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Optimization of geothermal well doublet placement

MSc Thesis Report

Abstract

The lifetime of geothermal projects mainly depends on the thermal breakthrough (thermal breakthrough occurs when a cold water front reaches the producer). Currently, geothermal-energy production is marginally economical because of its uncertainties and risks associated with the subsurface such as lifetime, flow rate, temperature. Lifetime of a geothermal reservoir plays the most important role in the use of geothermal energy because it mainly determines whether or not geothermal-energy production is economically viable.

Through optimization of the well positions from one or more geothermal doublets in a homogeneous or heterogeneous reservoir, the profitability of the project, which is largely dependent on the time of compositional breakthrough, temperature breakthrough and the rate of temperature decline, can be improved. This thesis studies optimization of the well positions such that the Net Present Value (NPV) of a project is maximized in a 2D geothermal reservoir for the selected heterogeneity structure. For this purpose an automated, gradient-based optimization method is used. The approach is based on the concept to surround the wells, whose locations have to be optimized, by so-called pseudo-wells. The reservoir simulations are performed using the Finite Element Method in the program COMSOL Multiphysics 4.2a. The major features of the simulation results are discussed in detail.

The compositional front moves faster than the thermal front (the ratio of these two is the thermal retardation factor). Breakthrough of water with altered composition will therefore occur at an early stage in the doublet lifetime. Reservoir heterogeneities influence the time at which thermal and compositional breakthrough occur and also determine the rate at which temperature and composition decline after breakthrough. The temperature and compositional decline curves after breakthrough are generally steeper in a homogeneous reservoir than in a heterogeneous reservoir. Therefore, the thermal breakthrough does not necessarily mean the end of the lifetime of a doublet. It is also shown that the effect of heterogeneities on the thermal retardation factor is small.

Three successful optimization sequences in two different reservoirs are described in this thesis. It is shown that, from an economical standpoint, it makes little sense to assume a doublet lifetime of more than 30 years. Furthermore, the effectiveness at which a geothermal doublet is able to deplete a reservoir (recovery factor) and profitability of a geothermal doublet are closely interlinked. However, a higher recovery factor does not necessarily mean that the doublet is more profitable and vice versa. There exists an optimum well spacing for doublets positioned in homogeneous reservoirs, such that additional gain of later breakthrough (when placing the production well further away from the injector) is negated by the loss in pressure support of the injection well. This optimum well spacing is found to be an important factor, influencing the profitability in homogeneous and heterogeneous reservoirs. In addition, it is found that the optimum well spacing of a doublet for greenhouse heating is the same as the optimum well spacing of a doublet for spatial heating.

The heat production from an aquifer can be maximized through the usage of multiple doublet layouts. It is found that, even in a heterogeneous reservoir, it is best to use a checkers-board well arrangement, which is more effective than a tramrail well arrangement.

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Index

Abstract	II
Acknowledgements	IV
Index	V
Nomenclature	1
1. Introduction	4
1.1. Thesis objectives	5
1.2. Outline	5
1.3. Background	6
1.3.1. Reinjection	7
1.3.2. Thermal Breakthrough	7
1.3.3. Compositional Breakthrough	8
1.3.4. Industry convention: Interference.....	8
1.3.5. Industry convention: Recovery factor	9
1.3.6. Geothermal doublets in the West Netherlands Basin	10
1.3.7. Optimization of well placement	11
2. Physical model.....	12
2.1. Compositional and thermal flow behavior	12
2.1.1. Gravity effects	13
2.1.2. Piston displacement.....	13
2.1.3. Incompressible flow	13
2.2. The continuity equation	14
2.2.1. Laminar Flow	14
2.3. Conservation of energy	15
2.3.1. Non-conservative heat transfer.....	16
2.3.2. 1D heat transfer	16
2.4. Mass transport equation	17
2.4.1. Effective diffusion coefficient.....	18
2.5. Thermal retardation factor	19
2.6. Péclet number.....	20
2.7. Thermodynamic relations	21
2.7.1. Viscosity.....	22
2.7.2. Density	22

2.7.3.	Heat Capacity of brine.....	23
2.7.4.	Thermal Conductivity of brine	24
2.7.5.	Heat Capacity of reservoir rock.....	25
2.7.6.	Thermal conductivity of reservoir rock.....	25
2.7.7.	Thermal diffusivity.....	26
2.7.8.	Diffusion coefficient of sodium chloride	26
3.	The numerical model	27
3.1.	COMSOL Multiphysics	27
3.2.	Stability and Convergence	28
3.2.1.	Mesh size.....	28
3.2.2.	Tolerances	30
3.2.3.	Numerical stabilization	31
3.3.	Boundary conditions	32
3.3.1.	Steady-state conditions.....	33
3.3.2.	No-flow boundaries.....	33
3.3.3.	Wells	33
3.3.4.	Variable boundary condition	33
3.4.	Numerical values	35
4.	Optimization method	36
4.1.	The economical model.....	36
4.1.1.	Net Cash Flow	37
4.1.2.	Alternative NCF	37
4.1.3.	Net Present Value (NPV)	38
4.1.4.	Economical Parameters	38
4.1.5.	Heat production	39
4.2.	The objective function	40
4.3.	Application of indirect gradients.....	41
4.4.	Gradient calculation	42
4.5.	Iterative optimization	43
4.6.	Implementation	44
4.6.1.	Structure	44
4.6.2.	Implementation of pseudo-wells	45
4.6.3.	Remarks to optimization	47
4.6.4.	Cluster computing	47
4.7.	Uncertainty of data.....	47

5.	Reservoir Model	48
5.1.	Approach.....	48
5.2.	Assumptions.....	49
5.2.1.	General assumptions	49
5.2.2.	Non-conservative heat transfer.....	49
5.3.	Verification model	50
5.3.1.	Numerical 1D model	51
5.3.2.	Analytical 1D model	51
5.4.	Reservoir conditions	52
5.4.1.	Brine and rock properties	52
5.4.2.	Initial conditions.....	53
5.5.	Production constraints.....	54
5.5.1.	Pressure and rate constraints	54
5.5.2.	Temperature constraints	55
5.6.	Temperature and compositional breakthrough.....	56
5.7.	Delft Sandstone model	56
5.7.1.	Porosity and permeability.....	56
5.7.2.	Homogeneous reservoir.....	57
5.7.3.	Heterogeneous reservoir.....	57
5.8.	SPE10 model.....	58
5.8.1.	Upscaling.....	59
6.	Results and Discussion	62
6.1.	Verification of numerical model	62
6.1.1.	Comparing analytical and numerical results	63
6.1.2.	2D numerical solution	63
6.1.3.	Impact of thermodynamic dependencies	65
6.2.	Impact of heterogeneities on breakthrough time	67
6.3.	Compositional breakthrough.....	70
6.3.1.	Ratio of front velocities	74
6.4.	Doublet placement	75
6.4.1.	Spacing of injector and producer.....	75
6.4.2.	Interference with adjacent doublets.....	76
6.4.3.	Impact of heterogeneities	77
6.4.4.	Profitability and optimum well positions	80
6.4.5.	Uncertainty in reservoir data	85

6.5.	Optimization of well-doublet placement.....	86
6.5.1.	Optimization in the SPE10 model	86
6.5.2.	Optimization in the Delft Sandstone model	87
6.5.3.	Prospects of optimization	88
6.6.	Cooperating geothermal well doublets.....	90
6.7.	NPV calculations for optimum scenarios.....	94
7.	Conclusions	96
8.	Recommendations.....	98
	References	99
	Appendices	i
	APPENDIX A – Optimization Scheme	i
	APPENDIX B – Remarks to Optimization	ii
	APPENDIX C - Uncertainty of data	iii
	APPENDIX D - Fluid and Rock Properties	iv
	APPENDIX E - Production constraints.....	v
	APPENDIX F – properties of pumps.....	vii
	APPENDIX G - Failing Optimization	ix

Nomenclature

C	Specific heat capacity	J/(kg·K)
D	Diffusion	m ² /s
E	Gross heat production rate	J/s
HIP	Heat In Place	GJ
H	Overburden thickness	m
I	Investments	\$
J	Objective Function	\$
K	Thermal conductivity	W/(m·K)
L	Well spacing	m
L_c	Characteristic mesh-length	m
LT	Local Taxes	\$
M	Mobility ratio	-
MWL	Mean Water Level	m
N_c	Number of components	-
N_k	N° of timesteps	-
N_m	N° of gradient components	-
N_j	N° of (pseudo-) wells	-
NCF	Net Cash Flow	\$
NPV	Net Present Value	\$
NRI	Net Revenue Income	\$
OPC	Operating Cost	\$
P	Price of particular good	\$
Q	Mass flow rate	kg/m ³
Pe	Péclet number	-
P_{energy}	Price of electricity	Euro/GJ
Re	Reynolds number	-
R_t	Thermal retardation factor	-
R_{cons}	Conservation retardation factor	-
T	Temperature	K
T_k	Lifetime of project	years
U	Control vector	variable units
V	Reservoir Volume	m ³
W_{pump}	Power required by pump	kWh
WT	Wellhead taxes	\$
b	Discount factor	-
c	Concentration	kg/m ³
d_p	Average pore diameter	m
$\mathbf{d}$	Vector of direction	m
g	Gravity	m/s ²
h	Reservoir thickness	m
k_A	Absolute permeability	m ²
k_r	Relative permeability	-

m	Molality	mol/kg
p	Pressure	Pa
q	Rate of flux	m ³ /s
r	Cost or revenue	\$/m ³ or \$/GJ
r_{well}	Well radius	m
t	Time	s
t_k	Time in years	years
tol	Tolerance for num. model	-
u	Darcy velocity	m/s
$\mathbf{u}$	Darcy velocity vector	m/s
$\mathbf{v}$	Interstitial velocity tensor	m/s
$\mathbf{w}$	Vector of spatial coordinates	m
x,y,z	Spatial components	m
α	Thermal diffusivity	m ² /s
ϵ	Local error vector	-
λ	Mobility	m ² /Pa·s
μ	Dynamic viscosity	Pa·s
σ	Stress tensor	Pa
ρ	Density	kg/m ³
τ	Diffusion tortuosity	-
ϕ	Porosity	-
Φ	Pressure gradient vector	Pa/m
ω	Mass fraction	-
Subscripts		
0	Initial	
BT	@ Breakthrough Time	
R	Rock	
T	Fixed temperature	
a	Artificial	
$base$	Pertaining to the base-case	
c	Cold	
$comp$	Compositional	
$cons$	Conservative	
e	Equivalent	
eff	Effective	
$frac$	Fracture	
$fric$	Friction	
h	Hot or Heat	
in	Injection well	
$init$	Initial conditions	
j	(pseudo-) well-number	
k	Timestep	
m	Component of gradient	
max	Maximum of values	

<i>min</i>	Minimum of values
<i>num</i>	Numerical
<i>p</i>	Production well
<i>pore</i>	Pertaining to pores
<i>r</i>	Relative
<i>res</i>	Pertaining to the reservoir
<i>thermal</i>	Thermal
<i>thres</i>	Threshold value
<i>v</i>	Vertical
<i>w</i>	Water
<i>x, y, z</i>	Special direction of tensor
α	Component α
Superscripts	
<i>i</i>	Iteration number
$\sim$	Perturbation run
Other Acronyms	
BC	Boundary Condition
BHP	Bottom Hole Pressure
ESP	Electrical Submersible Pump
THP	Tubing Head Pressure

1. Introduction

This thesis investigates the effects of heterogeneities, thermal breakthrough and salt breakthrough, in the absence of gas, on well placement and profitability of geothermal projects in the Netherlands. This topic is related to the growing interest for the exploration and exploitation of geothermal energy. In addition, the aspects of spatial planning become increasingly important in the Netherlands.

Many studies acknowledge that heterogeneities have a large impact on the profitability of geothermal well doublets. Nonetheless, decisions on the well locations of geothermal projects are currently mainly based on the presumption that geothermal reservoirs are considered to be homogeneous. Although many studies on well placement optimization in heterogeneous reservoirs have been performed on projects in the oil and gas industry, little of this knowledge has yet been applied for geothermal projects.

Now that geothermal energy is becoming more interesting for exploitation, risks of interference increase. However, the knowledge on well interference among geothermal doublets is limited. Especially when heterogeneities are introduced, it is difficult to assess whether interference effects with adjacent projects within the lifetime of such projects will occur or not.

1.1. Thesis objectives

In light of the issues addressed earlier, the scope of this thesis can be captured in the hypothesis that:

Through optimization of the well positions from one or more geothermal doublets in a homogeneous or heterogeneous reservoir, the profitability of the project, which is largely dependent on the time of compositional breakthrough, temperature breakthrough and the rate of temperature decline, can be improved.

Arguments in favor of this hypothesis are formulated in chapter 6, assuming known heterogeneities and fluid properties, through the following objectives:

- 1) Assess the impact of thermal breakthrough and related temperature decline on the lifetime of a doublet.
- 2) Determine how reservoir heterogeneities can influence the time of thermal breakthrough and the rate of temperature decline after breakthrough has occurred.
- 3) Demonstrate why, apart from thermal breakthrough, compositional breakthrough should also be taken into account when determining the optimal positions of wells in geothermal doublets by quantifying how fast the compositional front propagates with respect to the thermal breakthrough.
- 4) Investigate the impact of the various reservoir properties, production constraints and project life time on the profitability and optimum well spacing of a geothermal doublet.
- 5) With the knowledge from the oil and gas industry, show that gradient-based optimization of the placement of geothermal wells in heterogeneous reservoirs is potentially rewarding.
- 6) Determine the an effective way to drain a geothermal reservoir by comparing the performance of multiple doublets layouts.

1.2. Outline

This thesis consists of 6 chapters, starting with chapter one as the introduction. In the rest of the first chapter some background information on geothermal well doublets and related issues is provided.

Chapters two and three respectively discuss the physical and numerical model that are used to develop the reservoir simulator for this thesis. The fourth chapter on optimization, first describes the economical model that is used for the calculation of the NPV of geothermal projects. Thereafter, it is explained how, based on this economical model and with the use of the reservoir simulator, a gradient-based optimization method for geothermal wells is developed. The reservoir models and other quantitative data used in this thesis, are described in chapter five. Next, the results and observations from the different numerical models, which analyze cooperative and competitive well doublet placement in homogeneous and heterogeneous geothermal reservoirs, are presented and

discussed in chapter six. The final two chapters of this thesis contain the conclusions and recommendations.

1.3. Background

A geothermal doublet consists of an injection well and a production well. Generally the way such a doublet works is as follows: Through a production well warm aquifer water is pumped to the surface. A heat exchanger extracts the heat from this water, which can be used for the heating of greenhouses or spatial heating (e.g., households). Finally, the cooled water is reinjected into the subsurface at the reservoir level (see Figure 1).

Figure 1: General layout of a geothermal doublet (T&A Energy, 2010)

The feasibility or Net Present Value (NPV, see section 4.1) of a geothermal project is mainly determined by the maximum geothermal power of the system. The geothermal power of a doublet depends of the water flux and the temperature difference between the produced water and the reinjected water.

In this thesis, a distinction is made between two situations in addressing the objectives listed in section 1.1:

- Cooperative situation: Only one actor (or a coalition of actors) is exploiting the geothermal potential of a reservoir and it seeks to maximize the Net Present Value by placing one or more geothermal wells in this reservoir.
- Competing situation: Two or more (competing) actors are exploiting the geothermal potential of a reservoir. All actors seek to maximize their NPV of geothermal projects while preventing well interference effects with the other actors.

1.3.1. Reinjection

Reinjection started purely as a disposal method, but it has more recently been recognized as an essential and important part of reservoir management. Gringarten (1979) was one of the first to investigate reinjection into geothermal reservoirs to improve the heat-recovery-factor. Only a small part of the thermal-energy-in-place in geothermal reservoirs can be recovered if reinjection is not applied (Stefansson 1997). In addition, reinjection can be used to counteract production induced subsidence.

Reinjection, no matter how promising it may seem, has positive and negative sides. One of the effects caused by reinjection of geothermal well doublets is the development of the typical thermal front of cold water. Moreover, when there is a contrast in salinity between the reservoir water and the reinjected water (e.g., due to abstraction, reaction or precipitation in surface facilities), a compositional front may be formed as well. Such fronts pose a risk to the sustainability of the geothermal well doublet. Most renowned is the thermal feedback after breakthrough of the thermal front. Depending on nearby aquifer usage, such as other geothermal doublets in adjacent concession blocks, compositional and thermal fronts may pose external risks to other users of the aquifer as well. (Banks 2009)

Lippmann and Tsang (1980) and Banks (2009), among others, pose that regional groundwater flow conditions may have a large impact on compositional and thermal breakthrough times.

In this thesis, reservoir units with flow conditions similar to the ones present in the West Netherlands Basin are considered (Chapter 5). This basin is highly compartmentalized, therefore the groundwater-flow velocity can be assumed to be negligible compared to the flow velocities induced by the pressure difference between injector and producer.

1.3.2. Thermal Breakthrough

When cold water is injected into a reservoir with a higher temperature, the fluid flows along the pressure gradient towards the production well. Given enough time, thermal breakthrough occurs at the producer (i.e., the cold water front will reach the producer). It is broadly accepted that cooling of production wells is one of the main issues associated with reinjection (Gringarten 1979).

After thermal breakthrough, the temperature of the water extracted from the production well will decline and once a certain minimum temperature is reached. At this point, the project is no longer feasible and the lifetime of the geothermal well doublet ends.

The thermal-breakthrough time depends in a complex way on the variation in reservoir properties, reservoir thickness, lateral extent of the reservoir, production rate, location of wells and technical boundary conditions. The optimal development and management of a geothermal resource require a good knowledge of the hydrological characteristics of the reservoir. Comprehensive interpretation and cooling predictions (well doublet modeling) and tracer testing are probably the most important tools for this purpose. (Stefansson 1996; Axelsson and Stefansson 2003)

Although thermal short-circuiting within the lifetime of a doublet should be prevented, the wells should not be placed too far apart since the main benefit from reinjection (pressure support) is maximized by locating the wells close together.

When choosing the locations for the producer and injector of a geothermal doublet, there is a trade-off between efficiency of the doublet and the lifetime of the doublet.

In effect, the optimal positioning and spacing of a geothermal doublet is therefore largely dependent on the economical lifetime of the project. Depending on the stake holding investors this could be 20 (e.g., banks) to over 100 (e.g., governments) years.

In Chapter 6, the impact of various parameters on the propagation of the thermal front and the relation that thermal breakthrough has on the optimal positioning of wells are assessed.

1.3.3. Compositional Breakthrough

While the temperature of the reservoir water determines the amount of energy that can be withdrawn from the fluid, the amount and kind of minerals that the aquifer water contains is of importance for the functioning of the surface facilities of a geothermal doublet.

The composition of the produced water may be altered in surface facilities. This can happen, for example, in heat exchangers, screens, degassers or in storage facilities (Bennion et al. 1996; Seibt and Wolfgramm 2008). The injected water may therefore contain:

- Oxidation or corrosion products (by oxygen entry)
- Bacterial activity
- Drilling fluids
- More/less dissolved gasses
- Less salt or minerals due to scaling or abstraction at the surface

A compositional front moves much faster than a thermal front because the re-injected water must cool both the reservoir rock and reservoir water (see section 2.5). When a doublet is not placed at an appropriate distance from the concession border, the compositional front may propagate into the adjacent concession block potentially causing breakthrough of water with a different chemical composition at the competing doublet. This, in effect, may cause problems for the installed surface facilities of other doublets positioned in the same reservoir (e.g., by plugging or scaling).

In section 6.3, it is assessed how far such a compositional front propagates within the lifetime of a doublet.

1.3.4. Industry convention: Interference

Industry convention (van Driel et al. 2010) is to assume that placing geothermal doublets 1500 m apart is sufficient to prevent interference effects between these doublets within their lifetime. This convention however, is based on several assumptions:

- 1) Preventing thermal breakthrough is the only matter of importance when determining safe spacing distance with competing doublets

- 2) Reservoir properties are homogeneous
- 3) The reservoir bathymetry is known and predictable
- 4) Potential breakthrough of water with an altered chemical composition does not pose a threat to adjacent competitive or cooperating wells

1.3.5. Industry convention: Recovery factor

Due to legal reasons, it is the industry convention to assume that doublets are oriented in rectangles (van Wees et al. 2010). Two identical circles, representing the area of the influence of a well, are enclosed in such a rectangle (Figure 2a). The circles touch each other half way and the injector and producer well are located at positioned at the center of these circles (Figure 2b).

Figure 2: Industry convention of the area in which recovery factor is calculated a) The temperature profile of a doublet after 50 yrs of production, located in a homogeneous and approximately infinite reservoir b) Industry definition of geothermal doublet. Specification of the simulation $t = 50$ [yrs], reservoir thickness = 50 [m], injection temperature = 40 [°C], initial temperature = 77 [°C], initial reservoir pressure = 20 [MPa], permeability = 500 [mD], porosity = 0.2 [-], injection rate = 150 [m³/hour], BHP at producer = 19 [MPa].

In Figure 2a, the temperature profile is shown, after 50 years of doublet activity in a homogeneous and approximately infinite reservoir. This figure shows why it is chosen to use circles to represent the area of influence of a geothermal doublet. When only considering such a specified, rectangular, part of the reservoir (Figure 2b), it is theoretically possible to produce up to 50% of the Heat In Place (Gringarten 1978; van Wees et al. 2010). In this calculation, however, many important factors are not in consideration. Among these factors are:

- heterogeneity of reservoir properties
- reservoir architecture
- heat losses during production
- recharge of reservoir heat by inflow and radiation
- layout of multiple doublets in one reservoir
- well distance
- groundwater composition

Furthermore, this way of approaching effectiveness of geothermal doublets leaves to the question that why only the proximal area of the geothermal reservoir is considered in determining the recovery factor and not the entire reservoir.

Note: Because these limitations, it is chosen not to use the industry definition for the calculation of the recovery factor of geothermal doublets in this thesis. Since the reservoir domain is defined differently for various situations, the recovery factor is only used as a relative indication of how effectively a doublet is able to drain a specific part of the reservoir instead.

1.3.6. Geothermal doublets in the West Netherlands Basin

Geothermal energy is growing in the Netherlands. Several geothermal-well-doublet projects have been initiated in the West Netherlands Basin. Currently in operation are the doublets of Ammerlaan, Duyvenstijn, van den Bosch, Koekoekspolder and Aardwarmte Den Haag; more are planned. The increase of oil and gas prices and the demand for ever more energy make geothermal projects interesting investments.

Some studies have looked into the optimal planning of geothermal well doublets (Mijnlieff and van Wees 2009; van Leeuwen et al. 2010) in order to maximize the heat recovery factor from an aquifer (cooperative situation). In the study of Mijnlieff and van Wees (2009), the “tramrail-layout” and “checkers-board-layout” (see Figure 3) for the placement of geothermal doublets are compared. It is shown in this study that, for a homogeneous reservoir, the largest potential of a geothermal reservoir is utilized when a checkers-board layout of geothermal well doublets is used.

Figure 3: ‘Tramrail-profile’ (left) and the more effective ‘checkers-board profile’ (right) of geothermal doublets in a geothermal reservoir under the following conditions: $t = 60$ [yrs], reservoir thickness = 56 [m], initial temperature = 77 [°C], porosity = 0.19 [-], injection rate = 150 [m³/hour], initial pressure = 20 [MPa].

