Recommendations for improved geothermal well testing

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Contents

1. Introduction

A major benefit of physically flowing a well and interpreting the pressure response is that a good well test allows the engineer to ‘look’ into the reservoir much further than well logs can do. Logging tools typically have a depth of penetration of maximum a few meters, while the pressure response to a flowrate change has a depth of investigation of hundreds to thousands of meters, depending on the duration of the test. The resolution of well test data is however significantly less than the resolution of well log tools or core analysis: tools can have a resolution of centimetres or less and cores can be analysed on a microscopic scale, while such small scale geological features cannot be extracted from the more diffuse pressure response. In this sense, well logging / core analysis and well testing (and to a lesser extent seismic methods) are complementary to each other and should always be executed and interpreted jointly.

Interpreting the two different data gathering methods (for example logging and testing) does often not result in the same conclusions regarding the reservoir properties. Several reasons can be thought of to explain this discrepancy. The first one, as mentioned above, is that both methods have different depths of investigations: well logs only reveal information about the near well bore area (centimetres to maximum few meters), while well testing reveals information regarding the entire reservoir. Geological variability or heterogeneity on this scale is very likely and happens frequently, if not always. Secondly, none of the methods measure the geological properties of interest (e.g. permeability) directly. Well log tools measure a physical rock- or fluid property (sonic travel time, natural radioactive decay, resistivity, etc.) instead, and several models and correlations are used to convert these, step by step, into a permeability value. These models and the validity and availability of correlations carry a rather large range of uncertainty. The same applies for the well test: the pressure response does not measure geological properties like permeability. Mathematical solutions to the pressure response are used to identify the most likely flow regime, and appropriate models are selected to convert the pressure response to permeability. Also, the resolution of these known mathematical solutions to the pressure response of well tests is rather limited; the geological heterogeneity of reservoirs is far beyond the number of analytical models that exist.

Thirdly, and that is what this document is about, various datasets can only be calibrated against each other if they are complete enough, and of sufficient quality; the value of comparing two incomplete or incorrect datasets is rather low. The size of the logging suites (both open hole and cased hole) and core analysis from geothermal wells in The Netherlands is traditionally low, making a reliable estimate of the geological properties, like porosity or permeability, difficult. Well tests have been executed on every geothermal well in The Netherlands. However, data gathering during these well test often was limited, both in terms of quality and quantity. This forces the engineers and geologists to make assumptions or to use models, which introduces an additional source of inaccuracy and uncertainty. Because of this, it is not more than logical that discrepancies exist between logging datasets and well test data sets.

The goal of the TKI project ProperBase was to improve the predictability and understanding of reservoir properties of Dutch geothermal plays. This document covers work package C2: ‘Validation of reservoir models (properties) with well test data’. Based on the observations described above, it is however not possible within the initial objective of this work package to give recommendations on how to calibrate various datasets. Therefore the decision was made to slightly alter the scope of this work package, which is further elaborated on below.

Between 2023 and 2025 several geothermal exploration wells have been drilled which form part of the SCAN project[1]. The main objective of these research wells was to determine the geological properties of the target formations. However, these SCAN wells had many more secondary objectives, related to the testing of various operational methods. The overarching goals of these additional tests was to investigate how to improve the quantity and quality of the well test data, while simultaneously reducing the costs of well testing (without compromising on the quality of the data). Some of these secondary objectives included:

- Testing how to stabilise the production of geothermal brine in case gas lift is used as artificial lift method
- Testing whether jet pumps are a good (or better) alternative to gas lift or Electrical Submersible Pumps (ESPs)
- Testing to what extent a downhole shut-in device improves the quality of the well test data
- Testing how optimization of the well test program can reduce the cost of well testing

Many of these learnings have not been documented yet. This document provides tools how one can improve on the data gathering process, both in terms of quality and quantity, and how one can improve on the interpretation of the well test. It also allows operators to simultaneously reduce the costs of well testing, leaving more budget for e.g. well logging, coring or lab analyses. By doing so, larger, better and more reliable datasets can be obtained, which can be calibrated against each other in the future.

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[1] The SCAN program (https://scanaardwarmte.nl/) is a major geothermal exploration campaign funded by the Dutch Ministry of Climate and Green Growth, and is executed by EBN and TNO. SCAN acquires data in areas where insufficient subsurface data is available for a reliable estimate of the geological properties. As part of this project, several exploration wells were drilled between 2023 and 2025. Throughout this document reference is made to the data and the Data Acquisition reports of some of the SCAN wells that have been tested by the time of writing this document:

- Amstelland-1 (AMS-01)
- Oranjeoord-1 (ORO-01)
- Heesch-01 (HEE-01)
- De Bilt-01 (BLT-01)
- Stad van Gerwen-01 (SVG-01)

These data and reports, and publications that are largely or partly based on the observations form these SCAN wells, are used to provide examples of the statements made in this document. These references also show how specific well testing methods can help in improving the understanding of the geothermal play and how to reduce the costs of well testing without compromising on the quality and quantity of the data. The data and reports that support the findings and statements in this study are available from https://www.nlog.nl/ and on https://scanaardwarmte.nl/

2. Reading guide

Long-established well testing terminology from both the oil- and gas industry and hydrogeology are described in Chapter 3. Confusingly, both sectors do not always use the same definitions with respect to well testing terminology, which potentially leads to misunderstanding and miscommunication. Some of the (differences in) definitions are explained in Chapter 3, and how they are used throughout this document.

An important aspect of well testing is the design of a well test during the preparatory phases (see Chapter 4). This includes clearly defining the objectives of the test and up-front modelling of the lift performance and the pressure response of the reservoir. By doing so, the well test team can optimise the data gathering procedures while simultaneously trying not to spend unnecessary budget.

Prior to the start of any interpretation of well test data, one must ensure that the quality of the data is correct and sufficiently high, by minimising or eliminating any noise or unwanted signals. Chapter 5 (Data quality improvement) describes how geothermal engineers can improve on the data gathering process.

One of the biggest challenges in the geothermal sector is how to reduce the costs of exploiting geothermal reservoirs. Significant cost reductions can be achieved throughout the well testing process, and Chapter 6 provides recommendations how one can achieve this. Focus is on smart implementation of alternative hardware, and on the reduction of test water volumes. Examples from the SCAN wells show how this can be achieved while simultaneously increasing the quantity of the data and optimising the quality of the data.

Often, only parts of existing datasets are used to evaluate the geothermal well and the reservoir. It is not only the initial production test that can be evaluated using Pressure Transient Analysis (PTA). Any pressure change in the well during its entire life is equivalent to a well test that can be analysed as such. These are perhaps less obvious, but can be equally important and relevant. Chapter 7 describes how and which datasets can be used to analyse the reservoir- and well performance. Interpretation might be more complex due to, for example, temperature effects that have been introduced into the reservoir. Consequently, parts of the datasets cannot be used using conventional analytical PTA software, and can only be analysed numerically. Still, valuable information regarding the reservoir can be hidden inside the datasets, and this chapter provides tool how to get the most information out of the data.

It must be noted that this document focusses on the engineering aspects of the well tests of the SCAN wells only; the petrophysical and geological learnings, which are at least equally important, are not incorporated in this report.

3. Definitions

Small but relevant differences exist between nomenclature and definitions used by engineers coming from different backgrounds. The novel discipline of geothermal engineering falls in the grey area in between the classical petroleum engineering and hydrogeology disciplines; some geothermal engineers have a background in hydrogeology, while others have a background in petroleum engineering, each one having their own set of definitions. If there is no consensus on the definitions used, these differences in background can lead to misunderstanding and miscommunication, especially if one is unaware that various definitions are used. In order to shed some light on this, and to prevent any future misunderstanding, some relevant definitions used throughout this document are described in this chapter.

In this document a **well test** is considered to be the measurement of a reservoir's pressure response to a known and controlled flow rate change. Some sources adopt a much wider definition of well testing which includes well log measurements, static pressure measurements, fluid sampling, etc. For the sake of simplicity and scope reduction, the definition of well testing used in this document does not include these additional measurements. After *measuring* a reservoir's pressure response to a known and controlled rate change, the pressure response needs to be *analysed* using diagnostic methods. This is frequently called **pressure transient analysis (PTA)**.

It is always the objective of any well test to quantify the geological and hydraulic properties of the *reservoir*. It is not (or should not be) the objective to test the hydraulic properties of the *well*, since the well is drilled by the geothermal engineer and thus all of its properties are known a priori. In fact, it is the reservoir that needs to be quantified, not the well. The term 'well test' is thus misleading, and it might actually be better to rename it to a 'reservoir test'. However, it is not wise to deviate from a long-standing consensus and the term 'well test' will be used throughout this document, despite being misleading and – strictly speaking – incorrect.

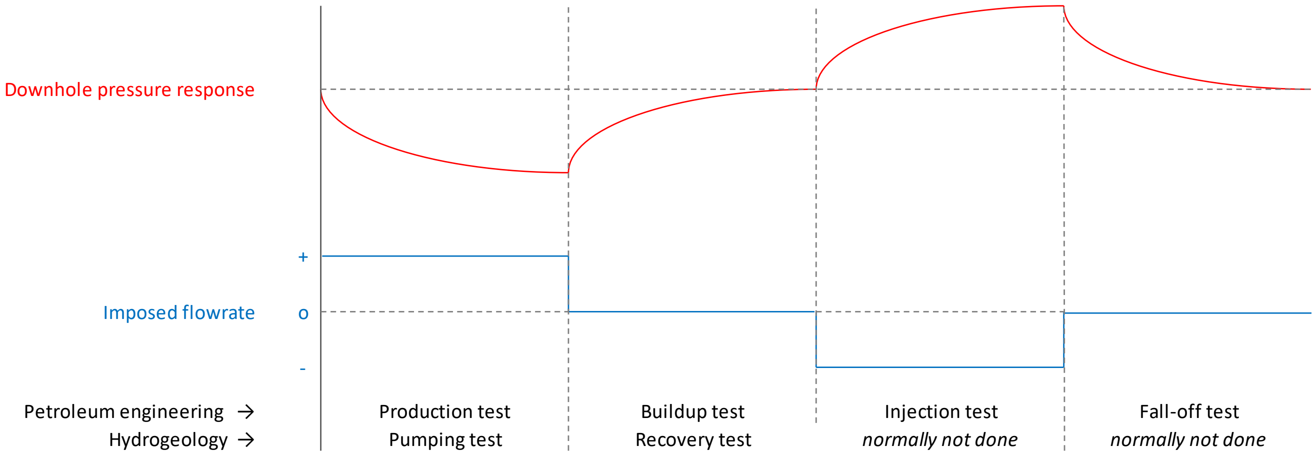


Figure 1. Well test nomenclature used by petroleum engineers and by hydrogeologists. The nomenclature used by petroleum engineers is used throughout this document.

Many different types of well tests exist to measure the reservoir's pressure response to a known and controlled rate change: drawdown test, production test, pumping test, pump test, recovery test buildup, injection test, fall-off test, multi-rate test, (modified) isochronal test, mini-frac, deliverability test, drill stem test, pulse test, interference test, slug flow test, etc. The names of the tests depend on the objective of the well test, the hardware used, the engineers' background, the flow direction of the fluid(s) under investigation, or the type of reservoir fluid. In this document the naming is based on the flow direction of the formation water (see Figure 1):

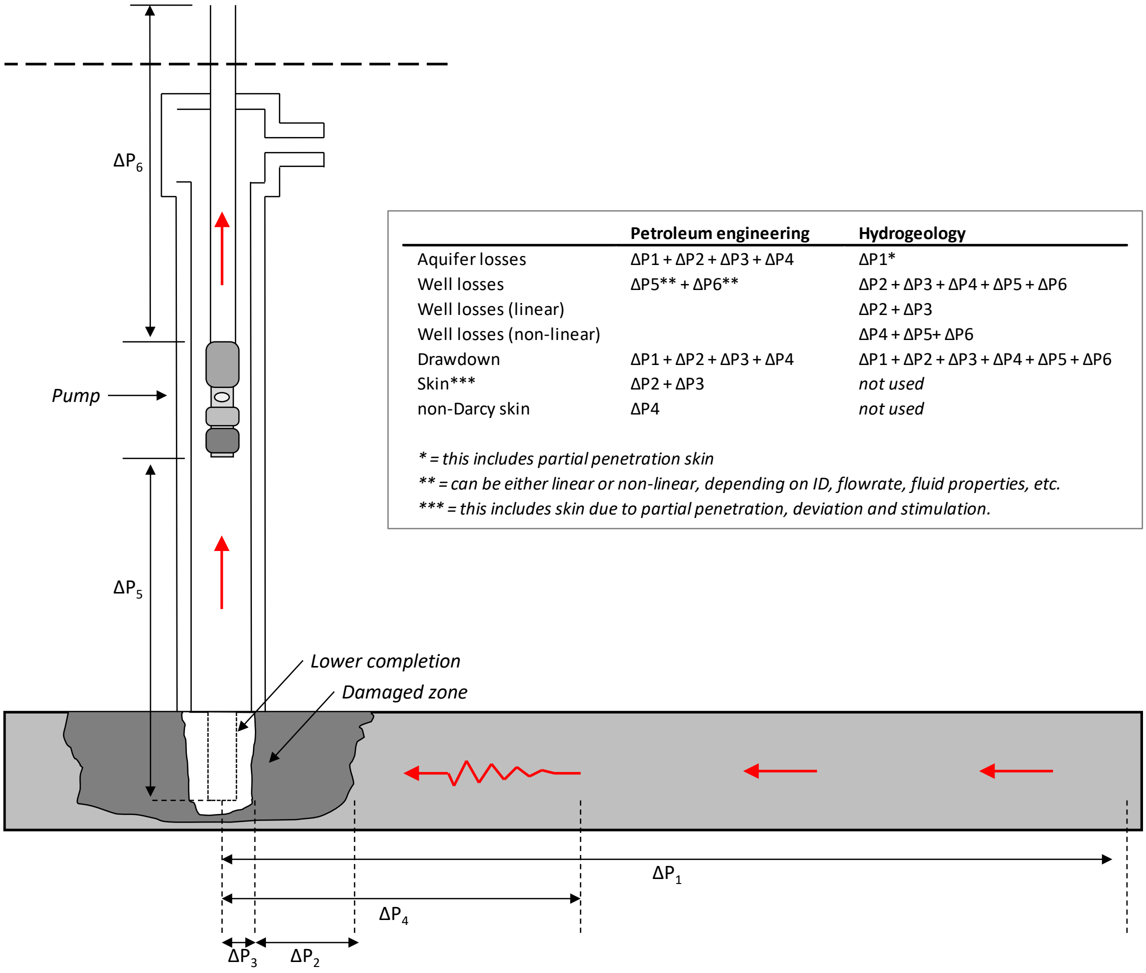
- **Production test**: fluid flow out of the reservoir, using some form of artificial lift
- **Buildup test**: a shut-in test following a production test
- **Injection test**: fluid flow into the reservoir, using an injection pump
- **Fall-off test**: a shut-in test following an injection test

A well test is often seen as the very first flow period after a well has been drilled. However, the first flow period is not the only source of reservoir pressure information: *every* pressure response to a known and controlled rate change is a well test that reveals valuable reservoir information when being analysed, irrespective of whether it's the very first rate change (i.e. immediately after drilling), or the nth rate change. Practically speaking, this means that every change in the ESP's or injection pump's frequency is a well test, which can be analysed. These well tests after commissioning of the geothermal system are often overlooked at, while they contain the same information regarding the reservoir – if properly analysed. Moreover, no costs are associated with these tests, since no additional downhole or surface equipment needs to be installed.

Skin is a dimensionless number incorporated into the Darcy flow equation for porous media, and represents the degree of reservoir formation damage and the reduction in permeability in the near wellbore area. The skin factor is made up of several components, of which the **mechanical skin** is the most well-known. The mechanical skin is defined as the skin caused by damage to the sand face, often caused by drilling mud in combination with an insufficient cleanout. Other types of skin include skin due to stimulation (fraccing or acidizing), partial penetration, turbulence in the reservoir (non-Darcy skin), perforations, and inclination. What all of these skins have in common is that they cause – by definition – an additional pressure change in the *reservoir*, not in the well.

According to petroleum engineers, **drawdown** is defined as the pressure difference between the average reservoir pressure and the flowing *bottomhole* pressure (see e.g. Dake, 1978). This is schematically shown in Figure 2, where the drawdown is equal to $\Delta P_1 + \Delta P_2 + \Delta P_3 + \Delta P_4$. Hydrogeologist, however, commonly adopt an alternative definition of drawdown: the drawdown consists of the combined pressure losses in the aquifer *and* in the well (see e.g. Kruseman and De Ridder, 1994). Following this definition, the drawdown in Figure 2 is composed of $\Delta P_1 + \Delta P_2 + \Delta P_3 + \Delta P_4 + \Delta P_5 + \Delta P_6$. The latter definition thus clearly includes frictional pressure losses in the well, while petroleum engineers deliberately exclude these pressure losses in their definition of drawdown. The reason for this difference is possibly that hydrogeologists historically use piezometers at a known distance from the well, to measure the water table in these observation wells (hence the convention to use meter as unit for drawdown). By using this methodology pressure losses in the well are indirectly and automatically included in the measurements. Petroleum engineers often lacked the luxury to drill observation wells and therefore used wellhead pressure gauges instead, later followed by downhole pressure gauges (hence the convention to use bar as unit for drawdown). Also, since tubings in oil- and gas wells are generally smaller and longer, the frictional pressure losses play a dominant role in the system's performance. For this reason the well is – in terms of friction and production optimization – considered as a separate entity, and is not included in the definition of drawdown.

