IMPACT OF COLD WATER INJECTION ON GEOTHERMAL PRESSURE TRANSIENT ANALYSIS: A RESERVOIR MODELLING ASSESSMENT

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ABSTRACT

Geothermal pressure transients are currently analysed using standard analytical methods from oil and gas well testing theory. It is known that these analytical models do not fully apply to geothermal well test analysis as the underlying assumptions that allow for an analytical solution are not satisfied. Of particular interest for this study is that the analytical models require one fluid temperature to be specified, which sets the fluid properties such as viscosity and density. This is a great dilemma to the geothermal reservoir engineer looking at an injection/falloff test - whether to use the properties of the hot reservoir fluid, or the properties of the cold injected fluid. This issue has previously been examined and the conclusion reached that it is best to use the properties at reservoir conditions. However, this is done with the knowledge that the reality is something in between: the temperatures and fluid properties in the reservoir will be non-uniform, time-varying, and will range between the injectate and reservoir properties.

This issue is addressed in this study using the TOUGH2 numerical reservoir simulator to model well tests. Both the properties of the cold injection fluid and the hot reservoir can be specified. A test model is setup based on a particular injection test into a single well, using a standard model design. The temperature of the injectate is varied from ambient temperature up to hot reservoir temperature, a range from 15°C to 310°C. The impact on the results of pressure transient analysis are examined. In particular the changes to the derivative plot are studied. The modelling showed that the injected fluid temperature has a major impact on the skin factor and a minor impact on the reservoir permeability. This issue is examined in isolation from thermal stimulation effects.

1. INTRODUCTION

Currently pressure transient analysis (PTA) of geothermal injection/falloff tests uses only the properties of the hot reservoir fluid, and not those of the cold injected fluid. This has been necessary because analytical models only allow the specification of one set of fluid properties. It has been demonstrated that it is better to use the reservoir fluid properties rather than the injectate fluid properties, but also recognised that this is an imperfect solution (Grant and Bixley, 2011).

Numerical simulators allow both the reservoir and injectate temperature and fluid properties to be specified. The continuum between the two as the fluids interact during the test is also dealt with. Numerical simulators are becoming increasingly common for the analysis of geothermal pressure transients. This allows for the first time some critical questions to be addressed: What is the effect of cold water injection into a hot reservoir? Does this significantly affect the results of PTA by analytical methods?

A standard model setup for geothermal PTA has been developed (McLean and Zarrouk, 2015) using TOUGH2 (Pruess, 1991) and PyTOUGH (Croucher, 2011). This standard model is utilised in this study to examine an injection test of cold water into a hot reservoir. The temperature of the injectate is allowed to vary from ambient temperature up to the temperature of the reservoir. The impact of this on the derivative plot is demonstrated.

Despite the limitations of analytical PTA in geothermal wells, the model output is subjected to analytical PTA using SAPHIR™. This is done in an attempt to demonstrate the extent to which a change in shape of the derivative plot translates to a change in the estimated reservoir parameters. This provides an estimate of the potential range of error introduced by ignoring temperature effects and treating these as standard analytical analyses. Ideally this reservoir parameter estimation would be demonstrated using numerical PTA methods, which are currently under development and unfortunately not available for this study.

2. BACKGROUND

2.1 Use of reservoir fluid properties for analytical PTA

Analytical methods for PTA allow the specification of one set of fluid properties, which are assumed to be uniform throughout the reservoir (O'Sullivan et. al., 2005). In hot geothermal reservoirs there is a large temperature difference between the injectate and the reservoir during injection/falloff tests. The established method of dealing with this for hot fractured geothermal reservoirs is to use the fluid properties of the reservoir, not the injectate (Grant and Bixley, 2011). This has been established by Grant (1982) by review of actual field observations from the Ngawha, Broadlands and Kawerau geothermal fields in New Zealand and Krafla geothermal field in Iceland. This is done by comparing the injectivity of a well during injection testing to its subsequent productivity measured during discharge.

Any pressure transient field dataset can in theory be matched by modelling the injection of more viscous cold water into a very permeable reservoir, or injecting less viscous hot water into a much less permeable reservoir.

