Persistence of Temperature Effects from Sea Water Injection

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1 Abstract

Observations on a recently drilled injection well indicated that the determination of oil saturations from log interpretation was affected by the measured temperatures, which were substantially below the initial reservoir temperature [1]. This well was drilled close to a previous injector that had been shut in for approximately nine months. Water injection in that well would have acted to cool the reservoir, but there appeared to be some surprise when these results were presented that the cooling has persisted so long.

It is not clear if expectations were confounded due to some unanticipated thermal behaviour, or simply because the phenomenon had not been investigated quantitatively. This work reports the results of a literature search to see if unexpected, persistent temperature changes have been reported before. It also includes some simple calculations, both analytic and using numerical simulation, investigating temperature changes using typical thermal properties obtained from the literature review.

The literature contained little information regarding the duration of reservoir cooling. However, data relating to thermal properties of reservoir rocks have been measured, but mostly in the context of thermal recovery processes such as steamflooding.

The analytic model calculations indicate that the rise in temperature following a period of water injection is very slow and significant cooling may remain for a few years, even in thin reservoir sections of approximately five metres. These results have been duplicated using numerical simulation, which found that water injection is very efficient at cooling the reservoir, but that the reservoir is very slow to warm with only small changes of temperature occurring over the first few years. Measurable temperature drops are predicted to persist even after 100 years in reservoirs with thickness greater than 100 metres.

These calculations show that the persistent nature of reservoir cooling caused by the injection of cold water should not be a surprise. Such effects could be expected for a reservoir where an interval of 10 metres or more has been cooled by injected water

2 Introduction

This study was prompted by observations on a newly drilled injection well in Magnus in which the determination of oil saturations from log interpretation was affected by the measured temperatures which were substantially below the initial reservoir temperature [1]. The well was drilled close to a previous injector that had been shut in for the previous 9 months. Water injection in that well would have acted to cool the reservoir but there appeared to be some surprise that the cooling would have lasted so long. This effect is not well documented or widely understood (it seems counter-intuitive that the reservoir does not warm up faster).

Apart from the impact on saturation calculations, there may be effects on 4D seismic interpretation, EOR/miscibility issues due to different phase behaviour and properties, future thermal fracturing may be less effective, and there may be an impact on cement recipe calculations, leading to zone isolation problems.

It is not clear if the “surprise” is due to some unexpected thermal behaviour or simply because the phenomenon had not been considered in a quantitative manner. To investigate further we performed a literature search, to see if unexpected, long-lived temperature changes had been previously reported and to assemble appropriate thermal data. This was followed by some simple calculations concerning temperature changes using thermal properties from the literature.

3 Literature Search

3.1 LONG-LIVED TEMPERATURE CHANGES

The SPE literature was searched for papers concerning long-lived temperature changes and unexpected thermal behaviour using the SPE web site. Nothing found addressed the topic directly, though we cannot be entirely sure that we have not missed anything due to the difficulty in choosing appropriate keywords for the search. The search did, however, provide some useful information.

One paper [2] concerned a replacement injector drilled in the Prudhoe Bay field in which reservoir cooling was measured. In that case, however, the original well was still injecting at the time, so it provides no information on the time scales for re-establishment of reservoir temperature. There was no suggestion that there was anything unusual about the cooling and the information was used to help understand reservoir performance through history matching using a thermal simulation model.

Another [3] reported the deduction of thermal diffusivity from temperature surveys through the cap-rock in steamflood and hot water injection projects. This gave results consistent with values calculated from laboratory-measured data, such as that given in Section 3.2 below. This lends confidence to our ability to calculate temperature changes. This paper also provides examples of temperature variations across the cap-rock, reservoir interval, and underlying formation for a hot waterflood project.

3.2 THERMAL PROPERTIES

The thermal properties required for reservoir temperature calculations are specific heat (c), thermal conductivity (K) and density (ρ) for the fluid and rock combinations encountered in and about the reservoir. A number of such measurements are reported in the literature, including [4, 5, 6]. More conveniently, data and correlations have been assembled in a number of books, including [7, 8, 9]. Some porous media data and single component data from [8] are given in Table 1 and Table 2 below.