Figure 2 also denotes the differences in views on turbulent flow (or non-linear flow) in the reservoir. Petroleum engineers consider this as a 'non-Dary skin', i.e. an additional rate-dependent pressure drop incorporated into Darcy's law. They consider this as part of the aquifer losses, and include this term into the definition of drawdown. Hydrogeologist however, consider this non-linear flow behaviour in the vicinity of the well as part of the well losses. This difference in definitions of non-Darcy skin effects has large implications for the interpretation and optimisation of geothermal well tests, and will be described in detail in chapter 6.



	Petroleum engineering	Hydrogeology
Aquifer losses	ΔP1 + ΔP2 + ΔP3 + ΔP4	ΔP1*
Well losses	ΔP5** + ΔP6**	ΔP2 + ΔP3 + ΔP4 + ΔP5 + ΔP6
Well losses (linear)		ΔP2 + ΔP3
Well losses (non-linear)		ΔP4 + ΔP5+ ΔP6
Drawdown	ΔP1 + ΔP2 + ΔP3 + ΔP4	ΔP1 + ΔP2 + ΔP3 + ΔP4 + ΔP5 + ΔP6
Skin***	ΔP2 + ΔP3	*not used*
non-Darcy skin	ΔP4	*not used*

** = this includes partial penetration skin*
*** = can be either linear or non-linear, depending on ID, flowrate, fluid properties, etc.*
**** = this includes skin due to partial penetration, deviation and stimulation.*

Figure 2. Frictional pressure losses in a well (gravitational losses are omitted). ΔP$_1$ = laminar pressure losses in the reservoir. ΔP$_2$ = additional pressure losses due to mechanical skin. ΔP$_3$ = additional pressure losses due to completion. ΔP$_4$ = additional pressure losses due to turbulence in the reservoir. ΔP$_5$ = pressure losses in the production casing. ΔP$_6$ = pressure losses in the tubing. See text for further explanation. References: Dake (1978), Kruseman and De Ridder (1994).

The **Productivity Index** (P.I.) is the ratio between the reservoir's downhole flowrate and the pressure drawdown in the reservoir. Based on the definition of drawdown in which pressure losses in the casing and tubing are *not* included (see Figure 2 and above text), the P.I. (or **Injectivity index** (I.I.) for flow into the reservoir) is thus a *reservoir* property, not a well property. This means that *bottomhole* pressures should always be used when calculating the P.I. or I.I. In the unfortunate and undesirable case that downhole pressure measurements are absent, models or correlations must be used to convert wellhead pressures or pump intake pressure to bottomhole pressures. Using wellhead pressures instead of bottomhole pressures (either measured or calculated) does not results in a PI or II, but the cumulative effect of the reservoir performance and the well performance.

Productivity Index (or Injectivity index for flow into the reservoir) is a *steady state* reservoir property, not a transient reservoir property. If the steady state conditions cannot be measured or calculated, transient conditions should not be used instead. An important reason to always use *steady state* conditions when reporting a P.I. or I.I. is that ESP suppliers assume steady state conditions when designing ESPs. Providing them incorrect P.I.'s will lead to premature failure of the ESP and unnecessarily high operating expenditures.

4. Well test preparation

The purpose of a well test is to meet specific objectives regarding the determination of reservoir properties. To meet these objectives, the test must be designed, and the key to a successful well test lies in the preparation and in the inclusion of an appropriate team (including geologists, reservoir engineers, well engineers, production engineers, well test engineers and external suppliers). All the objectives of the test must be set during these preparations.

An important step in the design is the upfront modelling of the test, both in terms of artificial lift (often done using nodal analysis) and in terms of PTA. Nodal analysis models should be used to ensure that the reservoir's inflow performance matches the well's lift performance (irrespective of what type of lift is used), for the entire range of expected reservoir performance. Lift performance modelling is often done by the pump supplier. If not, or in the case of gas lift, the well test team must model the lift performance themselves, to ensure stable flow for the entire range of expected geology. Modelling lift performance also allows the team to design an appropriate fit-for-purpose lift method, such that there is no unnecessary budget overrun.

PTA software can be used to simulate the response of a well test from the range of expected geological parameters and the dimensions of the well. The software can be used to test the effect of various types of flow periods and the duration of the shut-in periods on the results. This allows the team to minimise the amount of production water and hence to minimise the costs, while simultaneously reaching the well test objectives. It also allows the team not to prolong the buildup unnecessarily long, thereby reducing the costs of the test.

Once a preliminary test design has been selected, the team can proceed to select, amongst others, appropriate pressure gauges with adequate accuracy and resolution. Next, the surface equipment must be selected which is sufficiently large to process all the water of all modelled well tests, while simultaneously being sufficiently small to minimise the costs.

The recommendations provided in the subsequent chapters in this document can be applied to future wells, and should ideally be discussed among the well test team during the abovementioned preparatory phases of a well test. By doing so, the well test team can design a safe and economical plan to reach the test objectives.

5. Data quality improvement

The value of a well test largely depends on the quality of the data gathered during the test. Poor data (both in terms of quality and quantity) result in conclusions that carry a large degree of uncertainty; the higher the quality of the data, the higher the engineer's confidence level in the correctness of the results. The SCAN well tests were executed using different methods, with the objectives (a.o.) to evaluate how to improve on the quality of the data measurements, such that the geological uncertainty can be reduced. These methods focussed on:

- Buildup and falloff tests: how a *downhole* shut-in removes unwanted noise
- Production tests with gaslift: how gaslift optimisation removes unwanted noise
- Downhole pressure gauges: how downhole pressure gauges remove the necessity to use correlations
- Production Logging Tool (PLT): how additional logging aids in the estimation of the permeability.

The value of these methods and how they improve the quality of a well test is described below.

Downhole shut-in

The installation of a downhole shut-in device during buildup and in many fall-off periods is perhaps the most important aspect of improving the quality of well test data, and should always be deployed in every geothermal well. This is extensively documented in Bruijnen (2024b). By installing such a device the wellbore storage effects, which massively hinder a reliable interpretation of the pressure transient, are removed and not recorded anymore by the downhole pressure gauge. Only by doing so, the engineer can reliably interpret the well test. There is a high chance that not installing a downhole shut-in tool will lead to incorrect conclusions regarding the skin and crucial reservoir properties. Numerical and analytical simulations supporting these statements are provided in Bruijnen (2024b), as well as a literature review on wellbore storage effects, and recommendations on how downhole shut-in devices can be deployed.

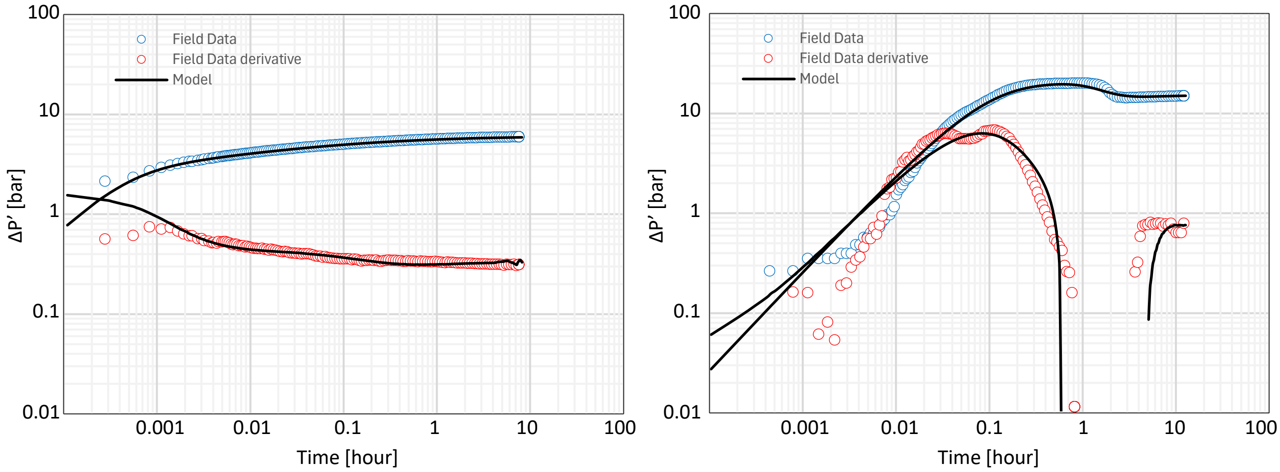


Figure 3. Field data and the PTA model of a buildup in well ORO-1. Left picture: data and model of a downhole shut-in, thus eliminating wellbore physics. Right picture: data and model of the same well and same reservoir of a buildup with a surface shut-in, thus including wellbore physics. It takes up to 4-5 hours for this Bourdet derivative in the right picture to stabilise and to show true reservoir behaviour. The first 4-5 hours of the buildup (which translates to 100's of meters of reservoir radius) are entirely overprinted by wellbore storage effects, not allowing for a reliable geological interpretation anymore. (source: Bruijnen, 2024b).

An example of the value and necessity of a downhole shut-in tool for well testing is shown in Figure 3, where two buildups of SCAN well ORO-01 are shown. The buildup with a downhole shut-in (left picture) allows for reliable determination of skin and reservoir properties, while the buildup without a downhole shut-in device (right picture) results in a Bourdet derivative that does not represent the reservoir response anymore.

Stabilisation of gas lifted production

Stable production (and injection) periods are important in establishing a productivity (or injectivity) index; unstable flow periods result in high uncertainty regarding the P.I. or I.I.. Also, production periods can be interpreted using PTA as well (see chapter 7), provided that the production is stable. For these reasons it is important to stabilise the production period as much as possible.

Since geothermal reservoirs are almost always at hydrostatic pressure and the wells thus don't flow naturally, some form of artificial lift is required in order to lift the brine out of the wells. Pumps are frequently used to lift the brine, which normally results in stable production behaviour. In case gas lift is used, the addition of an extra phase results in multiphase flow in the well which can result in highly unstable production behaviour and a test that is very hard to interpret. In this chapter, a simple yet effective method is given to stabilise gas lifted wells.

The well test of AMS-01 was executed with gas lift. The production period resulted in extremely fluctuating flowrates (both gas and water) and bottomhole pressures, see Figure 4 (left). In the design of the well test the following operational considerations were implemented in order to avoid such fluctuations, which are not uncommon in gas lifted wells (either oil or geothermal wells):

- Minimise wellhead pressure (e.g. Economides et al (2012), Hu (2004))
- Keep the wellhead pressure constant
- Keep gas injection rate constant (Hu, 2004)
- Gas-lift operating valve (or CT nozzle in the case of AMS-01) installed as deep as possible
- Minimize (or avoid) human intervention in order to attempt to suppress fluctuations (by e.g. adjusting chokes sizes, etc).

Despite these operational implementations, the well showed very unstable production behaviour with macroscopic instabilities (Hu, 2004). This does not only prevent the engineer to perform Pressure Transient Analysis (PTA) on the production period (see chapter 7), it also makes a reliable estimation of the Inflow Performance Relationship (IPR) impossible (see Figure 4, right picture). For these reasons, and to optimise stable (=safe) operations, it is important to stabilise this two-phase flow inside the wellbore.

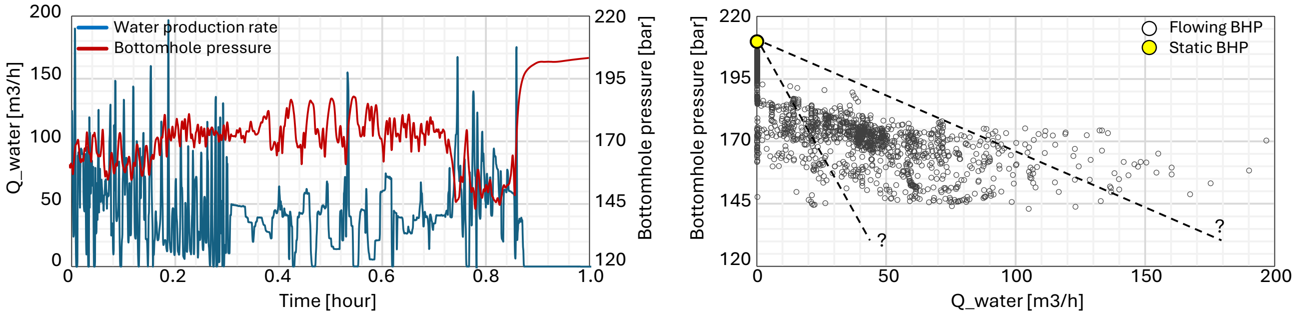


Figure 4. Well test results of AMS-01. Left picture: measured bottomhole pressure and water production rate vs. time. Right picture: bottomhole pressure vs. water production rate of the same datapoints. Clearly visible in the left picture are the massively fluctuating flowrates and large-scale instabilities, resulting in continuously fluctuating bottomhole pressures. The right picture shows the impossibility of drawing a straight line IPR through this cloud of data (note that a straight line IPR must go through the static BHP). See text for further explanation.

Hu (2004) mentions that unstable production phenomena were commonly given the name 'heading' by petroleum engineers. In the case of gas lift operations, were in the oil industry the casing is commonly used as the injection medium, 'casing heading' is a major concern and is often a source of irregular cyclic variations in pressure and flowrate. Xu and Golan (1989) describe how open communication between the gas-filled casing and the tubing results in cyclic instabilities, which can be prevented by removing the communication port between the tubing and casing. The problem obviously is how to prevent pressure communication while there should simultaneously be mass transport from the casing to the annulus. The solution is to instal a choke in the gas lift port or valve (Economides et al, 2012), such that the velocity of the injection gas increases to values above the critical flow (see Figure 5). Once the gas velocity reaches critical flow, pressure disturbances downstream of the choke cannot migrate upstream anymore, resulting in the removal of the casing heading effect.

Although gas lift in AMS-01 was not done via the casing but via a 2" coiled tubing, it is believed that the same effects have taken place during the production period of this well test: pressure communication between the CT and the well. In order to improve on the quality of the data, a 0.075" choke was installed in the CT nozzle during the gas lift operations in the subsequent SCAN well, ORO-01. Injection pressure was increased to allow critical flow to develop through the choke. Injection pressure, injection rate and choke size were designed using appropriate nodal analysis models. The effect this choke had on the production performance of the well test of ORO-01 is shown in Figure 6. This figure shows that the flowrate and accompanying bottomhole pressure were very stable, not suffering from any micro- or macroscopic instabilities. Additional stability was achieved by implementing the bullet points mentioned before (minimize wellhead pressure, constant injection rate, inject as deep as possible, minimise human intervention during the operation).

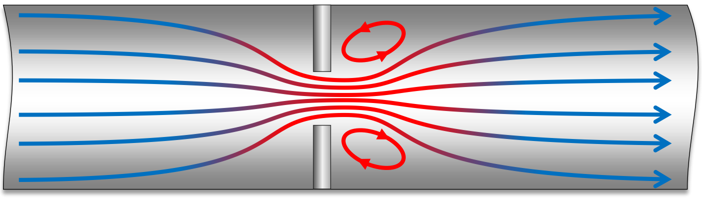


Figure 5. Working principle of choke. A restriction with an opening smaller than the inlet/outlet diameter creates an increase in the fluid's velocity, resulting in a decrease in the in situ pressure (Bernoulli's law). Sufficiently high velocities in the opening prevent downstream pressure disturbance to migrate upstream.

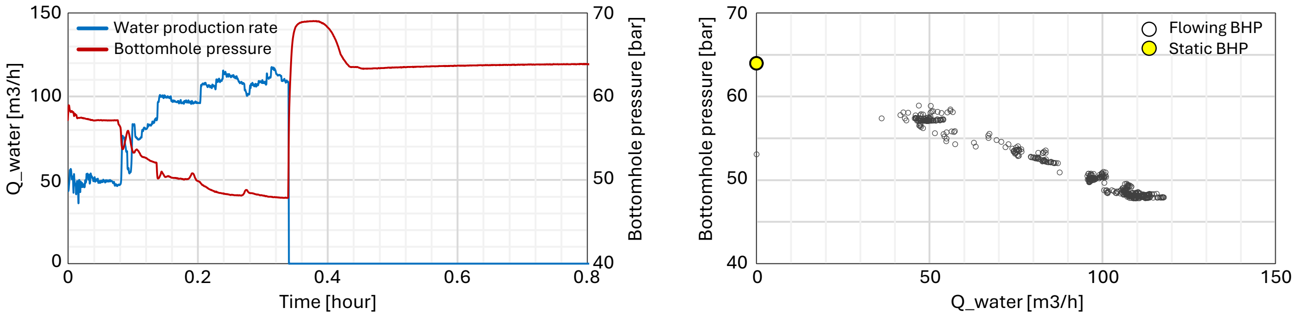


Figure 6. Well test results of ORO-01. Left picture: measured bottomhole pressure and water production rate vs.. time. Right picture: bottomhole pressure vs.. water production rate of the same datapoints. Clearly visible in both graphs is that the production period is very stable without any wellbore instabilities. This results in clear and well-interpretable productivity index (see right picture). See text for further explanation.

Based on the learning from well ORO-01, it is strongly recommended to implement the same or a comparable approach in other geothermal wells, in order to stabilise production periods using gas lift. Gas lift optimisation, including downhole choke design, can be modelled upfront in the design phase using nodal analysis software.