The studies by Mijnlieff and van Wees (2009) and van Leeuwen et al. (2010) also acknowledge, but do not look into, the fact that the structure of the aquifer (i.e., the primary characteristics and heterogeneities) and interference with nearby well doublets

will strongly influence the pressure, temperature and salinity dependent flow rate and lifetime of a geothermal field. (for a more thorough synopsis see Appendix A)

In section 6.6, a comparative analysis is made between the tramrail-profile and checkers-board profile for homogeneous and heterogeneous reservoirs.

1.3.7. Optimization of well placement

In order to make a geothermal project feasible, the subsurface should be studied to be able to choose good positions for the wells. Manually interpreting what good well positions are, however, is difficult since the profitability of a doublet depends in a complex way on production constraints, fluid properties and reservoir heterogeneities. Therefore, automatic optimization algorithms pose a solution.

Multiple of such optimization methods have been developed by the oil and gas industry to determine optimal positions for producers and injectors in heterogeneous reservoirs (e.g., Güyagüler and Horne 2004; Kraaijevanger et al. 2007; Zandvliet et. al 2008; Kalla and White 2007; Wang et al. 2012). This topic will be further discussed in chapter 4.

In principle it is possible to boost NPV and the cumulative heat production from geothermal projects by applying such well-placement-optimization techniques. Up to date, however, no study to such optimization of the well placement of geothermal doublets has been performed.

In this thesis an objective function is proposed for geothermal doublets (section 4.2). This objective function quantifies how profitable a geothermal doublet is likely to be when placed in a certain position with given constraints. With the use of this objective function, an optimization algorithm is developed with which it is shown that automatic optimization of the positions of geothermal wells is potentially rewarding (section 6.4).

2. Physical model

The flow of aquifer water through a porous medium can be fully described by a set of partial differential equations that describe the transport of mass, momentum and energy. In this chapter, these equations are described, such as they are used for the numerical model created for this thesis.

First a general note to the physics involved with reservoir-thermal-flow behavior is given (section 2.1). Thereafter, the continuity equation, which describes the conservation of mass, is derived in section 2.2. The conservation of energy is then described by the energy equation in section 2.3. Next, the mass transport equations are given in section 2.4. A relation between the velocity at which the thermal front and the compositional front move is given by the thermal retardation factor, which is discussed in section 2.5. In the final section of this chapter (section 2.7), the thermodynamic relations of aquifer brine and reservoir rock are given.

2.1. Compositional and thermal flow behavior

When cold water is injected in a reservoir with higher temperature the fluid will flow along the pressure gradient and heat transfer from the rock to the fluid will occur. The energy transfer consists of convection forces by injection (advection) and heat conduction. This will lead to a thermal front moving away from the injector towards the producer.

The propagation of the thermal front for single-phase flow in homogeneous porous media was first studied by Bodvarsson (1972). He revealed that, by neglecting the thermal conduction, the conservation equations can be developed such that the ratio of the fluid-to-temperature velocities is a constant.

After Bodvarsson (1972), many more investigated the movement of the compositional and temperature front through a homogeneous aquifer during reinjection of a fluid. Analytical closed-form solutions to directly calculate the thermal breakthrough time in homogenous media have been proposed (Gringarten and Sauty, 1975; Kocabas and Horne, 1990). Studies on the propagation of the thermal plume concluded that neglecting thermal conduction still yields good approximations of the thermal and compositional breakthrough times for both homogeneous and heterogeneous, non fractured media (Woods and Fitzgerald, 1992; Shook, 2000)

In this thesis, use is made of 1D and 2D (top view) scenarios. The physics, described in the following sections, do therefore not incorporate gravity dependencies. Motivation for not incorporating the gravity is given in section 2.1.1.

While reliable methods for calculation of breakthrough times for homogeneous fields have been presented over the years, a lot of uncertainty is involved when it comes to estimating breakthrough for real cases with heterogeneous-reservoir properties.

2.1.1. Gravity effects

When injecting cold water into a geothermal reservoir, heavier cool water sinks to the lower part of the reservoir because of gravity. It has been shown, however, that this effect is suppressed by the fact that cold water is also more viscous. (Serpén and Aksoy 2005; den Boer 2008). This is also the case for slightly inclined reservoirs (Figure 4).

Figure 4: Cold water, injected into a slightly inclined reservoir on the left, displaces hot reservoir water. Image by den Boer (2008).

Neglecting gravity effects in a 2D, top view, simulation is therefore a valid assumption even though it is a huge simplification.

2.1.2. Piston displacement

The interface between the cold and warm water is inclined to move in a piston like manner. This effect can be explained by the mobility ratio, M . In geothermal reinjection this ratio involves the mobilities of the cold injection bank, $\lambda_{w,c}$, and hot water reservoir, $\lambda_{w,h}$. Assuming a line-drive-reinjection scheme for a piston like flow, the mobility ratio can be expressed as follows:

$$M = \frac{\lambda_{w,c}}{\lambda_{w,h}} = \frac{\mu_{w,h}}{\mu_{w,c}}, \text{ since } \lambda_{\alpha} = \frac{k_A k_{r\alpha}}{\mu_{\alpha}}. \quad \text{Eq. (1)}$$

$$k_{rw,c} = k_{rw,h}$$

It is assumed here that the permeability is the same in both banks. In effect, the mobility ratio is reduced to the ratio of the viscosities of both banks.

Considering that the viscosity of hot water is always less than the viscosity of cold water (see section 2.5), the mobility ratio for geothermal injection will be always less than 1. This means that the interface movement will be unconditionally stable since the hot water is more mobile than the cold water, i.e., no ‘fingering’ will occur and the cold-water front will be inclined to remain vertical (Serpén and Aksoy 2005). This corresponds with the observations about the mobility ratio in geothermal reinjection.

2.1.3. Incompressible flow

The assumption of incompressibility is acceptable for liquids under typical subsurface conditions. The compressibility of liquid water, for example, is in the order of 4×10^{-10} [1/Pa] (Janssen and Warmoeskerken 2006), thus a pressure change of 1 MPa will change the density by only 0.05%.

Through inclusion of thermodynamic dependencies however, some degree of compressibility is indirectly introduced in the model. A change in pressure, temperature

or salt concentration will cause a change in the density of the fluid and hence a change in the pressure and velocity field of the reservoir will occur.

2.2. The continuity equation

The underlying physical principle of the continuity equation is the conservation of mass, this mass balance describes the rate of change of mass in time resulting from a net mass influx

$$\phi \frac{\partial(\rho_w)}{\partial t} + \nabla \cdot (\rho_w \mathbf{u}) = 0, \quad \text{Eq.(2)}$$

where ϕ [-] is the porosity, ρ_w [kg/m³] is the water density, t [s] is time in seconds and $\mathbf{u}$ is the Darcy (water) velocity. Since a rigid matrix is assumed, there will be no compression effects and the porosity is constant such that:

$$\rho_w \frac{\partial \phi}{\partial t} = 0. \quad \text{Eq.(3)}$$

The Darcy velocity in this equation is given by:

$$\mathbf{u} = -\frac{k}{\mu} \vec{\nabla} \Phi \quad \text{where} \quad \vec{\nabla} \Phi = \begin{bmatrix} \frac{\partial p}{\partial x} \\ \frac{\partial p}{\partial y} \\ \frac{\partial p}{\partial z} - \rho_w g \end{bmatrix}. \quad \text{Eq.(4)}$$

In the above equation, the vertical direction, z , is downward. For a scenario in 1D, equation 2 simplifies to:

$$\phi \frac{\partial \rho_w}{\partial t} + \frac{\partial}{\partial x} (\rho_w u_x) = 0. \quad \text{Eq.(5)}$$

2.2.1. Laminar Flow

A note to the Darcy equation, is that it only describes laminar flow. Means to evaluate the flow regime for single phase flow are given by the dimensionless Reynolds number (Re) which is ratio of inertial forces to viscous forces:

$$\text{Re} = \frac{\rho_w d_p v}{\mu} \quad \text{Eq.(6)}$$

In this expression, the interstitial velocity is given by v . This interstitial velocity is the Darcy velocity (u) divided by the porosity fraction (ϕ). Furthermore, the average pore diameter is given by d_p and the viscosity of the water flowing through the pores by μ .

When injecting water into a reservoir of 50 [m] thickness with a porosity fraction of 0.2 [-] at a rate of 150 [m³/hour], the fluid velocity 10 meters away from the wellbore is equal to approximately:

$$\frac{150}{2 \cdot \pi \cdot 50 \cdot 0.2 \cdot 10} \approx 0.24 \left[\frac{m}{hr} \right] \approx 6.6 \cdot 10^{-5} \left[\frac{m}{s} \right]$$

By further assuming a water density of 1000 [kg/m³], a water viscosity of 0.00052 [Pa·s], and a pore throat diameter of 0.1 [mm], the Reynolds Number can be calculated to be approximately 0.01.

Since laminar flow occurs for $\text{Re} < 2 \cdot 10^3$ (Janssen and Warmoeskerken 2006), it can be concluded that the assumption of laminar flow in a reservoir is valid.

Though it should be mentioned that in practice, turbulent flow near the wellbore or through fractures may occur. This is not considered in this thesis as turbulent flow is likely to only affect a minor part (as was shown with the above calculation) of the reservoir.

2.3. Conservation of energy

Heat transfer in an aquifer can be defined as the movement of energy due to a difference in temperature. It is characterized by two mechanisms: conduction and convection. The law governing all heat transfer is the principle of conservation of energy (equation 7), which will be referred to as the heat equation from here on:

$$\frac{\partial}{\partial t} (C_{eff} T) + \nabla \cdot (\mathbf{u} \rho_w C_w T) = \nabla \cdot (K_{eff} \bar{\nabla} T). \quad \text{Eq.(7)}$$

This relation assumes that mass is always conserved, which means that the density and velocity must be related through equation 2 (mass balance). The term on the right is the heat-conduction term. Typical for heat conduction is that heat flux is proportional to the temperature gradient. Heat conduction takes place through different mechanisms in different media. Theoretically, it takes place in a fluid through oscillations of each molecule in a “cage” formed by its nearest neighbors. In the reservoir rock, it takes place by molecular motion in the form of lattice vibrations.

The second term on the left of equation 7 describes heat convection. Heat convection takes place through the net displacement of a fluid, which transports the heat content in a fluid through the fluid's own velocity. The term convection also refers to the heat dissipation from a solid surface to a fluid, typically described by a heat-transfer coefficient. (Bird, Stewart and Lightfoot 2007)

The specific heat capacity, C_{pw} , describes the amount of heat energy required to produce a unit temperature change in a unit mass of the water. The effective volumetric heat capacity of the solid-liquid system can then be calculated from:

$$C_{eff} = (1 - \phi)\rho_R C_R + \phi\rho_w C_w. \quad \text{Eq.(8)}$$

The thermal conductivity of water K_w , describes the relationship between the heat flux vector and the temperature gradient. The effective thermal conductivity can be calculated similarly to the effective heat capacity:

$$K_{eff} = (1 - \phi)K_R + \phi K_w. \quad \text{Eq.(9)}$$

2.3.1. Non-conservative heat transfer

By assuming the velocity, density and heat capacity of rock and fluid are constant in a reservoir, the non-conservative form of the heat equation can be obtained:

$$C_{eff} \frac{\partial T}{\partial t} + \mathbf{u} \rho_w C_w \nabla \cdot T = \nabla \cdot (K_{eff} \nabla T). \quad \text{Eq.(10)}$$

Motivation for the usage of this non-conservative heat equation is given in sections 5.2.2 and 6.1.3.

2.3.2. 1D heat transfer

For a scenario in 1D, the heat equation simplifies to the 1D advective-diffusion equation for the temperature. This relation in the conservative form reads as follows:

$$\begin{aligned} & \left([\phi\rho_w C_w + (1 - \phi)\rho_R C_R] \frac{\partial}{\partial t} T + T \frac{\partial}{\partial t} [\phi\rho_w C_w + (1 - \phi)\rho_R C_R] \right) \\ & + \left(\rho_w C_w u_{w,x} \frac{\partial}{\partial x} T + C_w u_{w,x} T \frac{\partial}{\partial x} \rho_w + \rho_w u_{w,x} T \frac{\partial}{\partial x} C_w + \rho_w C_w T \frac{\partial}{\partial x} u_{w,x} \right) \\ & - \left(K_{eff} \frac{\partial^2}{\partial x^2} T + \frac{\partial K_{eff}}{\partial x} \frac{\partial T}{\partial x} \right) = 0, \end{aligned} \quad \text{Eq.(11)}$$

and the non-conservative 1D advection-diffusion equation is given by

$$[\phi \rho_w C_w + (1-\phi) \rho_R C_R] \frac{\partial}{\partial t} T + \rho_w C_w u_{w,x} \frac{\partial}{\partial x} T - K_{eff} \frac{d^2}{dx^2} T = 0. \quad \text{Eq.(12)}$$

The 2D advective-diffusion equations in the conservative and non-conservative form, can be obtained in a similar way by using that the nabla-operator in equations 7 and 10 also contains a $\frac{\partial}{\partial y}$ -component.

2.4. Mass transport equation

In this section the mass transport equation is derived similar to Ruoff (2011). Mass transport can be described by the continuity equation (equation 2), which for component α can be written as:

$$\phi \frac{\partial \rho_\alpha}{\partial t} + \nabla \cdot (\rho_\alpha \mathbf{u}_\alpha) = 0. \quad \text{Eq.(13)}$$

In this equation, ρ_α [kg/m³] is the mass concentration of component α and $\mathbf{u}_\alpha$ [m/s] is its velocity. Direct computation of the component velocity also requires implementation of the momentum interaction of the components in the water. Generally the specific behavior of this interaction is unknown and therefore the component velocity is often expressed in terms of mass averaged fluid-phase velocity.

Bird, Stewart and Lightfoot (2007) presume that the mass averaged phase velocity is defined by the sum of the product of the mass fraction and velocity of all components:

$$\mathbf{u} = \sum_{\alpha=1}^{N_c} \omega_\alpha \mathbf{u}_\alpha, \quad \text{Eq.(14)}$$

where N_c is the number of components in the water and ω_α is the mass fraction of the components. Using equations 2 and 13, the component velocity is incorporated into the component mass balance by expressing the component velocity in terms of the mass averaged velocity and the difference between these two, it reads

$$\phi \frac{\partial \rho_\alpha}{\partial t} + \nabla \cdot (\rho_\alpha \mathbf{u}) = -\nabla \cdot (\rho_\alpha [\mathbf{u}_\alpha - \mathbf{u}]). \quad \text{Eq.(15)}$$

The term on the right side is also referred to as diffusion velocity (Bird, Stewart and Lightfoot 2007). This diffusion velocity is proportional to the mass fraction gradient by factor D_{eff} , the (effective) diffusion coefficient with the unit [m²/s]:

$$\rho_\alpha [\mathbf{u}_\alpha - \mathbf{u}] = -D_{eff} \nabla c_\alpha. \quad \text{Eq.(16)}$$

In the above equation $c_\alpha = \rho_\alpha \omega_\alpha$ [kg/m³]. In this relation, ρ_α is the phase density and not the component density.

Since this thesis assumes that the only component in the water is sodium chloride (see section 5.4.1), the subscript α is dropped from the equation. Furthermore, it is assumed that no adsorption takes place and there is no gas fraction present in the liquid. By combining equations 15 and 16, the desired form of the mass transport equation in saturated porous media is now given by:

$$\phi \frac{\partial c}{\partial t} + \nabla \cdot (c \mathbf{u}) = \nabla \cdot (D_{eff} \nabla c). \quad \text{Eq.(17)}$$

The two terms on the left-hand side of equation 17 correspond to the accumulation of salt mass within the liquid and the convection due to the directional velocity $\mathbf{u}$, respectively. On the right-hand side, the first term introduces the spreading of mass due to diffusion. It is assumed that no reactions with salt are taking place in the reservoir.

For a 1D case, the convection term from equation 17 can be written as follows:

$$\nabla \cdot (c \mathbf{u}) = \mathbf{u} \left(\frac{\partial c}{\partial x} \right) + c \left(\frac{\partial \mathbf{u}}{\partial x} \right). \quad \text{Eq.(18)}$$

In this relation it is assumed that

$$c \left(\frac{\partial \mathbf{u}}{\partial x} \right) = 0. \quad \text{Eq.(19)}$$

With this assumption, the mass transport equation is no longer mass conservative. However, the changes in the density as a result of change in salinity are considered to be negligible in the example-study performed in this thesis. Therefore, this is a valid assumption that also greatly reduces the issues related with stabilization in the numerical model (see section 3.2).

2.4.1. Effective diffusion coefficient

The effective diffusion coefficient for the mass transportation equation is the product of porosity (ϕ), the diffusion tortuosity factor (τ) and the diffusion coefficient for sodium chloride (D)

$$D_{eff} = \phi \tau D. \quad \text{Eq.(20)}$$

The diffusion tortuosity factor accounts for the fact that the solid grains impede Brownian motion. This factor can be obtained by noting the difference in the transport coefficient values with and without the porous media according to equation 20. By doing

so, the retardation influence of the porous media is captured, and hence the tortuosity factor is determined (Al-Tarawneh et al. 2009). In this thesis, the tortuosity model posed by Millington and Quirk (1961) has been used, which assumes that

$$\tau = \phi^{\frac{1}{3}}. \quad \text{Eq.(21)}$$

2.5. Thermal retardation factor

As cold groundwater flows through a warm aquifer matrix, heat is absorbed from the matrix into the groundwater until a thermal equilibrium is attained. i.e., this process cools the reservoir rock. This has the effect of retarding the thermal travel front. Therefore, the composition travel time from injector to producer is shorter than the thermal travel time over the same trajectory. The ratio between the thermal flow rate and compositional flow rate is called the thermal retardation factor.

The 1D interstitial velocity for fluid propagation (v_{comp}) of a single injection well with radius r , is given by:

$$v_{comp} = -\frac{u_x}{\phi} = \frac{q}{2\pi\phi hr}. \quad \text{Eq.(22)}$$

In this equation, q is the flow rate and h is the reservoir thickness. With this formula the velocity of the flow in a homogeneous and isotropic aquifer with a fully penetrating well operating at constant flow rate can be estimated.

The speed of the thermal front at given temperature (neglecting thermal diffusion), can be found by rewriting the non-conservative 1D equation of energy (equation 12) to:

$$v_{thermal} = \left(\frac{\partial x}{\partial t} \right)_T = -\frac{\rho_w C_w u_x}{\phi \rho_w C_w + (1-\phi) \rho_R C_R} = -\frac{1}{1 + \frac{(1-\phi) \rho_R C_R}{\phi \rho_w C_w}} \frac{u_x}{\phi}. \quad \text{Eq.(23)}$$

The convective speed ratio between the fluid and the thermal front is defined by the thermal retardation factor, R_t . Shook (2001) used the retardation factor to demonstrate that the ratio of fluid-to-temperature velocities is a constant, even in heterogeneous media. The same notation as used by Shook (2001) is used in this thesis:

$$\frac{v_{comp}}{v_{thermal}} = 1 + \frac{(1-\phi) \rho_R C_R}{\phi \rho_w C_w} = R_t. \quad \text{Eq.(24)}$$

Now following from these equations, the time it takes for a thermal breakthrough to occur is:

$$t_{thermal,BT} = t_{comp,BT} \cdot (R_t), \quad \text{Eq. (25)}$$

$$x_{thermal,BT} = \frac{x_{comp,BT}}{(R_t)} t. \quad \text{Eq.(26)}$$

In equation 26, $x_{thermal,BT}$ and $x_{comp,BT}$ denote the distance from the injector at which breakthrough occurs at a specific time t .

Equation 12 can now be rewritten and the advective-diffusion equation for the temperature front can be numerically approximated with the following equation:

$$\frac{\partial T}{\partial t} = -\mathbf{u} \cdot R_t \nabla \cdot T + \alpha \cdot \nabla \cdot (\nabla T). \quad \text{Eq.(27)}$$

In the above equation, α is the thermal diffusivity, which is a material property which describes the rate at which heat flows through a material, such that

$$\alpha = \frac{K_{eff}}{C_{eff}}. \quad \text{Eq.(28)}$$

Note that the formulation of the thermal retardation factor is based on non-conservative flow. The impact of conservative heat transfer on the retardation factor is investigated in section 6.1.3.

2.6. Péclet number

The Péclet number (Pe) is a measure that indicates how diffusive a displacement front is and describes the ratio between convection and diffusion. The Péclet numbers for the compositional (Pe_{comp}) and thermal ($Pe_{thermal}$) front, are given by equation 29 and 30:

$$Pe_{comp} = \frac{v_{comp} d_p}{D_{eff}}, \quad \text{Eq.(29)}$$

$$Pe_{thermal} = \frac{v_{thermal} d_p}{\alpha}, \quad \text{Eq.(30)}$$

When non-conservative equations are used, the ratio of Pe_{comp} to $Pe_{thermal}$ is reduced to

$R_t \frac{\alpha}{D_{eff}}$ (using equation 24). Hence ratio of the compositional front velocity to the thermal front velocity is reduced to the ratio of diffusivities when simulations are non-conservative.

2.7. Thermodynamic relations

In this section, relations are provided that approximate the aquifer-water properties at in-situ conditions. This is especially important for density and viscosity variations since these properties significantly affect the flow regime of water. It is therefore necessary to find a way to accurately take these variations into account for given in-situ reservoir conditions.

Viscosity and density variations and also the heat capacity and thermal conductivity of the water and reservoir rock as a function of pressure (p), temperature (T) and salt (NaCl) concentration (c) and are implemented in the numerical model.

For reasons explained in section 5.4.1, it is assumed that only sodium chloride is dissolved in the aquifer water. Furthermore, the ranges for pressure, temperature and concentration for geothermal doublets in the Delft sandstone in the West Netherlands Basin are in the following ranges presented in Table 1.

Table 1: Ranges of conditions for Pressure, Temperature and Concentration, present in the West Netherlands Basin.

Symbol	Range of Reservoir Conditions
<i>Pressure</i>	$17.7 \text{ [MPa]} < p < 25 \text{ [MPa]}$
<i>Temperature</i>	$298.15 \text{ [K]} < T < 348.15 \text{ [K]}$
<i>Concentration</i>	$1.86 \text{ [mol / kg]} < c < 2.15 \text{ [mol / kg]}$

There are thermodynamic relations available, that link physics to the properties of aqueous Sodium Chloride. Implementing such relations is time consuming and computationally expensive. Instead, accurate empirical correlations (within the given ranges of reservoir conditions) are used to estimate properties of rock and aquifer water. These empirical correlations will be discussed in the following sections.

In the following subsections, graphs of the relations for various rock and fluid properties are given. Each property is only slightly dependent on pressure and varies more with changes in temperature and salinity. To avoid cluttered graphs, the pressure is therefore kept constant at 20 [MPa], while relations are plotted for various values of temperature and salinity.

2.7.1. Viscosity

It is assumed that the fluids behave Newtonian, i.e., the stress strain relationship of the fluid is assumed to behave linearly with temperature. The constant of proportionality μ , is called the dynamic viscosity [Pa·s] (Atkins 2006).