Table 1: Properties of Some Typical Rocks at 30°C

	Porosity	Density (kg/m^3)	Specific heat ($kJ.kg^{-1}.K^{-1}$)	Thermal conductivity ($W.m^{-1}.K^{-1}$)
Sandstone saturated: with air	0.196	2,080	0.766	0.877
with water[1]	0.196	2,275	1.055	2.75
with oil[2]	0.196	-	-	1.36
with oil and water[3]	0.196	-	-	2.47
Shale saturated: with water[1]	0.071	2,390	0.892	1.69
Limestone saturated: with air	0.186	2,195	0.846	1.70
with water[1]	0.186	2,390	1.114	3.55
with oil[2]	0.186	-	-	2.15
with oil and water[3]	0.186	-	-	2.92

[1] Distilled water, $K=0.611\ W.m^{-1}.K^{-1}$
[2] Light lubricating oil, $K=0.133\ W.m^{-1}.K^{-1}$
[3] Approximately 35% water, 65% oil

Table 2: Properties of Some Liquids and Solids at 20°C and Atmospheric Pressure

	Density (kg/m^3)	Specific heat ($kJ.kg^{-1}.K^{-1}$)	Thermal conductivity ($W.m^{-1}.K^{-1}$)
Water	1000	4.182	0.602
Decane	730	2.193	0.140
Benzene	876	1.722	0.146
Calcite	2,720	0.82	3.6
Quartz (crystalline)	2,650	0.74	7.7
Granite	2,700	0.82	2.0

Densities and specific heats of rock/liquid combinations can be calculated from component properties but thermal conductivities cannot. It is interesting to note that the thermal conductivity of porous reservoir rock is much less than for solid rock. This can be seen by comparing the value quoted for air-saturated sandstone in Table 1 with that for quartz in Table 2. This reduction is probably due to the small area of contact between grains, and makes the conductivity sensitive to the properties of the saturating fluids.

4 Heat Conduction Calculations

In the UKCS, most oil production has been supported by water injection. The injected water is usually at a lower temperature than the original reservoir temperature, and thus acts to cool the reservoir.

Exact solutions for the temperature response may be obtained for some one-dimensional problems in which convection is the sole mechanism for heat transfer. For example, a radial solution is given in [10]. The temperature front lags behind the waterflood front due to the thermal inertia of the rock and residual oil. The lag is smallest for high porosity rocks because the thermal capacity of the injected water relative to that of the rock increases with increasing porosity. Similarly, the presence of non-net rock will increase thermal inertia and slow the thermal front. Example calculations in [10] for a good quality reservoir show the waterflood front advancing at about 4 times the rate of the thermal front.

On the reservoir scale, heat conduction in the direction of flow of the injected water can be ignored compared to heat convection. However, conduction perpendicular to the injected water may be important because of the shorter distances involved and the lack of convection in that direction. This conduction may act to reduce the temperature in reservoir zones bypassed by the injected water as occurs, for example, when a low permeability sand lies between two high permeability sands. It also acts between the reservoir and the overlying cap-rock and underlying formation. This will act to cool the overlying and underlying formations and warm the cooled reservoir zones. Examples of such behaviour are given in [10].

It seems likely, because of the difference in length scales, that the important thermal conduction can be described by the one-dimensional heat conduction equation

$$\frac{\partial T}{\partial t} = \kappa \frac{\partial^2 T}{\partial x^2} \qquad (1)$$

where T is the temperature, t the time, x the distance in the direction perpendicular to the water flow, and κ the thermal diffusivity, given by:

$$\kappa = \frac{K}{\rho c} \qquad (2)$$

Equation (1) has been well studied and many solutions are given in standard texts, for example [11]. Whilst none of these correspond exactly to the problem of interest here, the solution to one problem is highly illuminating concerning timescales for conduction-induced temperature changes in waterflooded reservoirs. It also provides a test of the capability of temperature modelling in reservoir simulators.

4.1 ANALYTIC MODEL OF RESERVOIR WARMING

An analytic solution exists which corresponds to an idealised representation of a cooled reservoir where the reservoir region has been cooled to temperature T_c, but the cap and base rocks remains at the original temperature T_o as shown in Figure 1. If the reservoir has thickness 2h with centre at depth z=0, then the temperature profile assuming conduction only, from time t=0, is given by [11]

$$\frac{T(z,t) - T_c}{T_o - T_c} = \frac{1}{2}\left\{ erfc\left(\frac{h-z}{2\sqrt{\kappa t}}\right) + erfc\left(\frac{h+z}{2\sqrt{\kappa t}}\right)\right\} \qquad (3)$$

In particular the temperature at the centre of the formation (z=0) is given by

$$\frac{T(z,t) - T_c}{T_o - T_c} = erfc\left(\frac{h}{2\sqrt{\kappa t}}\right) \qquad (4)$$

The solution has been plotted for various thicknesses from 3 to 150 metres (10 to 500 feet) in Figure 2. The rock density has been set to 2080 kg/m^3, the heat capacity to 1000 J/kg/K and the thermal conductivity to 2 J/m/K/s which corresponds to a thermal diffusivity of 9.6 x 10^{-7} m^2/s. Figure 2 shows a dramatic increase in the time required for the centre of the reservoir to warm with increasing thickness. The centre of the 3 metre reservoir (h = 1.5 metres) reaches 85% of the temperature difference after approximately 1 year, whereas a period of 100 years is required for a reservoir of 30 metres. Essentially the time increases with the square of the reservoir thickness.