Downhole pressure gauges

All of the SCAN well test were executed using *downhole* pressure gauges. Downhole pressure gauges (i.e. as close to the reservoir as possible) are a very valuable addition to the well test data set for the following reasons:

- Under *flowing* conditions, surface or mid-well gauges do not measure the pressure response of the reservoir, but the pressure response of the reservoir + the well section between the perforations and the pressure gauge. The latter includes frictional losses in the wellbore, and models must be used to correct for this. Models always carry uncertainty, which should be avoided. An excellent example on how shallow gauges can result in an incorrect interpretation of e.g. the skin, is provided by TestWells (2025): shallow gauges in this gas well resulted in an 'apparent' skin of 23, while deepset gauges resulted in a skin of 0.4. This difference was purely caused by friction in the wellbore, which was incorrectly accounted for; deepset gauges clearly indicated that a skin was almost absent. This example shows how incorrect conversion of wellhead pressures to bottomhole pressures can result in an incorrect diagnosis, with potential incorrect follow up actions.
- Under *shut-in* conditions, the surface or mid-well gauges cool down in the case of buildup periods, while they often heat up during fall-off periods (although that depends on the setting depth of the gauges). These temperature changes have an impact on the pressure readings of the gauge, and should be accounted for using models. These models always carry uncertainty, related to the static geothermal gradient, thermal properties of the overburden en tubulars/cement, the thermal properties and absolute motor temperature of the ESP during production, and other installed hardware. This makes a conversion of surface – or mid-well gauges to depth highly uncertain.

Needles to say, since it is highly recommended to install a downhole shutin device to prevent large wellbore storage effects during the buildup, this automatically implies that a downhole pressure gauge (below the shutin device) needs to be applied too.

Production Logging Tool

The primary aim of a production logging tool (PLT), or an injection logging tool (ILT), is to determine where the fluids are coming from in a production well or to determine where the fluids are going to in an injection well, both during flowing and shut-in conditions. More specifically, a PLT or ILT can be run to:

- Monitor geological performance:
  - Determine the relative contribution of flow zones in a well
  - Identify possible thief zones
  - Assess the productivity or injectivity of individual zones
  - Identify cross flow
  - Identify natural fractures
  - Etcetera
- Monitor well performance and integrity:
  - Identify leak paths or channelling behind casing
  - Monitor the effectiveness of the sand retention of sand screens
  - Monitor the effectiveness of perforation

- Diagnosing well problems
- Identify recompletion options
- Evaluation of the effect of stimulation operations
- Etcetera

In addition to these objectives for geothermal wells, many complementary objectives exist in the case of multiphase flow (e.g. identification of gas or water breakthrough, movement of water or oil columns during shut-in, etc.). A PLT/ILT is thus a very versatile tool, and the application of this tool allows the engineer to evaluate reservoir- and well performance that cannot be done using only well logs or well tests. A PLT/ILT should preferably be run multiple times during the life of a well, not only after production problems arise. It is recommended to establish a 'base line' production log immediately after drilling, completion and testing the well.

Perhaps the most important reason to run a PLT / ILT as part of the data gathering suite after drilling a well, is to establish what the 'h' is in the well test 'kh'. Reason for this is that pressure transient analysis can only yield a kh - the product of the permeability and thickness - and can never determine what the absolute value of the permeability or the thickness is. A petrophysicist can establish a net-height of the reservoir, but complexities can arise in the estimation of the h based solely on well logs:

- It is often unknown what cut-off criteria to use; this problem does not exists in PLTs.
- Open fractures might not always be detected using well logs, while they can easily be spotted using a PLT
- The definition of 'h' in the 'kh' is the *net thickness of the reservoir that contributes to flow*, which is not the same as the *net thickness of the reservoir*, which is a purely geological definition. Parts of the reservoir might not contribute to flow at all, for reasons other than geological ones:
  - Partial perforation (either deliberately or unintentional) or other incorrectly installed lower completions.
  - Skins that are not uniformly distributed along the reservoir interval result in reservoir intervals that do not contribute to flow, despite having good reservoir properties.
  - Vertical reservoir pressure differences, either geological by nature or induced by exploitation of the reservoir, result in parts of the reservoir that do not contribute to flow.

These complexities can easily result in an incorrect estimation of the h, and hence in an incorrect estimation of the permeability from well test analysis. The only way to avoid this and to increase the quality and hence the value of well test data, is by means of PLT / ILT.

An example of the added value of an PLT/ILT is shown in Figure 7, which shows the ILT profile of the lower part of the Upper Breda member in SCAN well SVG-01. The PTA of the well test of this well (not shown) resulted in a best estimate kh value. The gamma ray in this figure is fairly constant, suggesting that the formation is homogenous and each flow zone contributes equally to flow. However, the spinner response and the temperature log show that below 883 meter (dotted line) the intake of the reservoir is close to zero; the lower part of the reservoir does not contribute to flow at all. Based on this GR alone one would expect a net reservoir height of 163 meters (top perforations to bottom perforations), while the ILT clearly indicates that the 'h' in the well test kh is 163 / 2 = ~ 81.5 meters. This implies that the actual reservoir permeability k is twice as high as one would expect in case the ILT has not been run. ILTs or PLTs thus help estimating the permeability and assist in calibrating the petrophysical analysis.

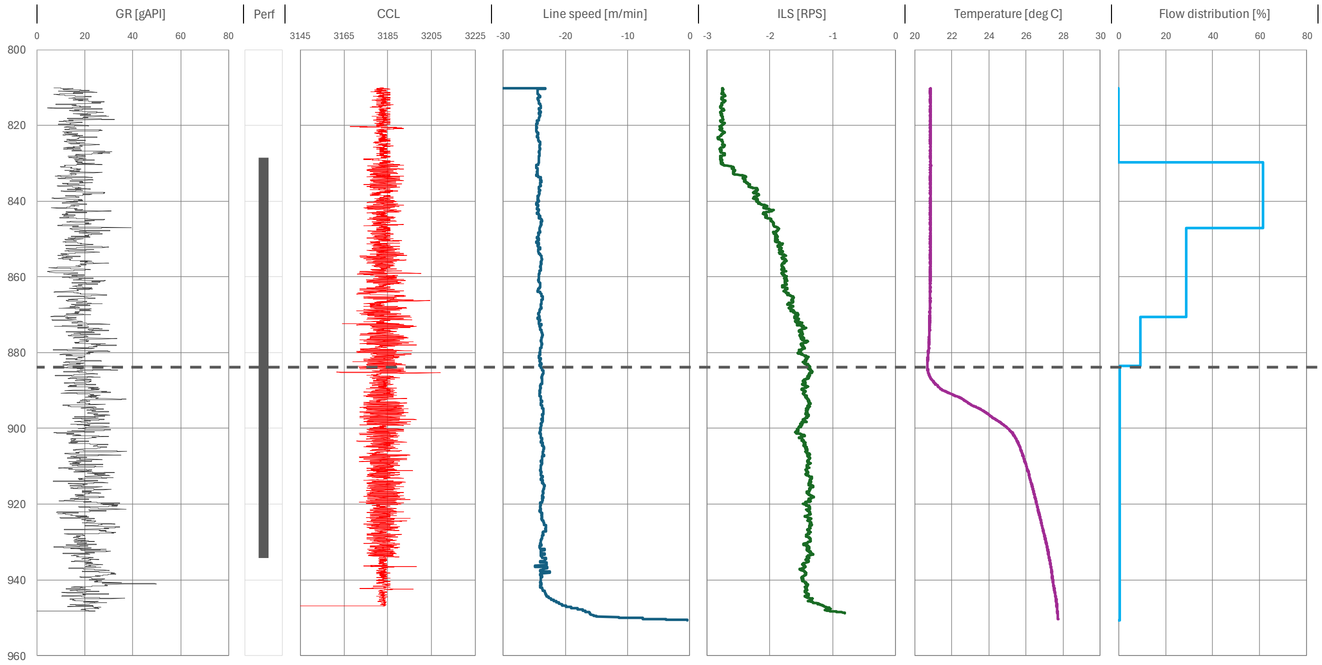


Figure 7. ILT of SVG-01, NUBRU formation (lower interval). Injection rate is 725.2 l/min. See text for explanation.

6. Cost reduction

This chapter describes how to reduce the expenditures of the well test sequence without compromising on the quality or quantity of the data. This can be achieved by using alternative hardware, by reducing the amount of production water or by better tuning the test program to the well test objectives. All methods described here are based on the experience gained while testing the SCAN wells, supplemented with analytical and numerical modelling.

Artificial lift alternatives

Historically seen, ESPs have been used as the artificial lift method of choice to produce geothermal water, although gas lift has been used recently as well. Both methods involve however large rental costs of well test equipment. In ORO-01 a venturi pump (jet pump) was installed, with the objective to test the applicability of this alternative form of artificial lift, and whether this pump could be used to evaluate the reservoir's properties. The pump's performance was very stable, and a comparison between the Bourdet derivatives of the buildup of a jet pump-lifted production period and a build-up of a gas lifted production period in well ORO-01 resulted in identical results of the PTA, see Figure 8.

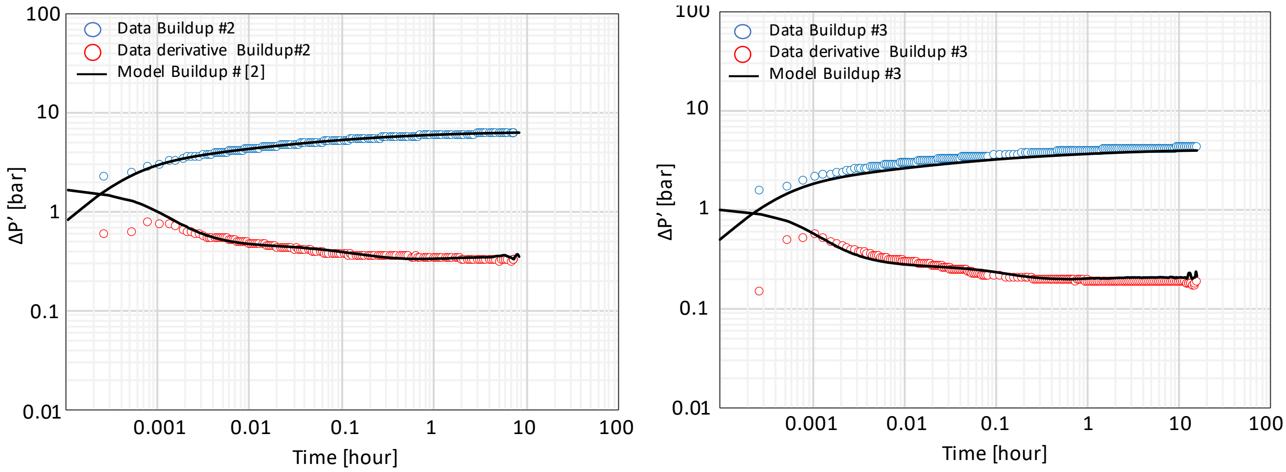


Figure 8. Data and Bourdet derivative of ORO-01 well test. Left picture: buildup following a gaslifted production period; right picture: buildup following jet pump lifted production period. Note the extremely comparable shape of the derivative and the matched models. Reference: Bruijnen (2024a).

A major advantage of a jet pump compared to alternatives like ESP or gas lift, is the costs of this concept. The jet pump itself is significantly less complex than e.g. an ESP, and as such cheaper to purchase or rent. High injection pressures are required, but in case the test is executed using a drilling rig, the injection pumps and even the rig's tubulars can be used to inject high pressure power fluid into the downhole jet pump, bypassing the necessity to rent additional injection pumps and tubing/coiled tubing. For continuous operation on a commercial basis, jet pumps might not be the optimal method, because the injection pump specifications most likely result in higher power consumption per produced volume of water than for ESPs. Also, the maximum achievable flowrates might not be as high as for ESPs. For well testing purposes however, jet pump can be a good alternative to other pumps.

Although jet pumps appeared to be suited for the objectives of the SCAN well tests, other lift methods might be more appropriate for other situations, since every well and reservoir is unique. It is recommended to design and select the optimal lift method for each specific well test.

Reduction in production water

The shear amount of production water is a major challenge in geothermal well testing. Producing large volumes of water is not only time consuming; very large test equipment needs to be installed (large storage tanks, large gas lift + processing equipment, etc.). In the past several studies on the processing of produced geothermal water have been executed (e.g. IF Technology B.V. (2016) and Royal Haskoning (2020)). These studies focus on possible solutions to deal with the water *after* the brine has been produced, and include, amongst others, re-injection into a well, evaporation of the water, discharging to surface water, and transport to industrial waste processing facilities. Re-injection of the produced water is probably the cheapest of all options, but this might negatively influence the near-wellbore properties of the newly drilled well. For this reason it can be more desirable to transport this waste water to an industrial waste disposal company, but this comes at a significant cost.

Unfortunately, no solutions have been found to date that do not impose a risk to the performance of the injection well, that do not impose any risk to the environment, and are still low-cost. The cumulative production water during initial geothermal well tests is generally more than 3000 m^3, volumes in excess of 4000 m^3 are no exceptions, and up to 6000 m^3 has been reported (NLOG, 2025).The total costs associated with the production and management of geothermal test water can therefore easily add up to 1.0 million euro or more, based on these large volumes of test water that have been produced in the past and the costs of industrial waste processing.

Since prevention is better than cure, it is better to reduce the volume of produced water instead. During the testing phases of the SCAN wells, one of the secondary objectives was to determine the minimum amount of production water that still allowed the engineers and geologists to evaluate the geological parameters with maximum confidence. The learning of these secondary objectives are outlined in this chapter: several methods are described that allow operators to reduce the amount of production water, while still maximising the quality and quantity of the well test data. It is demonstrated that it is not a necessity to produce large volumes of water, and producing the well at low flowrates for a brief period is sufficient to allow for the determination of the reservoir properties and the well's production capacity. By doing so, the cumulative volume of production water needed to accurately and reliably test a geothermal well can easily be reduced by a factor 10 or more, thereby reducing the costs of well testing massively.

Reduction of flow duration of the test

The principle of superposition (see Figure 9, left) states that any sum of individual solutions to the diffusivity equation is also a solution to that equation. Or, in other words: the total pressure drop recorded by a downhole gauge is the sum of all pressure changes caused separately by each new flow rate change (Ahmed & McKinney, 2004). This concept can be applied to account for the effect of variable flow rates, including the shut-in period (which is – mathematically – a flow rate too). This implies that using the superposition principle, pressure signals of e.g. the reservoir boundary can be detected during the buildup period, even if this signal was not detected during the drawdown. The initial duration of the production period is not an absolute limit for the duration of an interpretable build-up, so it is possible that a larger area of investigation is analysed during the buildup than what was seen during the drawdown (KAPPA Engineering, 2024). The limiting factor is in fact the resolution of the gauges and possible presence of background noise, not the duration or the intensity of the production period. Luckily the resolution of present-day gauges is extremely high. This means that production periods do not need to be very long in order for the buildup to detect the entire area of interest; a brief or short *production* period suffices as long as the *buildup* is long enough.

Production periods in the SCAN wells were often very short, 3 hours or even shorter. An example of a buildup following a short production period is shown in Figure 9 (right). Plotted in this figure is the Bourdet derivative of a 24-hour buildup (with downhole shutin) of SCAN well BLT-01, following a three-hour production period. The Bourdet derivative displays a typical signature of a sealing fault at a distance of ~ 4.5 hours from the well, despite the fact that the production period lasted shorter than the time to detect the reservoir boundaries of the buildup. This confirms that production periods do not need to be very long in order for the buildup to detect a much larger area; it's the combined duration of the production - and buildup period that determines the radius of investigation. It is therefore recommended to minimise the duration of flow periods, in order to reduce the amount of production water and hence to reduce the costs of the well test.

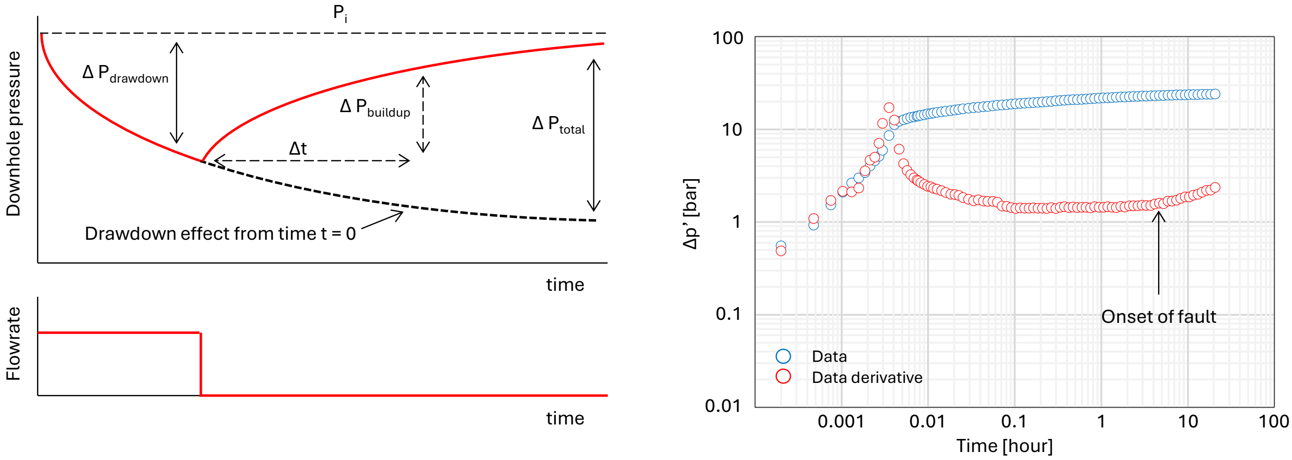


Figure 9. Left: concept of buildup superposition. Right: SCAN well BLT-01, Bourdet derivative of buildup following a brief (3 hour) production period. See text for further explanation.

Reduction of the number of multi-rate steps

Multi-rate tests in oil- and gas wells are executed in order to determine the non-Darcy skin effects in the reservoir. This chapter describes why multi-rate tests have hardly any additional value in geothermal wells, despite the fact that they are commonly executed in oil wells and especially in gas wells. Omitting multi-rate tests from the test sequence results in a large reduction in the volume of produced water and therefore in a large reduction in the costs of geothermal well tests.