Following Darcy's Law if the more viscous cold injectate properties are used then the permeability of the reservoir will be predicted to be very high and so will the injectivity. If those results were reflective of reality then during subsequent discharge when hot reservoir fluid with an order of magnitude lower viscosity flows through that same highly permeable reservoir, the productivity measured should be massive, an order of magnitude higher than the injectivity. This is not what is observed in field data. On average the productivity is the same, or less than the injectivity (Grant, 1982). The use of injectate fluid properties results in a gross overestimate of reservoir permeability (Grant, 1982).

2.2 Thermal stimulation

The injection of cold water usually increases the permeability of a well and this has been established by both practical studies (Grant, 1982; Horne, 1982; Grant et. al., 2013) and numerical studies (Nakao and Ishido, 1998; Ariki and Akibayashi, 2001). This effect has recently been quantified using actual field data, for practical industry application (Siega et. al., 2014). Thermal stimulation is reversible and considered to be the result of an increase in porosity and permeability as a result of contraction of the rock matrix.

This changing permeability poses a big challenge for pressure transient analysis which estimates a constant reservoir permeability not one which changes with temperature and time. It is not meaningful to report a single number for permeability without also describing the well condition.

This change in permeability from thermal stimulation is a separate issue to the objective of this paper which deals with non-uniform fluid properties. It is however highly relevant to geothermal PTA and must be taken into consideration. It has been found to affect the permeability measured during injection testing, even over the short time periods between flow rate changes. Villacorte and O'Sullivan (2011) dealt with this by analysing each flow rate as a different stage. It was found that for each stage, as the flow rate increased, the permeability also increased. The permeability then decreased during the fall-off stage. This "stage-wise" analysis is a good practical way to deal with changing permeability. Advanced studies are capable of modelling the change in permeability during the course of a single transient (Riffault, 2014) but are too complex and time-consuming for broad practical application.

2.3 Skin effect

The region of the reservoir in the immediate vicinity of the wellbore commonly has a different permeability to the wider reservoir. It is common in oil and gas drilling to use drilling mud, which invades the reservoir close to the well and results in a lower permeability there, which is known as a positive skin effect or skin damage. Conversely, methods for well stimulation can increase the permeability in the near-wellbore region, known as a negative skin effect.

A skin effect due to a damaged or stimulated zone is quantified by the skin factor s which is calculated as follows (Horne, 1995):

$$s = \left(\frac{k}{k_s} - 1\right) ln \frac{r_s}{r_w} \tag{1}$$

Where:

k = reservoir permeability (mD)

k_s = permeability in damaged or stimulated zone (mD)

r_s = radius of damaged or stimulated zone (m)

r_w = radius of well (m)

Positive skin is characteristic in the derivative plot as a large hump in the transition between the unit slope characteristic of wellbore storage and the flat region characteristic of the infinite acting radial flow regime (Horne, 1995). The size of the derivative hump shrinks as skin factor decreases and becomes negative (Figure 1).

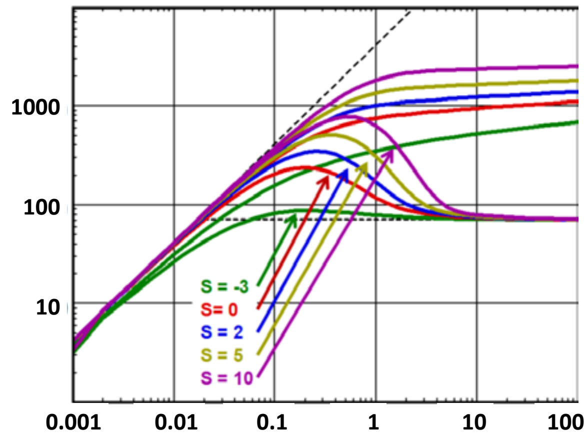

Figure 1: Effect of changing skin on derivative plot (reproduced with kind permission of KAPPA Engineering).

3. MODEL SETUP

A numerical model was set up based on an injection test into a hot 310°C well in Ohaaki geothermal field, NZ, following the standard guidelines outlined by McLean and Zarrouk (2015b). A schematic of this model is shown in Figure 2 and key model parameters given in Table 1.