Multiple algorithms to model the dependency of solution sodium chloride have been proposed in the literature. Adams and Bachu (2002) compared the algorithms of Kestin et al. (1981) and Phillips et al. (1981), the pressure-corrected algorithm presented by McCain (1991) and the algorithm of Palliser and McKibbin (1998). In his study, Bachu (2002) mentions that only Kestin et al. (1981) and Palliser and McKibbin (1998) algorithms accurately take the temperature, salinity and pressure dependencies into account over the range of reservoir conditions. This study also notes that Kestin et al. (1981) algorithm seems to be the most versatile for the calculation of water viscosity. Another study by Spivey (2004) also states that the Kestin viscosity correlation agrees extremely well with the IAPWS correlation for the pure water viscosity.

Figure 5: Viscosity dependence of temperature and salinity at 20 [MPa], Kestin et al. (1981) correlation

This correlation has an estimated uncertainty of 0.5% for temperatures between 25 and 150° C and pressures up to 30 MPa and for a sodium chloride concentration between 0 and 5.4 moles/kg water. This validity range encompasses the required range of reservoir conditions, therefore the correlation given by Kestin et al. (1981) is used for the estimation of the aquifer water viscosity in this thesis.

2.7.2. Density

Many equations for the brine density can be found in the literature (e.g., Rogers and Pitzer 1982; Spivey et al. 2004; Mao and Duan 2008)

It was chosen to use the brine-density correlation of Spivey (2004) that gives the density of sodium chloride brines. This correlation is valid from 0 to 275° C, pressures from 0.1 to 200 MPa and Sodium Chloride content from 0 to 6 moles/kg H₂O.

The densities given by the Spivey (2004) correlation are accurate within 0.01% for temperatures between 25 and 85° C and pressures up to 100 MPa. Thus this relation is valid within the given range of reservoir conditions.

Figure 6: Density dependency of temperature and salinity at 20 [MPa], Spivey (2004) correlation

2.7.3. Heat Capacity of brine

Sharqawy et al. (2010) compared several correlations for the calculation of the heat capacity of water with dissolved sodium chloride as a function of pressure and temperature. In this comparison it is clear that the relation by Jamieson et al. (1969) has the best accuracy for water in the window of reservoir conditions that are considered in this thesis. The heat capacities of this relation are accurate within 0.28% for temperatures between 0 and 180° C and salinities varying from 0 to 3.07 moles/kg H₂O. Which is well within the conditions of the considered reservoir.

Figure 7: Brine heat capacity dependence of temperature and salinity at 20 [MPa], Jamieson et al. (1969) correlation

In this correlation, the dependency of pressure on the heat capacity is neglected. Other correlations for the heat capacity that do incorporate pressure have a far larger uncertainty in the range for which precision is required (e.g., Bromley et al. 1970; Millero et al. (1973) and Sun et al. 2008). Neglecting the pressure dependency of heat capacity does not have big implications. With the correlation proposed by Sun et al. (2008), for example, the change in heat capacity when the pressure rises from 18 to 25 [MPa] is less than 0.1%. The uncertainty of this correlation, however, is estimated to be 4.62%.

2.7.4. Thermal Conductivity of brine

For the thermal conductivity of brine, a comparison between the correlation found by Yusufova et al. (1975) and Nagasaka et al. (1983) has been made.

Phillips et al. (1981) found the relation of Yusufova et al. to reproduce experimental data within an accuracy of 2% for a temperature range between 20 and 80° C and salinities between 0 and 5 moles/kg H₂O. The relation does not incorporate the pressure effects. For higher temperatures the relation remains valid (the author claims until 330° C) but the results in this region have a much higher uncertainty (10-30%).

The correlation given by Nagasaka et al. is accurate within 0.5% of the experimental data between 0 and 80° C, for salinity between 0 and 5 moles/kg NaCl and for pressures up to 40 MPa.

Figure 8: Brine thermal conductivity dependence on temperature and salinity at 20 [MPa], Nagasaka et al. (1983) correlation

The validity range, especially for the temperature, of the latter correlation is not large. In this thesis however, no temperatures higher than 80° C are considered. Therefore, the relation of Nagasaka et al. (see Figure 8) is, in the cases described in this thesis, preferred over Yusufova et al.

2.7.5. Heat Capacity of reservoir rock

In the paper of Lee and Deming (1998) five temperature dependent relations for the heat capacity of rocks are being compared. The relation of Somerton (1992) was found to have the error (6.5%) for sedimentary rocks of these five relations. Another study by Stopa and Wojnarowski (2006) compares a series of relationships among which the relation of Somerton (1992).

In this comparison, the maximum difference between these relationships is shown to be less than 6%. Therefore the correlation presented by Somerton (1992), which is most frequently cited, is applied.

Figure 9: Rock heat capacity dependency on temperature, Somerton (1992) correlation

This relation is only a function of the temperature. For the required temperature window, 25 to 80° C, the thermal conductivity rises almost linear from 847 to 904 [J/(kg·K)] as can be seen in Figure 9.

2.7.6. Thermal conductivity of reservoir rock

Thermal conductivity for any specific rock type varies according to its mineral content, porosity, pore fluid, and anisotropy (Clauser and Huenges 1995). Lake (1989) used a constant value of 2.5 [W/(m·K)] for dry sandstone. This value also corresponds with the observations by Emirov and Ramazanov (2007), who state in their study that for a sandstone reservoir, the thermal conductivity is typically in the range of 2.5 to 3.5 [W/(m·K)]. Therefore the thermal conductivity of the reservoir rock is set at a constant value of 2.5 [W/(m·K)].

2.7.7. Thermal diffusivity

Thermal diffusivity is a material property which describes the rate at which heat flows through a material. This property can be calculated from the thermal conductivity, density, and specific heat capacity of the given material. Hence, it becomes a complex variable once a heterogeneous reservoir is considered. The thermal diffusivity of water with different salinities at a constant pressure of 20 [MPa], calculated with the use of the correlations proposed in previous sections, is given in Figure 10.

Figure 10: Brine thermal diffusivity dependence on temperature and salinity at 20 [MPa]

2.7.8. Diffusion coefficient of sodium chloride

Manheim (1970) suggests a diffusion coefficient of 10^{-10} [m²/s] for dissolved sodium chloride. In order to accurately model such a small diffusion coefficient, the mesh size needs to be small and the required computational power big. Instead, a diffusion coefficient of 10^{-7} [m²/s] was assumed to make it possible to solve 2D numerical models with salinity contrasts. Based on the spread of the compositional front at breakthrough, the error in the estimation of the breakthrough time of a salinity front in a doublet with a spacing of 1500 [m] is approximately 2%.

3. The numerical model

This chapter describes the numerical model that is used for this thesis and the issues related to its application. The first section will briefly discuss how the physics and the numerical model are combined (section 3.1). Thereafter, in section 3.2, it is discussed how to cope with convergence and stability related issues of the model by controlling local errors and mesh size. Section 3.3 explains what boundary conditions are used in the models and in the final section of this chapter it is described what tolerance values and mesh sizes are used to attain stability in the models used in this thesis.

3.1. COMSOL Multiphysics

In this thesis, use is made of the finite element simulator program COMSOL Multiphysics version 4.2a. This program has built in modules of convection-diffusion equations that can be combined to solve complex convection-diffusion problems. Major advantages of this package are that the numerical Finite Element Method (FEM) has been built in, which is generally considered to be one of the most robust numerical methods around. Other advantages of COMSOL, are that meshing is easy and can be visualized and solutions can be stored easily. A challenge with FEM though, is obtaining stable displacement fronts of temperature and concentration (Zienkiewicz et al. 2005).

For the implementation of the non-conservative physics, use is made of the Darcy's Law, Heat Transfer in Porous Media and Species Transport in Porous Media Modules, such as described in chapter 2. COMSOL does not have built-in modules that use conservative heat transfer equations. Instead, the coefficient form PDE module is used to implement these equations. This mathematical module is more versatile and allows for implementation of various dependencies.

The thermodynamic dependencies of rock and fluid properties (section 2.7) are implemented through continuous approximations. These are 4th or 5th order polynomials, dependent on pressure, temperature and salinity made in Excel and implemented into COMSOL.

It is also possible to directly use data sheets in COMSOL. This is done for the porosity and permeability fields. For the thermodynamic relations, however, many data points are required for stable and accurate solutions. As a result, the simulator becomes slow, therefore the continuous approximation is preferred.

3.2. Stability and Convergence

A major issue with numerical simulations is to define the problem such that computations of a simulation will converge to compute valid solutions. It is a challenge to obtain reliable solutions from a simulation that does not need an excessive amount of time to run. Apart from correct equations and input variables, the mesh (section 3.2.1) as well as the tolerances for the error of the solutions (section 3.2.2) play an important role in obtaining correct numerical solutions.

3.2.1. Mesh size

The mesh density is an important control factor for the accuracy of a numerical model. Generally the calculation error will be reduced when the density of a mesh is increased. Therefore, a good way of verifying whether a numerical model yields a good solution, is to refine the mesh and see if the same results are obtained (Zienkiewicz et al. 2005).

In order to find a balance between accuracy on one hand and the computational time and memory consumption on the other hand, the mesh should be constructed with reasonable mesh densities such that computations are swift (see section 0).

Not every region in the simulation domain is of particular importance for the solution of the numerical problem at each time step. By applying a finer mesh in simulation domains where a high resolution is necessary and using a coarse mesh in regions where less accuracy is required, the memory consumption by a simulation can be reduced.

Since pressure gradients close to a well is larger than further away, local grid refinement around the well (which is defined as a circle in COMSOL) can improve the solutions in this area but this will also restrict the timestep-size of the simulation (Ewing et.al 1998). An example of such a mesh, used for the one of the homogeneous reservoir models is shown in Figure 11 below:

Figure 11: Refinement of mesh near wells, where the pressure gradient is higher

Heterogeneous reservoir models have more eccentric flow behavior. Since there are local contrast in pressure gradients the flow velocities vary. As it is usually not known in advance where the velocity gradient will be high, it generally means that a finer mesh

grid is required for convergence of the simulation. This is an issue especially when conservative equations are used, where the flow velocity varies with time and space.

Of big impact on the required mesh size is whether a contrast in salinity is introduced. When this is the case, the model requires a far denser mesh as a salt displacement front has a steeper gradient (due to the generally small magnitude of the mass diffusion coefficient) than a temperature front. The distribution of the mesh for a stable non-conservative simulation of temperature and concentration is shown in Figure 12a and for a stable non-conservative simulation of temperature only in Figure 12b.

High flow velocities in high permeability regions near the (no-flow) boundaries can cause instabilities in the domain when the mesh is not small enough. This is why for some heterogeneous fields, extra refinement of the mesh is also required near the boundaries (Figure 11 and Figure 12a).

Figure 12a) Dense mesh for accurate calculations with both salt and temperature in a heterogeneous reservoir and b) Coarse mesh for fast calculations with only temperature

A more complicated situation arises when thermodynamic dependencies are introduced. By doing so, the fluid effectively becomes compressible (section 2.1.3). The result is that the velocity component v , is no longer only dependent on the location, but also on time. Because of this compression-induced acceleration of the fluid, the numerical solution could potentially become unstable when the grid size is too large. Because of complications caused by heterogeneities and compression effects, creating a good mesh requires some trial-and-error.

Numerical Péclet number

The numerical Péclet number can help determine what mesh size should be used to obtain stable simulations. It describes the relative importance of convective in relation to diffusive effects (for either heat or mass transfer). A large Péclet number indicates that the convection effects dominate over the diffusion effects. For mass-transfer problems the Péclet number is given by

$$Pe_{\text{num}} = \frac{vL_c}{2D_{\text{eff}}} . \quad \text{Eq.(31)}$$

In this equation, the flow velocity is given by v and the characteristic length of a mesh cell is given by L_c . In the denominator of the above Péclet equation, D_{eff} is the effective diffusion coefficient. A numerically stable solution is found for $Pe < 1$. This is why the size of the D_{eff} determines how big the mesh size should be in order to compute a non-oscillating solution.

3.2.2. Tolerances

Relative and absolute tolerances are used by the time-stepping algorithms for time dependent simulations in COMSOL to determine how big errors of solutions are allowed to be. As a result, the values for these tolerances should be chosen with care since they are closely linked to the accuracy of the numerical solution.

In fact, the time-dependent solver of COMSOL goes to the next step when the estimated local error vector, ϵ , in the integration step satisfies the following inequality:

$$abs(\epsilon(j)) \leq tol_r \cdot abs(y(j)) - tol_A(y(j)) \quad \text{Eq.(32)}$$

In this equation, y is the vector of variables (e.g., pressure, temperature, concentration) that depend on the according parameters, j .

In equation 32, tol_r is the relative tolerance, a dimensionless quantity used in each iteration, which is the same for all dependent variables.

The absolute tolerances, tol_A , are represented in the same units as the dependent variables to which they apply. This tolerance is used in each iteration but can be assigned separately for each dependent variable.

Note that the time-stepping algorithm will effectively use the tolerance that is the easiest to fulfill. The absolute tolerance almost always has to be modified to be made fit for a specific variable since there is no way of giving a good general default value.

The pressure, for example, may have an absolute error in the order of Pascal (10^0), as the flow regime and water characteristics only affected by pressure changes in the range of [MPa]. Concentration differences, on the other hand, may lead to different flow behavior even if the increase/decrease in salinity is slight.

The tolerances should be small enough to prevent numerical dispersion, caused by large errors in the solutions close to displacement fronts. If the tolerances are not small enough, non-physical solutions may be the result.

The smaller the tolerances, the longer it takes for the inequality posed by equation 32 to be satisfied. Since the time it takes to compute a solution is dependent on the size of the tolerances, it is indeed wise to put some effort in finding the right tolerances for each variable. The influence of the choice of tolerances on 1D flow simulations is shown in Figure 13 below.

Figure 13: The influence of tolerance selection on the propagation of the temperature front. The position of the thermal front plotted after 10 (blue), 20 (red) and 40 (green) years and compared with the analytical solutions (black lines) for different settings of the tolerances. The settings of the tolerances used the simulations are a) $\text{tol}_t=1\text{e-}3$, $\text{tol}_A=1\text{e-}3$; b) $\text{tol}_t=1\text{e-}4$, $\text{tol}_A=1\text{e-}3$; c) $\text{tol}_t=1\text{e-}4$, $\text{tol}_A=1\text{e-}5$; d) $\text{tol}_t=1\text{e-}7$, $\text{tol}_A=1\text{e-}7$

It can be seen in the above figure, that when the selected tolerances are too big, the displacement front becomes dispersive (top left image in Figure 13). When the tolerances are too small, the solutions are very accurate, i.e., close to the analytical approximation, but computation time becomes very large (lower left image in Figure 13). If many sequential simulations need to be carried out, for example for optimization purposes (see section 0), it is therefore wise to put some effort in finding an optimum such that solutions are accurate enough, but do not take too long to be computed (lower right image in Figure 13).

3.2.3. Numerical stabilization

The conditions posed by Péclet, in theory, always be satisfied by refining the mesh (Zienkiewicz et al. 2005). Though this is often impractical since it requires increasingly more computational power to refine a mesh (i.e., a larger mesh means more equations that need to be solved).

When the Péclet number becomes bigger than one, instabilities in the solution may occur. In COMSOL these instabilities usually show as non-physical oscillations in the solution. Such oscillations can be seen, for example, at the foot of the thermal front in the top right

image of Figure 13. Some techniques for stabilization are suggested by COMSOL which make it possible to solve problems with larger Péclet numbers. The two main options are:

- Adding artificial diffusion
- Applying adaptive mesh refinement

Neither of these two methods have been applied in this thesis. Instead a larger diffusion coefficient has been selected (see section 2.7.7) and effort has been put in finding a good balance between the two main actors in stabilizing the solution: the mesh sizes and tolerances.

Artificial diffusion

Artificial diffusion is widely used throughout the oil- and gas-industry to make reservoir models more stable and easy to solve. In this thesis however, no artificial diffusion is used to solve the models. As a result, the models including varying salinity, require many mesh cells (over $2 \cdot 10^5$) for convergence and take over two days to run.

For future research with models including varying salt concentrations and other displacement fronts should be referred to Zienkiewicz et al. (2005). In this book a number of solutions are posed to decrease the number of mesh cell and computation time while maintaining accuracy on the computations made with FEM simulators.

3.3. Boundary conditions

All reservoir models, used in this thesis, assume steady-state boundary conditions at the injector (section 3.3.1) and these models are either approximately infinite or bounded by no-flow boundaries (section 3.3.2). How wells are represented in the 2D models used in this thesis, is discussed in section 3.3.3. The producers and injectors are subject to the following boundary conditions:

$$BC_p = p_p,$$

$$BC_{in} \begin{cases} p_{in} < p_{thres} & q_{in} = 150 \left[\frac{\text{m}^3}{\text{hour}} \right], \\ p_{in} \geq p_{thres} & p_{in} = p_{thres}. \end{cases}$$

Thus, the production wells are assumed to always function at a constant bottom hole pressure namely p_p . The injection wells on the other hand, will switch from a fixed injection rate, q_{in} , to a fixed pressure once a certain pressure threshold, p_{thres} , is reached.

3.3.1. Steady-state conditions

The assumption of steady-state flow (no start up compression effects) is a very rough assumption and would in reality also not be correct for a single well located in the middle of an infinite aquifer. In practice, most wells are turned on and off on a number of occasions during a production month, and therefore they are rarely in steady state conditions. This level of detail can only be captured once very short timesteps (i.e., numerical solutions) are used. This is not done in this thesis, instead it is assumed that the long term behavior of such reservoir flow can be approximated by assuming steady-state conditions.

3.3.2. No-flow boundaries

No-flow boundaries have been used to bound the reservoir in this thesis. An alternative would have been constant pressure boundaries. In reality, however, neither of these BC's is directly applicable to a reservoir. Natural reservoirs are usually not bounded by straight impermeable faults nor are they infinite. Rather often, the aquifers pinch out or are bounded by (partially) sealing faults of complex nature. For the purposes of this thesis however, straight no-flow boundaries will suffice as no real case, for which accurate modeling of reservoir geometry and heterogeneity is required, will be simulated (Carlson, 2003).

Some models in this thesis, are simulated in 'approximately infinite' reservoirs. In these models, reservoir boundaries are far away from the doublet (at least 2 times the distance of the doublet spacing) as to approach an infinite reservoir.

3.3.3. Wells

The wells in the COMSOL models are represented by circular extrusions in the reservoir domain of 5 inch each. By refining the mesh around this circle, an accurate approximation of radial flow obtained and no Peaceman equation needs to be implemented.

A downfall from this method is that the refinement of the mesh near the wellbore requires more computational power than would have been the case for a point wise representation of wells with the analytical Peaceman approximation of the flow regime.

3.3.4. Variable boundary condition

In order to prevent a discrete transition in the boundary condition of the injector, a smoothed Heaviside function with a continuous second derivative without overshoot is used. This function is in COMSOL defined by a sixth-degree polynomial. A characteristic feature of this function is that it incrementally increases from 0 to 1 over a set interval, thereby avoiding Dirac delta like transitions in the numerical solutions. In the model, a transition zone of 0.2 [MPa] is used (Figure 14). The boundary condition for the injector is now represented by:

$$q_{in} = q_1 + (q_2 - q_1)heaviside(p),$$

$$q_1 = 150 \left[\frac{m^3}{hr} \right] \quad = \text{Initial BC, inject at a maximum rate of } 150 [m^3] \text{ per hour.}$$

$$q_2 = 1 \left[\frac{m^3}{hr} \right] \quad = \text{Alternate BC when } p_{in} \geq p_{thres}$$

$heaviside(p)$ = Smoothed Heaviside function to prevent convergence problems with the numerical model in COMSOL. (Figure 14)

Figure 14: Smoothed Heaviside function, for smooth transition between boundary conditions

This equation assures that the injection pressure never exceeds 25 [MPa] by slowly lowering the injection rate once the pressure exceeds 24.8 [MPa].

3.4. Numerical values

In order to obtain reliable results, stable and converging simulations are required. As mentioned earlier in this chapter, no artificial diffusion is used but instead the mass diffusion coefficient was increased (see section 2.7.8) and appropriate mesh size and tolerances is selected for each reservoir model.

The values for the tolerances, used in this thesis for the 1D and 2D cases are listed in Table 2a. The relative tolerance is (in most cases) selected to be equal to 10^{-5} but is decreased to 10^{-8} for the simulations incorporating salinity contrasts.

The size of the mesh cells largely depends on the size of the reservoir in which simulations are carried out. The minimum and maximum amount of mesh cells per reservoir are given in

Table 2b. The exact amount of mesh cells varies a lot from one simulation to another. Depending on the amount and location of the (pseudo-)wells and the shape and size of the reservoir (approximating an infinite reservoir or a bounded reservoir), the exact amount of mesh cells is defined.

Table 2a) Selected absolute tolerances for temperature, pressure and concentration in the 1D and 2D simulations. b) Range of mesh cells size for which stable solutions are found in 1D, 2D for temperature only and 2D incorporating a thermal and a compositional front

	Tolerances			Mesh sizes	
	1D	2D		Minumum	Maximum
<i>Temperature</i>	10^{-5} to 10^{-7}	10^{-5}	<i>1D</i>	750	7500
<i>Pressure</i>	10^{-1}	10^{-5}	<i>2D, T only</i>	8000	50000
<i>Concentration</i>	10^{-9}	10^{-9}	<i>2D, T and c</i>	150000	250000

4. Optimization method

Determining the best locations for wells in a given geothermal reservoir has a potential high economic impact. Finding these optimal locations is a complex problem that depends on reservoir and fluid properties, well and surface equipment and economic criteria.

With a method proposed in this chapter, it is shown that numerical simulations using gradient-based optimization algorithms, when used for the optimization of well placement, can significantly enhance profits of geothermal projects.

Gradient-based optimization algorithms are used for optimization purposes throughout the oil and gas industry (e.g., Yeten et al. 2003; Bangerth et al. 2004; Güyagüler and Horne 2004; Özdöğün and Horne 2006; Zandvliet et al. 2008; Onwunalu and Durlofsky 2011; Wang et al. 2012). These algorithms provide a systematic way to explore a wide range of well positions and have the goal to find the optimal (or at least very good) well positions for given boundary conditions (e.g., restrictions on surface facilities and the reservoir geometry).

The basis of such gradient-based optimization algorithms requires the definition of an economical model, which is presented in section 4.1. Using this economical model, an objective function is developed (section 4.2), which forms the basis of the optimization method developed for this thesis.

The way gradients are applied with the use of so-called ‘pseudo-wells’ is explained in section 4.3. Thereafter, in section 4.4 it is explained why it is chosen to use a relatively straight forward gradient-based optimization technique called the perturbation method. Then in section 4.5 it is explained how the next well positions are guessed using the perturbation method. How this gradient-based optimization method is implemented, using the “COMSOL with Matlab” software, is explained in section 4.6.

In the final section of this chapter, a short note on the uncertainty involved with optimization is given (section 4.7).

4.1. The economical model

Reservoir simulation is inextricably related to economical forecasts. Optimization methods depend on reservoir and fluid properties, but optimum well locations are determined based on economical factors.