Horne (1990), among many other authors, mentions that one of the difficulties of gas well test interpretation is due to the 'turbulent' or non-Darcy flow effects close to the wellbore, which appear as a rate-dependent skin. In contrast to the conventional 'mechanical skin', this rate-dependent skin is a function of the flow rate, and it is highly desirable to separately evaluate the two different skin effects. It is this estimation of the rate dependent effect that requires gas wells to be tested at multiple rates, using e.g. a flow-after-flow test or a modified isochronal test. Horne does not mention non-Darcy flow effects to be present in non-gas wells, like oil wells above the bubble point or water wells.

Dake (1978) mentions that non-Darcy flow effects are negligible at low flow velocities. For a given pressure drawdown, however, the velocity of gas is at least an order of magnitude greater than that for oil, due to the low viscosity of the gas (Dake, 1978). The viscosity of gas is 0.01 to 0.03 cp at reservoir conditions (although highly dependent on the composition, pressure and temperature). The viscosity of geothermal brine at typical formation depths in The Netherlands is 0.5 to 1.0 cp, largely depending on salinity and temperature, and to a lesser extent on pressure. The viscosity of geothermal brine is thus approximately 16 to 100 times higher than that for gas, so the brine's velocity in the reservoir is up to 2 orders of magnitude lower than that for gas, for a given drawdown. Bearing in mind that petroleum engineers consider non-Darcy effects negligible in oil wells due to the low velocity of the oil, non-Darcy effects become even more negligible in geothermal reservoirs. Geothermal engineers should also realize that a major part of the reservoir's inflow comes from the (often) very large reservoir thicknesses in geothermal reservoirs: up to 200 meter of net sand have been observed. The flow velocity per meter reservoir is thus not as high as one would expect solely based on the well's flow rate.

Rather than the derivation of the non-Darcy skin factor from well tests, methods exist to predict the non-Dacy skin factor based on empirical correlations. All relationships reported in the literature (no exceptions have been found by the author) contain *gas* flowrates and *gas* properties like *gas* gravity and *gas* viscosity; no relationships have been published that contain properties of non-compressible fluids like oil or water. Apparently no non-Darcy effects in oil or water wells have been reported in literature.

The effect of the physical properties of water on the shape of the Inflow Performance Relationship is shown in the P-Q curves in Figure 10. This figure shows the typical shapes of oil-, gas- and water IPRs respectively. Oil and gas reservoirs have curved IPRs, caused by the physical properties of the gas in the reservoir and reservoir's multiphase flow effects like relative permeability. The IPR of water, in contrast, is a straight line. This is the reason why the performance of water reservoirs can be conveniently be denoted using a single quantity, the Productivity Index; gas reservoir and oil reservoirs below the bubble point do not have a P.I..

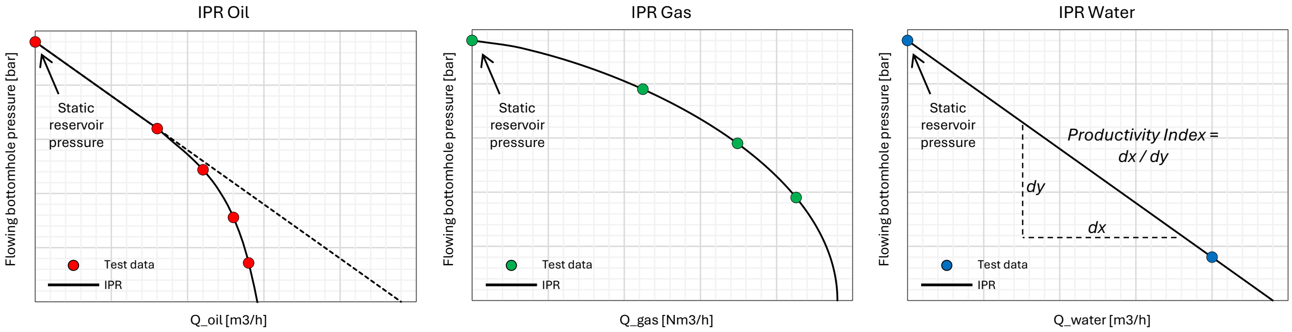


Figure 10. Inflow Performance Relationship (IPR) for Oil (left picture), gas (middle picture) and water (right picture). The IPR of an oil reservoir is a straight line above the bubble point, and a curved line below the bubble point; only one test points (in addition to the static reservoir pressure) above the bubble point is needed, while multiple test points below the bubble point are required to accurately determine the shape of the curved IPR. The IPR of a gas reservoir is curved line, and multiple test points (in addition to the static reservoir pressure) are needed in order to determine the shape of this curve. The IPR of a water well is a straight line and only a single data point (in addition to the static reservoir pressure) is needed in order to determine the slope or the Productivity Index of this straight line.

The fact that water reservoirs have a straight line IPR is further proven in Figure 11, showing test results of SCAN well HEE-01 (Nederweert Sandstone). Although the measured datapoint were still in a transient flow regime, extrapolations of these datapoints to steady state rates and pressures (yellow dots in Figure 11), clearly shows that these data points lie on a straight line IPR, the Productivity Index. The R^2 has a value of 0.999, indicating that non-Darcy skin effects do not exist in this well. This confirms that the absence of non-Darcy effects is in line with the theory.

Figure 11 also shows that it is not needed to flow at multiple rates during a well test in order to determine the P.I.: a single data point, in addition to the static (shut-in) reservoir pressure, is always sufficient to deduce the P.I., since only two points are needed to draw a straight line through. Extrapolation of the transient flowing bottomhole pressures to steady state conditions is relatively straightforward using e.g. a Horner extrapolation. The recommendation therefore is to degrade the number of flow steps during a production or injection period from three or four to merely one.

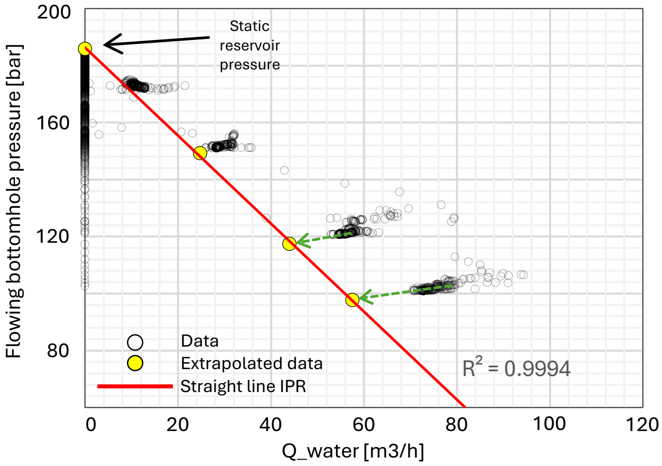


Figure 11. Multi-rate test results from HEE-01 (Nederweert Sandstone). Black dots are all measured bottomhole pressures during the production- and buildup periods. Yellow dots are the Horner-extrapolated (both pressure and flowrate) stable conditions. The red line is the best-fit line through these datapoints, clearly yielding a straight line IPR.

To summarise the above:

- Multi-rate tests are developed by the oil- and gas industry to quantify the effects of very large flow velocities of gas in the reservoir, thereby causing a non-Darcy skin. The value of a non-Darcy skin is based (in addition to reservoir properties) by the properties of gas only, not by the properties of compressible fluids like water.
- This non-Darcy skin results in a deviation from the straight-line behavior in a P-Q plot. The curvature of this line is a measure of the absolute value of the non-Darcy skin. Or, in other words, the non-Darcy skin can be quantified by flowing a well at multiple rates and analysing the curvature accordingly.
- The IPR's of geothermal wells do not show a curvature in P-Q plots and form a straight line. It is for this reason that the performance of geothermal reservoirs can conveniently be denoted using a single value: 1 over the slope of this line. This is also called the Productivity Index (or Injectivity Index).
- Multirate tests have been executed in well HEE-01, which confirm the absence of non-Darcy skin effects
- Since only two test points are needed determine the slope of a straight line, a well can be flown at a single rate (the other test point being the shutin pressure).

It must be noted that some well test reports on Dutch geothermal wells have reported non-Darcy skins. These reported non-Darcy skins are either:

- Extremely small, smaller than the accuracy of the measurements and are therefore – according to the statistical theories – invalid. Moreover, if these would be statistically valid, extrapolation of the measured data points of a multi-rate test to the AOF would not result in observable deviations from the straight line IPR.
- Calculated frictional pressure losses between the perforations and the pressure gauge (which is often at mid-well depth). Friction in the liner or casing is sometimes – incorrectly – denoted as non-Darcy skin, see chapter xxx. If someone's objective is to determine the frictional pressure losses in a newly installed pipe, then easier and cheaper methods exist to quantify these pressure loss components; no expensive multi-rate well tests need to be performed to achieve this. A simple yet effective method is to use correlations that include the pipe's roughness, which can be obtained from the supplier. Alternatively, a pipe's frictional pressure losses can easily be measured at surface, prior to the installation of the pipe in the well, as part of the factory acceptance tests.

Based on the above it can be concluded that not performing multi-rate tests as part of the well test sequence allows for a significant cost reduction. It is recommended to perform a single rate test instead, since this does not result in lesser information about the reservoir. If it's someone's objective to quantify the pressure losses in the well rather than in the reservoir, it is more beneficial to use other methods to determine these.

Reduction of flowrate of tests

Often, it is attempted to produce a well during the well test at its maximum achievable rate, limited by the pump's technical limits or by the maximum lift gas injection rate. This might be justified in case the engineer tries to maximise the cleanup, or in case for example the sand retention capabilities must be tested. However, for the sake of well testing purposes (not cleaning purposes) this is by no means a necessity: any pressure disturbance caused by a flow rate change results in an interpretable well test. This implies that – if the objective is to determine the skin and reservoir properties - even low flowrates suffice in achieving the objectives. Figure 12 (left) displays several models generated in Kappa, each one having different skins. This figure shows that even in the case of extremely large skins, the Infinite Acting Radial Flow period still develops in the Bourdet derivative, and the reservoir's transmissivity can still be interpreted; irrespective of the skin, the geological properties can still be interpreted with confidence.

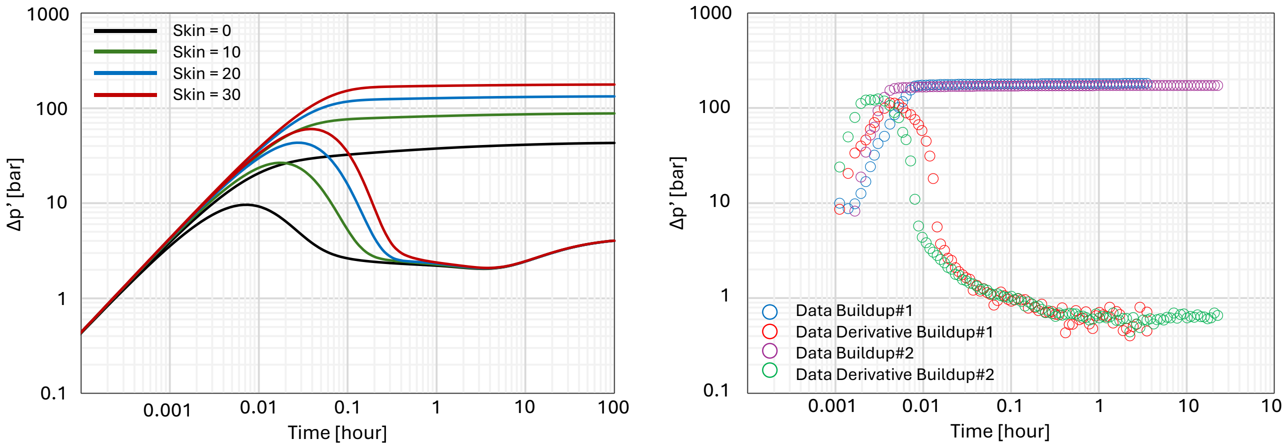


Figure 12. Left picture: theoretical models of buildups periods, generated in Kappa. Flowrate prior to buildup is 100 m³/h, wellbore storage = 0.023 m3/bar, skin = 0, transmissivity = 10 Dm, and distance to a no-flow boundary is 1000 m. Sensitivity is done on the skin, to evaluate the impact of skin on the derivative. Visible is that the transmissivity can still be deduced, even at very large skin values. Right picture: Data and Bourdet derivative of two flow periods of SCAN well SVG-01 Upper Breda formation, upper interval. The first buildup (buildup#1) is preceded by a production rate of 7.2 m³/h, while the second buildup (buildup#2) is preceded by a production rate of 18 m³/h.

In addition to these theoretical models shown in Figure 12 (left), the concept of testing at various flowrates, with the objective to demonstrate that large flow rates do not result in better well tests, is tested in SCAN well SVG-01, NUBRU formation, upper interval. This is shown in Figure 12 (right). Plotted in this figure is the Bourdet derivative of two buildups preceded by two different flow rates. The first buildup is preceded by a production rate of 7.2 m^3/h, while the second buildup is preceded by a production rate of 18 m^3/h. (CHECK WITH LIZA!). This picture clearly shows that both buildups are very similar (apart from a time shift in the end of the wellbore storage period, caused by the closing speed of the downhole shutin tool).The IARF stabilisations are identical, just like the vertical distance between the data and the derivative, implying the same transmissivities and skins respectively. Therefore the conclusion can be drawn that the flowrate does not impact the quality of the buildup, and an engineer might as well flow at low flow rates, for the sake of cost reduction.

An additional reason for not flowing at the maximum achievable flow rate, is that the IPR of geothermal wells is always a straight line (see previous chapter and Figure 11). This makes it is straightforward to extrapolate a certain (low) flow rate to higher flowrates, and one can easily determine the well's capacity for future operational or commercial decisions. Producing geothermal wells at the maximum achievable flowrate, just for the sake of determination what that maximum achievable flowrate is, does not result in additional reservoir information.

Re-evaluate the objective of the well test

For none of the SCAN wells the objective was to minimize the skin. Reason for this is the exploratory character of the wells, with a primary objective to characterize the geological properties of the reservoirs, while secondary objectives include evaluating different test methods. Neither of these objectives require the wells to have a low skin; even in case of excessively large skin values, a reservoir engineer can still evaluate the geological properties (see Figure 12) as long as the test is designed and executed in the correct way. This allowed the operator to test the SCAN wells at moderate or even low rates, much lower than in the case of operational wells, which require that the skin would be minimized; a large skin in the SCAN wells is not considered to be a risk, just a possibility.

This SCAN well test strategy can serve as food-for-thought to design a fit-for-purpose well test for commercial wells yet to be drilled, but that requires a change in mind-set and a re-evaluation of the well test objectives. Initial well tests executed after drilling the well do not have to be large or complex or expensive; that fully depends on the objective of the test.

For example, the objective of a test could be (and has often been in the recent past) to test the commerciality of a potential geothermal development and to decide whether the second well should be drilled or not. If this is the case, a very brief single production period at low production rates (fraction of the maximum flow rate), followed by a buildup using a downhole shut-in would be an excellent test to achieve this goal. Such a well test would be rather cheap, just a fraction of the costs of historical geothermal well test. Possibly (not necessarily) this result in a large skin, but this does not automatically hamper the decision making, because minimising the skin was not the objective of this test. The possible outcomes of this fictional test could be:

1. High skin + geology not good enough for a commercial project
2. Low skin + geology not good enough for a commercial project
3. High skin + geology good enough for a commercial project
4. Low skin + geology good enough for a commercial project

In case of outcome 1 or 2, the operator can proceed to abandonment, and is able to make this decision using a cheap well test. In case of outcome 3 or 4, the operator can confidently proceed to further development of the second well and geothermal processing facilities. During commissioning of both wells and the facilities, the first will well automatically be cleaned to the max, irrespective of outcome 3 or 4, via the optimally designed operational ESP (not a rental one) and existing facilities (not the rental test facilities). Only in case of outcome 3, one might want to temporarily include additional sand catchers or other hardware to be hooked up to the facilities, to prevent contamination of the plant, but the total costs of this will still be significantly less than a full well test spread.

This thought-experiment will result in a large cost reduction, without compromising on the quality or quantity of the well test data:

- Lower production volumes (so less storage costs, less waste management)
- Lower production rates (so smaller tanks, smaller separator, smaller nitrogen hardware, etc)

Another example of how costs may be reduced is by testing the well with a coiled tubing unit rather than with the drilling rig. Operational costs of a coiled tubing unit are much lower than those of a drilling rig. Disadvantage of this is that a coiled tubing unit does not allow for a lot of flexibility and ad-hoc problem solving in case of unexpected circumstances is more difficult.

An operator might even contemplate not to clean and test a newly drilled well at all, and simply await hooking up this well to existing facilities (possibly with some minor modifications to the process to allow for the processing of dirty production water). The very first flow period after commissioning of the well still allows for the determination of all necessary reservoir properties. This method is often applied by oil- and gas operators, for the sake of cost reduction.

These examples might seem very extreme, and might certainly not be the best option for each project, since every well and operator is unique. The purpose of these examples is solely to demonstrate that multiple test scenario's are possible and some are more beneficial than others. By carefully re-evaluating and re-defining the objective of the well test, it might very well be possible to reduce the costs of a well test, at the sole expense of postponing some information regarding the well, not at the expense of data quality or - quantity.

Potential cost reduction

In this chapter several methods to reduce the costs of testing and cleaning geothermal wells were described, largely based on the learnings from the SCAN wells. The absolute cost reduction that can be achieved is quantified below by making several (very high-over) assumptions regarding the costs of well testing. These assumptions, plus the potential reduction in costs, are shown in Table 1. It must be noted that the costs mentioned in this table are indicative only; actual costs obviously depend on many more parameters (test specifications, contracting, etc.). Also, this table is not complete: further optimisations opportunities exist and should be evaluated on a well-to-well basis (e.g. coiled tubing testing v.s. rig testing, shorter shutin times based on pre-test modelling, etc.). The column 'cost estimate – suboptimal' contains a cost estimate based on 3000 m^3 of produced brine (being representative for an average geothermal well test in The Netherlands so far), while the column 'cost estimate – optimised' is based on 500 m^3 of produced brine (approximately equivalent to a SCAN well test).