In practise, the overburden and underburden will have been cooled by the water injection. This has the effect of increasing the “effective thickness” which should be used in the analytic solution, causing a slower rise in temperature than predicted by this simplified model. For example, if the surrounding rocks are cooled to a depth of 6 metres, then the effective thickness to be used for the 3 metre reservoir is 15 metres in Figure 2. For this scenario the centre of the reservoir reaches 33% of the temperature difference after 1 year.

This model has been compared against our reservoir simulator, *tech*SIM. The analytic and simulated solutions are shown in Figure 3, which shows that the temperature predictions made by the simulator are in good agreement with this analytic solution.

The depth of the cooling of the cap and base rocks can be estimated approximately as $2\sqrt{\kappa t}$. For example, if we assume that the cooled waterflood region in a reservoir lies immediately above an aquifer with thermal properties for which $\kappa = 9.6 \times 10^{-7}$ m^2s^{-1}, this gives a cooling depth of 0.6 m after one day and 11 m after one year, showing fairly slow propagation of the cooled zone into the aquifer. The square root dependence, $\sqrt{\kappa t}$, reduces the effects of the uncertainties in the thermal properties and slows the rate of advance as t increases.

The long-lived nature of the reservoir cooling seen in Magnus is thus consistent with the expected thermal properties of the reservoir.

5 Illustrative Temperature Changes from Waterflood Simulation

5.1 HOMOGENEOUS MODELS

The temperature effects presented in previous sections have been investigated using simulation. A single-well model using radial geometry has been constructed. The original reservoir temperature was set to 96 °C (205 °F). Approximately one pore volume of cold water, at temperature 24 °C (75 °F), was injected at the centre of the model over a period of 10 years. This was followed by a lengthy shut-in, to determine how quickly the reservoir temperature rises. Thermal boundaries have been modelled using both grid blocks out to a thickness of 1000 feet and analytic models applied to the faces of the reservoir.

The impact of reservoir thickness has been examined by modelling several thicknesses of 3, 7.5, 30, and 150 metres (10, 25, 100 and 500 feet). The outer radius has been set to 762 metres (2,500 feet), the permeability to 500 mD and the porosity to 0.2. The rock heat capacity has been taken as 1000 J/kg/K and the density as 2080 kg/m^3. The rock thermal conductivity was set to 2 J/m/K/s except for some sensitivity calculations. The oil and water specific heat capacities were set to 2,000 J/kg/K and 4,000 J/kg/K respectively.

The cases listed in Table 3 have been run.

Table 3: Homogeneous Simulations Performed

Name	Thickness (metres)
Case 1	3 (10 feet)
Case 2	7.6 (25 feet)
Case 3	30 (100 feet)
Case 4	152 (500 feet)

5.1.1 Case 1: Thickness 3 metres (10 feet)

Water was injected for a period of 10 years (step 10). The well was shut-in and the reservoir allowed to warm. The production and injection profiles are shown in Figure 4.

The temperature profile in the reservoir and surrounding rocks is shown in Figure 5. This shows that the temperature front has advanced approximately one quarter of the way across the model i.e. about 200 metres. The front has also extended into the over- and under-burden out to a distance of about 30 metres. The distance is less vertically because heat also transfers by fluid convection in the horizontal direction. Figure 5 also shows the temperature profiles after 1 (step 14), 2 (step 18) and 100 (step 34) years of shut-in. These indicate that the reservoir region has only slightly warmed after the first two years and is still showing a noticeable temperature difference after 100 years close to the well.

The calculated temperatures show some numerical dispersion in the radial direction. The increasing size of grid block with radius smears out the temperature front resulting in a less sharp temperature profile than might otherwise be expected. The cooled region around the well should be smaller and more sharply defined than shown in Figure 5. However, as the warming of the reservoir is primarily due to conduction from the base and cap rocks, this is not thought to significantly affect the results. The grid in the vertical direction has been designed to accurately capture the temperature profile.

