Writing a Master thesis

Practical experience

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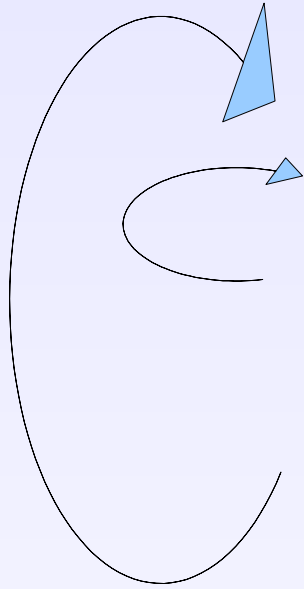
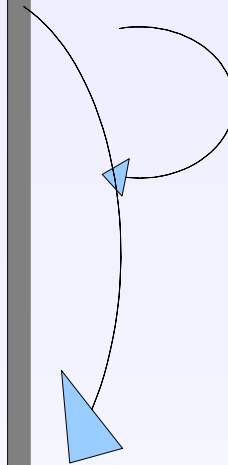**Final product**

Process

Experience

1. Main problem /Model

2. Results

3. "Background knowledge"

4. Introduction

5. Conclusion

- Outline

- Feedback

- "Individual style"

- Several advisers

Chapter 1

Geological storage of CO$_2$

Geological storage of CO$_2$ corresponds to injecting and storing CO$_2$ in deep geological formations. In this chapter we give a general overview of geological storage and discuss the main challenges for its practical application. Furthermore, some of the challenges attached to this concept are discussed.

1.1 Background

Geological storage involves injection of captured CO$_2$ into deep geological formations. Of the different geological formations *deep saline aquifers* are the most ubiquitous and offers the largest potential storage volume [1]. In addition, deep saline aquifers can be used immediately in contrast to oil and gas reservoirs that must be exploited first. For these reasons, deep saline aquifers are very attractive for geological storage of CO$_2$. A deep saline aquifer consists of deep sedimentary rocks saturated with formation water or *brine*. The term brine is used for water saturated with or containing large amounts of a salt, especially of sodium chloride. According to U.S. Geologic Survey (USGS) classification, water classified as brine contains more than 35,000 ppm (parts per million) total dissolved solids of salt.

To increase the storage volume the CO$_2$ is injected at *super-critical state*, [15]. Having the CO$_2$ in super-critical state means that temperatures T and pressures P are above the critical point, that is $T_c = 31, 1°$ C and $P_c = 7, 38$ MPa, see Figure 1.1. CO$_2$ at super-critical state has higher density than in gas phase and smaller *viscosity* than in fluid phase. Viscosity will be defined in the next chapter. Given typical geothermal gradients the conditions for having the CO$_2$ in super-critical state are found at depths around 800m below sea level [3].

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variations with a well defined average. This means that quantities within a porous media are considered as averages over a *representative elementary volume* (REV) of the medium around the point considered [6].

Each fluid present in a porous media is called a *phase*. For example, brine in deep saline aquifers is considered as a phase. The phases can move with in the connected pores, and the governing equations for this movement will be presented throughout this chapter.

The connected (effective) pore volume, V_{Pp}, is the actual volume of the pores where the phases can move in. The ratio between the connected pore volume and the total volume, V_T, of the medium is called the *effective porosity* ϕ, of the porous medium, i.e.

$$\phi = \frac{V_P}{V_T}.$$

Usually this dimensionless quantity is expressed as a percentage. From now on, we will refer to the effective porosity as the porosity. Note that the porosity is a property of the rock. In the next section some properties of the fluid or the phases will be presented.

2.2 Properties of a Fluid Phase

These properties concerns each individual phase regardless of how many phases that are present in the system.

Each fluid phase has a *density* ρ, which is mass of fluid per unit volume with units of [kg/m^3] in the SI system. The *viscosity* μ of a fluid phase reflects the internal resistance to flow of that phase. For example, water has low viscosity, while oil has high viscosity. Since this property reflects resistance the SI-unit is [Pa s] = [kg/ms].

In fluid mechanics the *compressibility* c of a phase is a measure of the volume change of the phase due to a pressure change in the phase. The compressibility is defined as;

$$c = -\frac{1}{V}\frac{dV}{dp} = \frac{1}{\rho}\frac{d\rho}{dp},$$

where V is total volume and p is the pressure [29].

When more than one phase is present in the system the physics becomes

Thank you!