Table 1. Cost saving opportunities for well testing. Assumptions and estimates are very high over and should be treated as such; the actual cost reduction is therefore indicative only. Note: the additional costs of highly recommeded hardware to improve on the data quality (downhole shutin valve, downhole gauges, downhole sampler), see chapter 5, are incorporated into this table.

Item	**Details**	**Cost estimate - subtoptimal**	**Optimisation opportunity**	**Cost estimate - optimised**	**Cost reduction**
Welltest package	MOB-N/U-WT- N/D-DEMOB +staff	Large welltest package: **300 k€**	Smaller welltest package due to lower production rates	Small welltest package: **175 k€**	**125 k€**
Storage capacity	Rental costs to temporarily store production water in tanks: 2.8 €/day/m3	Based on 15 days rental and 3000 m3 production water: **125 k€**	Less storage capacity due lower cumulative produced water (lower rates, no multirate steps, shorter production periods)	Based on 15 days rental and 500 m3 production water: **25 k€**	**100 k€**
Production water disposal	Disposal to industrial waste processing company, including transport: 210 €/m3	Based on 3000 m3 production water: **630 k€**	Less disposal water due lower cumulative produced water (lower rates, no multirate steps, shorter production periods)	Based on 500 m3 production water: **105 k€**	**525 k€**
Rig	Burnrate rig: 100 k€/day	Based on 5 days rig availability during welltesting: burnrate rig: **500 k€**	Shorter production periods, no multirate test, no splicing of ESP cable, etc.	Based on 4 days rig availability during welltesting: burnrate rig: **400 k€**	**100 k€**
Artificial lift	ESP v.s. jetpump	ESP rental + running: **200 k€**	Jetpump instead of ESP	Jetpump + downhole shutin valve + packer + PT gauge + sampler tool: **120 k€**	**80 k€**
				Grand Total	**930 k€**

The conclusion can be drawn that, by applying alternative test strategies, a major cost reduction approaching one million euro can be achieved. The largest contributor is the reduction in the disposal of production water. In case the decision is made not to dispose this produced water but to reinject the brine into a well, cost reductions of ~ 400.000 € can be achieved. It is therefore worth evaluating these and other alternatives prior to the execution of the well test.

7. Applicability of various well tests types

Historically, it is the convention in the geothermal sector to evaluate the very first buildup test only. One reason for this is that PTA's require the (downhole) flowrate to be known and stable, and the most stable flowrate that is possible is zero. Fall-off tests also have zero flow, but additional complexity to the interpretation is added due to e.g. the introduction of temperature – and hence viscosity effects, possibly thermal or hydraulic fraccing, etc. Although buildup tests are preferred over the other types of tests shown in Figure 1, this does not mean that these other tests should be discarded. In fact, if properly analysed, the same type of information regarding the reservoir can be extracted from these tests, and as such their value is the same. An important additional advantage of injection- and fall-off tests, is that they are generally cheaper and easier to execute, since no artificial lift is needed. Also, every buildup test is – by definition - preceded by a production test. So if one analyses a buildup test, one might as well analyse the production test too (doubling the data for the same costs).

This chapter describes how to get the most information out of well test data, with special focus on tests that are not the very first buildup. This includes production-, injection and fall-off tests, and special attention is given to numerical well test analyses.

In addition to the more conventional analytical analysis, each and every well test can be modelled numerically too. One major advantage of modelling well tests numerically is that dynamic simulators like e.g. Schlumberger's Eclipse, CMG's IMEX or Kappa's numerical analysis package, can implement temperature-dependant viscosity relations (although that may be software specific). Another advantage of dynamic models is that the level of detail that can be applied to the reservoir is much larger than for analytical software's, since the known analytical solutions to all the various flow equations are limited. This is especially true for the reservoir heterogeneity, which can modelled on a grid-cell base in the dynamic simulators. Dynamic simulators thus allow the engineer to be much more flexible in selecting appropriate reservoir- and well models, not restricted to the (limited set of) existing analytical solutions.

Numerical simulators however come at a price: the licence costs can be rather large in case of commercially available software. Also, a significantly higher level of engineering knowledge is required to construct numerical well tests, although this may be software specific. Generally speaking, the construction of a numerical model takes much longer than the construction analytical model. Moreover, a numerical model requires much more (geological) input than analytical models, which is often unknown. This implies that extra uncertainty must be introduced into the input deck. Often it is better to assume simplified geology (analytical models) than pretending having all the necessary geological knowledge (numerical models).

Despite these drawbacks it might be worth investigating well tests numerically, in addition to analytical methods. In the remainder of this chapter, such a numerical approach is used to investigate how and to what extent the various types of well tests can be analysed, in various stages of their operational life.

Numerical simulations

Well tests are often associated with the very first production- and buildup period after drilling the well, and are often executed in combination with a thorough cleanup of the well and near wellbore area. As discussed before, also pressure disturbances caused by flow rate changes during the operational life of the field can be analysed. This does not only apply for the production well, but also for the injection well. Injection tests are usually more complex to interpret, because of:

- The possibility of hydraulic or thermally induced fractures created during injection of (cold) pressurised water.
- Temperature changes that are being introduced into the reservoir, resulting in viscosity changes of the brine.

Commercially available analytical well test software is iso-thermal, implying that temperature – and hence viscosity alterations of the fluids cannot be modelled in a conventional way; the software assumes constant temperature and viscosity throughout the reservoir. Because of this mathematical limitation problems arise when a cold(er) fluid is being injected in a warm(er) reservoir. Injection of cold water reduces the mobility of the reservoir, see equation 1 (Dake, 1978):

$$\lambda = \frac{k}{\mu} \qquad [1]$$

where λ = mobility, k = permeability and μ = viscosity. The mobility of the warm(er) reservoir fluid is thus higher than the mobility of the cold(er) injection fluid. As shown by Kappa Engineering (2024) the sensitivity on 1/ μ is the same as the sensitivity to k on all parts of the pressure response, so a change in μ manifests itself in a derivative plot as an *apparent* change in k or kh. Due to the isothermal nature of the boundary conditions of the software, viscosity changes cannot be accounted for, leading to derivative plots with *apparent* transmissivity changes, which makes a reliable interpretation of the Bourdet derivative complicated.

In this chapter, it is shown how injection – and fall-off tests can be analysed using analytical software, taking viscosity effects into account. Numerical reservoir simulations, which have the flexibility to model changing viscosity, were set up, which allowed for the creation of a synthetic well test. These synthetic well tests were subsequently exported to an analytical well test package, to evaluate the characteristics of the Bourdet derivative. Based on the outcomes of these simulations, recommendations are given on how to deal with changing mobilities in the reservoir, and how to reliably extract reservoir information from well tests that are influenced by viscosity changes. This can be used to analyse injection – and falloff tests, both during an initial well test in a virgin reservoir, and during the operational life of an injection well.

Numerical model description

In order to assess the impact of viscosity effects on the Bourdet derivative of injection- and fall-off tests, numerical simulations were setup in Eclipse 100 (SLB, 2024), which includes temperature dependent viscosity modules. Each model contains two wells (to ensure voidage replacement): a production well producing at a constant bottomhole temperature of 80 ^{0}C and an injection well re-injecting the produced water at a constant bottomhole temperature of 20 ^{0}C. The model contains 401 cells in both the X- and Y-direction, and a single layer in the Z-direction. Most cells have an dimensions of 10 x 10 x 80 meter (X-Y-Z), but locally near the wells a local grid refinement is applied, reducing the cell dimensions at the well locations to 1 x 1 x 80 meter. Total model width is 3740 meter in the x direction and 3875 meter in the y-direction, see Figure 13. The dimensions (including the local grid refinement) were chosen such that numerical dispersion was minimised, resulting in smooth results not disturbed by discretisation characteristics. Grid and cell dimensions are illustrated in Figure 13.

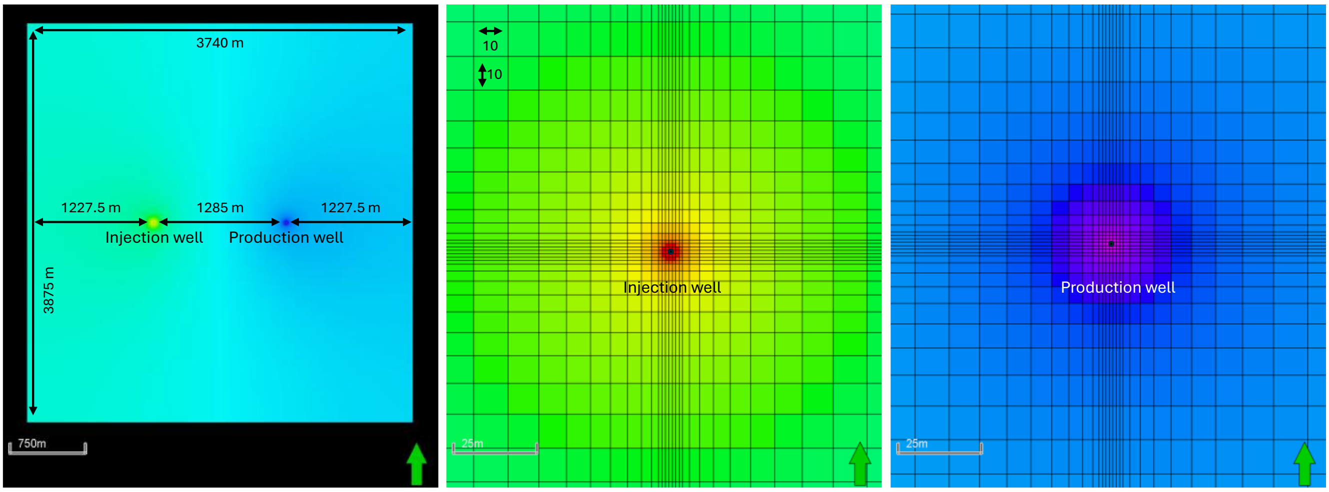


Figure 13. Grid and cell dimensions. Left picture: entire reservoir model, top view. Middle picture: detail of the vicinity of the injection well. Right picture: detail of the vicinity of the production well.

Two vertical wellbores are placed at a distance of 1285 meters to each other. Top reservoir is 2000 m TVDSS and reservoir pressure is 221 bar. The reservoir temperature at the same depth is 80 ^{0}C. Permeability is 50 mD, porosity is 20%, NTG is 1 and a perfectly homogenous (aerially and vertically) is assumed. The mechanical skin is set to 5 and any wellbore storage effects are deliberately not modelled. Various flow- and shut-in periods are evaluated; the temperature of the injection water is 20 ^{0}C, having a viscosity of 1.27 cp. The viscosity of the virgin reservoir fluids at a temperature of 80 ^{0}C is 0.55 cp..

The goal of these numerical models is to demonstrate how and to what extent injection- and fall-off tests can be used to accurately derive reservoir properties like transmissivity and faults. This is thus an extension of the study described in the data acquisition report of AMS-01 , where the conclusion was that injection of cold water in a *virgin* reservoir results in graphical (visual) artifacts in the Bourdet derivative, which impacts the early-, middle- and late time regions of the derivative. The current study however not only assumes *virgin* reservoirs, but also reservoirs where a cold-water region around the injection well has already developed.

Various models are described in the remainder of this chapter, and all models and evaluations of the models follow the same step-rate approach:

Step 1: initial flow period.

Initial flow period from production well into the injection well in a virgin reservoir. The flow rate of both wells is 100 m^3/h, thus ensuring voidage replacement. The duration of this flow period is either 12 hours, 10 days, 1 year, or 30 years. This reflects various stages of cold-water front development: a very short period of initial injection results in a very marginal cold-water front development and low (pressure) radius of influence, while the longer initial injection periods result in larger cold-water front development and pressure radius of influence that have detected the reservoir boundaries. The four pressure- and temperature developments in the reservoir model after the various flowing periods (12 hours, 10 days, 1 year and 30 years) is shown in Figure 14 to Figure 17 respectively.

The four flowing periods result in transient bottomhole pressures of both the injection and production well, which can be analysed using Pressure Transient Analysis in e.g. Kappa. Also, the endpoint of these flow periods, i.e. the situations visually shown in Figure 14 to Figure 17, forms the starting point of the next step, the initial shut-in period.

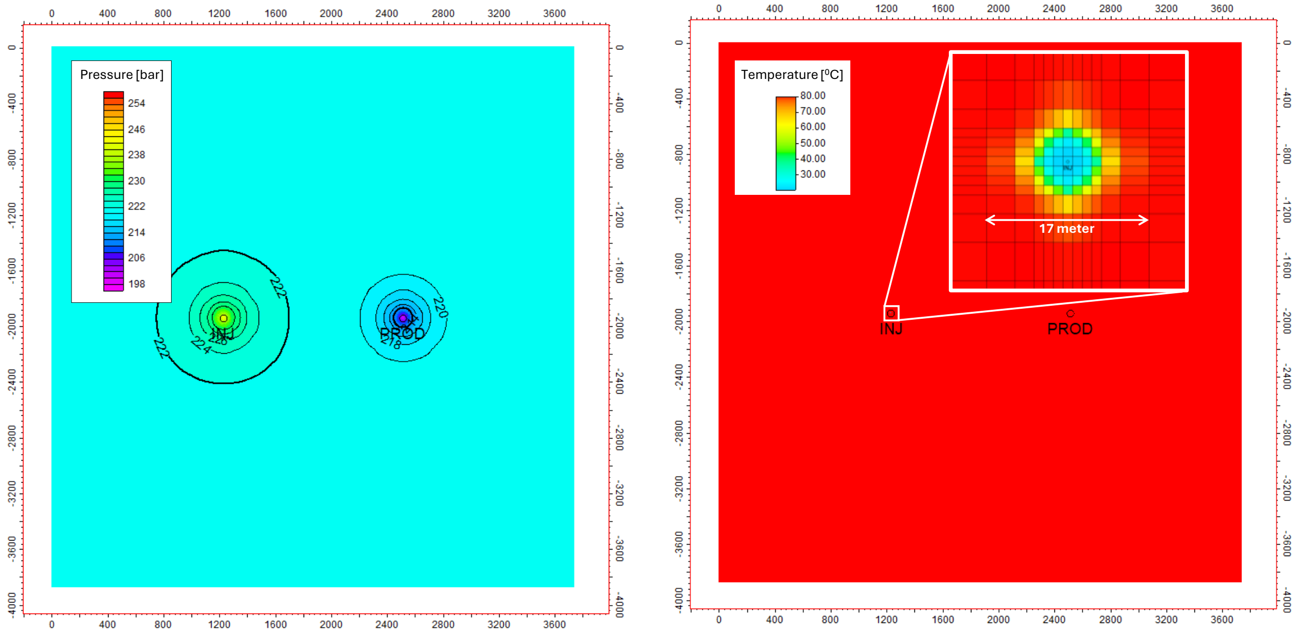


Figure 14. Pressure development (left) and temperature development in the reservoir (right) after 12 hours of cold-water injection at a temperature of 20 ºC and a flow rate of 100 m³/h. Clearly visible is that the pressure front is still in a fully transient state and that the temperature front has prograded merely ~ 8.5 meter radially into the reservoir.

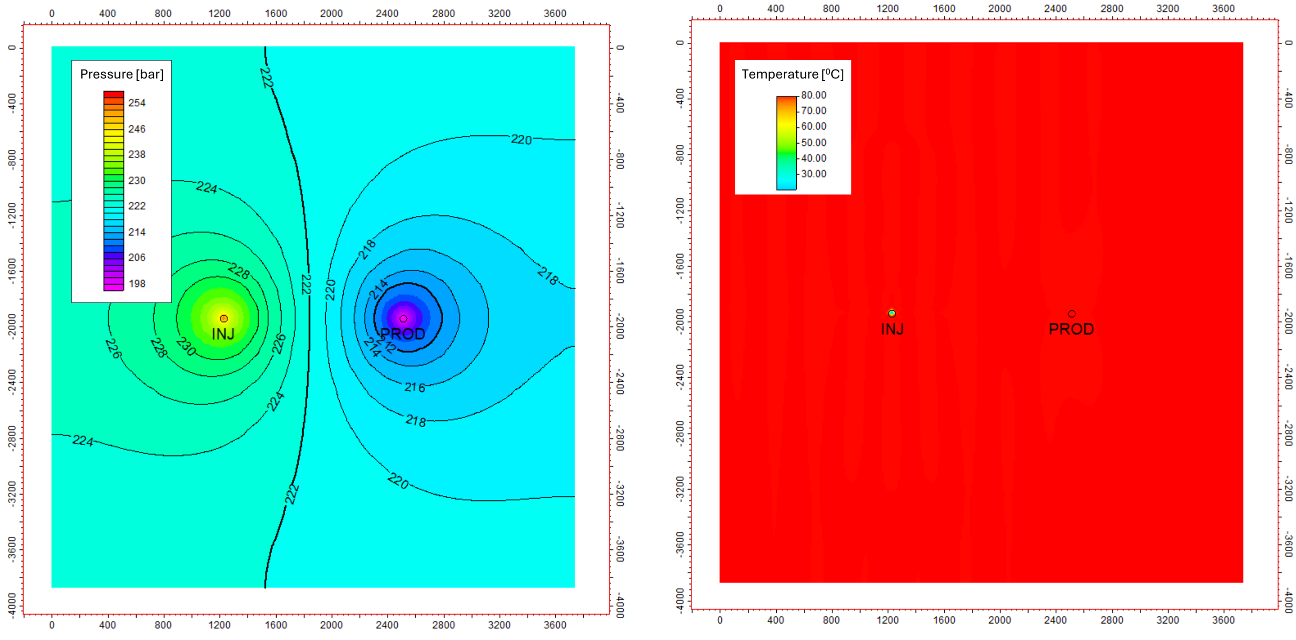


Figure 15. Pressure development (left) and temperature development in the reservoir (right) after 10 days of cold-water injection at a temperature of 20 ºC and a flow rate of 100 m³/h. It is shown in the left picture that the pressure fronts have reached all edges of the model and that the pressure fronts of both wells are influencing each other. Moreover, a steady-state pressure distribution appears to have developed. In contrast, the temperature front near the injection wells has only marginally developed and clearly lags behind the pressure development; a 70 meter diameter (35 meter radius) cold-water front has developed after 10 days of injection.