From an economical perspective, the main challenge in reservoir management is to optimize economic measures like NCF or NPV (Fanchi 2002). Therefore, it is important that an economical model is defined.

4.1.1. Net Cash Flow

The economical value of a geothermal doublet is a function of tangible costs, intangible costs, the time that the doublet is active and the rate at which warm water is being produced. By calculating the sum of the future Net Cash Flows (NCF) it can be determined how profitable a project is likely to be.

While omitting subscripts for time and well-number, in favor of the readability of the formulas in this section, the NCF of a geothermal project can be estimated with the following formula:

$$\text{NCF} = -E \cdot \text{NRI} \cdot P_h - \text{OPC} - T - I. \quad \text{Eq.(33)}$$

The first term of this formula denotes the net income because of heat production, by taking the product of the gross heat production rate E , the Net Revenue Interest NRI , and the heat price P_h . The other terms denote the costs involved with a geothermal project, namely: the Taxes T , Operating Costs OPC , and investments I . Eq.27 and following equations use the convention that the injection rates are positive and the production rates are negative (hence the minus sign before the heat production rate).

All variables in the above equation are a function of time. By summing all the Net Cash flows over all years the cumulative NCF, an indication of the profitability of the project is obtained:

$$\text{cum. NCF} = \sum_{t_k=0}^{T_k-1} \text{NCF} \Big|_{t_k}^{t_{k+1}}. \quad \text{Eq.(34)}$$

In this equation, t_k is the time in years and T_k is the lifetime of the project in question in years.

4.1.2. Alternative NCF

In section 4.2, the NCF will be used as the basis for the development of the objective function. For this reason the operating cost will be written in terms of water production q_p and the water injection q_{in} and we combine the Net Revenue Interest and heat price in one term, yielding:

$$-r_p \cdot q_p + r_{in} \cdot q_{in} = \text{OPC}. \quad \text{Eq.(35)}$$

$$r_h = \text{NRI} \cdot P_h. \quad \text{Eq.(36)}$$

In equation 35 and 36, r_h , r_{in} , and r_p represent the heat production revenue per unit heat; the water-injection cost per unit volume and the water-production and processing cost per unit volume, respectively.

The water-injection and –production cost are effectively dependent on the amount of power that the pumps need to exert (W_{pump}) and the price of electricity (P_{energy}). Therefore, one can write:

$$r_{in} = P_{energy} \cdot W_{pump} . \quad \text{Eq.(37)}$$

All variables in the in equation 33 are either continuous or discrete contributions to the Net Cash Flow, and all these variables are dependent on time. When we combine equations 33 through 36, and do not consider taxes, we get an alternative Net Cash Flow formulation:

$$NCF_{alt}(t) = r_h \cdot E + r_p \cdot q_p - r_{in} \cdot q_{in} - I . \quad \text{Eq.(38)}$$

4.1.3. Net Present Value (NPV)

Although the cumulative Net Cash Flow is a measure used to estimate the profitability of a project, it does not take into account the time value of money. This can be done by discounting the NCF of each year with a discount factor. By doing so, the discounted cumulative net cash flow or Net Present Value of a project can be obtained. This is broadly considered to be one of the most important economic measures, used in reservoir management.

Making use of equation 34 and implementing the time value of money, the formula to calculate the NPV can be written as:

$$NPV = \sum_{t_k=0}^{T_k-1} \frac{NCF|_{t_k}^{t_{k+1}}}{(1+b)^{t_k+1}} . \quad \text{Eq.(39)}$$

In this equation, t_k is the time in years, T_k is the lifetime of the project in years and b is the discount rate. By choosing a discount factor larger than zero, the fact that costs and profits in later years will be increasingly less significant to the risk on the investment are also taken into account.

NPV calculations can be applied to a range of well placement strategies. A comparative analysis of different well placement strategies can then be used for optimization purposes and gives decision makers valuable information for making informed decisions.

4.1.4. Economical Parameters

The economical parameters that are used in this thesis for the calculation of the NPV of a geothermal project, are shown in Table 3 on the next page. These values are also used by TNO (van Wees et al. 2010) for their ThermoGIS information system.

Table 3: Values for economical parameters, used in this thesis

Description	Variable	Value
Heat Price for sales	r_h	7.05 [Euro/GJ]
Electricity price for operations	P_{energy}	0,07 [Euro/kWh]
Discount rate	b	0,07 [-]
Fixed OPEX	OPC	0.05 [-] fraction of active capex
Tax	T	0.255 [-] fraction of taxable income
Heat Exchanger	I	$0.1 \cdot 10^6$ [Euro]
Pump	I	$0.5 \cdot 10^6$ [Euro]
Pump refurbishment	I	$0.25 \cdot 10^6$ [Euro]
“MEI subsidie”	I	$1.5 \cdot 10^6$ [Euro]
Drilling Operation	I	$7.15 \cdot 10^6$ [Euro]
Permits and Research	I	$0.6 \cdot 10^6$ [Euro]
Abandonment	I	$0.5 \cdot 10^6$ [Euro]

4.1.5. Heat production

The profitability of geothermal doublets, lies in the fact that energy in the form of heat can be extracted by heat exchangers from produced reservoir water. The total amount of energy [Joule] present in a produced volume of water is given by:

$$E = q_p(t) \cdot \rho_w(T, p, c) \cdot C_{pw}(T, p, c) \cdot T. \quad \text{Eq.(40)}$$

The volume of produced water is dependent on the flow rate q_p and the timespan, t , over which the water has been produced. The density ρ_w and heat capacity C_{pw} of water determine the amount of energy that is stored in water. Both variables are a function of temperature T [K], pressure p [Pa], and salinity c [mol/kg].

The water that is reinjected however, still contains energy. The effective produced amount of energy can be written as:

$$E_p = q_p(t) \cdot \Delta(\rho_w \cdot C_w \cdot T), \quad \text{Eq.(41)}$$

$$\Delta(\rho_w \cdot C_w \cdot T) = (\rho_w \cdot C_w \cdot T)_p - (\rho_w \cdot C_w \cdot T)_{in}. \quad \text{Eq.(42)}$$

In the above equations, the subscripts p and in belong to the variables pertaining to the produced water and injected water, respectively.

4.2. The objective function

In this section the objective function (J), derived from the NPV calculation for geothermal doublets, is presented. The equations from the previous sections on economics will be used as the basis of the construction of this objective function.

In any well placement optimization process, the objective function plays a major role. The reason for using the objective function in well placement optimization algorithms is that, depending on the heterogeneities of the reservoir, some locations are, from an economical perspective, more favourable for well placement than others. Maximizing the objective function therefore means finding the optimized well locations.

Determining optimal locations and operation parameters for wells in geothermal reservoirs has a potentially high economic impact. Investment costs (I), such as drilling and maintenance of facilities however, are assumed to be independent of the well locations and therefore a constant part of the NPV calculation. Therefore these values can be omitted in the objective function since they will not influence the optimization process.

We use that the alternative NCF equation (equation 38) is a function of the vector of spatial coordinates, $\mathbf{w}$, of the to-be-optimized wells in the 2D plane of the reservoir. While neglecting investment costs, and including the previously neglected subscripts for time (k), well number (j), we yield:

$$\text{NCF}_{alt}(\mathbf{w}) = -\sum_{j=1}^{N_j} r_h E_{p,j,k}(\mathbf{w}) + \sum_{j=1}^{N_j} r_p q_{p,j,k}(\mathbf{w}) - \sum_{j=1}^{N_j} r_{in} q_{in,j,k}(\mathbf{w}). \quad \text{Eq.(43)}$$

In this equation, N_j is the number of wells and k is the timestep. The vector of the spatial coordinates of the to-be-optimized wells is represented by $\mathbf{w}$. In the case of the 2D, top view, simulation the vector of spatial the coordinates contains the x- and y-coordinates.

Like the NPV, the objective function, can be defined as a measure of profitability of a project over a certain period, discretized with K timesteps. Combining the equation for the NPV from the previous section (equation 39) with equation 43, an objective function for a geothermal project with production and injection wells can be found:

$$J(\mathbf{w}) = \sum_{k=0}^{N_K-1} \left[\begin{array}{c} -\sum_{j=1}^{N_j} r_h E_{p,j,k}(\mathbf{w}) + \sum_{j=1}^{N_j} r_p q_{p,j,k}(\mathbf{w}) \\ -\sum_{j=1}^{N_j} r_{in} q_{in,j,k}(\mathbf{w}) \end{array} \right] \frac{\Delta t_k}{(1+b)^{t_k}}. \quad \text{Eq.(44)}$$

Here t_k and Δt_k are the time and stepsize (in years) corresponding to timestep k , where N_k is the total number of timesteps. The form in which the objective function is presented in the above equation, is based on the functions used by basically all well-placement optimization methods for oil and gas reservoirs. (e.g., Yeten et al. 2003; Bangerth et al. 2004; Güyagüler and Horne 2004; Özdöğün and Horne 2006; Zandvliet et al. 2008; Onwunalu and Durlofsky 2011; Wang et al. 2012).

In equation 44, the convention is used that the injection rates are positive and the production rates negative. A note to this equation is that, since taxes and tangible costs are neglected, the objective function is not the same as an NPV calculation.

The objective function presented here poses effective means to quantify the profitability of a geothermal doublet and is a tool that can be used to optimize well positions of geothermal wells.

4.3. Application of indirect gradients

The basis of many optimization algorithms is the use of gradients of the objective function. By minimizing or maximizing this gradient the search direction for optimization algorithms can be determined.

One way of applying such gradients of the objective function indirectly, is surrounding each to-be-optimized “main-well” by eight “pseudo-wells” (Sarma et al. 2008; Zandvliet et al. 2008). These pseudo-wells are placed in the grid blocks neighboring the main-well in the 2D plane (top view). Each of these pseudo-wells produces (or injects when considering an injector) at a very low rate to minimize their respective influence on the flow behavior of the reservoir.

Now, the gradient of the objective function over the lifetime of the reservoir with respect to the rate at each pseudo-well can be calculated. Various methods have been developed to calculate this gradient. Best known and most used among these methods are various perturbation methods, the forward sensitivity equations method and the (backwards) adjoint method (Biegler 2000; Kraaijevanger et al. 2007). In this thesis a perturbation method is used and elaborated on in the next section.

Figure 15: Pseudo-well method, the well is moved to the position of the most favorable pseudo-well at the next iteration

The largest positive gradient value among the eight gradients (of the pseudo-wells) determines the direction in which the main-well should be moved to increase the objective function in the next iteration. (see Figure 15)

Since the gradients of the objective function, with respect to the rate of the pseudo-well, are used, rather than the gradients of the objective function with respect to actual optimization parameters, this is called an indirect application of gradients.

There are, however, some limitations to this pseudo-well-approach. One drawback is that, a pseudo-well approach limits itself to only a limited amount of search directions for each well per iteration. In the optimization method for geothermal wells proposed in this thesis, the amount of pseudo-wells is limited to 8, such as also proposed by Zandvliet et al. (2008) and Sarma et al. (2008). Though in theory there is no limitation on the amount of pseudo-wells that can be used in COMSOL.

Another drawback of this method is that each well is typically set to move only one grid block per iteration, which is numerically quite inefficient.

Finally, there is a possibility that a main-well converges into a corner, assuming a rectangular reservoir. This means that only three of the eight pseudo-wells can be used because the rest lie outside the domain of the reservoir. In this scenario, the search direction of the algorithm is limited to only three directions.

4.4. Gradient calculation

The main advantage of gradient-based optimization algorithms, with respect to gradient free optimization methods is that it usually requires far fewer iterations to converge to an optimum. Another benefit is that gradient-based optimization guarantees that each second iteration yields a solution equal to or higher than the initial solution (Sarma et al. 2008).

The perturbation method as described by e.g., Biegler 2000 and Kraaijevanger et al. 2007., is used in this thesis. This perturbation method is, as opposed to other gradient calculation methods, quite easy to implement. What makes this method relatively easy to use is that it requires no adaptation of the forward FEM numerical algorithm (which cannot be altered in COMSOL).

The basic principle of this method is that the gradient of the objective function can be approximated by calculating the differences between a so-called ‘base-case’ run and a ‘perturbation’ run by marginally varying a component from the control vector $\mathbf{U}$. In this thesis the flow rate q has been chosen to be the defining control variable for all (pseudo-) wells.

Now the m^{th} perturbation of the j^{th} pseudo-well, contributing to the total derivative, $\frac{dJ}{d\mathbf{U}}$, is then approximated by the gradient:

$$\frac{\partial J}{\partial U_{j,m}} = \frac{\tilde{J} - J_{base}}{\Delta q_{j,m}}. \quad \text{Eq.(45)}$$

In this equation, $\tilde{J}$ is the objective function resulting from the perturbation run and J_{base} is the objective function resulting from the base run. The increment $\Delta q_{j,m}$ has to be chosen such that the influence on the overall flow is negligible but bigger than the numerical errors introduced by the FEM in COMSOL. In addition a suitable number of perturbations N_m per pseudo-wells has to be chosen, such that the gradient is approached. In the selection of the amount of perturbations, a balance should be found between precision and computation time.

Although this perturbation method is a valid means to calculate a gradient, this method has two drawbacks. Firstly, in order to get a good approximation of the gradient, the required number of perturbation runs per iteration is generally quite large (in this thesis 10 are used). This is detrimental for the efficiency (speed) of the optimization sequence. A second drawback is that there is no way of telling what the right increment size (Δq) should be in order to have a good performance of the optimizer. (Sarma et al. 2008)

Nonetheless, it is possible to realize the objective proposed in section 4.2 and use this perturbation method to verify that application of gradient-based optimization to the optimization of the placement of geothermal wells is potentially rewarding. Finding the most efficient means to apply such optimization is therefore left to future study on this topic.

4.5. Iterative optimization

Like all gradient-based optimization methods, the gradient calculation method proposed in this study is based on the concept of maximizing the objective function. This is done with the use of the total (indirect) derivative of some well (j) with respect to some control variable (in this thesis the flow rate, q , is used) from the control vector $\mathbf{U}$:

$$\frac{dJ}{d\mathbf{U}_j^i} = \sum_{m=1}^{N_m} \left(\frac{dJ}{d\mathbf{U}_{j,m}^i} \right). \quad \text{Eq.(46)}$$

The iteration counter is denoted by the superscript i . The best well position for the next iteration ($i+1$) can be found for the injector and the producer by maximizing the gradient of the objective function. The maximum value of the summed derivatives, $j_{\max}$, can be found by summing up the gradients of all wells for all perturbation runs

$$j_{\max} = \arg \max_{j=1, \dots, N_j} \sum_{i=1}^{N_j} \left(\frac{dJ}{d\mathbf{U}_j^i} \right). \quad \text{Eq.(47)}$$

Zandvliet et al. (2008) used a similar relation to calculate the maximum value of the summed derivatives. When the equations 46 and 47 are combined and the perturbation method (equation 45) is implemented, it is obtained that:

$$j_{\max} = \arg \max_{j=1, \dots, N_j} \sum_{m=1}^{N_m} \left(\frac{\tilde{J} - J_{base}}{\Delta q_{j,m}^i} \right). \quad \text{Eq.(48)}$$

The position of the pseudo-well with the largest summed partial derivative will be the position for the main injector at the next iteration. Effectively, only the gradients of the active wells are summed since the partial derivatives of other pseudo-wells are zero throughout the runtime of the simulation.

With this technique new well locations are found after each iteration for which **J** will increase until an optimum is found. The vector of main-well locations at the next iteration is given by:

$$\mathbf{w}^{i+1} = \mathbf{w}^i + \mathbf{d}^i. \quad \text{Eq.(49)}$$

The supposed ‘improving’ direction $\mathbf{d}^i$, of a main-well is found by taking the difference between the position of the best pseudo-well $\mathbf{w}_{j_{\max}}^i = [x_{j_{\max}}^i, y_{j_{\max}}^i]$ obtained with equation 48 and the main-well ($\mathbf{w}^i$):

$$\mathbf{d}^i = [w_{x,j_{\max}}^i, w_{y,j_{\max}}^i]^T - \mathbf{w}^i. \quad \text{Eq.(50)}$$

4.6. Implementation

In this section will be discussed how the perturbation method, discussed in the previous sections, has been applied to the cases considered in this thesis.

4.6.1. Structure

The optimization method developed for this thesis makes use of the ‘COMSOL with Matlab’ add-on. This feature allows Matlab to execute and analyze COMSOL models, thereby making it possible to implement iterative loops, required for optimization.

The developed iterative algorithm is, in its simplified form, shown in Figure 16. In Appendix A, a more elaborate scheme of the algorithm can be found.

Figure 16: The implemented iterative optimization scheme

The optimization algorithm is tested with one injector and one producer. Using the pseudo-well optimization technique, which was also implemented by Zandvliet (2008), the total number of wells (N_j) in the numerical model is 18 in the cases considered in this thesis. Wells 1 to 8 are pseudo-production wells and wells 10 to 17 are the pseudo-injection wells. Now well 9 is the main producer and well 18 is the main injector.

This optimization method can, in theory, be applied to more than one doublet. The limiting factor for doing so, is the computational power that is required to execute the COMSOL model.

4.6.2. Implementation of pseudo-wells

In order to calculate the gradient of a pseudo-well, the influence of the flow rate of each pseudo-well on the overall objective function needs to be evaluated. Therefore we choose M times lapses for which each pseudo-well injects (or produces) slightly more than the other pseudo-wells. An example of such a small increase in the flow rate is shown in Figure 17.

Since the gradients of all each pseudo-wells are considered individually, the injection- or production rate, $q_{j,m}$, of all non-active pseudo-wells are set to zero.

Now, the amount of simulations that need to be carried out for one iteration (i.e., one step closer towards the ‘optimum’ well position), is the product of the amount of pseudo-wells (N_j) and the amount of time lapses or perturbations (N_m).

It is chosen to use 10 perturbations (i.e., $N_m = 10$) for each pseudowell to approximate its gradient (Figure 18). Each of these perturbations corresponds to a certain timeframe in which the pseudo-well in question is active. The increment for the pseudo-wells is set to $0.015 \text{ m}^3/\text{h}$, which corresponds to 0.01% of the rate of the main-wells. Such small rates do not influence the overall flow regime of the field but make sure that the induced flux is one order bigger than the numerical error of the model. Zandvliet et al. (2008) used similar rates for the pseudo-wells in his study.

Figure 17: Flowrate over time of a pseudo-well j at perturbation run m

In Figure 18, the gradients of the pseudo-producing wells have been plotted. The perturbation number is indicative at what point in time of the lifetime the perturbation was made. For example, the first perturbation means that the pseudo-well in question was active during the first $1/10^{\text{th}}$ of the lifetime of the doublet.

The contributions of the perturbation runs at an earlier stage in the doublet lifetime are bigger than the ones at a later stage for the following reasons:

- The objective function contains the time value of money through the discount factor. Profits and losses made at later points in time are therefore less valuable/costly.
- After thermal breakthrough has occurred, the additional gain of producing a bit more water from the pseudo-wells is smaller than before breakthrough.

Figure 18: Gradients of pseudo-producer wells (PS). 10 perturbations are carried out per pseudo-well, indicating for each perturbation of each well how profitable it was. The largest sum of all perturbations per pseudo-well, indicates which direction has the largest gradient and is most favorable for the next iteration.

4.6.3. Remarks to optimization

The optimization method for geothermal doublets proposed in this chapter is usable but, as mentioned in section 4.4, has limitations. Some recommendations for future research on this topic are listed in Appendix B.

4.6.4. Cluster computing

Computing one simulation of the propagation of the thermal front in a 2D reservoir model throughout the lifetime of a doublet, takes 5 to 30 minutes (depending on the model and processor that are used). For the optimization scheme described in the previous sections, running one iteration step requires 170 simulations. Therefore one optimization sequence of 10 iterations may take 6 days to a month to complete when executed in sequence on a single computer. Reduction of computation time is therefore welcome.

In an attempt to reduce the computation time, the optimization algorithm has been executed on a cluster of ten nodes. By letting each node execute 16 simulations, the time per iteration is reduced to four up to twelve hours.

One major drawback of the cluster in question has been that some of the cluster nodes are considerably slower than others, and cope memory issues when dealing with larger COMSOL models.

By assuming that an effective iteration can be performed when more than 7 perturbations per pseudo-well are known, the delays in the optimization sequence caused by slow cluster-nodes have been limited. (see Appendix A)

4.7. Uncertainty of data

One major issue with optimization is that the model forecast data usually contain a certain amount of uncertainty since the numerical models on which they are based are uncertain. (for a more elaborate discussion on uncertainty, see Appendix C)

Subsurface geology is highly uncertain and normally it is necessary to account for this uncertainty when optimizing the location of new wells. This thesis, however, does not incorporate an assessment of uncertainty of the input data. This is not necessary, since no 'real' case-study is considered.

Another type of uncertainty was investigated by Zandvliet et al. (2008), who observed that production constraints (induced by the output requirements) significantly affect the well-placement problem. In this study it is shown that a well configuration that is optimal when the wells are operated with one set of constraints may be far from optimal when wells are operated with another set of constraints.

This type of uncertainty is mitigated in this thesis by assuming only one set of constraints (see chapter 5).

5. Reservoir Model

The previous chapters have explained the physics, numerical model and optimization method. In this chapter the reservoir conditions, used for the simulations in this thesis, are described.

In the first section it will be explained why a numerical 2D approach has been chosen for this problem (section 5.1). Thereafter, the assumptions that were made for the model are described (section 5.2).

In order to test the numerical model, a theoretical homogeneous matrix with constant fluid and rock properties is used. This model is referred to as ‘the verification model’. The conditions and properties used in this theoretical model are listed in section 5.3.

In section 5.4 the reservoir conditions used for the simulation of more realistic cases (with fluid and rock dependencies of temperature and pressure) and heterogeneous reservoir conditions are discussed. Thereafter the production constraints that are used for wells in this thesis are described (section 5.5) and the definition of what is considered to be a breakthrough, is given in section 5.6.

In order to investigate the effect of heterogeneities on well placement, two different case study geology models have been chosen. The first is a model with analogies to the Delft sandstone and is described in section 5.7. The second model, called the SPE10 model, is discussed in section 5.8 and is an artificial reservoir model with extreme heterogeneities.

5.1. Approach

Instead of using more sophisticated and realistic 3D models, it has been chosen to mainly work with 2D, top view, models.

In chapter 6, 1D models are used for the verification of the numerical method and for the comparison between conservative and non-conservative heat transfer. Thereafter only non-conservative 2D, top view, models are used to assess the effects of heterogeneities on well placement. These models are, under the assumptions listed in the next section, able to capture thermal and compositional front propagation in homogeneous and heterogeneous reservoirs. Furthermore, with the help of such 2D, top view, simulations the influence of heterogeneities on radial reservoir flow and interference effects between adjacent doublets can be captured.

5.2. Assumptions

In this section, a distinction is made between the conservative cases and non-conservative cases described in this thesis. Firstly, all the general assumptions are listed. Thereafter, additional assumptions for non-conservative flow are given.