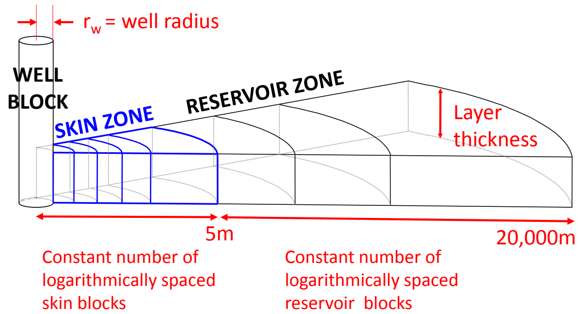

Figure 2: Schematic of standard model setup using TOUGH2 and PyTOUGH (McLean and Zarrouk, 2015b).

Table 1: Key model parameters for test model

PARAMETER	VALUE
Reservoir permeability (mD)	10
Reservoir temperature (°C)	310
Skin factor	0

Number of blocks in skin zone	50
Number of blocks in reservoir zone	100
Skin zone width (m)	5
Model radial extent (km)	20
Layer thickness (m)	600
Well radius (m)	0.1
Well porosity	0.9
Well volume (m^3)	81.4
Well compressibility (Pa^{-1})	$6x10^{-8}$

Injectate temperature is specified in the model as the enthalpy of injection into the well block. Using PyTOUGH this temperature can be specified, and automatically converted to enthalpy using built-in steam tables.

4. RESULTS AND DISCUSSION

From preliminary runs of the model it was immediately apparent that the effect of varying injectate temperature closely resembles the skin effect. Therefore a variety of scenarios are examined with the same range of values for the injectate temperature parameter, but different skin values:

Scenario 1: skin factor = 0

Scenario 2: skin factor = -2

Scenario 3: skin factor = 5

The injectate temperature is commonly given the value of ambient temperature at the surface, around 15°C or 20°C. In the case of this well test, the reservoir temperature is 310°C. The temperature of the injectate by the time it has reached the PT tool depth in the well is 57°C. To investigate across this range, the temperature has been assigned the following values: 15, 57, 100, 150, 200, 250, 310°C.

4.1 Scenario 1: skin factor = 0

The initial test model has a skin factor of zero. A derivative plot of the numerical simulation results is shown in Figure 3. It is apparent that if cold water injection produces an effect which looks like positive skin, then fitting analytical models will produce an over-estimate of skin factor. Analytical PTA methods are applied to these model output datasets using SAPHIR^{TM} and using reservoir fluid properties. The results for skin factor and permeability are presented in Table 2, for both model fits and semilog analysis. The objective of this is to quantify the error in skin factor introduced by the injectate temperature effect, and also any potential error in the results for permeability.

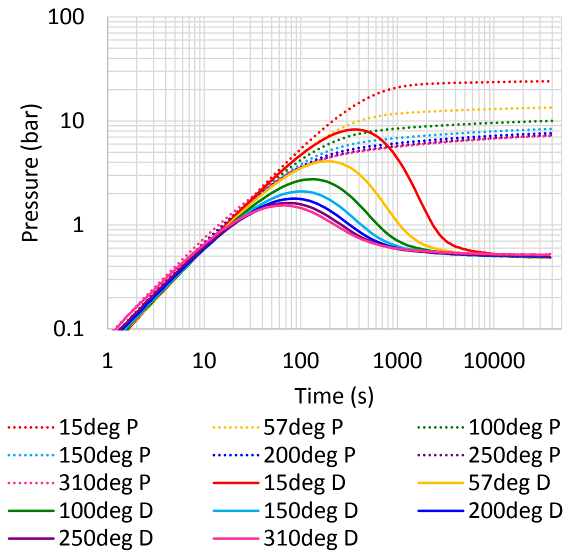

Figure 3: Scenario 1 results: Log-log plot showing changes to pressure derivative with varying injectate temperature for zero skin (P = pressure difference, D = pressure derivative).