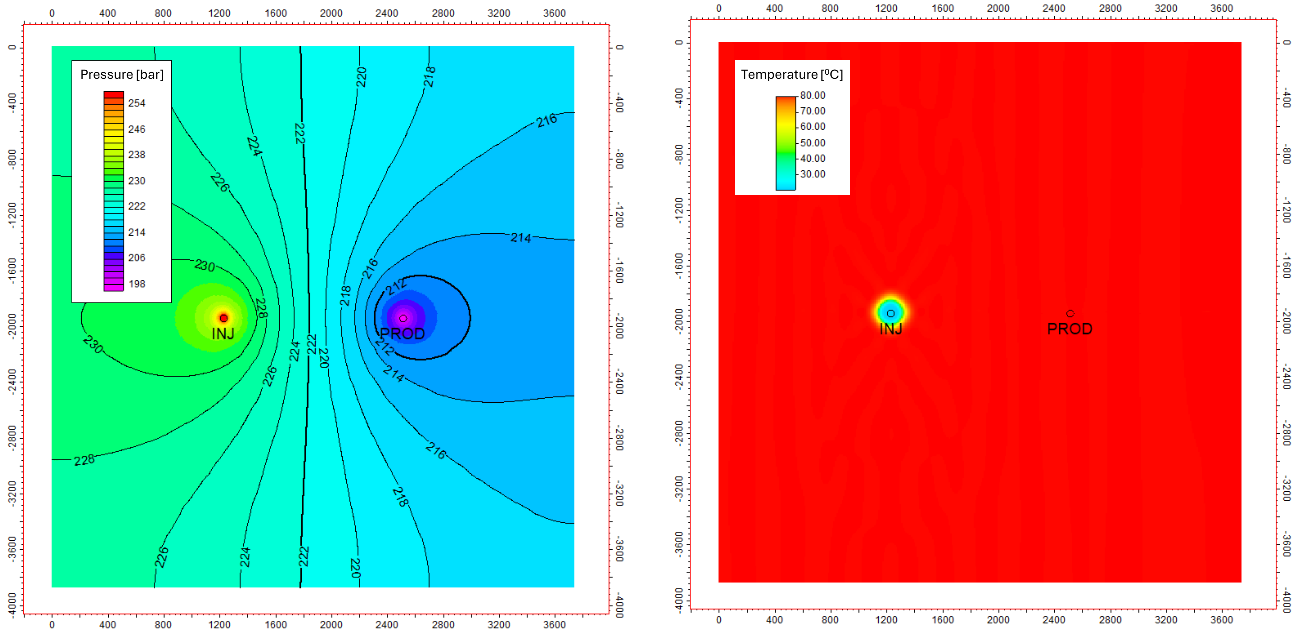


Figure 16. Pressure development (left) and temperature development in the reservoir (right) after 1 year of cold-water injection at a temperature of 20 ^{0}C and a flow rate of 100 m^3/h. Pressure has reached a steady state in the entire reservoir, while the temperature front has a diameter of 300 meter (150 meter diameter)

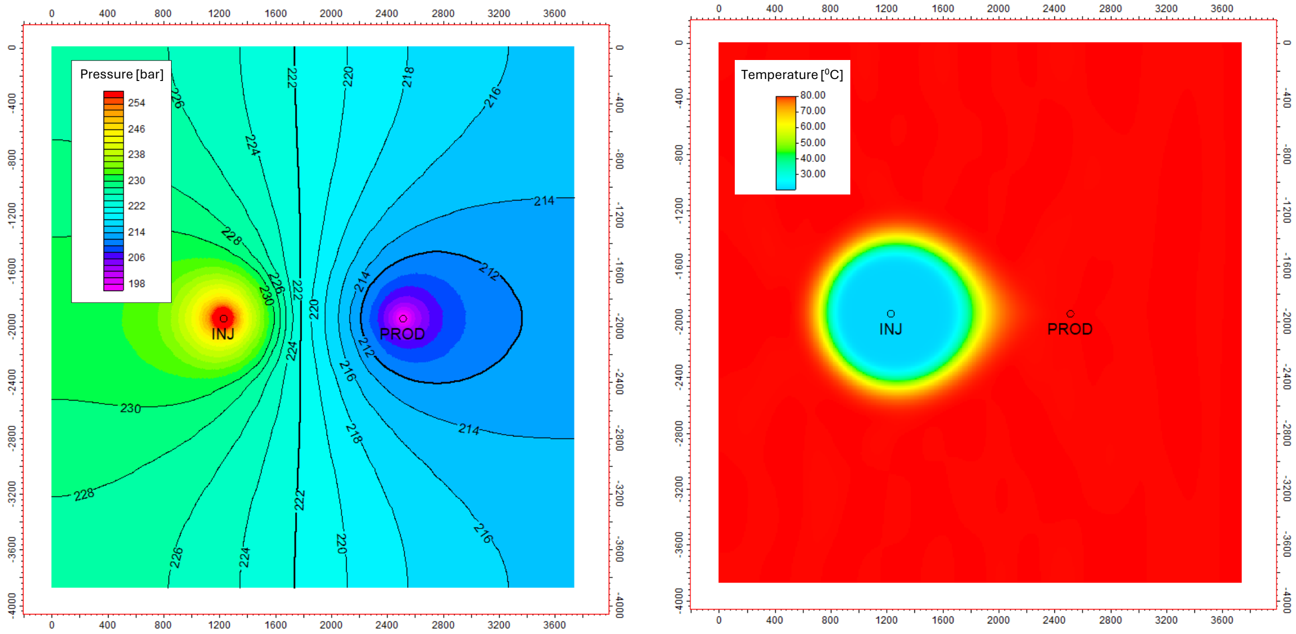


Figure 17. Pressure development (left) and temperature development in the reservoir (right) after 30 year of cold-water injection at a temperature of 20 ^{0}C and a flow rate of 100 m^3/h. Pressure distribution has not changed significantly compared to the situation after 1 year. The temperature front has a diameter of approximately 1400 meter (700 meter radius)

Step 2: initial shut-in period (buildup and fall-off)

After the abovementioned flow periods, both wells are shut-in for either buildup (production well) or fall-off (injection well). The shut-in periods start (obviously) at the endpoint of the preceding flow periods where the reservoir has partly cooled down. The shut-in periods last for 12 hours. The synthetic datasets of the buildup and fall-off periods are exported to Saphir (KAPPA Engineering 2024).

Step 3: second flow period.

Following the buildup and fall-off periods, the doublet starts to flow again for a period of 12 hours with a bottomhole injection temperature of 20 ^{0}C at a flow rate of 100 m^3/h. The synthetic bottomhole pressure datasets are exported to Saphir (KAPPA Engineering 2024).

Figure 18 summarises the setup of the 4 models run, including the various steps undertaken and flow- or shut-in periods that can be analysed.

	Step 1: flow @ 100 m3/h			Step 2: shutin			Step 3: flow @ 100 m3/h		
	Production well	Injection well @ 20 deg C		Production well: Buildup	Injection well: Fall-off		Production well	Injection well @ 20 deg C	
Model 1	12 hours	12 hours	← *figure 19*	12 hours	12 hours	← *figure 20*	12 hours	12 hours	← *figure 21*
Model 2	10 days	10 days	← *figure 22*	12 hours	12 hours	← *figure 23*	12 hours	12 hours	← *figure 24*
Model 3	1 year	1 year	← *figure 25*	12 hours	12 hours	← *figure 26*	12 hours	12 hours	← *figure 27*
Model 4	30 year	30 year	← *figure 28*	12 hours	12 hours	← *figure 29*	12 hours	12 hours	← *figure 30*

Figure 18. Overview of the 4 models run. Each of the 24 time periods in this matrix result in a pressure transient, which can be analysed. The validity and applicability of these 24 PTAs is described in the next chapters.

Results

The 24 pressure transients extracted from the models as shown in Figure 18 are described in this chapter. The flowing bottomhole pressures as calculated by the numerical software is exported and imported into the analytical software. The rock properties (most notably kh) and the grid properties (cell dimensions, model size and location of the well with respect to the model boundaries) are identical for all 24 pressure transients. The only differences between the 24 pressure transients are the size and location of the temperature front and hence the viscosity interface. An accurate comparison between the 24 pressure transients thus allows for an evaluation of the impact viscosity effects have on the Bourdet derivative.

The Bourdet derivative of the 24 pressure transients is shown in Figure 19 to Figure 30. In each of these graphs two horizontal lines are shown, each depicting two different Infinite Acting Radial Flow (IARF) regimes:

- Magenta line: this line shows the IARF in case a transmissivity of 4.0 Dm is applied to the model (which is identical to the transmissivity of the Eclipse model) in combination with a viscosity of 0.55 cp (i.e. the viscosity of a 80 ^{0}C formation brine)
- Green line: this line shows the IARF in case a transmissivity of 4.0 Dm is applied to the model (which is identical to the transmissivity of the Eclipse model) in combination with a viscosity of 1.27 cp (i.e. the viscosity of a 20 ^{0}C formation brine).

It is important to realise that the green line could also represent a transmissivity of 1.7 Dm (namely 4.0 Dm x (0.55 cp / 1.27 cp)) in combination with a viscosity of 0.55 cp. Obviously this transmissivity of 1.7 Dm is incorrect, because the modelled transmissivity in Eclipse was 4.0 Dm. It might however yield a (visual) good match to the synthetic dataset, in case an incorrect water viscosity is assumed. This exposes one of the crucial issues of PTA of tests where cold water is injected: assigning the appropriate viscosity to the PTA model is very important.

Discussion

The following discussion is based on the results of this study, complemented with field observations from other wells.

Production well: impact of cold front

- When observing Figure 19 to Figure 30 it becomes clear that the pressure transient of the production well is not impacted by the temperature decrease near the injection well; all synthetic datasets show signatures that are fully in line with the expectations. All datasets can be modelled using PTA by assuming the viscosity of the virgin formation temperature; the iso-viscosity assumption of the models can be applied correctly.

Production well: various test periods

- Each test period of the production well (initial production, subsequent buildup, subsequent second production period) can be analysed correctly and confidently; as long as the flowrates are known and stable, each test period has comparable (or identical) signatures. The conclusion can be drawn that a well test engineer might very well analyse a production period, if a buildup period is not available (for example the well was not shut in at all). (ref: this report)

- In order to apply PTA to a production period, it is very important that the flowrates are stable and are accurately known and no drifting or other deviant flow inaccuracies happen during the test. Small deviations, possibly too small to observe, might still impact the shape of the derivative and hence quality of the match (ref: AMS-01)

- For any buildup period in geothermal wells it is crucial to apply a downhole shut-in device (ref: AMS-01, ORO-01, Bruijnen, 2024B), otherwise the interpretation of the pressure transient will become difficult or even impossible using conventional techniques.

To summarise: both production- and buildup periods can be analysed using conventional PTA software, provided that

1) For production periods: the flowrate is known and stable
2) For buildup periods: a downhole shut-in is applied.

Injection wells:

- If the injection temperature is equal to the reservoir temperature, no additional viscosity effects are being introduced in the reservoir and the PTA can be performed using conventional analytical techniques (ref: AMS-01). Two prerequisites must be met:
    1. In case of analysing an injection period: the flow must be stable and known; small deviations, possibly too small to observe, might still impact the shape of the derivative and hence quality of the match. (ref: AMS-01).
    2. For any falloff period in geothermal injection wells it is crucial to either apply a downhole shut-in device (ref: Bruijnen, 2024B), or the engineer should only analyse that part of the well test that exhibits wellhead pressures that are larger than atmospheric pressures. If the wellhead pressure falls below the vaporization pressure during the fall-off, water vapour will form and suddenly large and non-interpretable wellbore storage effects start to develop (ref: Bruijnen, 2024B, AMS-01)
- Injection of cold water in a virgin reservoir results in PTA’s of injection periods that are uninterpretable (ref: AMS-01, this report).
- Fall-off tests following a period of injection where no temperature effects have been introduced into the reservoir, can be analysed using conventional PTA techniques (ref: AMS-01 report).

- Fall-off tests following a period of injection where temperature effects haven been introduced into the reservoir can still be analysed using conventional PTA techniques, albeit with an important side note (ref: this report). The viscosity of the cold water is larger than the viscosity of the undisturbed formation fluid, hence a mobility contrast is created in the reservoir, while commercial analytical PTA software commonly assumes iso-viscosity conditions throughout the reservoir. A simple yet effective workaround is to bisect the Bourdet derivative into two separate models:
    1. A model covering the first part of the Bourdet derivative, where the viscosity of the injected water should be applied. The validity of this model extends to point where the (pressure) radius of investigation coincides with the cold front radius.
    2. Once the pressure front has prograded beyond this point, a second model should be applied, covering the second part of the derivative where the formation water is unaffected by the injection of cold water.

  Failure to use such a bi-sected model with a dual viscosity approach will result in an incorrect estimation of the reservoir transmissivity. It is wise to check that the (pressure) radius of investigation of any fall-off test does not extend beyond the cold front radius. One can assume that – for practical purposes – this is the case for injection wells that have been operational for a long time (e.g. few years or longer).

  Als an alternative, a 'radial composite reservoir model' can be applied, although the engineer must realise that the change in reservoir properties that might come out of this model, is a reflection of the mobility contrast, not the transmissivity changes; when assuming that the transmissivity does not change radially, the *apparent* change in transmissivity is a pure reflection of the viscosity changes.

  It must be noted that rather large transition from the green line to the magenta line in Figure 19 to Figure 30 potentially blurs important reservoir characteristics like geological heterogeneity. Also, injection of (cold) water might introduce other additional flow regimes (e.g. hydraulic or thermally induced fracs) which further complicates the analysis of injection wells. The recommendation therefore is to prefer production tests to analyse (provided that the operational and logistical context allows to choose between a production – or injection well).

- Injection tests where injection of cold water is not in an undisturbed reservoir, experience the same double-viscosity phenomenon as the fall-off tests described in the previous bullet point.

The above discussion is graphically shown in flow diagram of Figure 31.

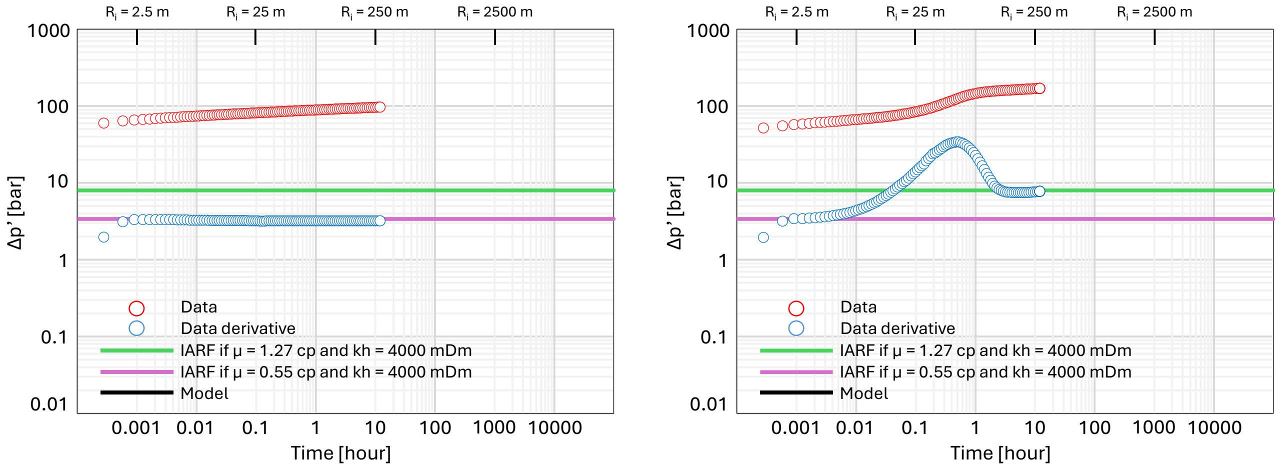


Figure 19. Model 1 - Step 1. Left picture: production well. Right picture: injection well. The production well only shows IARF: wellbore storage effects are absent, and the pressure has not detected the model edges yet. The latter is confirmed by the pressure map in Figure 14. Analysis of this pressure transient is thus 'straightforward'. The Bourdet derivative of the injection well shows a deviant signature, which is described in detail in the AMS-01 Report (reference). Analysis of this pressure transient is therefore cumbersome and might lead to incorrect conclusions.