5.2.1. General assumptions

In the previous sections, several assumptions with regard to reservoir flow have been made. Especially in chapter 2 on the derivation of the fluid flow and heat and mass transfer equations and the thermodynamic relations, many assumptions are given. A brief summary of the major assumptions is given here:

1. The groundwater is composed of pure water and dissolved sodium chloride.
2. Groundwater flow velocity is zero before production initiates.
3. Groundwater flow is laminar (see section 2.2.1).
4. Darcy conditions can be assumed and ground water flow can adequately be simulated using homogeneous, saturated porous medium assumptions.
5. It is assumed that fracture pathways are absent.
6. Dispersion effects (hydrodynamic dispersion and conductive thermal diffusion) can be neglected. In reality some thermal breakthrough will likely occur ahead of the calculated mean travel time due to these effects.
7. Thermal equilibration between aquifer water and aquifer matrix is instantaneous.
8. Conductive heat losses into overlying or underlying strata are negligible as well as in-situ heat generation by radioactive decay or water influx.
9. Gravity has no effect on reservoir flow (see section 2.1.1).
10. The change in the flow velocity due to the change in the fluid density is negligible (no mass conservation).
11. All wells considered to be vertical and identical, such that a radial flow regime can be assumed.
12. There is no skin in the near wellbore areas of the wells.

The assumptions posed above are applicable to granular, porous-medium aquifers such as alluvial sands and gravels or porous sandstones (like the West Netherlands Basin) and are likely to be poorly applicable for fissured and fractured aquifers (e.g., chalk, limestone and crystalline bedrock).

5.2.2. Non-conservative heat transfer

All simulations, done to assess the impact of heterogeneities on the profitability (except for the section where the impact of conservative heat transfer is investigated), use the non-conservative set of heat transfer equations (equation 10, section 2.3).

Thereby it is assumed that, even though the variation in the rock and fluid properties is not incorporated, the solutions still yield a good approximation of the behavior of the thermal front in homogeneous and heterogeneous reservoirs.

This assumption is justified by the fact that the transient region, in which the non-conservative equation for heat is not valid, is small compared to the total length of the domain. When considering a 1D model of 1500 m, for example, the temperature front only occupies up to 1/15th of the domain.

It is shown section 6.1.3 that the shape of the thermal front and the temperature decline curve in a 1D and a 2D homogenous reservoir, are very similar for conservative and non-conservative heat transfer.

In section 6.1.3, it is also shown that the thermal front propagates slower than what would be expected, based on non-conservative calculations. When using the conservative form of the heat transfer equations, the propagation of the thermal front is slowed down by some factor, the conservation retardation:

$$R_{cons} = \frac{V_{thermal,cons}}{V_{thermal,non-cons}}. \quad \text{Eq.(51)}$$

In this equation, R_{cons} is the conservation retardation factor (see section 2.5). Although R_{cons} is calculated in section 6.1.3, for the reservoir conditions and production constraints provided in this chapter, the rest of chapter 6 does not consider this retardation effect.

In effect, all reservoir simulations in this thesis, performed with the non-isothermal heat transfer, will have later thermal breakthrough in real cases. Since the purpose of this thesis is to illustrate the potential impact of heterogeneity on well locations and profitability and no real case-studies are performed in this thesis, using the non-conservative and neglecting the conservation induced thermal retardation factor is justified.

5.3. Verification model

The verification model is used to verify that the 1D numerical model could be approached by the analytical solutions to the problem. For this reason constant values for the fluid and rock properties were assumed for these 1D calculations. In the results (chapter 6), the 1D model is also compared to a 2D model with similar reservoir properties.

5.3.1. Numerical 1D model

To test the numerical model it is chosen to work with a geothermal doublet with a spacing of 1500 m. The Darcy flow velocity, u_w , in the 1D simulations is calculated as follows:

$$u_w = \frac{q}{h \cdot L} = 5.556 \cdot 10^{-7} \left[\frac{\text{m}}{\text{s}} \right].$$

Such a flow rate, yields a bottom hole injection pressure of:

$$p_{in} = -\frac{\mu}{k} u_w L + p_p = 20.1 \text{ [MPa]}.$$

These and other specifications of the verification model are given in Table 4.

The maximum mesh element size of the numerical model is 2 meter and the relative and absolute tolerance are set to 10^{-7} . With these settings the oscillation effects, inherent to a discontinuity in a finite element simulation, is minimized (i.e., no longer visible on the scale of the obtained graphs).

Table 4: Specifications of homogeneous 1D model without fluid or rock property dependencies on pressure, temperature and salt concentration

Symbol	Magnitude	Description
q	150 [m ³ /hour]	Injection rate
L	1500 [m]	Well spacing (between injector and producer)
h	50 [m]	Reservoir height
p_{prod}	19 [MPa]	Production well BHP
p_{inj}	20.1 [MPa]	Injection well BHP
u_w	$5.556 \cdot 10^{-7}$ [m/s]	Flow velocity
k	500 [mD]	Permeability
ϕ	0.2 [-]	Effective porosity
u_w	$5.556 \cdot 10^{-7}$ [m/s]	Darcy velocity
$T_{x=0}$	313.15 [K]	Temperature of injector water
T_{init}	350.15 [K]	Initial temperature
ρ_w	1000[kg/m ³]	Fresh water density
ρ_R	2600[kg/m ³]	Matrix density
K_R	3[W/(mK)]	Thermal conductivity of matrix
K_w	0.6622[W/(m·K)]	Thermal conductivity of water
C_r	1000 [J/(kg·K)]	Heat capacity of matrix
C_w	4193 [J/(kg·K)]	Heat capacity of water
μ	$5.2 \cdot 10^{-4}$ [Pa·s]	Viscosity of water

5.3.2. Analytical 1D model

The advective-diffusion equation for the temperature front given by equation 52, has the well-known analytical solution given by Ogata and Banks (1961) which is also used in various other literature (e.g., Lake 1989; Geiger et al. 2006; Jaiswal et al. 2010):

$$T(x,t) = \frac{T_{x=0}}{2} \left(\operatorname{erfc} \left[\frac{x - v_x t}{2\sqrt{\alpha t}} \right] + \exp \left[\frac{v_x x}{\alpha} \right] \operatorname{erfc} \left[\frac{x + v_x t}{2\sqrt{\alpha t}} \right] \right). \quad \text{Eq.(52)}$$

In this equation, the temperature T , is a function of location, x , and time, t . The shape of the thermal front depends on the thermal diffusivity, α (see section 2.3) and the speed at which the front propagates is dependent on the interstitial velocity, v . In the 1D case which this analytical function is describing, the velocity is a tensor in the x -direction, hence the subscript, x .

5.4. Reservoir conditions

It has been chosen to work with conditions similar to the ones present in the West Netherlands Basin in this thesis at a depth of approximately 2000 meters. The main reason to work with these conditions is that doublets operate in this basin at the given depth (see section 1.3.6).

In this section the fluid and rock properties, initial conditions, production constraints and the Heat In Place (HIP) of the considered reservoir are discussed.

5.4.1. Brine and rock properties

As explained in section 2.7, brine and rock properties are dependent on pressure, temperature and salinity. A summary on the relations that have been applied to approximate the values of these properties as well as their validity ranges are given in Appendix D.

Rock properties

In this thesis the conditions present in the Delft sandstone member are considered. Therefore, the rock matrix of the reservoir models used in this thesis is assumed to be made of unconsolidated and incompressible sandstone. A second assumption is that the rock does not interact with the aquifer water or reinjected fluids.

Brine properties

Aquifer brine usually contains many types of ions. In Table 5 three recent and representative measurements of the Delft and Rijswijk sandstone are given. The wells from which samples have been taken have penetrated both Delft and Rijswijk sandstone and, therefore, it can be assumed that the salinity of the aquifer water is of roughly the same composition.

Chloride and sodium ions constitute to more than 90% of the salt dissolved in the water in the three measurements presented in Table 5. For convenience it is therefore assumed that brine density can be approximated by assuming that sodium chloride is the only soluble present in the brine. Since this thesis gives a general insight into interactions between geothermal production and injection wells, this assumption will suffice.

Table 5: Salt concentrations in three different measurements

Ions	Rijswijk and Delft Zandsteen, ADH productie	Rijswijk and Delft Zandsteen, ADH injectie	Delft Zandsteen, PN-GT0304 (2011)
Na+	34,00	37,00	29,39
Cl-	81,00	74,00	71,99
Other Ions	10,89	5,46	7,57
TDS [g/kg]	125,89	116,46	108,95
Salt [mol/kg]	2,15	1,99	1,86

5.4.2. Initial conditions

The values for these initial conditions are given in Table 6. The reasoning behind the magnitude of these values are given in the following subsections.

Table 6: Constant initial values, assumed for the Delft sst. analogue and SPE10 model

Symbol	Magnitude	Description
T_{init}	348.15 [°K]	Initial temperature
c_{init}	1.9 [mol/l]	Initial NaCl concentration in reservoir water
P_{init}	20 [MPa]	Initial Reservoir Pressure
HIP	92 [MJ/m ³]	Heat In Place

Initial salinity concentration

In Table 5, the PN-GT0304 estimation is the most accurate since it only concerns the Delft Sandstone. The rest of the measurements has measured the content of water from the Rijswijk and Delft Sandstone. Accordingly it is assumed in this thesis that the reservoir water initially has a concentration of 1.9 [mol/l] dissolved sodium chloride. In the results (Chapter 6), some of the cases, which investigate the behavior of a compositional front, assume the injected water has a somewhat lower salinity of 1.81 [mol/l] for the reasons mentioned in the first chapter (section 1.3.4).

Initial pressure

For the approximation of the initial reservoir pressure at a depth of 2000 m, a pressure gradient of 100 [KPa/m] is assumed. Accordingly, the pressure at this depth is 20 [MPa], which corresponds with several measurements from the Ammerlaan and Duijvestijn doublets in the West Netherlands Basin.

Initial temperature

The temperature of extracted water, depends on the depth and geothermal gradient of the reservoir in question. The higher the temperature of the produced water (at a deeper depth), the larger the energy yield at the surface. On the other hand, a deeper depth requires higher initial investment and higher operating costs due to the extra energy consumption of the pumps to overcome the friction losses in the production and injection well.

Currently, multiple geothermal well doublets have been installed at a depth of >2000 m in the West Netherlands Basin. In this basin, the temperature at this depth is approximately 75 °C (van Wees et al. 2010).

Heat In Place (HIP)

The heat capacity of an aquifer or Heat-In-Place is defined as the maximum theoretically extractable heat in an aquifer in several studies (e.g., Gringarten 1978; van Wees et al. 2010). The HIP is given in Mega Joules [MJ] by the following formula:

$$\text{HIP} = (C \cdot \rho)_{\text{eff}} (T_h - T_c) \cdot V \cdot 10^{-6}. \quad \text{Eq.(53)}$$

In this relation, the reservoir volume is represented by V , the heat capacity is given by C and ρ is the density. The volumetric heat capacity of fluid saturated rock is defined as:

$$(C \cdot \rho)_{\text{eff}} = \phi \rho_w C_w + (1 - \phi) \rho_R C_R. \quad \text{Eq.(54)}$$

It is assumed that one m^3 of reservoir can potentially be cooled down 35 [°K] and that the volumetric heat capacity of the reservoir is $2.63 \cdot 10^6$ [J/($\text{m}^3 \cdot \text{K}$)]. The presumed HIP can now be calculated to be 92 MJ per m^3 reservoir, approximately.

5.5. Production constraints

Zandvliet et al. (2008), among others, demonstrated that optimal locations of wells are affected by production and injection constraints such as pressure and rate. For conventional vertical wells there is just one control variable, which can be the tubing head pressure (THP), bottomhole pressure (BHP) or an injection/production rate.

The choice for these constraints is not completely free. It should be taken into account that there are certain operational limits such as rate and pressure constraints. These operational limits correspond to inequality constraints in terms of variables of the reservoir system (e.g., temperature, pressure or concentration).

The models in this thesis operate the production wells with a pressure constraint and the injectors with a rate constraint (section 5.5.1). In addition the producers have also temperature constraints (section 5.5.2).

5.5.1. Pressure and rate constraints

In practice, the NPV for geothermal projects is attempted to be maximized by producing as much water as possible from the reservoir. The general constraints on the wells are shown in Table 7.

Table 7: Production constraints

	Production Constraints
<i>Water injection rate</i>	Max. 150 m^3/h
<i>Injector BHP</i>	Max. 25 MPa
<i>Producer BHP</i>	17.72 MPa

Consequently, all wells continuously produce or inject at the highest possible rate without violating the constraints shown in Table 7. How the values for these constraints are obtained is explained in Appendix E.

When assumed that the efficiency and energy consumption per generated Pascal overpressure is the same as for ESPs, the booster pump operates at a energy consumption rate as shown in Figure 19. In this figure the energy consumption of two pumps of Baker Hughes (see Appendix F) are plotted. The trendline through these two points is the relation used by the objective function to determine the costs involved with energy consumption of the pumps.

For example, when the booster pump has to generate 1 [MPa] of overpressure for one month, it can be derived from Figure 19 that this will cost approximately 5000 Euros.

Figure 19: Pump energy costs per month for both the ESP and booster pump. The relation given by the blue line is used by the objective function.

5.5.2. Temperature constraints

Research and technology organization TNO (van Wees et al. 2010) assumes that temperatures over 45 °C are sufficient for heating of greenhouses and temperatures over 65 °C are sufficient for spatial heating. The heat exchanger is capable of using the geothermal heat of the produced water down to a certain temperature limit, which is equal to the temperature of the re-injected water. For greenhouse heating, the reinjection temperature is assumed to be 25 °C and for spatial heating 40 °C.

Table 8: Values for production and injection temperatures (TNO, van Wees et al. 2010)

Purpose	Min. Production T	Reinjection T
<i>Greenhouse</i>	318.15 °K	298.15
<i>Spatial</i>	338.15 °K	313.15

The optimization algorithm (presented in chapter 4), uses the constraints for spatial heating presented in the above table (except when mentioned otherwise), such that geothermal doublets are operated with a minimum-temperature constraint.

5.6. Temperature and compositional breakthrough

Small oscillations in the measurements at the producer, just before the occurrence of compositional and temperature breakthrough, complicate the indication of the exact time of this breakthrough. The exact time of breakthrough therefore requires a clear definition. In this thesis, the thermal breakthrough is defined as the moment when the temperature at the producer has dropped by 0.01 [°K]. The compositional breakthrough has been defined as the moment when the salinity at the producer has dropped by 0.01 [mol/l].

5.7. Delft Sandstone model

Smits (2008) describes the Delft Sandstone Member as stacked distributary-channel deposits in a lower coastal plain setting and its occurrence is in the western and central parts of the West Netherlands Basin. The thickness of the Delft Sandstone Member varies between 0 and 130 meters.

Since 2D models are used in this thesis, it is assumed that the net thickness of the reservoir is a constant of 56 m. This corresponds to the P50 value for the net thickness that was used by Smits (2008) in his study.

5.7.1. Porosity and permeability

Multiple cores of the Delft Sandstone Member have been taken from the Moerkapelle Oilfield. The data obtained from these cores are representative for the Delft Sandstone Member and also used in other studies (Smits 2008; Gilding 2010). The available porosity and permeability data consists of measurements taken from 3 cores and multiple side wall samples on which porosity and permeability measurements have been performed. The porosity distribution as shown in Figure 20 was derived from these measurements.

Figure 20: Delft Sandstone porosity data (Gilding 2010)

The empirical porosity and permeability relationship of the Delft Sandstone Member, (Equation 55) is based on a study by Smits (2008):

$$k = 0.0762e^{35.552\phi} \pm 12\% .$$

Eq.(55)

5.7.2. Homogeneous reservoir

It may be clear from Figure 20 that the Delft Sandstone member is not homogeneous. The ‘average’ permeability and porosity are estimated nonetheless, such that it is possible to demonstrate what the effects are when the geothermal wells in a heterogeneous reservoir are planned as if it were a homogeneous reservoir.

In this case, it is chosen to approximate the average permeability of the reservoir by taking the weighted average of the permeability. Ahmed (2010) poses that this averaging method is typically used to determine the average permeability in a layered-parallel beds with different permeabilities. Since the Delft Sandstone consists of sheet like fluvial deposits, this averaging method will be a good choice. The same is done for the porosity values. Using again the porosity derived values for the permeability from Gilding (2010), we obtain:

$$\phi_{weighted} = 0.19 [-]$$

$$k_{weighted} = 254 [mD]$$

5.7.3. Heterogeneous reservoir

A static geological heterogeneous model of the Delft Sandstone member has been created by Gilding (2010) in the Schlumberger software package Petrel. This is just one realization of the possible structure of the subsurface and, therefore, not representative for any part of the reservoir. Nonetheless, the ranges of porosity and permeability as well as the nature of the heterogeneities are assumed to be interpreted correctly by Gilding (2010). Since this model is a close approximation of the Delft Sandstone reservoir structure, this model was selected to show the effects on well placement in a reservoir with real-case heterogeneities.

Figure 21: Realization of porosity field of the Delft Sst.

The Petrel model of the Delft Sandstone member consists of 123x144x33 cells. The dimensions of each gridblock are 58.5x42.7x25.7 [m]. In the COMSOL model the reservoir properties of Layer 24 of this model have been used and are displayed in Figure 21 and Figure 22.

Figure 22: Realization of permeability field Delft Sandstone and close-up

5.8. SPE10 model

The Tenth SPE Comparative Solution Project was designed to compare the ability of upscaling approaches used by several participants to predict the performance of a waterflood in a simple but highly heterogeneous black oil reservoir that is described by a fine-scale cell (60x220x85 cells) Cartesian geological model. The dimensions of each gridblock are 3x6.1x0.6 [m] (Coats 2000; and Christy 2001).

This project exhibits 10 orders of magnitude local variation in gridblock-average values of areal permeability. These variations are many orders of magnitude greater than in any realistic description at the geologic model scale.

A model with such extremities in the porosity and the permeability field, allows to quantify the effects of heterogeneities on the positioning of the wells and the profitability of a geothermal project. In this thesis, use will be made of the 26th layer of the SPE10 model, which shows the patterns of a fluvial deposit, though the heterogeneities are far more extreme than cases observed in nature (Coats 2000).

A thickness of 56 m is assumed for the reservoir model, which is the same as the thickness that is used for the Delft Sandstone case.

5.8.1. Upscaling

Because the grid cells of the SPE10 model are extremely fine, the mesh in COMSOL should also be at least as fine. If this is not done, undesired upscaling will occur when a course mesh is used (see Figure 23).

Figure 23: The top images show the log-scale permeability field (left) plotted when a fine mesh is used (right). The images on the bottom show the upscaling effects when a mesh coarser than the permeability grid size is chosen.

Locally high permeability contrasts can result in unstable simulations and implementing optimization with such heterogeneities becomes difficult. Furthermore, by refining the mesh the computation becomes slow and time consuming. For these reasons the permeability model is upscaled to gridcells of 21x36 [m] and the permeability contrast is reduced to 3 orders of magnitude. The result from upscaling the porosity field is shown in Figure 24. The result from upscaling the permeability field and reducing the order of magnitudes of the permeability is shown in Figure 25.

Figure 24: The porosity field of the 26th SPE10 layer, (top) before and (bottom) after upscaling.

It can be seen that although the porosity has been upscaled (bottom image of Figure 24), the global lows and highs are still arranged in the same patterns. The changes for the permeability are far more extreme (the bottom image of Figure 25). Although the positions of high permeability streaks are still positioned in the same positions after alteration, the nature of the heterogeneities has changed completely. Nonetheless, because of the absence of large changes in heterogeneities locally, this altered SPE10 model can be used perfectly to test the optimization algorithm presented in chapter 4.

Figure 25: The log-scale permeability field of the 26th SPE10 layer, (top) before and (bottom) after upscaling and reduction of permeability range

6. Results and Discussion

In this chapter the hypothesis of this thesis is tested through the realization of several objectives and related reservoir simulations, such as given in section 1.1. It is shown that the optimal well placement for a geothermal doublets depends in a complex way on the reservoir properties, heterogeneities and production constraints. How these factors affect the optimum well spacing is investigated with the use of numerical models and through the application of the objective function, presented in previous chapters.

In the first sections of this chapter, the numerical model is verified and the differences between conservative and non-conservative heat transfer will be investigated. This will be done in section 6.1, where the numerical model of a homogeneous reservoir in 1D is compared with the analytical solution. In the same section, the differences between the 1D and 2D model and the impact of the implementation of the thermodynamic relations are investigated.

Then in section 6.2, the impact of heterogeneities on the thermal-breakthrough time and related temperature decline is investigated. Subsequently, the importance to take salinity contrasts into account is discussed in section 6.3. Next, the influence of various reservoir properties, temperature constraints and project lifetime on the profitability and the optimum spacing of geothermal doublets in homogeneous and heterogeneous is investigated in section 6.4. Several realizations of optimization sequences, realized with the optimization method proposed in chapter 4, are discussed in section 6.5. In addition, it is shown that automated optimization of geothermal wells is potentially rewarding.

Section 6.6 of this chapter evaluates what well arrangement best to use when multiple doublets are placed in one reservoir. In the final section, an economical assessment of the optimum cases is made.

6.1. Verification of numerical model

A numerical model provides means to compute, under given assumptions (see section Assumptions5.2), approximations to complex problems that would not be possible to solve analytically. Before such a numerical model may be used however, it must be proven that its results are accurate. Therefore the first step is to prove with a 1D numerical model that its solution approximates the analytical solution. After that, simulations can be run in 2D using the same settings (for tolerances and diffusion) as in the 1D case, being certain that the computations are correct.

In this section, the numerical results and the analytical solution of the generic one-dimensional advection-diffusion equation (equation 52) are compared.

6.1.1. Comparing analytical and numerical results

For the numerical model and the analytical equation, the values from Table 4 are used. The results of both the analytical and the numerical solutions are plotted in Figure 26. Temperature breakthrough occurs after approximately 49 years.

Figure 26: The numerical temperature displacement front corresponds with the analytical solution. Simulation in a homogeneous reservoir, with tol_r and tol_A set at 10^{-7} .

As we can see in Figure 26, the analytical and numerical result for the temperature front displacement show satisfactory correspondence (the error, $\epsilon < 0.02$ °K for the thermal front after 40 years). In this figure the relative and absolute tolerance are both 10^{-7} . For the results shown in Figure 27 the relative and absolute tolerance are 10^{-4} and 10^{-5} , respectively. It can be seen that such settings will result in higher oscillations at the tail ($\epsilon < 0.6$ °K for the thermal front after 40 years), but still yield a stable displacement front.

Figure 27: The numerical temperature displacement front with higher tolerances. The tail shows visible oscillations but the temperature front is stable. Simulation in a homogeneous reservoir, simulated with $\text{tol}_r = 1e-4$ and $\text{tol}_A = 1e-5$.

6.1.2. 2D numerical solution

Since it is now proven that the numerical model is able to accurately simulate reservoir flow in 1D, a second dimension is added to the model. While the flow between the injector and producer in a 1D model is constant, in a 2D model the flow regime is radial

and thereby the flow velocity depends on the location in the reservoir relative to the positions of the injector and producer. The difference between a 1D and 2D flow regime is shown in Figure 28.

Figure 28: Comparison between 1D (left) and 2D (right) pressure gradient between injector and producer

When keeping the input parameters the same (constant) and making sure that the no-flow boundaries are far away from the wells (see section 3.3.2), temperature breakthrough occurs after approximately 47 years (see Figure 29).