The temperature changes can be better appreciated by considering the temperature profile through the reservoir and surrounding rock at fixed distance from the well. Figure 6 shows the temperature profile at 35, 140, 250 and 400 metres from the well for various times after shut-in. Close to the well (< 50m) the reservoir and overburden has been significantly cooled. The temperature is very slow to rise with only a small increase in temperature after 2 years. The temperature after 10 years is still 30°C less than the original value at the centre. Further away from the well (>200 metres), there is less cooling of the reservoir and the base and cap rocks. Consequently, the temperatures appear to rise faster.

The temperature profile around the well can also be understood by considering the number of pore volumes of injected water passing through. This is defined as the reservoir volume of water leaving the enclosed volume divided by its pore volume; it varies inversely with the square of the distance from the injection well. Close to the well, the throughput is of the order of tens of thousands of pore volumes dropping to approximately 1 at the outer radius. This explains why most cooling occurs close to the well.

The rate of temperature change is sensitive to the thermal conductivity of the rock. For demonstration purposes, cases with it increased and decreased by an order of magnitude have been run although these extreme values may not be realistic. Increasing the thermal conductivity by a factor of 10 results in a smaller region around the well being cooled due to increased heat transfer from the surrounding rock. The temperature front advances further into the over and under burden. After shut-in, the reservoir warms much faster due to the increased thermal conductivity. If the thermal conductivity is decreased by a factor of 10, then there is less heat transfer between the reservoir and surrounding rock. Consequently the temperature front propagates further into the reservoir. After shut-in, the warm up is much slower.

Cold water injection into thin reservoirs results in a small cold region close to the well, but with temperatures close to the original temperature at distances greater than 250 metres from the well. The temperature front extends into the cap and base rocks by up to 30 metres. After cessation of water injection, the time required for the reservoir to warm depends on the thermal properties of the rocks. Typically, higher thermal conductivity results in a smaller cooled region and faster warming after water injection has ceased. However, significant cooling may persist in the near well (i.e. less than 140 metres) for at least two years.

5.1.2 Case 2: Thickness 7.6 metres (25 feet)

The temperature profile in the reservoir and surrounding rocks is shown in Figure 7. After completion of water injection the temperature front has advanced approximately two fifths of the way across the model, i.e. about 300 metres. The front has also extended into the over- and under-burden out to a distance of about 80 metres. Figure 7 also shows the temperature profiles after 1 (step 14), 2 (step 18) and 100 (step 34) years of shut-in. Close to the well (< 140m) the reservoir and overburden has been significantly cooled. The temperature is very slow to rise with only a small increase in temperature after 2 years. The temperature after 10 years is still 20°C less than the original value at the centre. Further away from the well (>250 metres), there is less cooling of the reservoir and the base and cap rocks and the temperatures rise faster. The reservoir region is still showing a noticeable temperature difference after 100 years close to the well (< 50 metres).

By comparing Figure 7 and Figure 5, we can see that the temperature front has advanced further through the reservoir. This is because the surrounding rocks are less able to compensate for the cooling effect of the greater water injection volume and thicker reservoir. Consequently the reservoir warms more slowly after shut-in.

The extra cooling results in an increase in the viscous pressure gradient across the model. This is because the viscosity of the oil varies from 0.6 cp at 96 °C to 1.4 cp at 24 °C and the viscosity of water varies from 0.24 cp at 96 °C to 0.64 cp at 24 °C. The larger cooled region results in a larger pressure drop and hence potential loss of injectivity.

The temperature front advances faster through the thicker reservoir due to a combination of increased injected water volume and less effective temperature support from the base and cap rocks. The water volume injected is the dominant mechanism in cooling the formation and results in greater propagation of the temperature front both horizontally and vertically. The increased cooling of the base and cap rocks and the extra reservoir thickness retards the warming process as heat needs to travel over greater distances.

5.1.3 Case 3: Thickness 30 metres (100 feet)

The temperature profile in the reservoir and surrounding rocks is shown in Figure 8. On completion of the waterflood, the temperature front has advanced approximately three quarters of the way across the model i.e. about 600 metres. The front has also extended into the over- and under-burden out to a distance of about 90 metres at shut-in. There is more cooling of the base rocks because of the tendency of gravity to cause the water to slump to the bottom of the model and so more water passes through these layers. Figure 8 also shows the temperature profiles after 1 (step 14), 2 (step 18) and 100 (step 34) years of shut-in. These indicate that the reservoir region near the well has only slightly warmed after the first two years and is still showing significant temperature reduction after 100 years close to the well.

This case shows a continuation of the trends seen in the previous two cases. The surrounding rocks are less able to compensate for the cooling effect of the larger water volume injected plus the greater distance over which heat must move. Consequently there is a significant time delay before the centre of the reservoir warms with virtually no temperature increase over the first two years. A temperature drop of 20 °C still persists 250 metres from the well after 50 years.