It can be seen from Figure 3 that as the temperature of the injectate decreases, the size and steepness of the derivative hump increases in a manner similar to increasingly positive skin. The late-time derivative plot behaviour seems to be largely unaffected and this is reflected in the consistent values for reservoir permeability, which generally vary by only a few percent (Table 2). The derivative shape is more sensitive to changes at low temperature and less so at higher temperatures. This is not surprising as the dependence of viscosity on temperature is not linear. At lower temperatures viscosity changes rapidly with temperature and less so at higher temperatures.

Table 2: Results of analytical PTA of numerical model output seen in Figure 3.

INJECTATE TEMPERATURE (°C)	Comment on model fit	SAPHIR^{TM} model fits		SAPHIR^{TM} semilog analysis	
		k (mD)	skin factor	k (mD)	skin factor
15	poor	310	10	402	15.1
57	good	420	5.1	405	4.7
100	good	418	1.5	407	1.3
150	good	415	-0.2	405	-0.4
200	good	411	-1.0	403	-1.2
250	good	405	-1.5	399	-1.6
310	good	393	-1.8	390	-1.8

It can be observed in Table 2 that a standard uniform porous media analytical model fits well to almost all the numerical model outputs shown in Figure 3. The exception is the derivative for an injectate temperature of 15°C, which is too steep and therefore fits poorly. While the injectate may be 15°C at the surface, this is not relevant as by the time the reservoir "sees" the injectate it has travelled down the well and been heated conductively along the way. The temperature profile in any well during injection will vary with depth, increasing towards the bottom of the well. It is suggested that a practical injectate temperature value to use for the modelling is the temperature at the tool depth at the start of the transient. In this case that temperature is 57°C. It is known that for all injection tests, the temperature profile in the well will progressively cool as injection proceeds. Some average value of temperature may in fact be required to more accurately model the temperature effect and this will be the subject of future study.

Considering only the good model fits in Table 2, across a range of injectate temperature from 57°C to 310°C, the following observations are made:

- Model fits and semilog analysis produce very similar results.
- As injectate temperature increases the estimate of permeability decreases slightly. The range for good model fits is 420 – 393 mD which represents a change of only 7%.
- As injectate temperature increases the estimate of skin factor is affected drastically. The range for good model fits is from moderately positive at 5.1 to moderately negative at -1.8.

This is a very hot reservoir and represents an extreme example of the temperature effect.

4.2 Scenario 2: Skin factor = -2

The skin factor in the model is set to be moderately negative at -2. A derivative plot of the numerical simulation results is shown in Figure 4. Analytical PTA methods are applied as per Scenario 1. The results for skin factor and permeability are presented in Table 3.

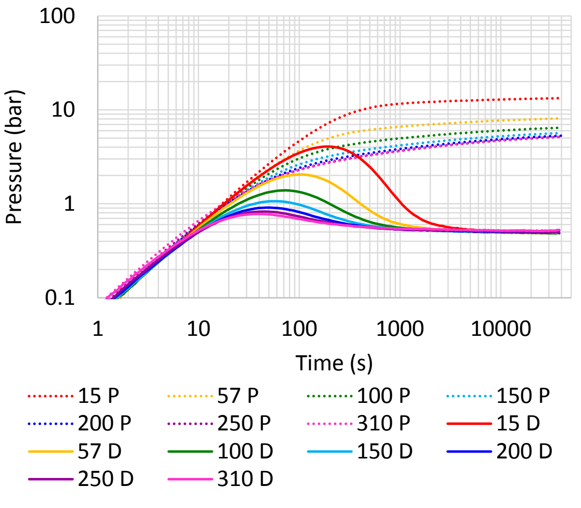

Figure 4: Scenario 2 results: Log-log plot showing changes to derivative with varying injectate temperature for a skin factor of -2.

It can be seen from the shape of the derivative plot results (Figure 4) that the effects of injectate temperature are less apparent for negative skin than for zero skin (Figure 3). This is consistent with the fact that the temperature effect resembles positive skin, and therefore is countered when negative skin is present.

Table 3: Results of analytical PTA of numerical model output seen in Figure 4.