Figure 29: Temperature distribution in a homogeneous 2D reservoir after 50 years. Properties of the rock and fluid independent of T, p and c.

In Figure 29, the temperature profile in a 2D simulation around the time that breakthrough occurs is shown. At this point in the lifetime of the doublet, the cold water takes on the contour of a droplet, stretching out toward the production well. This is due to the fact that in a radial flow regime, the front side of the displacement front will accelerate faster than the back side, resulting in an elongated temperature front. This does not happen when the pressure gradient is linear such as in a 1D simulation of the

propagation of the temperature front in a horizontal reservoir, as could be seen in the previous section.

Although breakthrough occurs faster, after breakthrough the temperature declines less rapidly in a 2D model compared to the temperature decline in a 1D case. This effect will be further discussed in the next section.

6.1.3. Impact of thermodynamic dependencies

In this section, it is shown what the effects on the propagation of the thermal front and temperature decline-curve are, when a conservative set of equations (equation 7) is used instead of a non-conservative set of equations (equation 10). It is also shown in this section, that thermal breakthrough does not mean the immediate end of the lifetime of a doublet.

In the models presented in this section, the rock and fluid properties are calculated with the thermodynamic relations from section 2.7. The rest of the production and reservoir parameters can be found in Table 4.

Impact of conservation

The result of a 1D simulation with homogeneous reservoir properties, for three different time steps, is shown in Figure 30. The dashed and solid lines indicate the location of the thermal front using the non-conservative form (equation 12) and the conservative form of the heat equation (equation 11), respectively.

Figure 30: Propagation of the thermal front in a homogeneous 1D reservoir. The non-conservative simulation yields a thermal front that propagates faster through the reservoir than thermal front obtained with the conservative simulation.

It can be seen from Figure 30, that the propagation of the thermal front is retard by approximately 40% when the conservative form of the heat equation is used, with respect to when the non-conservative form of the heat equation is used. In effect, the conservation retardation factor, R_{cons} , as defined by equation 49 is 1.4.

Based on the conclusions from section 2.1.2, it can be expected that due to the ratio of viscosities of the cold and hot water banks, at least some alteration of the thermal front

takes place when the conserved heat equation is used. When the shape of the conservative thermal fronts is compared with the non-conservative thermal fronts in Figure 30 it can be concluded, however, that these fronts appear similar. Hence, it can be assumed that the change in velocity around the thermal front in the conservative case is negligible

Temperature-decline curve

The rate at which the temperature declines after thermal breakthrough is investigated with a homogeneous 2D, top view, reservoir model. The results from a conservative simulation with a non-conservative simulation are compared (Figure 31).

Figure 31: Comparison between the conservative and a non-conservative temperature-decline curves after breakthrough at the production well in a homogeneous 2D model. The doublet spacing is 1500 [m] and the injection rate 150 [m³/hour].

Thermal breakthrough occurs after 30.9 and 22.1 years for the conservative and non-conservative solution of the heat equation (equation 10), respectively. This means that, also when radial flow is concerned, the thermal front is retarded by approximately 40% due to the conservation of the heat transfer equation (i.e. $R_{cons}=1.4$)

As can be seen in Figure 31, the shape of the temperature decline curves after breakthrough of the two cases is similar. For the conservative and non-conservative case, the produced water remains warmer than 340 °K for 24 and 21 years, respectively. The slightly slower cool down of the production water for the conservative case, can be attributed to the fact that the thermal front in the conservative simulation takes longer to reach the producer. The thermal diffusivity causes the front to expand over time. This is caused by the piston-like flow behavior, discussed in the previous sub-section.

Since the 2D-conservative case is the most accurate case, it can be argued, that while temperature breakthrough at the producer in a geothermal doublet is an indicator for the nearing end of the life-time of a doublet, it will still be able to operate for at least some time after this breakthrough has occurred.

Influence of variables

It can be concluded that when non-conservative heat transfer equations are used, the shape of the thermal front and the decline curve is roughly the same. The velocity at

which the front propagates, however, is retarded by approximately 40% as was demonstrated in the previous sub-sections.

Figure 32: Thermal front of 1D simulation at $t = 40$ years. The impact of the conservation of the variables from equation 5 is investigated

heat capacity, slightly increases the velocity of the thermal front. Expectedly, the conservation of the fluid velocity does not have a lot of impact on the propagation of the front in the homogeneous 1D model (in Figure 32 there is no visible difference with the conservative solution).

Conservation of the volumetric heat capacity inflicts the biggest change on the propagation of the thermal front. Effectively, C_{eff} becomes larger in time which means that the energy, required to heat a constant amount of water, becomes larger.

Validity

The simulations of conservative 1D models (Figure 30, 31 and 33) are performed with a mesh-size of 2 m over the entire length of the domain. When the mesh density is increased 10 times (such that the mesh-size is 0.2 m) the maximum difference in between the solutions of the thermal fronts between the two simulations, is 0.02 [K]. This demonstrates that the numerical result generated by COMSOL is stable.

6.2. Impact of heterogeneities on breakthrough time

In this section, the influence that reservoir heterogeneities have on the time of thermal breakthrough and on the temperature decline of the water flowing into the producer, is investigated. Here, the input parameters from the verification model are no longer used. Instead the constant porosity and permeability values and conditions present and the Delft Sandstone model are used for the homogeneous case (section 5.4 and 5.7.1). The Delft

The impact that the conservation of different variables has on the heat equation (equation 7) can be investigated through the graph in Figure 32. This shows a close up the thermal front at $t = 40$ years. For each realization, one variable is not conserved. For example, by letting the density be non-conservative, equation 7 can be rewritten to:

$$\frac{\partial}{\partial t}(C_{eff}T) + \rho_w \nabla \cdot (\mathbf{u} C_w T) = \nabla \cdot (K_{eff} \bar{\nabla} T).$$

It can be seen from Figure 32, that through the conservation of the volumetric heat capacity (C_{eff}) accumulation term and through the conservation of density, the thermal front propagates slower. Conserving the brine

Sandstone analogue (section 5.7.3) is used for the heterogeneous case. As mentioned in Chapter 5, this heterogeneity model is just one out of many possible realizations of the Delft Sandstone Member. Simulations are carried out using the non-conservative heat transfer equations.

In order to make an assessment of the impact that heterogeneities have on the breakthrough time of a doublet, usually many simulations on different realizations of the heterogeneities have to be made in order to approximate a Monte-Carlo-like distribution of results.

Figure 33: 2D, top view, permeability field of the Delft Sandstone analogue. The positions of the three blocks in the permeability field are shown in which simulations have been carried out to investigate the influence of heterogeneities on breakthrough times. The red lines indicate the orientations of the different doublet orientations that have been investigated.

In this section a different approach is used. Using a spacing of 1500 m between injector and producer, simulations have been made of 3 different doublet orientations in 3 different areas in the reservoir (see Figure 33). The temperature-decline curves at the producer for these 9 different cases plus the homogeneous case are given in Figure 34a. The thermal breakthrough times of these cases are shown in Figure 34b.

In this section we refer to the nine cases by first naming the location and thereafter the setting. For example: Case 2.3 is positioned in the second block in the 3rd setting (see Figure 33).

Figure 34a) Temperature-decline curves at the producer in the geothermal doublet, using different doublet positions in the (heterogeneous) reservoir for each simulation. b) Amount of production years before thermal breakthrough occurs at the producer. Among the heterogeneous cases, Case 2.1 has the earliest thermal breakthrough after 41 years, Case 1.1 has the latest thermal breakthrough after 55 years.

The first observation that can be made from Figure 33 and Figure 34a and b, is that thermal breakthrough occurs earlier for all heterogeneous cases compared with the homogeneous case (which has thermal breakthrough after 62 years). This can be attributed to two factors:

1. In the heterogeneous cases ‘fingering’ can occur through highly permeable streaks of the reservoir. The first hints of cold water will therefore reach the producer sooner than they would have in the case of the homogeneous reservoir. In section 6.6, these ‘fingering’-effects are further investigated for multiple well layouts.
2. it is assumed here that 9 different realizations of the doublet in heterogeneities are sufficient to tell something about the general nature of the heterogeneities, it is possible that the 9 cases discussed here have fast breakthrough, while 9 other realizations might show later breakthrough.

Apart from the fact that in all the heterogeneous cases, breakthrough occurs earlier than in the homogeneous case, it can be observed that there is a lot of difference in the times at which breakthrough occurs in the heterogeneous cases. Among the heterogeneous cases, Case 2.1 has the earliest thermal breakthrough (41 years). Case 1.1 has the latest thermal breakthrough (55 years). Generally, the wells positioned according to setting 3 have a slightly later breakthrough than the wells positions according to setting 2. This might have to do with the paleo-flow direction at the time of deposition of the reservoir sediments and related orientation of the heterogeneities.

The temperature decline (Figure 34a) after breakthrough also differs a lot between the heterogeneous cases and the rate at which they decline is much more capricious than for the homogeneous case (Figure 31). The doublets in Case 2.3 and Case 3.2, for example, have breakthrough after 45 years of production. The doublet in Case 3.2, however, shows way faster temperature decline after breakthrough. Hence, heterogeneities do not also

influence the time at which breakthrough occurs but also the rate at which temperature declines after breakthrough.

Last but not least, it can be observed that in none of the heterogeneous cases, the temperature has dropped below 338.15 [°K]. This indicates that, given the TNO standard (see Table 8), for the given reservoir properties, a doublet in this reservoir with a spacing of 1500 m will likely be able to maintain production up to 80 years when the water is used for spatial heating.

6.3. Compositional breakthrough

As mentioned in chapter 1, the composition of reinjected water differs from the composition of the reservoir water. In order to assess the impact of heterogeneities on the breakthrough times of temperature and composition and on the associated retardation factor, use has been made of a confined reservoir (a square with no-flow boundaries) with a production and injection well in the opposite corners. In this section the homogeneous and heterogeneous models that approximate the reservoir properties of the Delft Sandstone are used (see chapter 5). The permeability field used for the heterogeneous case is shown in the close-up in Figure 22.

The behavior of the compositional front in a homogeneous reservoir, the impact of heterogeneities on this front and on the retardation factor (section 2.5) can be investigated. In Figure 35 and Figure 36, the propagation of the thermal and compositional front is shown at various times for the homogeneous and heterogeneous case, respectively.

In Figure 35 and Figure 36 it can be seen that the compositional and thermal front move relatively fast through the reservoir. This is due to the fact that the wells are located in the corners of the reservoir. The no-flow boundaries cause the cold water to be directed towards the producer. The reason for this approach is that only the flow between the producer and injector is of importance for the study to the behavior of the thermal and compositional front. What happens in the rest of the reservoir is irrelevant in this case.

Another observation that can be made from Figure 35 and Figure 36, is that the compositional front moves a lot faster than the temperature front in both the homogeneous and heterogeneous case.

Because the pressure gradient increases close to the wells, a ‘fingering’ effect occurs and this is more pronounced in the heterogeneous case. Therefore, the sweep of both water composition and temperature is less efficient in the heterogeneous reservoir. This can be seen when comparing the water composition profiles in the homogeneous (Figure 35) and heterogeneous (Figure 36) cases at $t = 15$ yrs. The uppermost part of the reservoir is left untouched in the heterogeneous case, while at this time, almost the entire reservoir is swept in the homogeneous case.

Figure 35: Plot of concentration (left row) and temperature (right row) at different times in the homogeneous reservoir. Injected water has a slightly lower salinity than the reservoir water. The porosity and permeability of the reservoir are constant, 0.19 [-] and 256 [mD], respectively.

Figure 36: Plot of concentration (left column) and temperature (right column) at different times in a heterogeneous (Delft sandstone) reservoir. Injected water has lower salinity than reservoir water

The salt concentration and temperature levels at the producer are made dimensionless by dividing them by their initial values. Figure 37 and Figure 38 show the dimensionless composition- and temperature-decline curves for the homogeneous and heterogeneous case, respectively.

Figure 37: Dimensionless decline curves of temperature and salinity concentration in the homogeneous scenario at the producer.

Figure 38: Dimensionless decline curves of temperature and salinity concentration in the heterogeneous scenario at the producer.

Figure 37 and Figure 38 show that the decline of concentration in both cases is far steeper after breakthrough than the temperature decline. The shape of the decline curve after breakthrough mainly depends on the amount of diffusion of the front and the Péclet number (see section 2.6). The difference between the decline curves is due to the fact that the thermal diffusivity (α) is much higher than the mass diffusivity (D_{eff}) and because the thermal Péclet number ($Pe_{thermal}$) is lower than the compositional Péclet number (Pe_{comp}).

When comparing the compositional and temperature breakthrough times of the homogeneous and heterogeneous case, it can be seen that differences are quite large (Figure 39). The thermal front arrives approximately 9 years earlier at the producer in the heterogeneous case, which indicates that the heterogeneities have a big impact on the flow behavior in the reservoir.

A second observation is that, although the compositional and temperature front reach the producer at an earlier stage in the heterogeneous case, the decline rates are not as high. In fact it can be seen in Figure 39 that after 30 years of production, the produced water will be colder in the homogeneous case than in the heterogeneous case. This is due to the fact that the front becomes more dispersed when heterogeneity is introduced, meaning that the rate of the decline is lower than in the homogeneous case in which the front is less dispersive.

Figure 39: Comparison between the homogeneous and heterogeneous case of the compositional breakthrough and decline (top) and temperature breakthrough and decline (bottom). The green dashed vertical lines indicate the times of compositional breakthrough and the red solid vertical lines indicate the times of temperature breakthrough

6.3.1. Ratio of front velocities

Because the non-conservative heat transfer equation is used, the ratio of the compositional front velocity to the thermal front velocity is reduced to the ratio of diffusivities (see section 2.6).

The dispersive nature of the fronts increases according to the thermal diffusivity and the diffusion coefficient of dissolved salt. The thermal diffusivity is larger, therefore the time the doublet has been active will affect the ratio of front velocities. In effect, the longer it takes for breakthrough to occur the smaller the retardation factor will be since the thermal front is more dispersive.

Table 9: Breakthrough times of the compositional front, the thermal front and the associated retardation factor for the homogeneous and the heterogeneous case.

	Compositional breakthrough time [yrs]	Temperature breakthrough time [yrs]	Ratio of front velocities [-]
<i>Homogeneous Case</i>	5.99	22.06	3.68
<i>Heterogeneous Case</i>	3.65	13.30	3.64

In Table 9, the ratio of the velocities between the homogeneous and heterogeneous case has been calculated by dividing the temperature breakthrough time by the compositional breakthrough time. From Table 9, it can be derived that, as expected, there is difference in the retardation factor between the homogeneous and heterogeneous case.

The impact of heterogeneities on the breakthrough times is, as can be seen in Figure 39, quite large. The effects that this contrast in breakthrough times has on the ratio of fluid velocities, however, is quite small: the difference in the ratio of fluid velocities between the homogeneous and heterogeneous case is approximately 1%. Therefore, it is assumed for the next sections that the ratio of fluid velocities in these 2D, top view models, is a

constant value of 3.65. Since this value is the ratio between the front velocities and neglects effects from the mass diffusion and thermal conductivity, this value is effectively the thermal retardation factor (see section 2.5).

Effects of conservation

The impact on the retardation factor when using conservative relations for both the heat and mass transfer is not investigated in this thesis. Since the propagation of the thermal front propagates slower when the heat transfer equation is conserved, the same will likely happen for the mass transfer equation. How the retardation factor is affected, through conservation of heat and mass, is an interesting topic for future research.

6.4. Doublet placement

The absolute positions of the producer and injector for a geothermal doublet in a reservoir, determine its effectiveness and profitability. In this section, it is analyzed how to determine the optimal well positions of a doublet in homogenous and heterogeneous reservoirs.

6.4.1. Spacing of injector and producer

Assuming an infinite homogeneous reservoir, the spacing of a geothermal doublet determines at what time, temperature and compositional breakthrough will occur at the producer. In this section it is investigated how the breakthrough times of these fronts are affected when the spacing between the injector and producer is varied. In this section it is assumed that production takes place from a homogeneous (Delft Sandstone analogue) reservoir under the constraints given in chapter 5.

By increasing the spacing between the injector and producer with steps of 50 meters, from a spacing of 50 m to 4000 m it is measured at what time thermal breakthrough occurs for each case. Figure 40 plots the spacing of the doublet versus temperature and compositional breakthrough time.

Figure 40: Location of thermal and compositional front as a function of time in a homogeneous reservoir. On the horizontal axis, the amount of years since production started is indicated. The vertical axis tells how many meters the front is removed from the injector. The two vertical lines indicate the positions of the temperature and compositional front after 30 years and after 60 years.

Figure 40 shows that after 30 years, temperature breakthrough occurs when production wells are located within a range of 1070 m and at this time, compositional breakthrough occurs for wells located within a range of 2045 m. After 60 years, the thermal breakthrough occurs for production wells within a range of 1540 m and compositional breakthrough for wells located within a range of 2950 m.

From these observations it follows that in radial coordinates, the ratio of the compositional front radius to the thermal front radius is the square root of the ratio of front velocities which is approximately 1.9 for the cases described in the previous section.

6.4.2. Interference with adjacent doublets

When placing a geothermal doublet in a reservoir, it is of important to make sure no interference occurs with adjacent doublets within the lifetime of the doublet (see section 1.3.4).

Figure 40 can give an indication of the minimal distance that two doublets should be removed from one another to prevent such interference. It can be observed that, when only taking into account temperature breakthrough a minimal spacing of 1500 m between adjacent doublets is, for a doublet with a lifetime < 57 years is indeed sufficient. However, when salt breakthrough at adjacent producers is also considered to be undesired within the lifetime of the doublet, the minimal spacing between the doublets should be increased to 3000 m.

Consequently, it can be concluded that given the reservoir conditions and production constraints of chapter 5, the radius of the influence of the compositional front is approximately 2 times further removed from the injector than the radius of the influence of the temperature front when the lifetime of the doublet is between 30 and 60 years. This is a rough estimate, but it does underline the impact that propagation of the compositional front may have on the positioning of geothermal wells in the subsurface relative to adjacent competitive doublets.

It should be noted here that the velocity at which a front moves depends on the pressure gradient. An adjacent doublet with a higher or lower production rate, may therefore cause faster or slower propagation of the front towards its producer, respectively. That being said, Figure 40 only gives an indication of the relative positions of the compositional and the temperature front for the doublet in the given reservoir. The form of the curves in this figure are highly dependent on the reservoir properties and production constraints.

6.4.3. Impact of heterogeneities

When a reservoir is not homogeneous nor infinite, it becomes more difficult to find the optimal wells positions as the optimal spacing is no longer the only factor determining the effectiveness and profitability of a reservoir.

To illustrate the issues that arise when searching for optimal well positions in heterogeneous reservoirs, an assessment of the optimal placement in the unaltered SPE10 model is made. This model is, as mentioned in chapter 5, extremely heterogeneous and bounded by no-flow boundaries. Since this model is quite small, a doublet lifetime of 20 years is assumed for each realization.

By manual interpretation of the porosity and permeability field, the best positions for the producer and injector are estimated. In Figure 41, the temperature profile of this realization after 20 years of production is shown.

Because of the extreme differences in porosity and permeability in this reservoir, the boundary condition of the injector almost immediately switches from a rate-constraint to a pressure constraint (section 5.4). As a result, the injection rate drops to $\sim 20 \text{ m}^3/\text{hour}$ throughout the lifetime of the doublet. Hence the hot water has only infiltrated a relatively small part of the reservoir after 20 years.

Figure 41: Temperature distribution profile in the (unaltered) SPE10 model after 20 years of production. The positions of the injector and producer are manually selected.

One question that now arises, is how ‘good’ the manual interpretation has been. In order to quantify this, the profitability and effectiveness of these manually selected positions of the injector and producer need to be compared with other realizations.

In order to assess the *profitability* of various well settings, use has been made of the objective-function that is presented in section 4.2. The *effectiveness* of various well settings is assessed with the use of the recovery factor, which indicates how well a reservoir has been drained of heat (section 1.3.5).

By fixing the injector to one position in the SPE10 model and moving the producer throughout the reservoir while calculating the objective function value and recovery factor for every realization, Figure 42 is obtained. In order to accurately capture the capriciousness of this very heterogeneous model, it is divided into 19x73 segments. One realization has been made per each segment by sequentially placing the producer in a different segment while keeping the location of the injector constant. Thus each image of Figure 42 is composed of 1387 realizations.

In Figure 42a, the objective-function value from each realization is plotted against the distance the producer is placed away from the injector for that specific realization. In Figure 42b, the objective-function values are plotted in 2D to visualize which regions of the reservoir are more profitable. In Figure 42c, the recovery factor for each realization is plotted in 2D to see in which areas the producers have been most effective in draining the reservoir. In this thesis, the recovery factor is, as mentioned in section 1.3.5, used as a relative measure since it only captures how much heat from a specified part of the reservoir has been produced.

From Figure 42a it can be derived that, although the reservoir is very heterogeneous, the spacing is, from an economical standpoint, still of importance in determining the optimal position. This is due to the fact that when the producer is placed too close to the injector, thermal breakthrough will occur at a very early stage in the project, leading to little energy production over 20 years and early abandonment of the wells due to rapid temperature decline.

Further away from the injector however, some positions with low profitability can be found. This can be attributed to the fact that locating the production well in a very low-permeable zone (which leads to low production rates) can have very negative consequences for the injection rate and thereby for the amount of produced heat. This can be verified by comparing Figure 42b and Figure 42c, where it can be seen that the low objective-function locations of the producer correspond to the low heat-production locations.

The close correspondence between Figure 42b and Figure 42c verifies that effectiveness and profitability of a geothermal doublet are closely interlinked. Though the correspondence will be less big when the heterogeneities are less severe as will be shown in the next section.

From Figure 42a and b, show that the location of the producer selected manually (Figure 41) corresponds to the region with the highest objective function values. This does not mean, however, that these are the (globally) best positions of the wells. By moving the injector to a different segment in the SPE10 model, a completely different NPV plot will be obtained. This stipulates the importance of optimization methods in determining well locations.

Figure 42: The injector is fixed in the SPE10 model and the producer is moved through the reservoir, for each place a simulation of 20 years of production is made. a) Top image; graph of the objective function as a function of the absolute distance between producer and injector. b) Middle image; 2D graph depicting positions that yield a high or low objective function value. c) Lower image; 2D graph depicting which positions yield a high or low heat recovery factor.

6.4.4. Profitability and optimum well positions

In this section, it is shown how the optimal spacing of a doublet in a homogeneous and approximated infinite reservoir is determined with the use of the objective function, which was also used in the previous section. An analysis is made on what impact various constraints and variations in the main reservoir properties have on the optimum placement of wells. For the cases considered in this section the homogeneous Delft Sandstone analogue is taken (section 5.7). The reservoir is assumed to be approximately infinite (see section 3.3.2).

In the top two rows of Table 10, the results of an analysis on the ‘Base-Case’ are depicted. In the rest of the rows, four other cases with different constraints or reservoir properties are investigated. For all cases (except for the Short Lifetime case) a doublet lifetime of 60 years is assumed. Besides the greenhouse Base-Case, all cases assume spatial heating conditions (i.e., water of 313.15 [°K] is injected)

Shape of the objective-function plot

The shape of the objective function plot for all cases are presented in the first column of Table 10. These objective-function plots can be divided into three distinct regions: starting on the left, first a ‘steep-gradient region’ can be seen, where the objective function increases rapidly; then an ‘optimum’ is reached; finally the ‘tail’ of the function is reached and the objective function steadily declines.

