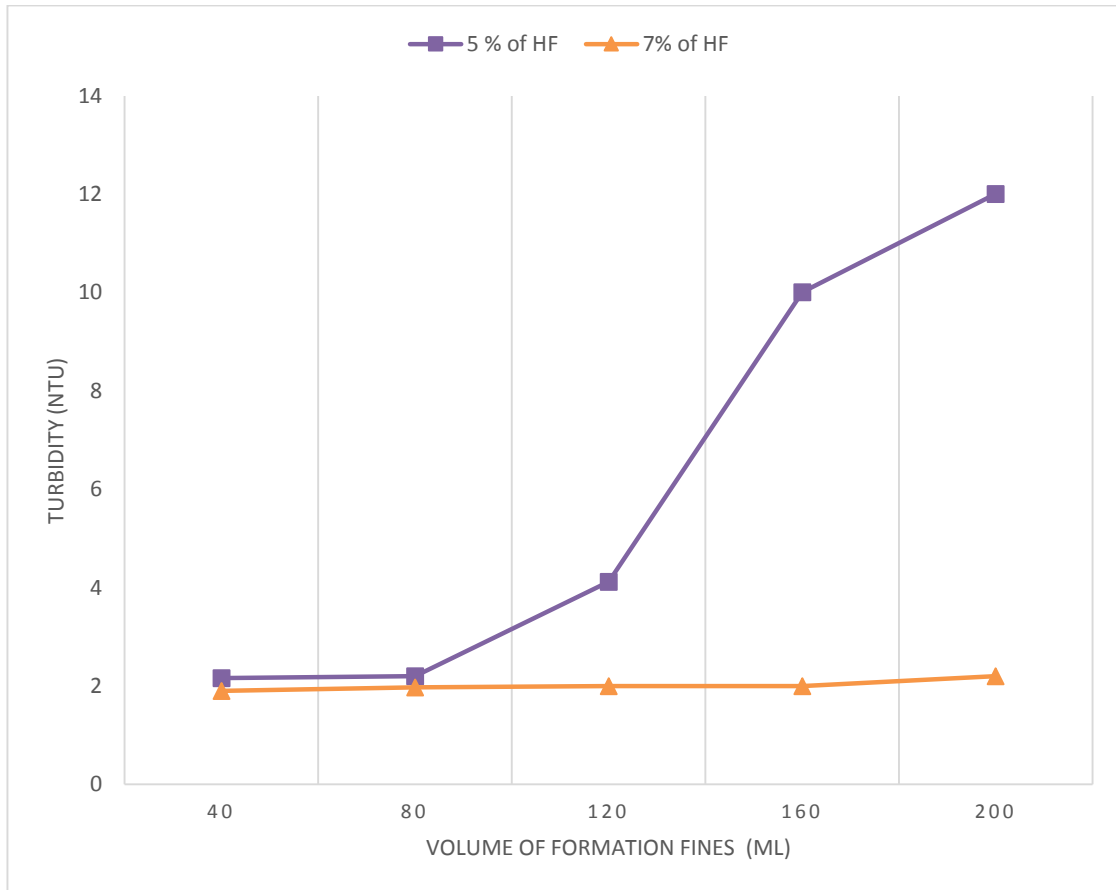


Figure 14: Turbidities of effluent from 2500 ppm simulated formation fines through 20/40 sand pack

Each cylinder represent about 40 ml of formation fines solution to flow through the pack. Based on above figure, as the volume of the formation fines increases, the turbidity reading is also increases. This is due to the reaction between hydrofluoric acid and the clay which result in dissolving the fines in the solution. For the 5% concentration of hydrofluoric acid, the value of the turbidity is below 5 NTU until it reaches 120 ml, indicates that the formation fines is completely dissolve in the solution. However, as the volume of formation fines solution is increases to 160 ml and 200 ml, the NTU readings is above 5 NTU. This shows that no reaction was occurred between the hydrofluoric acid

and formation fines. This may be due to the limited number of HF molecules present in the saturated sand pack that can react with the formation fines.

A picture of effluent samples in **Figure 13** shows that as the large volume of formation fines solution flowed through the 7% saturated sand pack, more fines dissolved in the sand pack as shown by the crystal clear effluent. The effluent samples from the 7% saturated sand pack had lower turbidity readings than 5% saturated sand pack even with 200 ml of formation fines solution. This is because of the reaction between hydrofluoric acid and formation fines which causing stabilized undissolved fines to be obtained. The number of HF molecules present in the saturated sand pack is enough for the reaction to occur to dissolve the formation fines.

However, a detailed experimental study by Kunze and Shaughnessy (1983) has revealed that fluoboric acid spend at rapid rate similar to conventional hydrofluoric acid (HF) at typical formation temperatures. Therefore, this will limits its application in most sandstone formations. When the reaction rate is fast, the fluoboric acid can effectively stop fines migration within 1 ft (0.3 m) of the wellbore only.

CHAPTER 5

CONCLUSION AND RECOMMENDATION

This project can be considered as one of the well stimulation techniques to improve the productivity of the producing well. It is very much related to the current conditions of the wells that are reducing in formation permeability because of the fines migration and deposition results in high positive skin near the wellbore. From the study, the use of fluoboric acid can permanently stabilize formation clays, thus increases the permeability of the formation. It hydrolyzes and reacts with silicates to create a bond that stabilize clay in the formation.

From the experiments, it is concluded that as the concentration of the hydrofluoric acid increases, more fines are dissolve in the formation. The 5% and 7% concentration of hydrofluoric acid result in crystal clear effluent which indicates the fines are dissolved in the sand pack. This is due to the high amount of HF molecules leads to higher concentration of hydrofluoric acid causing stabilized undissolved fines to be obtained. In contrast, the effluent sample from untreated sand pack (0% concentrated of hydrofluoric acid) had turbidity very close to the initial formation fines solution, demonstrating that the fines were able to migrate out through the pack. The 7% concentration of hydrofluoric acid provides a good result in treating fines migration as shown by the crystal clear effluent collected. The effluent samples from the 7% saturated sand pack had lower turbidity reading than 5% saturated sand pack even with 200ml of formation fines solution. The number of HF molecules present in the saturated sand pack is enough for the reaction between hydrofluoric acid and formation fines to occur to dissolve the formation fines.

For expansion and continuation, to clearly define the effectiveness of the acid, the test need to be run under reservoir conditions, which at high pressure and temperature. By using this method, the rate of reaction and the length of penetration can be known. This is because the temperature and pressure affects the acid reaction. Furthermore, the porosity and the permeability of the sand pack must be measured and kept constant throughout the experiment. The porosity can be measured by using weight method while the permeability is measured with brine solution after porosity measurement. Other study that could be considered is to develop a new chemical formula that may be beneficial in treating fines migration.

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