INJECTATE TEMPERATURE (°C)	Comment on fit	SAPHIR™ model fits		SAPHIR™ semilog analysis	
		k (mD)	skin factor	k (mD)	skin factor
15	good	427	5.2	414	4.8
57	good	427	-0.3	417	-0.4
100	good	426	-2.0	415	-2.2
150	good	422	-2.9	412	-3.0
200	good	417	-3.3	408	-3.4
250	good	412	-3.6	403	-3.6
310	good	400	-3.7	393	-3.8

The following can be observed in the results in Table 3:

- All model fits are good, because the temperature effect is countered by the negative skin.
- Overall the observations are similar to Scenario 1.
- Model fits and semilog analysis produce very similar results.
- As injectate temperature increases the estimate of permeability decreases slightly. The range for good model fits is 427 – 400 mD which represents a change of only 7%.
- As injectate temperature increases the estimate of skin factor is affected drastically. The range for good model fits is from moderately positive at 5.2 to strongly negative at -3.7.

4.3 Scenario 3: Skin factor = 5

The skin factor in the model is set to be moderately positive with a value of 5. A derivative plot of the numerical simulation results is shown in Figure 5. Analytical PTA methods are applied as per Scenario 1. The results for skin factor and permeability are presented in Table 4.

It can be seen from the shape of the derivative plot results (Figure 5) that the effects of injectate temperature are more apparent for positive skin than for zero skin (Figure 3). This is consistent with the fact that the temperature effect resembles positive skin, and therefore in combination with a real positive skin the apparent effect is very large.

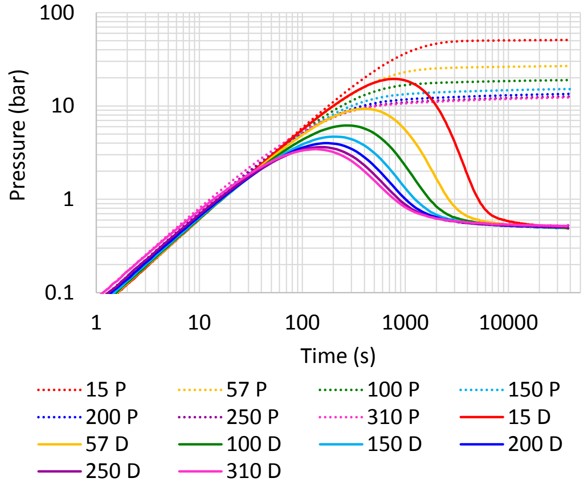

Figure 5: Scenario 3 results: Log-log plot showing changes to derivative with varying injectate temperature for a skin factor of 5.

Table 4: Results of analytical PTA of numerical model output seen in Figure 5.

INJECTATE TEMPERATURE (°C)	Comment on fit	SAPHIR™ model fits		SAPHIR™ semilog analysis	
		k (mD)	skin factor	k (mD)	skin factor
15	poor	268	25.4	390	40.1
57	good	438	20.0	404	17.9
100	good	415	10.5	405	10.1
150	good	403	6.3	404	6.3
200	good	396	4.4	400	4.5
250	good	388	3.3	396	3.5
310	good	373	2.6	387	3.0

The following can be observed in the results in Table 4:

- The combination of positive skin and injectate temperature effect produces a pronounced hump which cannot be fitted with analytical models at the low injectate temperature of 15°C.
- At 57°C and above all the analytical model fits are good.
- For good model fits the results are very similar to those from semilog analysis.
- As injectate temperature increases the estimate of permeability decreases slightly. The range for good model fits is 438 – 373 mD which represents a change of 17%.
- As injectate temperature increases the estimate of skin factor is affected drastically. The range for good model fits is from strongly positive at 20.0 to weakly positive at 2.6.

4.4 Discussion of SAPHIR™ model fits

Models in SAPHIR™ are analytical and are based on a number of assumptions which do not hold in a geothermal scenario (McLean and Zarrouk, 2015). The result of this is that analytical models do not fit geothermal field data in the vast majority of cases. Even if a model does fit it does not therefore follow that the estimated reservoir parameters are meaningful.