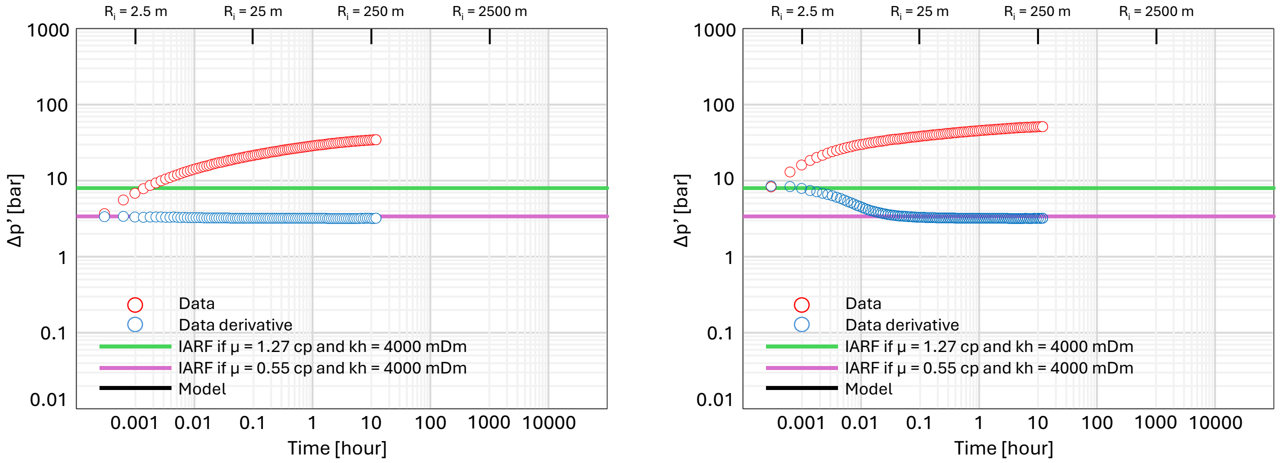


Figure 20. Model 1 - Step 2. Left picture: production well. Right picture: injection well. The production well only shows IARF: wellbore storage effects are absent, and the pressure has not detected the model edges yet. Analysis of this pressure transient is thus 'straightforward'. The injection well shows a 'double-viscosity' effect: the initial (very brief) stabilisation level at ~ 0.001 hour lies on the green line, indicating that the viscosity of the very-near wellbore area is indeed comparable to the viscosity of the injected water. However, since the cold front has prograded only several meters into the reservoir (see Figure 14), the IARF period from ~ 0.02 hours onwards lies on the magenta line, and thus indicative of the virgin reservoir temperature. This IARF period coincided with a radius of pressure investigation of ~ 17 meter, see also Figure 14. Analysis of the pressure transient is thus possible, but the engineer must be aware that the cold front bisects the derivative into two parts, and this is by no means a transmissivity effect but a mobility effect.

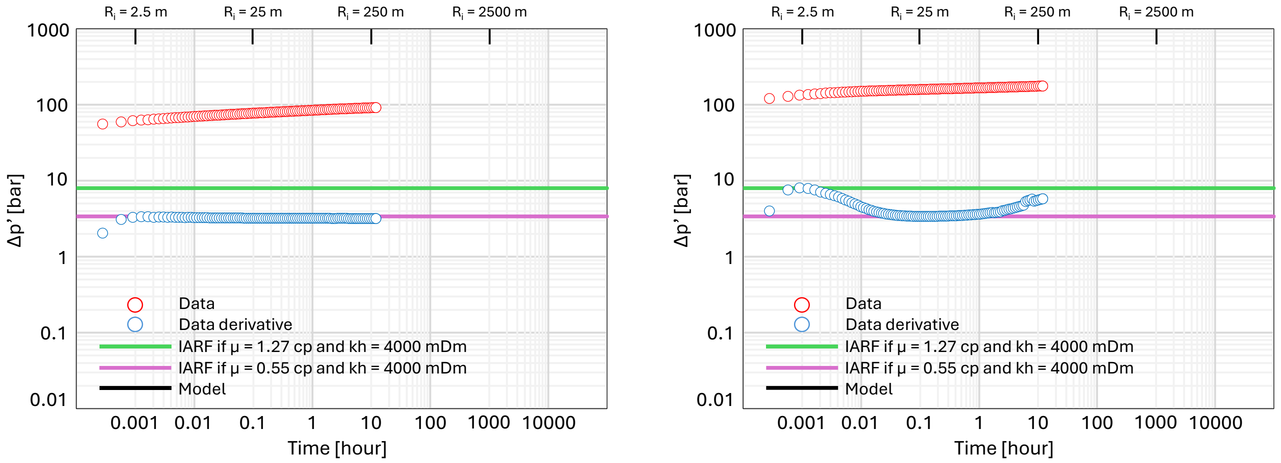


Figure 21. Model 1 - Step 3. Left picture: production well. Right picture: injection well. The production well only shows IARF: wellbore storage effects are absent, and the pressure has not detected the model edges yet. Analysis of this pressure transient is thus 'straightforward'. The injection well shows the same odd (uninterpretable) behaviour, as this is a continuation of the behaviour observed in Figure 19. See also the data acquisition report of AMS-01. Analysis of this pressure transient is therefore cumbersome and might lead to incorrect conclusions.

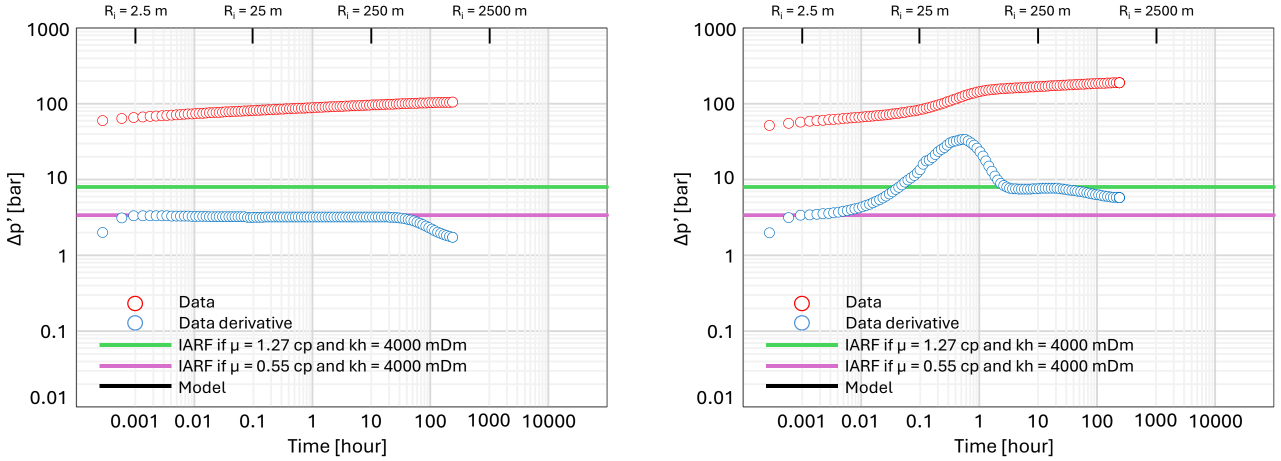


Figure 22. Model 2 - Step 1. Left picture: production well. Right picture: injection well. The production well shows that the Bourdet derivative starts dropping from t=30 hours onwards, when the radius of pressure influence is 500 to 600 meter. This constant pressure boundary is formed by the mirroring injection well, located at a distance of twice this radius, see Figure 13. No no-flow boundaries (reservoir or model edges) have been detected yet after these 10 days of production/injection, see Figure 15, although it might not take much longer to detect the edges of the model. Analysis of this pressure transient is thus 'straightforward'. The Bourdet derivative of the injection well shows a deviant signature, which is described in detail in the data acquisition reports of AMS-01. Analysis of this pressure transient is therefore cumbersome and might lead to incorrect conclusions.

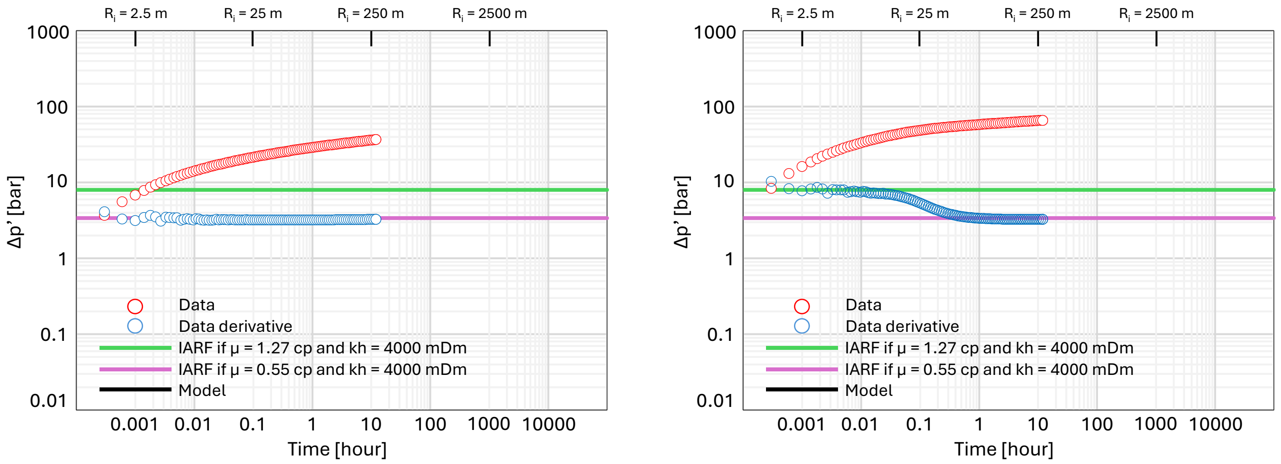


Figure 23. Model 2 - Step 2. Left picture: production well. Right picture: injection well. The production well only shows IARF: wellbore storage effects are absent, and the pressure has not detected the model edges yet. The effect of the injection well is not detected yet during these 12 hours of buildup. Analysis of this pressure transient is thus 'straightforward'. The injection well shows very comparable behaviour to Figure 20, albeit that the 'double-viscosity' effect is somewhat delayed compared to Figure 20. An initial stabilisation level up until ~ 0.2 hour lies on the green line, indicating that the viscosity of this near-wellbore area is indeed equal to the viscosity of the injected water. However, since the cold front has prograded only several tens of meters into the reservoir (see Figure 15), the IARF period from ~ 0.2 hours onwards lies on the magenta line, and thus indicative of the virgin reservoir temperature. Analysis of the pressure transient is thus possible, but the engineer must be aware that the cold front bisects the derivative into two parts, and this is by no means a transmissivity effect but a mobility effect.

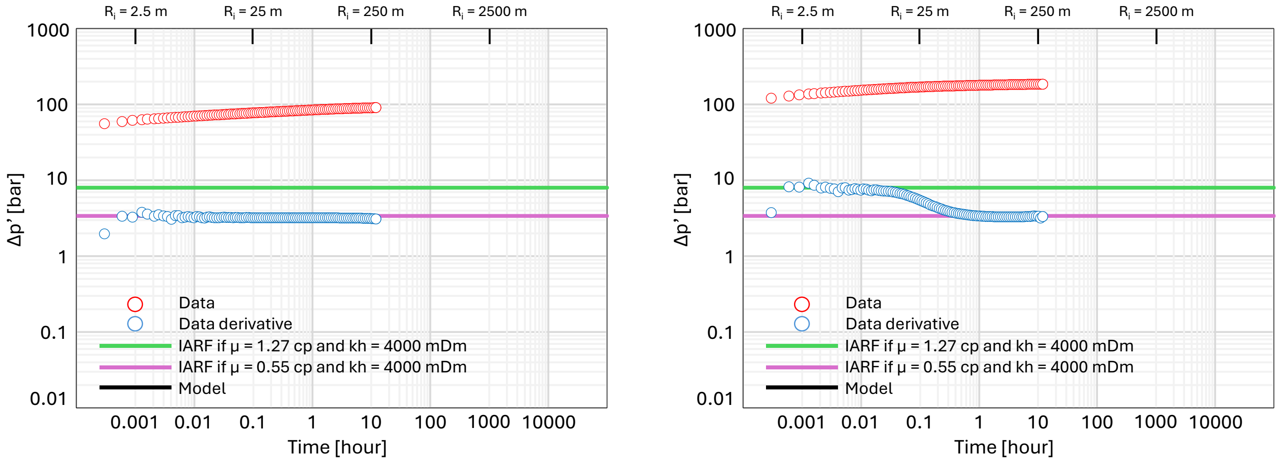


Figure 24. Model 2 - Step 3. Left picture: production well. Right picture: injection well. The production well only shows IARF: wellbore storage effects are absent, and the pressure has not detected the model edges yet. The effect of the injection well is not detected yet during these 12 hours of production. Analysis of this pressure transient is thus 'straightforward'. The derivative of the injection well show the 'double-viscosity' behaviour, and the first stabilisation period coincides with the viscosity of the injected water. However, since the cold front has prograded only few tens of meters into the reservoir (see Figure 15), an IARF period from ~ 50 meters onwards would lie on the magenta line and thus indicative of the virgin reservoir temperature. Analysis of the pressure transient is thus possible, but the engineer must be aware that the cold front bisects the derivative into two parts, and this is by no means a transmissivity effect but a mobility effect.

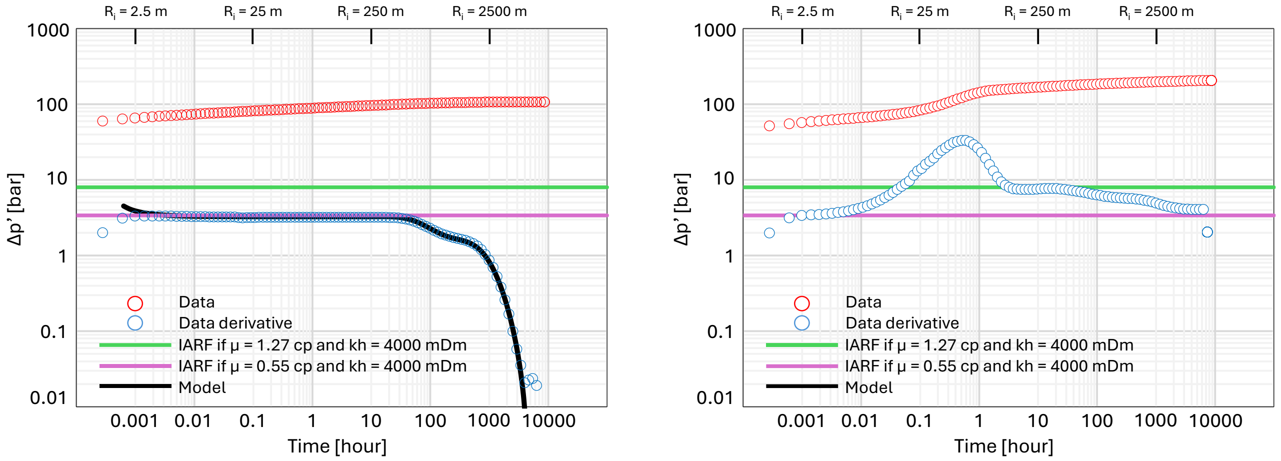


Figure 25. Model 3 - Step 1. Left picture: production well. Right picture: injection well. The production well shows that the Bourdet derivative starts dropping from t=30 hours onwards, when the radius of pressure influence is 500 to 600 meter. This constant pressure boundary is formed by the mirroring injection well, located at a distance of twice this radius, see Figure 13. No-flow boundaries (reservoir or model edges) have been prominently established after these 1 year of production/injection, see Figure 16, and are visible as a sharp decrease in the derivative from ~ t=1000 hours onwards. The shown model has three no-flow boundaries which coincides with the setup of the numerical model, see Figure 13 . Analysis of this pressure transient is thus 'straightforward'. The Bourdet derivative of the injection well shows a deviant signature, which is described in detail in the data acquisition reports of AMS-01. Analysis of this pressure transient is therefore cumbersome and might lead to incorrect conclusions.

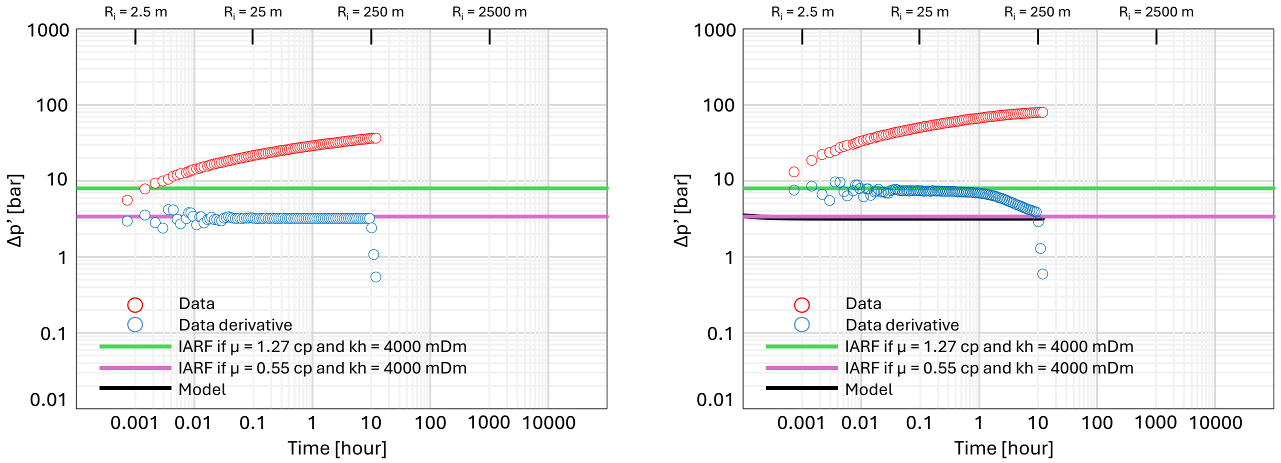


Figure 26. Model 3 - Step 2. Left picture: production well. Right picture: injection well. The production well only shows IARF: wellbore storage effects are absent, and the pressure has not detected the model edges yet. The effect of the injection well is not detected yet during these 12 hours of buildup. Analysis of this pressure transient is thus 'straightforward'. The injection well shows very comparable behaviour to Figure 20 and Figure 23, albeit that the 'double-viscosity' effect is even further delayed compared to the other figures. An initial stabilisation level up until ~ 1 hour lies on the green line, indicating that the viscosity of the reservoir up to several tens of meters into the reservoir is indeed comparable to the viscosity of the injected water. However, since the cold front has prograded 200 to 250 meters into the reservoir (see Figure 16), an IARF period from ~ 250 meters onwards would lie on the magenta line (if the fall-off would have lasted long enough) and thus indicative of the virgin reservoir temperature. Analysis of the pressure transient is thus possible, but the engineer must be aware that the cold front bisects the derivative into two parts, and this is by no means a transmissivity effect but a mobility effect.