This shape can be explained by looking at the two variable parameters in the objective function, namely: the heat production and the pressure of the injection well (see section 4.2). In the first several hundred meters away from the injector, the heat-production variable is dominant: the amount of energy produced is increased a lot by moving the producer a bit further away from the injector, causing a steep slope of the objective function. At further distances, the influence of the heat production is decreased since breakthrough takes place in a later stage or (when moved away far enough) no breakthrough occurs at all within the lifetime of the doublet. At some point away from the producer, the benefit of delaying the breakthrough even more is negated by the additional increase in pressure required by the pumps at the injection well to maintain a rate of 150 m³/hour. This is the optimum well position.

After the optimum has been reached, the negative contribution of the additional energy required for a small increase in pressure at the injection well, causes a decline in the objective function. Though in most cases shown in Table 10, this value is so small that the objective function appears to stabilize for spacings bigger than approximately 1100 meters.

It can also be observed that the steep-gradient region of the 1D objective-function graphs in Table 10 is quite capricious and has a stepwise nature close to the injector. This is due to the fact that the objective function is calculated as the sum of the profits per year. After each subsequent year it is assessed whether the production well is not violating the temperature constraint for spatial heating (section 5.5.2). If this is the case, production is stopped. In the steep-gradient region, close to the injector where the gradient of the

objective function is steep, these cutoffs can be observed as the capricious, stepwise nature of this side of the graphs. As a result the steep-gradient region becomes smooth when the time-step size, at which the temperature constraint is evaluated, is decreased.

- **Base cases**

The difference between the two base cases, shown in Table 10, is that the water for greenhouses is cooled down further in the heat exchanger (down to 298.15 [°K]), than for spatial heating (down to 313.15 [°K]). Another difference is that produced water with a temperature down to 318.15[°K] is usable for greenhouse heating, while spatial heating requires water hotter than 338.15 [°K] (see section 5.5.2).

Due to the extra energy produced for the greenhouse heating case, the objective function is much higher at the optimal position: 13.6 million compared with 8.9 million for the spatial heating case. As a result, the impact of an early breakthrough on the objective function is also larger. This can be seen, when comparing the steep-gradient regions of the objective function between the two cases: it can be observed that this part of the function is steeper for the greenhouse-heating case (see the 1D plot of the objective function for the greenhouse-heating case in Table 10). Note that the values for the objective function are not equal to the NPV values for the two cases projects, these will be presented in the last section of this chapter.

It can be seen that the optimal spacing for both base cases is at approximately 1273 meters from the injector. Since measurements are taken at intervals of 50 m, it cannot be said if the positions for both cases are located exactly at this position. It can be concluded though, that the temperature constraints implied on a geothermal project do not have a large impact on the optimal spacing position of the doublet.

Table 10: Various objective function plots and recovery factor plots to study respectively the profitability and effectiveness of the reservoir models in question. From top to bottom: Base Case (spatial heating), Base Case (greenhouse heating), 30 year Case, low permeability Case, small N/G Case, heterogeneous Case

- **Short lifetime case**

In this case, the doublet is only active for a period of 30 years. It can be seen that the optimum position of the production well is almost 300 m closer to the injector than in the spatial heating Base Case. Though the gain of the additional pressure support is small, placing the wells in the optimum positions yields an objective-function value of 8.18 Million Euros while placing the wells at the optimum position for a doublet with a lifetime of 60 years yields an objective-function value of 8.11 Million in this case.

The recovery factor is a lot lower at all positions in this case, when compared with the Base Case. This is logical, given that the doublet is active only half of the lifetime of the Base Case. Another observation that can be made in comparison with the Base Case, is that the objective-function value for the wells in the optimum positions is not substantially lower. Considering that the optimum for the Base Case yielded 8.89 Million, the decrease in objective-function value is only 8.5% when the project lifetime is reduced by half. This is due to the fact that the profits from the heat production in the later years do not contribute as much to the objective function as the first years on one hand (time value of money) and because of temperature breakthrough at later years on the other hand.

- **Low permeability case**

In this case, the permeability in the reservoir is reduced by approximately a factor of 5 (from 254 mD to 50 mD). The optimum value of the objective function is also reduced to 1.76 million and the optimum producer position has moved towards the injector, such that the spacing is only 650 m.

In this setting the producer can benefit from the higher pressure gradient between injector and producer but thermal breakthrough occurs in a very early stage of the lifetime of the project.

When the producer is moved further away from the injector, however, the objective function declines quite rapidly. This situation is opposing the one observed for the Base Cases, where the decline rate of this part of the curve was quite low. This effect is due to the fact that the injection-pressure component of the objective function plays a more prominent role in determining the optimum location of the producer.

When the producer is moved beyond a certain point, we can see that the recovery factor becomes lower instead of higher. This indicates that the rate constraint of the injector is switched to a pressure constraint at a certain point during the lifetime of the doublet (section 5.5).

- **Small N/G case**

In this case, it is assumed that the net-to-gross ratio of the reservoir is smaller than for the Base Cases. Instead of 56 m, the effective thickness of the reservoir is assumed to be 30 m.

It can be seen that the optimal location of the producer is much further away from the injector, located at 1612 m from the injector and the objective-function value is 7.77 million for this well spacing.

The spacing in this case is larger since, because of a smaller N/G ratio, the flow rate of the water is higher: the same amount of water is injected in a thinner reservoir interval.

Whilst, the temperature front also propagates much faster, causing the fast breakthrough in parts close to the injector.

The optimum value of the objective function is also reduced to 7.8 million compared with 8.9 million of the Base Case. The reduced profitability is for the larger part due to the fact that the flow rate of the water is increased, which requires a higher pressure gradient. For a minor part this decrease is caused by the fact that the wells are placed further apart, leading to a less effectively operating doublet since driving force of the injector is reduced compared to the Base Case.

- Heterogeneous case

For this heterogeneous case, the Delft Sandstone analogue model is implemented.

As can be seen from the 2D objective-function plot, the profitability of the doublet is not only a function of the well spacing in this case. Like the heterogeneous SPE10 model considered in the previous section, some parts of the reservoir located further away from the injector still yield quite a low objective-function value while others at the same distance are quite high.

In this case, there is only 1 optimum position in the reservoir located at 1164 m from the injector. An optimum objective-function value of 8.74 million is yielded, which is not significantly different from the homogeneous-spatial-heating Base Case.

Comparing the figures belonging to the heterogeneous case with the ones from the homogenous Base Case, it is clearly visible that a homogeneous approximation of the heterogeneous reservoir is a rough estimate but not quite a precise representation of the actual reservoir. For example, a difference in the outlines of the 1D objective function graphs can be seen. In the graph pertaining to the heterogeneous case, not only the optimum is located closer toward the injector, but also the far end of this curve also appears to decline faster. These differences correspond to, though are less severe than, the ones observed for the low-permeability case. This indicates that the heterogeneous field has a lower effective permeability than that of the homogeneous case (at least in this part of the reservoir).

Still, the rough outlines as well as the magnitudes of the 1D objective-function graph of the heterogeneous case are comparable to one from the homogeneous Base Case. For this reservoir it can therefore be assumed that the optimized position in the homogeneous case gives a good enough indication of at what spacing a doublet should have. Manual interpretation of the heterogeneities and/or optimization techniques can then determine where to place the wells exactly.

When comparing this heterogeneous case to the example considered in the previous section (Figure 42), it can be concluded that the heterogeneities are far less severe. It can also be seen that the effectiveness and profitability are, in the heterogeneous case considered in Table 10, not completely interlinked. In the bottom right corner of the 2D objective function plot there is a region with very low values, while the recovery factor plot does not seem to be affected by much in that region.

6.4.5. Uncertainty in reservoir data

Considering that there is always some degree of heterogeneity present in natural reservoirs, it can be concluded that results from simulations with a homogeneous reservoir are never close to reality. Through multiple realizations of the reservoir and careful assessments of the uncertainties involved with the magnitude of the various reservoir conditions and fluid properties, an approximation of reality can be made.

Some recommendations regarding well placement in real fields can be given, based on the assessment of the NPV profiles in this section:

- The hazards involved with placing the wells too close together are higher than placing them too far apart.
- Placing the wells too close together may risk of moving into the high-gradient region of the objective function (see the first column of the graphs in Table 10) .

This can be the case when, for example, the porosity estimate has been too high or the Net/Gross ratio is estimated too high (see the low N/G case in Table 10). As a result, breakthrough may occur at an early stage in the lifetime of the doublet and jeopardize the feasibility of the geothermal project.

- Placing the wells too far apart, however, involves reducing or losing communication between injector and producer, which will in effect increase the pumping costs of the injector.
- Given a discount factor of 7%, it makes little sense to calculate the potential gain from production years more than 30 years from now as all the contributions after 30 years (until infinity) are likely to represent less than 10% of the NPV. As a result, it is recommended to optimize geothermal wells for a lifetime of 30 years, to make more efficient use of the pressure support of the doublet. Though it should be noted that in the Short Lifetime case (Table 10) moving the well 300 m closer has little impact on the NPV since the extra gain by pressure support is low at this distance from the injector.

6.5. Optimization of well-doublet placement

To assess all possible placements of injector and producer in a heterogeneous reservoir with 1000 grid blocks, one million simulations are required. When two doublets are considered the amount of possible solutions increases to 10^{12} . By applying gradient-based optimization techniques, the number of iterations required to find an optimal solution will be greatly reduced. In this section the optimization method proposed in chapter 4 is tested on the SPE10 model and thereafter applied to the Delft Sandstone case.

6.5.1. Optimization in the SPE10 model

Since the SPE10 model is a small, confined reservoir, optimization with the perturbation method proposed in this thesis is relatively fast. Furthermore, it is reasoned that with well defined permeability streaks, the optimization method would be easy to test.

After some attempts, it appeared that the heterogeneities of the SPE10 model are too extreme in nature for this type of optimization even when the pseudo-wells are located close to the main wells (see Appendix G). Therefore, the SPE10 model is upscaled and the permeability range is reduced (see Figure 25).

With this altered heterogeneity field, two successful optimization sequences for different starting positions of the wells were carried out, which are shown in Figure 43.

Figure 43: Two optimization sequence 1 (top) and optimization sequence 2 (bottom) in the upscaled and altered SPE10 model. Left: The initial and final positions of the injector and producer are shown on the permeability field of the reservoir; Right: the value for the objective function at each consecutive iteration is shown.

The spacing between the main wells and the pseudo-wells, and consequently the stepsize per iteration, was selected to be 15 meters. This is approximately half the distance of one porosity/permeability block. Both optimizations sequences appear, as expected, to follow the high permeability streaks until the optimum is found.

In the first optimization sequence, the objective function value is -1.88 million for the initial well positions. After 10 iterations an optimum of 0.16 million is found. In the second optimization sequence, the objective function value is -1.8 million for the initial well positions. After 14 iterations an optimum of 0.18 million is found.

The conclusion from this is that different starting positions of wells yield different end positions. Moreover, no ‘global’ optimum is found with the optimization method proposed in this thesis. Though in both optimization sequences, the iterative optimization method is clearly able to find considerably better well positions.

6.5.2. Optimization in the Delft Sandstone model

In this section the same optimization algorithm is applied to the Delft Sandstone model. As the starting positions, the wells are placed 1272 meters apart, which was found to be the optimal spacing between wells placed in the homogeneous reservoir (see section 6.4.4). The part of the reservoir in which the optimization is carried out, is equal to the part that was investigated with an objective-function plot in section 6.4.4 (bottom column of Table 10). The initial spatial positioning of the wells is chosen arbitrarily and can be seen in Figure 44.

Though the optimization is carried out in a confined part of the heterogeneous model, the reservoir itself is much bigger (approximately 5000x5000m). Therefore the inflow and outflow of reservoir fluids from and to producers and injectors, respectively, are radial also when the wells are located at the sides of the optimization area. The reason for confining the optimization area, is to reduce the total amount of mesh cells (reducing computation time) and to make sure that wells do not move to a completely different location than intended.

The spacing between the main wells and the pseudo-wells, and consequently the stepsize per iteration, was selected to be 25 meters in this case. This is approximately half the distance of one porosity/permeability block.

Figure 44: Optimization trajectory (left) in the Delft Sandstone reservoir and the objective function plot as function of the iteration number (right) of an optimization sequence in the Delft Sandstone model.

In Figure 44 shows that the optimization trajectory is completed after 6 consequent iterations. Through this optimization, the objective function is increased by approximately 5.5% from 7.55 million to 7.97.

This is only a small increase, compared the values seen in the SPE10 case. But this can be explained by the fact that the starting positions of the wells in this case is far closer to the optimal position than they were in the SPE10 case. As a result, the optimization does not take place in the steep-gradient region of the objective function (see section 6.4.4), but near the optimum where the shape of the objective function is more flat.

6.5.3. Prospects of optimization

Since the gradient objective function proposed in this thesis is directly related to the NPV of a geothermal project, this function is a good measure of how successful a geothermal project will be.

Now that three consequent optimization sequences have been able to determine an improved location for the wells of a geothermal doublet, it can be assumed with reasonable certainty that the proposed gradient-based method for the optimization of geothermal wells in heterogeneous reservoirs has successfully been implemented.

Although the optimization algorithm has only been applied to a single doublet, the proposed optimization method is also applicable to the case where two or more doublets require optimization. The restrictions in doing so are computational power, computational time and the time required to adjust the algorithm to the case.

Other situations in which the optimization method, proposed in this thesis, or other gradient-based optimization methods could prove to be quite valuable are:

- History matching
- Investigation of the placement of a new doublet next to a doublet that has been functioning for several years
- Analysis of various production constraints

Remarks on optimization

Implementation of optimization is potentially rewarding, but quantifying the gain of such optimization for a project is difficult. This is due to several reasons:

- It is difficult to quantify how well the optimization method works. For the cases that have been studied, the optimization has worked though the global optimum is not likely to be found. There are risks that the optimization converges to a local optimum with very low yield. (Appendix G)
- Typically, a given heterogeneity field is only one out of many possible realizations. In order to properly assess the expectation of the NPV of the placement of a doublet wells, one would have to carry out optimization on multiple realizations of the heterogeneity field.
- The production constraints imposed on the project are as never rigid in real cases. This is due to for example: down time of the doublet, low or high demand of energy or temperature fluctuations (day/night and summer/winter).

Optimization is not a holy grail and some common sense when applying the optimization technique will be required to find the best well positions. In order to find the best well positions with the optimization proposed in this thesis it is recommended to:

- Use reservoir data that are as accurate as possible. Especially accuracy of the reservoir and fluid characteristics is important to the effectiveness of well placement optimization. If these data are not very accurate, the optimization sequence may propose optimum positions that in the actual reservoir are far off from the real optimum.
- First make an estimate of the optimal spacing of the doublet for a reservoir with homogeneous properties. Then maintain this spacing distance when determining the initial positions of wells for the optimization of the wells in the heterogeneous reservoir.
- Apply the optimization algorithm more than once with wells at different initial positions to see whether this will yield a different objective-function value. With different initial well positions, the optimization sequence will likely end at different final well positions and therefore probably different NPV is yielded for each optimization.

6.6. Cooperating geothermal well doublets

As mentioned in the introduction (section 1.3.6) well known arrangements for multiple doublets in homogeneous reservoirs are the tramrail profile and the checkers-board profile. In this section, it will be analyzed how effectively these two arrangements of wells are able to drain a geothermal reservoir in a period of 60 years and look into the effects that heterogeneities have on the efficiency of these profiles.

To obtain a sufficiently large heterogeneous reservoir, the Petrel model as presented in chapter 5 was used four times. A series of 10 doublets was used to create the required checker-board and tramrail-profiles. Both doublet layouts are shown in Figure 45.

Figure 45: Well doublet arrangements. A number is assigned to each production well in the arrangement. a) Arrangement of geothermal wells according to the Checkers-board profile b) Arrangement of geothermal wells according to the Tramrail profile. Producers and injectors are positioned next to each other in lines. Doublets are positioned in an alternating formation.

The spacing between each injector and producer is 1276 m, which was found to be the optimal spacing for a doublet in the homogeneous Delft Sandstone model in section 6.4.4. A homogeneous case and a heterogeneous case are analyzed for the two profiles mentioned above. The recovery factors of each scenario are given in Table 11.

Table 11: Recovery factors for the tramrail- and checkers-board-profile of multiple doublets in homogeneous and heterogeneous reservoirs

	Tramrail	Checkers-board	Difference
<i>Homogeneous</i>	0.2350	0.2496	6.21%
<i>Heterogeneous</i>	0.2014	0.2435	20.90%
Difference	16.68%	2.51%	

As mentioned in chapter 1, the recovery factor is merely used as a relative and not an absolute measure. The entire reservoir is substantially bigger than the part where the doublet profiles have been placed, in order to prevent interference effects with the no-flow boundaries at the sides of the domain.

It can be seen in the most right column of Table 11 that the checkers-board profile is indeed more effective in draining a geothermal reservoir in both the homogeneous and

the heterogeneous case. Respectively, 6.21% and 20.90% more heat can be produced from the reservoir with the checker-board profile in these two cases.

The impact of the heterogeneities (bottom row of Table 11) is also larger for the wells placed according to the tramrail profile when compared with the checkers-board profile. For the latter, the total amount of produced heat is only 2.51% less in the heterogeneous case, while for the tramrail profile the recovery factor drops by 16.68%.

The temperature distributions in the reservoir after 60 years of production and temperatures at the production wells are given Table 12 on the next page, for both homogeneous and heterogeneous reservoir cases.

The thermal-breakthrough times at each well for the homogeneous and heterogeneous case located according to the checkers-board and tramrail profile are plotted in Figure 46a and b respectively.

Figure 46: Comparison between the thermal breakthrough times in the homogeneous and heterogeneous case for the 10 producers. a) Breakthrough times of wells positioned according to the Checkers-board profile (Figure 45a). b) Breakthrough times of wells positioned according to the Tramrail- profile (Figure 45b).

When comparing the homogeneous tramrail and checkers-board cases, it can be observed that the thermal breakthrough occurs much later in the wells oriented in the checkers-board profile.

This can be attributed to the fact that the fluid injected by an injector in the tramrail profile, will for the major part be produced by one (for the injectors located at the side of the doublet layout) or two producers. The injectors in a checkers-board layout however, are surrounded by three or four (a five-spot pattern) producers. This leads to a far more effective drainage pattern. In fact, it can be observed that the checkers-board profile is so effective in a homogeneous reservoir, such that even after 60 years of production, breakthrough has only occurred in the production wells located at the sides of the well arrangement. Production wells 3, 6 and 7, which are located in a five-spot pattern however, are likely to produce few more years before thermal breakthrough occurs.

Table 12: From top to bottom: the homogenous reservoir exploited with the checkers-board profile; heterogeneous reservoir exploited with the checkers-board profile; homogenous reservoir exploited with the tramrail profile; heterogeneous reservoir exploited with the tramrail profile.

Temperature in Reservoir after 60 years of production		Temperature at producers in a multi- well layout	
Checkers-Board profile	Homogeneous Reservoir		
	Heterogeneous Reservoir		
Tramrail profile	Heterogeneous Reservoir		
	Heterogeneous Reservoir		

When comparing the heterogeneous cases with the homogeneous cases, we can observe a lot of capriciousness in thermal breakthrough times. In both the checkers-board well arrangement and the tramrail well arrangement, most production wells have thermal breakthrough earlier than they had in the case of the homogeneous reservoir. In some cases, however, thermal breakthrough occurs later in the heterogeneous case than in the case homogeneous case, e.g., production well 1 (see Figure 46).

The reason that later breakthrough did not happen in the case of a single doublet (section 6.2), can partially be attributed to the fact that the injected cold water in a multiple doublet layout can ‘choose’ in which direction it flows. The complex nature of pressure gradients for a geothermal project with multiple doublets in such a heterogeneous reservoir can cause cold water to flow through the easiest path towards a producer (which is not necessarily the one closest to the injector).

In the heterogeneous cases, thermal breakthrough occurs quite early in the lifetime of the geothermal project at some producers in both well-arrangements (see Figure 46). When considering the average temperature of all wells, however, it can be seen that the two cases show a completely different temperature decline after breakthrough (Figure 47). In the case where a checkers-board well arrangement is chosen, the temperature decline after breakthrough is far less steep then in the case when a tramrail well arrangement is chosen.

Figure 47: Comparison between average temperature of produced water from a heterogeneous reservoir with 10 doublets with a cumulative production rate of 1500 m³ in a tramrail profile well arrangement (blue line) and a checkers-board profile well arrangement (red line). The black dotted line indicates the minimal temperature (338.15 [°K]) at which water needs to be produced in order to be usable for spatial heating.

In fact, when the checkers-board arrangement is used, none of the wells produces water colder than 338.15 [K] after 60 years (see figure of temperature at producers for the checkers-board profile in the heterogeneous reservoir in Table 12). This means that according to the TNO standard (see Table 8) this series of doublets can be used for well over 60 year for a spatial-heating project. When a tramrail layout is used, this is not the case since the average production temperature declines quite rapidly after breakthrough and is lower than 338.15 [K] after 52 years as shown in Figure 47.

One major advantage of using the checkers-board well arrangement for exploitation of geothermal wells when comparing it with the usage of a single doublet, is that this allows for a smaller well spacing while still being able to produce enough heat throughout an extensive period (in this case 60 years). This allows for more efficient use of the doublet and reservoir and lower energy consumption by installed pumps. Thereby, the NPV per installed doublet will most likely increase.

This risk of an early breakthrough and fast temperature decline is also mitigated by using multiple wells. In section 6.2, for example, it could be observed that when a single doublet with a spacing of 1500m is used, the breakthrough time and decline rate of the temperature is very unpredictable in a heterogeneous reservoir.

6.7. NPV calculations for optimum scenarios

In section 6.4 it has been demonstrated the optimal spacings for various cases considering the production constraints and reservoir conditions proposed in chapter 5. For the case where a doublet was exploited for spatial heating and for the case where a doublet was exploited for greenhouse heating, the optimal spacing was determined to be 1273 m.

In this section, the financial gain in these cases is investigated by incorporating the initial investments, maintenance costs and taxes in the objective function, we obtain the NPV calculation as presented in section 4.1. Using the values from Table 3, it is found that a doublet installed for spatial heating yields an NPV of 1.6 million over a period of 60 years. The NPV of doublet for greenhouse heating with the same lifetime is 6.1 million.

In Table 13, the NPV development over the years and the yearly profits are displayed for the optimal case of greenhouse heating and the optimum case of spatial heating. (given the homogeneous reservoir settings as discussed in the previous sections)

Table 13: NPV plots (in the bottom row) and plots of the profits per year (top row) of the spatial heating case and greenhouse case. The break-even points (green dotted line) and times of thermal breakthrough (red line) are also shown in the graphs.

The curved shape of the NPV plots (the bottom two images in Table 13), is caused by the time value of money. It can be seen that most of the value of the project is contributed in the first years after the break-even points.