Despite the limitations of analytical models SAPHIR™ is used in this study to evaluate the results of numerical modelling. This is done out of necessity as no numerical tools are yet available to complete this inverse modelling process with practical speed. This is the subject of current study and will be one of the outcomes of the body of work of which this paper is part.

The analytical model results of SAPHIR™ and numerical model results of this study are calculated entirely differently. It is therefore not expected that the SAPHIR™ analysis will return values for permeability and skin equal to those used in the numerical forward model.

The purely numerical core of this paper stands separate to the analytical analyses. The numerical model setup is described and the numerical model results shown in Figures 3, 4 and 5. Visual examination of the results is sufficient to demonstrate that as injectate temperature decreases, the shape of the derivative plot changes in a manner resembling the positive skin effect. Also that this temperature effect is masked in the case of real negative skin (Figure 4). This is all based entirely on numerical modelling. The only reason to involve analytical models at all - and with great reluctance as this research is all part of a move away from analytical models – is an attempt to give some indication of the extent to which the change in shape of the derivative plot equates to a change in the estimated reservoir parameters.

4.5 Usefulness of accurately determining skin factor

Accurate characterisation of the skin effect in a geothermal well would be a useful monitoring tool. The permeability of the reservoir close to the well can change over time for various reasons. This could be the result of a long-term effect such as scaling, or the result of some deliberate intervention such as acidising or deflagration.

Early detection and monitoring of scaling in the reservoir would allow early identification of wells requiring workover, and potentially also assist in evaluating the efficacy of anti-scalant systems. Characterising the skin factor before and after a deliberate intervention allows the true effect of the intervention on the near-wellbore to be quantified.

4.6 Field examples

Unfortunately it is difficult to identify field examples of this effect for the following reasons:

- The main identifying factor is the steep drop down from the derivative hump, which is not unique. A steep drop such as this can be caused by other factors such as positive skin, or distortions due to

- slow valve closing or two-stage pump shut-down (McLean and Zarrouk, 2015).
- In most cases the analytical model fits are good and so it is not obvious there is a problem.
- Only when the injectate temperature is impractically low at 15°C is the shape distorted to the extent that the analytical models will not fit. This is masked when skin is negative and reinforced when skin in positive. Geothermal wells are drilled with aerated water and typically have negative skin, which will mask the temperature effect.

However, despite these difficulties, PTA of geothermal injection tests at well completion most often return positive values for skin, though negative values are expected when drilling with water and air. This trend has been observed by the authors and confirmed in discussion with industry-based reservoir engineers. In the absence of any practical explanation for positive skin in new wells, this is considered to be evidence of the invalidity of the method of analysis. The temperature effect described in this paper is likely to be a significant contributing factor to this trend. Over time, the use of numerical methods which have the ability to take account of the temperature effect may assist in validating geothermal PTA.

5. CONCLUSIONS

- Numerical models can be used successfully to model the effect of injectate temperature on PTA.
- Decreasing the temperature of the injectate in the numerical model increases the size and steepness of the derivative hump. This effect resembles positive skin.
- Without numerical models with the capability to reproduce the injectate temperature effect, it will be interpreted as positive skin by analytical PTA.
- Permeability from analytical PTA is minorly affected by the injectate temperature effect. The error in permeability is 7% or less when skin is zero or negative. The error in permeability is 17% or less when skin is moderately positive.
- Skin factor from analytical PTA is strongly affected by the injectate temperature effect.
- In all cases a straight line is present in the semi-log plot. Semi-log analysis of these straight lines does not produce results which are representative of the reservoir properties.
- Temperature effects on PTA are difficult to identify in field data as the effect on the derivative plot has no unique characteristics. It closely resembles the skin effect and is masked by negative skin which is common in geothermal wells.
- The temperature in the well at the tool depth at the start of the transient is suggested as a practical value to use for numerical modelling. As the model results are highly sensitive to temperature, this value should be selected with care. Inverse modelling of many field datasets is required to test this suggestion. Some other method for selecting the temperature value may result from future work.
- Accurate determination of the skin factor would enable short term and long term monitoring of the near-wellbore reservoir.
- It may be possible to derive a correction for this temperature effect for use when applying analytical models. This will be the subject of further work.

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