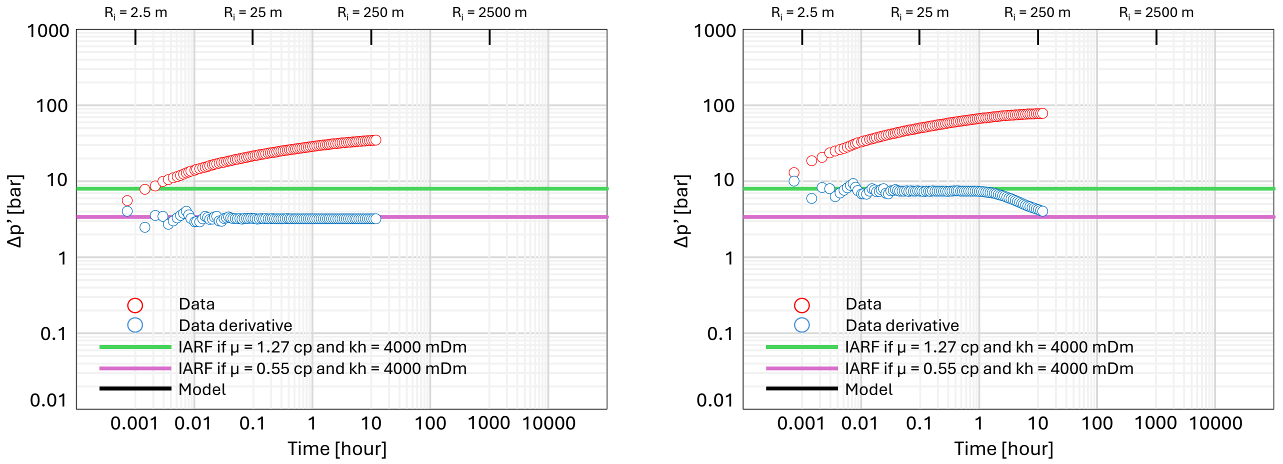


Figure 27. Model 3 - Step 3. Left picture: production well. Right picture: injection well. The production well only shows IARF: wellbore storage effects are absent, and the pressure has not detected the model edges yet. The effect of the injection well and reservoir edges are not detected yet during these 12 hours of production. Analysis of this pressure transient is thus 'straightforward'. The derivative of the injection well show the 'double-viscosity' behaviour, if this injection period would have lasted longer than these 12 hours. The first stabilisation period coincides with the viscosity of the injected water. However, since the cold front has prograded 200 to 250 meters into the reservoir (Figure 16), an IARF period from ~ 250 meters onwards would lie on the magenta line (if this injection period would have lasted long enough) and thus indicative of the virgin reservoir temperature. Analysis of the pressure transient is thus possible, but the engineer must be aware that the cold front bisects the derivative into two parts, and this is by no means a transmissivity effect but a mobility effect..

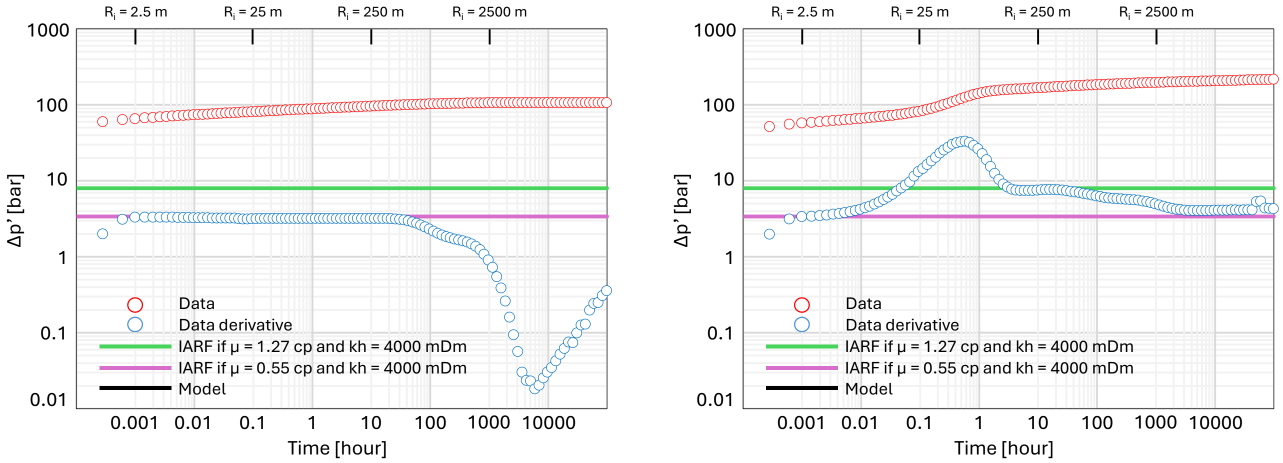


Figure 28. Model 4 - Step 1. Left picture: production well. Right picture: injection well. The production well shows that the Bourdet derivative starts dropping from t=30 hours onwards, when the radius of pressure influence is 500 to 600 meter. This constant pressure boundary is formed by the mirroring injection well, located at a distance of twice this radius, see Figure 13. No-flow boundaries (reservoir or model edges) have been prominently established after these 1 year of production/injection, see Figure 16 and Figure 17, and are visible as a sharp drop in the derivative from ~ t=1000 hours onwards. From t = 6000 hours onwards a late-time unit slope is manifested in the production period, indicative for closed systems like the modelled reservoir. Analysis of this pressure transient is thus 'straightforward'. The Bourdet derivative of the injection well shows a deviant signature, which is described in detail in the data acquisition reports of AMS-01. Analysis of this pressure transient is therefore cumbersome and might lead to incorrect conclusions.

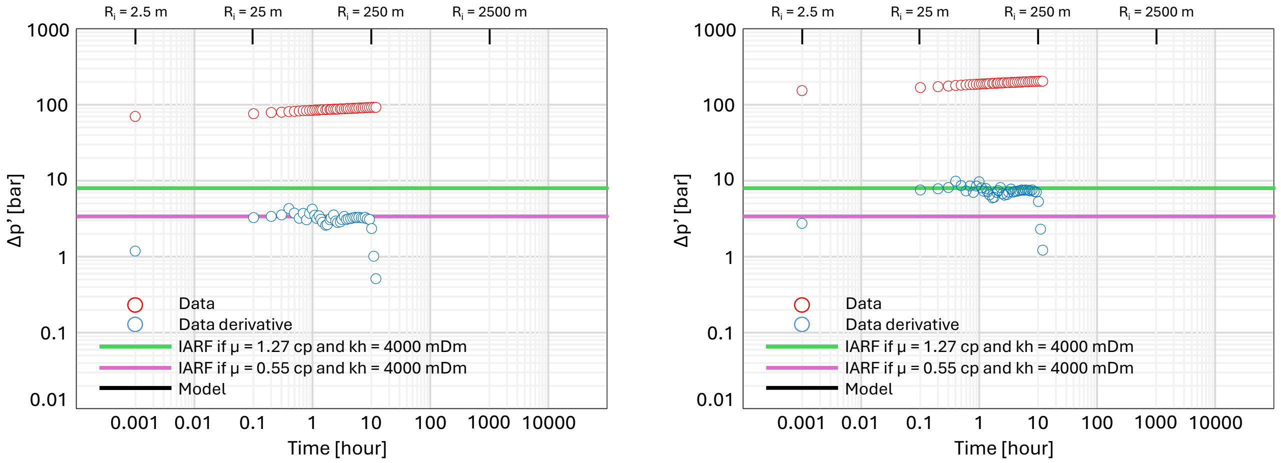


Figure 29. Model 4 - Step 2. Left picture: production well. Right picture: injection well. The production well only shows IARF: wellbore storage effects are absent, and the pressure has not detected the model edges yet. The effect of the injection well is not detected yet during these 12 hours of buildup. Analysis of this pressure transient is thus 'straightforward'. The injection well shows comparable behaviour to Figure 20, Figure 23 and Figure 26, albeit that the 'double-viscosity' effect is not observed anymore since this fall-off did not last long enough; the radius of investigation (~ 250 m) during these 12 hours was not wide enough to migrate beyond the cold front, which is ~ 600 m in radius (see Figure 17). Analysis of the pressure transient is thus possible, but the engineer must be aware that the cold front bisects the derivative into two parts (if this fall-off period would have lasted longer), and this is by no means a transmissivity effect but a mobility effect.

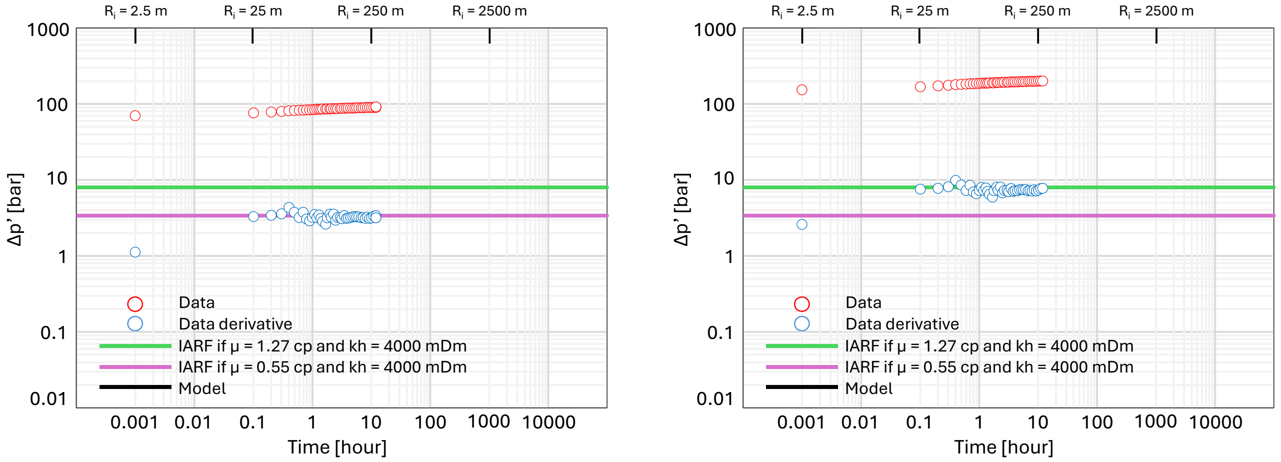


Figure 30. Model 4 - Step 3. Left picture: production well. Right picture: injection well. The production well only shows IARF: wellbore storage effects are absent, and the pressure has not detected the model edges yet. The effect of the injection well and reservoir edges are not detected yet during these 12 hours of production. Analysis of this pressure transient is thus 'straightforward'. A single stabilisation period is visible in the derivative of the injection well since this injection period did not last long enough for the pressure to travel beyond the cold frond radius. Analysis of the pressure transient is thus possible, but the engineer must be aware that the cold front bisects the derivative into two parts (if this fall-off period would have lasted longer), and this is by no means a transmissivity effect but a mobility effect

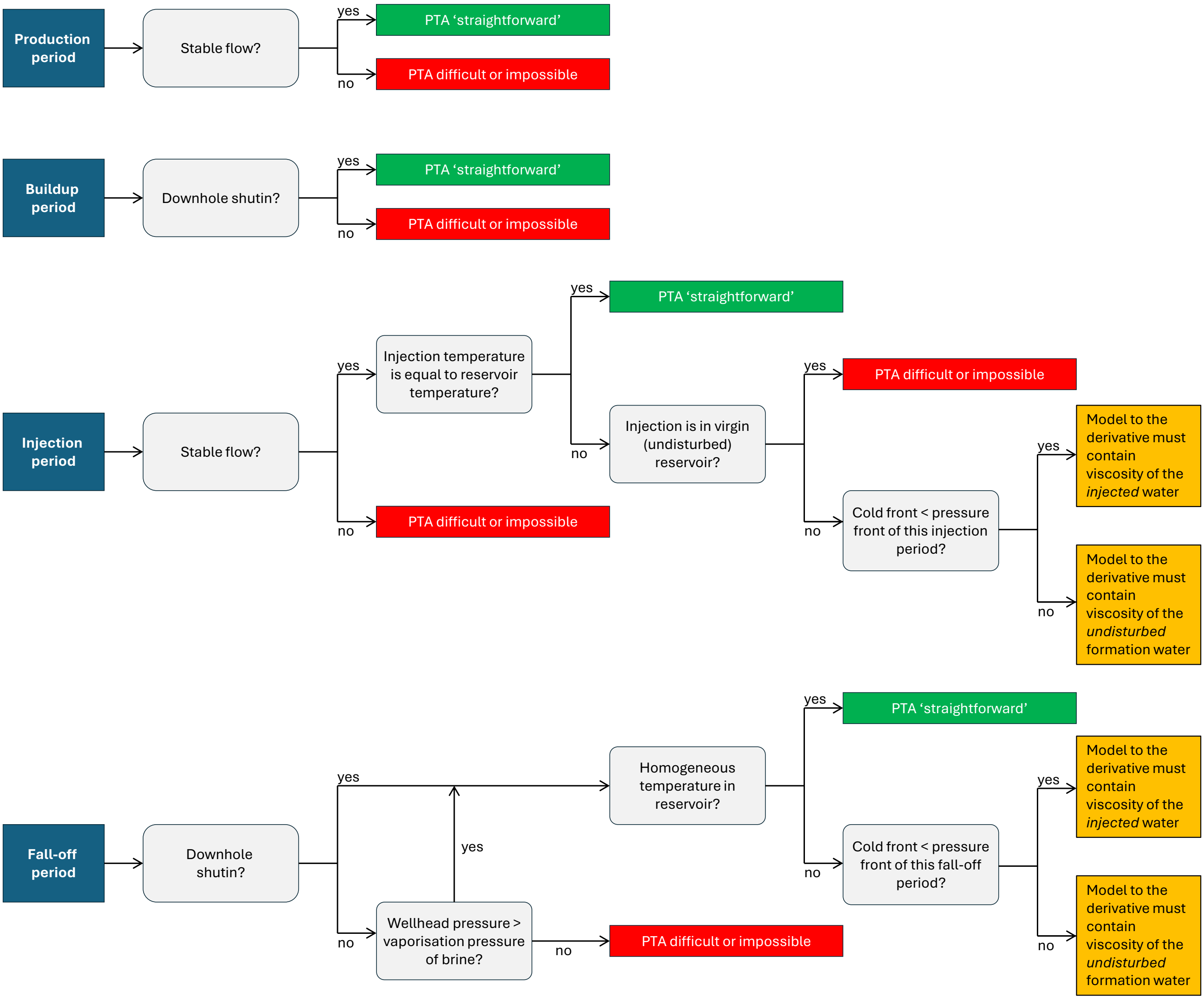


Figure 31. Flow diagram for various well test periods. 'PTA straightforward' does not imply that the analysis is simple or easy; the conventional PTA workflows can be followed which should normally result in appropriate and correct conclusions. 'PTA difficult or impossible' means that the engineer should be very reluctant or hesitant to use conventional PTA techniques, otherwise chances are very high that the interpretation will lead to incorrect conclusions. The orange boxes show where additional care should be taken when performing PTA. A reliable analysis can be performed using conventional analytical tools, but a workaround must be sought in case the Bourdet derivative experiences double-viscosity effects. See text for further explanation.

8. Summary and recommendations

Based on learnings from the SCAN well tests, additional numerical and analytical modelling, and on the literature, recommendations are given on how to improve on the quality of the well test data. Methods described in this document to achieve this include:

- Installation of downhole shut-in device, to remove unwanted wellbore physics during shut-in periods
- Stabilisation of the gas lifted production periods; to allow for the determination of a reliable P.I.
- Installation of downhole gauges; the closer the gauges are to the reservoir, the less the signal will be overprinted by unwanted noise.
- The usage of a PLT; only by inclusion of a PLT the PTA results will have the maximum value.

Investing marginal additional CAPEX in more extensive and more reliable datasets is outweighed by the better understanding of the geology and near wellbore area. This will aid in developing the doublet or the geological play, and helps optimising the production life of a well, both in terms of production rates and in OPEX.

Major cost reductions up to 1 million euro can be achieved by e.g.:

- Employment of alternative (less expensive) lift methods that are still fit for purpose.
- Reduction of the volume of production water. This can be achieved by testing at lower rates, shorter production periods, and by omitting unnecessary flow periods.
- Re-evaluating the well test objectives.

Existing datasets often contain a wealth of information regarding the reservoir properties. This includes for example production - and injection periods, and shut-in periods during the operational life of the wells. Care must be taken that downhole shut-ins are applied or that the flow periods are stable. Temperature effects in injection wells complicate the interpretation and care must be taken to use the appropriate viscosity values in the analytical software. Alternatively, numerical models can be used instead to evaluate a well test, although this brings some extra complexity.

It is also important to review the well testing methods for geothermal projects as described by subsidy facilities like the SDE++ and the guarantee fund. This report shows that some prescribed test components should be more stringent (e.g. installation of a downhole shut-in device, or a PLT to calculate the well test permeability) while at the same time others should be more loose (e.g. prerequisite of certain flow durations, multi-rate well testing, etc.). This will not only result in better well tests and improved understanding of the wells and reservoirs, it will simultaneously reduce the costs of well testing.

9. References

At the time of writing this document, the majority of the data from the SCAN wells and data reports were not yet or only partly published on https://www.nlog.nl and on https://scanaardwarmte.nl/. The data and reports can be found in due time on these websites.

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