The jigsaw shape of the plots of the profits per year (the top two images in Table 13) is due to the fact that each five years the pumps need to be refurbished causing additional expenses in these years. The first ten years also yield a slightly lower profit due to the pay-off of the initial investments. By doing this, these costs can be deducted from the taxes. After thermal breakthrough has occurred, a decline in the yearly profit can be seen, though the influence of this thermal breakthrough on the NPV plot is not visible on this scale. In year 60, the wells are abandoned and related abandonment costs cause a drop in the profits.

Considering that very little additional value is added to the projects NPV in the last 30 years of the lifetime, it would probably be more efficient to exploit a well for 30 years and to decrease the doublet spacing accordingly. In Table 10 the Short Lifetime case shows that the optimum well spacing for a doublet installed for spatial heating in a homogeneous reservoir, with a lifetime of 30 years, has an optimum spacing of 962 meter.

The break-even point occurs much later in the spatial heating case, because of the less efficient energy usage in this case. One could argue that with such a late break-even and low NPV, the spatial heating is not a very attractive investment. When production water has a higher temperature, the economical prospect of spatial heating will then be better.

The temperature of the produced water can be enhanced by, for example:

- Drilling in deeper layers
- Drilling in places with a higher thermal gradient
- Using the gas, produced as byproduct, to increase the temperature of the water

What is not considered in the above calculations, but could potentially have and affect on the NPV is:

- The volatility of energy prices. Which are likely to rise in the future
- Higher drilling costs due to calamities
- The down-time of doublets due to for example start-up, maintenance or low energy demand.
- The risks involved with drilling and erroneous positioning of wells, causing extra costs and/or reduced flow.

7. Conclusions

In the introduction several objectives were listed (see section 1.1) to provide proof for the hypothesis which states that: through optimization of the well positions from one or more geothermal doublets in a homogeneous or heterogeneous reservoir, the profitability of the project, which is largely dependent on the time of compositional breakthrough, temperature breakthrough and the rate of temperature decline, can be improved.

Through realization of the objectives, it can be concluded that:

- The thermal breakthrough at a producer in a homogeneous reservoir, does not mean the immediate end of the lifetime of the doublet. Even though temperature breakthrough at the producer of a geothermal doublet is an indicator for the nearing end of the lifetime of a doublet, it will still be able to operate for at least some time after this breakthrough has occurred.
- Heterogeneities do not only influence the time at which breakthrough occurs at the producer, but also the rate at which temperature declines after breakthrough. The temperature decline after breakthrough is generally steeper in a homogeneous reservoir than in a heterogeneous reservoir. As a result the temperature (and concentration) of the water produced from a heterogeneous field may remain higher than what would have been expected on basis of a homogeneous decline rate model.
- It is calculated, that the thermal retardation factor is 3.65 given the reservoir conditions and production constraints presented in chapter 5. Hence, the ratio of the compositional front radius to the thermal front radius is given the square root of the retardation factor which is approximately 1.9. The effect that heterogeneities have on this thermal retardation factor, is found to be approximately 1%. Hence, the impact of the differences in mass and heat diffusion on this retardation factor can be considered to be negligible.
- The effectiveness at which a geothermal doublet is able to deplete a reservoir (recovery factor) and profitability of a geothermal doublet are closely interlinked. A higher recovery factor, however, does not necessarily mean that the doublet is more profitable and vice versa. There exists an optimum well spacing for doublets positioned in homogeneous reservoirs, such that additional gain of later breakthrough (when placing the production well further away from the injector) is negated by the loss in pressure support of the injection well. This optimum well spacing for a doublet developed for greenhouse heating is (in the case considered in this thesis) approximately the same as the optimum well spacing of a doublet developed for spatial heating. Given a discount factor of 7%, it makes little sense to calculate the potential gain from production years more than 30 years as all contributions after 30 years (until infinity) are likely to contribute very little to the NPV of the project.

For the determination of well positions in heterogeneous reservoirs, the optimum spacing is an important decision making factor. The more extreme the heterogeneities are, the more gain of careful planning of wells in the subsurface.

- With three consecutive successful realizations of the optimization sequence, it can be assumed with reasonable certainty that the proposed automatic gradient-based method for optimization of geothermal wells in heterogeneous reservoirs, has been successfully implemented. The optimal solution, in these cases, was found in 6 to 14 iterations. It was observed that different initial positions yield different solutions, hence no global optimum is found with this optimization method. Initial well positions should therefore be chosen carefully. Consequently it is necessary to compute more than one optimization sequence with different guesses for the initial positions in order to assess how good a solution is and to approach the global optimum solution.
- The checkers-board layout of multiple doublets is more effective in exploiting a reservoir than a tramrail layout. When heterogeneities are involved, thermal breakthrough occurs roughly at the same time for tramrail and checkers-board layouts. The decline of the average temperature of produced water of the checkers-board arrangement however, is much slower such that exploitation of the field can be maintained for very long time after thermal breakthrough.

8. Recommendations

In this chapter, recommendations for future research, on the topics discussed in this thesis, are given.

Regarding the model:

1. It is concluded that reservoir conditions and production constraints significantly influence the profitability and the optimum locations of geothermal wells. Using the methods proposed in this thesis, it is also interesting to investigate the impact of different reservoir bathymetries. For example, the case of a compartmentalized reservoir, when there are non-permeable faults (i.e. no-flow boundaries) present in the reservoir.
2. In this thesis, all wells are considered to be vertical. In reality, however, many of the wells are penetrating the reservoir under an angle. This is likely to influence the time at which breakthrough occurs and it is therefore recommended to investigate the propagation of the thermal front when flow is not perfectly radial.
3. Non-isothermal heat and mass transfer equations are used to determine the thermal retardation factor in a homogeneous and heterogeneous 2D reservoir. As the compositional front propagates much faster than the thermal front and the compositional breakthrough is a potential hazard for geothermal doublets, it is recommended to investigate how the thermal retardation factor is affected when conservative heat and mass transfer equations are used.

With respect to the optimization method

1. It is proven that optimization of the positioning of geothermal doublet is possible with the provided optimization method. This optimization method, however, does not pose a limit to the amount of well positions that can be optimized simultaneously. The gain for optimizing multiple doublets is larger than for only one doublet and therefore it is interesting to investigate how rewarding the optimization will be when it is applied to:
 - i. Placement of multiple geothermal doublets
 - ii. Placement of a new doublet next to an already functioning doublet
2. Although the perturbation method works in the two reservoir models with 10 perturbations, it is recommended to perform a comparative study to the effect that increasing or decreasing the amount of perturbations in various reservoirs. This way the amount of perturbations can be optimized such that the gradient can be approximated with sufficient accuracy while not minimizing computational expense.
3. In principle the method is not limited to the use of only eight pseudo-wells per well. Better gradients and as a result more optimal positions can be obtained if more pseudo-wells are used. Therefore, it is interesting to investigate how much better solutions will be when more pseudo-wells are used.

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Appendices

APPENDIX A – Optimization Scheme

APPENDIX B – Remarks to Optimization

The optimization method for geothermal doublets proposed in this chapter is usable but, as mentioned in section 4.4, has limitations. Some recommendations for future research on this topic are listed below:

- The gradients are of discrete nature, this leaves to the question how well the gradients are approximated by 10 perturbation runs. A comparative study to this type of optimization with different amounts of perturbations could elucidate what the effect of increasing or decreasing the amount of perturbations is on the effectiveness of the optimization algorithm
- In principle the method is not limited to the use of only eight pseudo-wells per well. Better gradients and as a result more optimal positions can be obtained if more pseudo-wells are used (Zandvliet et al. 2008)
- For future research on optimization of geothermal wells in heterogeneous reservoirs, using COMSOL, it is recommended to perform a comparative study to more efficient optimization algorithms. There are many different optimization techniques available in the literature, which are likely to pose more efficient ways of calculating gradients in FEM simulator programs. A possible alternative, for example, is the EnOpt method proposed by Chen and Oliver (2008).
- A big difference between the pseudo-well method proposed in this thesis and the ones used by Sarma et al. (2008) and Zandvliet et al. (2008) is that it is applied in a FEM model. As a result, the pseudo wells are not located in the mesh cells directly next to the main well. Otherwise iterative optimization would take a very long time to complete, as the mesh cells close to the producer are quite small.

There are also some remarks with respect to the COMSOL software. While COMSOL is an easy-to-use multi-physics program, it is not (yet) easy to use for optimization due to multiple reasons:

- As it is not possible to access the main code of COMSOL, optimization methods such as the adjoint method cannot be implemented.
- The relatively new COMSOL with Matlab software still has a lot of unresolved errors and there is little literature at hand, which describes how to debug and best combine the Matlab functions with COMSOL commands. Unfortunately this makes implementation of the optimization scheme on different models a rather arduous task.
- The permeability field is altered when the wells are moved in the optimization process. This is due to the different orientation that the mesh elements have with respect to the permeability field for each iteration. Therefore, it is of importance to select a mesh size smaller than size of the porosity and permeability blocks to prevent undesired upscaling and altering the porosity and permeability fields. As a result, the gradient-based optimization method proposed in this chapter works better as the mesh density increases.

APPENDIX C - Uncertainty of data

Subsurface geology is highly uncertain and normally it is necessary to account for this uncertainty when optimizing the location of new wells. This thesis, however, does not incorporate an assessment of uncertainty of the input data. This is not necessary, since no ‘real’ case-study’ is in consideration. However, it is important to stipulate that optimization methods do not pose a flawless means to find optimum well locations.

Like all geological data, the data used in the numerical model which is used for the well-placement optimization, relies on data that contain a certain amount of uncertainty. E.g., the permeability field is one realization out of a million possibilities. Therefore, uncertainties in the data reflect themselves as uncertainties in the outcomes of well-configuration decisions.

Such uncertainty could be captured when the wells are optimized for several realizations of the reservoir geology. This method is computationally quite demanding when an increasingly large number of realizations is used to capture uncertainty.

A number of studies have been performed to the optimization of well-placement under uncertainty (Yeten et al. 2003; Güyagüler and Horne, 2004; Kalla and White, 2007; Wang et al., 2012). The main challenge for these studies has remained to minimize the computational power required to capture influence geological uncertainty in the output of the optimization algorithm.

In addition, Güyagüler and Horne (2004) state that, given a well-placement problem, every decision maker would act differently given options with probabilistic outcomes. Therefore, they reason, decision makers who decide not to balance the risks and outcomes according to his/her specific risk attitude, must define their objectives clearly because the optimum is not clear in case of uncertainty.

As mentioned before, this statement does not apply to the optimization procedure carried out for this thesis but must be taken into account when performing a well-placement optimization on a real field.

Another type of uncertainty is introduced by the character of the production constraints imposed on the project. Zandvliet et al. (2008) also observed that production constraints (induced by the output requirements) significantly affect the well-placement problem in that a well configuration that is optimal when wells are operated with one set of constraints may be far from optimal when wells are operated with another set of constraints.

APPENDIX D - Fluid and Rock Properties

Through the empirical relations, listed in the table below, dependencies on pressure, temperature and salinity

Variable	Description	Validity range	Source
$\rho_w(p, T, C_m)$	Brine density	$0 < T < 275$ [°C] $0 < p < 200$ [MPa] $0 < C_m < 5.7$ [mol]	Spivey (2004)
$\mu_w(p, T, C_m)$	Brine viscosity	$20 < T < 150$ [°C] $0 < p < 30$ [MPa] $0 < C_m < 5.7$ [mol]	Kestin (1978)
$C_p(T, C_m)$	Heat capacity of brine	$0 < T < 180$ [°C] $0 < C_m < 3.08$ [mol]	Jamieson, Tudhope, Morris and Cartwright (1969)
$C_{pr}(T)$	Heat capacity of reservoir rock	$0 < T < 100$ [°C]	Somerton(1992)
$k_w(T, C_m)$	Thermal conductivity of brine	$0 < T < 80$ [°C] $0 < p < 40$ [MPa] $0 < C_m < 5$ [mol]	Nagasaka et al. (1983)
k_r	Thermal conductivity of saturated reservoir rock	2.5 [W/(kg*K)]	Lake (1989)
$\epsilon(x, y)$	Porosity field	$0 < x < W$ [m] $0 < y < H$ [m]	**CASE STUDY
$\kappa(x, y)$	Permeability field	$0 < x < W$ [m] $0 < y < H$ [m]	**CASE STUDY

APPENDIX E - Production constraints

Fracture pressure

Legislation for the maximum bottom hole pressure of geothermal fields in the Netherlands is quite strict. In some cases the injection pressure is even not allowed to exceed the hydrolic pressure by more than 10%. In this thesis, the threshold pressure, P_{thres} , at the injector (see section ##) is set equal to the presumed fracturing pressure.

For the prediction of the pore pressure and fracture pressure profiles, a well established technology exists, making use of Poisson modulus (Kozlov et al., 2005). An often used approach to calculate the fracture pressure is posed by a formula was developed by Eaton (1976) and is presented by the equations below.

$$p_{\text{frac}} = \left(\frac{\nu}{1-\nu} \right) (\sigma_v - p_{\text{pore}}) + p_{\text{pore}} \quad \text{Equation 56}$$

$$\sigma_v = \int_0^H (\rho g) dz \quad \text{Equation 57}$$

In these equations, ν is the Poisson modulus and σ_v is the vertical stress tensor at reservoir level. The pore pressure is represented by p_{pore} , the initial fracturing pressure by p_{frac} and H represents the thickness of the overburden.

Since friable sands such as the Delft sandstone have little or no tensile stress, the tensile stress can be neglected. With rough estimations of the weight of the overburden, it can be yielded:

$$\sigma_v = 39.2 - 49.0 [\text{MPa}] \quad \text{for} \quad 2000 \left[\frac{\text{kg}}{\text{m}} \right] > \rho_{\text{overburden}} > 2500 \left[\frac{\text{kg}}{\text{m}} \right]$$

Using the Poisson ratio for friable sandstone given by Dominico (1983), $\nu = 0.2$, it is obtained that:

$$P_{\text{frac}} \approx 24.8 \text{ MPa} - 27.3 \text{ MPa}$$

A better estimate of the fracture pressure could be obtained once a better estimation is made of the densities and the velocities of the overburden. Since it is not the goal of this thesis to perform an accurate case study, the estimate of 25 MPa will suffice.

Electrical Submersible Pump (ESP):

For the desired flow rate of 150 [m³/hr] Baker Hughes supplies the pump 16-900WNE2100, which is able to increase the BHP by 35 bar. (see Appendix #). According to Baker Hughes, this pump will then operate at 393.6 [kW].

The THP needs to be maintained at 3 bars in order to cope with the pressure losses in the heat exchanger. The pressure losses caused by friction are assumed to be 5 bar. This means that while the mean water level (MWL) is at -86m, the BHP of the producer $p_{p,\min}$ can be maintained at:

$$p_{p,\min} = p_{res} - \rho_w \cdot g \cdot MWL - \Delta p_{ESP} + p_{THP,p,\min} + P_{fric}$$

$$p_{p,\min} \approx 17.7 \text{ [MPa]}$$

Note here that $p_{p,\min}$ is the BHP to which the pressure can be lowered if the ESP is working at its optimal frequency. In practice an exploiter of geothermal energy will try to maximize the rate at which the geothermal well operates (also depending on rate at which the water can be reinjected) while at the same time minimizing the energy consumption of the ESP. For convenience it is assumed that the bottom hole pressure at the producer is always equal to this given minimal production pressure. Thus:

$$p_p = p_{p,\min} = 17.7 \text{ [MPa]}$$

Booster pump

In order to be able to potentially inject at a pressure of 25 [MPa], a booster pump should be installed at the surface such that 5 [MPa] overpressure in the reservoir can be generated. In order to reach such overpressure, the booster pump needs to generate a pressure difference of:

$$\Delta p_{ESP,\max} = p_{p,\max} - p_{res} - \rho_w \cdot g \cdot MWL + p_{THP,p,\min} + p_{fric}$$

Using the same values as used for the calculations for the ESP pressure, it can be derived that:

$$\Delta p_{ESP,\max} = 4.1 \text{ [MPa]}$$

Flux

Starting point for the design of the geothermal doublet usually is that the system should work at minimal transmissivity (in the P90 case), which is a measure dependent of permeability (k) and net reservoir thickness (h) of the aquifer (Hooghart, 1988; Mottaghy et al., 2011). The wells and pumps of geothermal doublets are then dimensioned such that a certain production rate is reached.

The numerical studies performed for this thesis, assume wells which are designed for a maximum flowrate of 150 m³/h. This corresponds with the rates to which most of the geothermal wells in the West Netherlands Basin are designed (van den Bosch 1&2; Aardwarmte Den Haag; Ammerlaan; Duijvestijn and Koekoekspolder).

APPENDIX F – properties of pumps

16-900WNE2100

Baker Hughes Incorporated

Operating Parameters / Selection:

Design Point:
 Desired flow (total) = 150000 lts/hr
 % water = 99.9 %
 % Gas into pump = 0.0 %

Frequency = 37.9 Hz
 GOR into pump = 1.6 m3/m3
 TDH = 275 m
 Friction Losses = 0.381 bar

Pump Selection:
 Intake Pressure = 47.93 bar
 Flowrate = 155016 lts/hr
 Specific Gravity = 1.022 rel-H2O
 Viscosity = 0.412Cp

Discharge
 Pressure = 75.5 bar
 Flowrate = 154858 lts/hr
 Specific Gravity = 1.023 rel-H2O
 Viscosity = 0.419Cp

Pump Selected:
 IMW 16-900WNE2100
 Pshaft RPM = 2234
 Shaft HP @ 37.9 Hz = 263
 Shaft load =(Std 29%) / (HS 15%)
 Required Motor HP at 50.0 Hz = 355

Seal Selection:
 Well angle (set depth) = 0Deg fm vert.
 No sand present
 Pump uses floater-type stages
 Motor/Seal Oil type = CL6
 Seal Selected : ISFB3 [875 Series]
 Options : None

Oil temperature at thrust chamber = 108°C
 Chamber Cap Used (Top to Bot)= 13% 9%
 Thrust bearing load =4 %
 Shaft load = 21 %

Motor Selection:
 Terminal Voltage =2386.4 V
 Motor Current =109.9 A
 Load acc to N.P. =28.4 %
 Shaft Load =18.3 %

Fluid Speed =0.823m/s
 Eff/PF =70.66% / 62.88%
 Internal Temp =109°C
 Motor Selected: HMI 1250HP 3558V 211A [725Series]

Cable Selection:
 Surface Length = 15.24m
 Tubing Length = 694m
 MLE length = 6.096m
 Surface Temp = 88°C

Wellhead Voltage = 2452.8V
 Wellhead kVA = 466.7kVA
 Voltage Drop = 66.3V
 Cond Temp (main) = 121°C
 Temp Rating = 232°C

Surface Cable
 #1 CELF5.0kV 15.24m
 CEEF ex Aberdeen

Main Cable
 #1/0 STR CELF5.0kV 694m

MLE Cable
 #5 MLE-KHT5.0kV 6.096m

Controller Selection:
 Input kVA = 603.2kVA
 System kW = 306.2kW
 Max Ctrl Current = 1061.7A
 Power Cost/kWH = 0.05\$/kWH
 Total Power Cost = \$11024/month

Voltage Input = 480V
 Max Well Head Volts = 2453V
 Max Frequency = 37.9Hz (12.67V/Hz)
 Start Frequency = 10.0Hz
 Step-up Trafo = 9.664 ratio
 Selected: VSD 9315-VT 1550kVA/ 480V/ 1864A

Well test container = 500 KVA

4,332

14,82

16-900WNE2100

Baker Hughes Incorporated

Operating Parameters / Selection:

Design Point:

Desired flow (total) = 150000 lts/hr
 % water = 99.9 %
 % Gas into pump = 0.0 %

Frequency = 43.1 Hz
 GOR into pump = 1.6 m3/m3
 TDH = 350 m
 Friction Losses = 0.381 bar

Pump Selection:

Intake = 40.4 bar
 Pressure = 155064 lts/hr
 Flowrate = 1.022 rel-H2O
 Specific Gravity = 0.41Cp
 Viscosity = 0.419Cp

Discharge

75.5 bar
 154858 lts/hr
 1.023 rel-H2O
 0.419Cp

Pump Selected:

IMW 16-900WNE2100
 Pshaft RPM = 2540
 Shaft HP @ 43.1 Hz = 360
 Shaft load = (Std 35%) / (HS 18%)
 Required Motor HP at 50.0 Hz = 425

Seal Selection:

Well angle (set depth) = 0Deg fm vert.
 No sand present
 Pump uses float-type stages
 Motor/Seal Oil type = CL6
 Seal Selected : ISFB3 [875 Series]
 Options : None

Oil temperature at thrust chamber = 109°C
 Chamber Cap Used (Top to Bot)=
 14% 9%
 Thrust bearing load = 5 %
 Shaft load = 26 %

Motor Selection:

Terminal Voltage = 2712.8 V
 Motor Current = 112.8 A
 Load acc to N.P. = 34.0 %
 Shaft Load = 22.0 %

Fluid Speed = 0.823m/s
 Eff/PF = 74.24% / 69.76%
 Internal Temp = 110°C
 Motor Selected: HMI
 1250HP 3556V 211A [725Series]

Cable Selection:

Surface Length = 15.24m
 Tubing Length = 694m
 MLE length = 6.096m
 Surface Temp = 88°C

Wellhead Voltage = 2781.6V
 Wellhead kVA = 543.5kVA
 Voltage Drop = 68.8V
 Cond Temp (main) = 123°C
 Temp Rating = 232°C

Surface Cable

#1 CELF5.0KV 15.24m
 CEEF ex Aberdeen

Main Cable

#1/0 STR CELF5.0KV 694m

MLE Cable

#5 MLE-KHT5.0KV 6.096m

Controller Selection:

Input kVA = 683.8kVA
 System kW = 393.6kW
 Max Ctrl Current = 1090.1A
 Power Cost/kWH = 0.05\$/kWH
 Total Power Cost = \$14170/month

Voltage Input = 480V
 Max Well Head Volts = 2782V
 Max Frequency = 43.1Hz (11.15V/Hz)
 Start Frequency = 10.0Hz
 Step-up Trafo = 9.664 ratio
 Selected: VSD 9315-VT 1550kVA/ 480V/ 1864A

Well test container = 500 kVA

APPENDIX G - Failing Optimization

When heterogeneities are very extreme, the gain from optimization is potentially big. The heterogeneities observed in the SPE10 model, however, are too capricious for the optimization method proposed in this thesis.

A realization of the increase in profitability optimization sequence for the unaltered SPE10 model is shown in the figure below. The spacing between main wells and pseudo-wells was selected to be 6 meters, which corresponds to approximately one porosity/permeability block in the x-direction and two blocks in the y-direction.

It can be seen that the solution converges rather quickly: after 5 iterations the supposed optimum well position is reached. Though in this particular scenario the wells were both placed in quite unfavorable positions (near very low perm areas), and the potential for improvement was big. Another observation is that, although the stepsize is very small (only 6 meters), the change in the objective function is very big, which underlines the extremity of the heterogeneities of the model.

The optimum reached here is approximately -6.5 million while the optimum in objective function plot in Figure 42, is already a lot higher. This indicates that the solution has been trapped in a local optimum.