5.1.4 Case 4: Thickness 152 metres (500 feet)

The temperature profile in the reservoir and surrounding rocks is shown in Figure 9. On completion of the waterflood, the temperature front has advanced approximately four fifths of the way across the model i.e. about 600 metres. The front has also extended into the over- and under-burden out to a distance of about 90 metres at shut-in. There is more cooling of the base rocks because of the tendency of gravity to cause the water to slump to the bottom of the model and so more water passes through these layers. Figure 9 also shows the temperature profiles after 1 (step 14), 2 (step 18) and 100 (step 34) years of shut-in.

These results are very similar to Case 3 except that the cooled region is larger and the warming times correspondingly increased. A temperature drop of 20 °C still persists 400 metres from the well after 100 years.

5.1.5 Discussion

The thickness of the reservoir plays an important role in the cooling process for the homogeneous model. The models have been constructed in a way that similar overall throughput of injected water reservoir occurs (1 pore volume). The difference in behaviour arises from the volume of cold water injected and the supply of heat from the cap and base rocks. The latter is limited by the thermal conductivity of these rocks. More heat needs to be transported to warm a larger cooled volume and so effective cooling can be seen to increase with reservoir thickness. This heat transfer is limited by the thermal properties of the rocks and so the temperature front advances faster in thicker reservoirs. This also affects the reverse process and makes thick reservoirs slow to warm after injection of cold water ceases. For the examples run, the reservoir persists “cold” for at least a period of one year and more. For very thick reservoirs, the reservoir may remain cold for periods of tens of years.

The rate at which the reservoir warms is dominated by the thermal conductivity and heat capacity of the cap and base rocks. For higher values, the reservoir may warm faster, whilst for lower values, the reservoir will remain cold for even longer.

The cooling of the reservoir may lead to increased viscous pressure drops and hence to a loss of injectivity which might not be recovered for considerable time.

5.2 HETEROGENEOUS MODELS

Heterogeneity affects the transport of water through the reservoir, causing differential cooling. This effect has been investigated using the 30 metre (100 feet) and 152 metre (500 feet) reservoir models. The models used represent coarsening-up and fining-up sands. The permeability distributions used are shown in Figure 10 and Figure 11. The average permeability was again 500 mD. The cases run are listed in Table 4. Each simulation involved injecting one pore volume over a ten year period followed by an extended shut-in.

Table 4: Heterogeneous Simulations Performed

Name	Thickness (metres)	Permeability distribution
Case 5	30 (100 feet)	Figure 10
Case 6	30 (100 feet)	Figure 10
Case 7	30 (100 feet)	Figure 10
Case 8	30 (100 feet)	Figure 10
Case 9	152 (500 feet)	Figure 11
Case 10	152 (500 feet)	Figure 11
Case 11	152 (500 feet)	Figure 11
Case 12	152 (500 feet)	Figure 11

5.2.1 Coarsening-up Sands

The coarsening-up sands have higher permeability at the top of the reservoir. More water flows through these higher permeability layers leading to faster cooling of the top of the formation. Gravity tends to cause water to slump into the lower layers which increases their water throughput and the overall cooling effect. Cooling of the lower layers also occurs due to thermal conduction but this is much less significant than the cooling by the injected water.

For the 30 metre reservoir, this produces temperatures similar to the homogeneous case at distances more than 250 metres from the well as can be seen in Figure 12.

The differential cooling effect is more pronounced for the thicker reservoir model as can be seen in Figure 13. The formation interval is 1830 to 1980 metres. The temperature profile shows distinct cooling of the upper layers and cap rock but the lower 50 metres of the reservoir has hardly been cooled at all. The smaller vertical interval cooled by the injected water allows the temperature front to penetrate further into the reservoir. This effect is due to the greater water throughput at the top of the formation compared to the homogeneous case.

5.2.2 Fining-up Sands

The fining-up sands have lower permeability at the top of the reservoir. More water flows through the bottom layers. This effect is enhanced by gravity segregation of the oil and water.

For the 30 metre reservoir, this produces temperatures similar to the homogeneous case at distances more than 250 metres from the well as can be seen in

Figure 14. This is essentially the same as the corresponding coarsening-up sand models.

The differential cooling effect is more pronounced for the thicker reservoir model as can be seen in Figure 15. The formation interval is 1830 to 1980 metres. The temperature profile shows distinct cooling of the lower layers and base rock but the top 50 metres of the reservoir in noticeably warmer. The smaller vertical interval cooled by the injected water allows the temperature front to penetrate further into the reservoir. This effect is due to the greater water throughput at the bottom of the formation compared to the homogeneous case. This behaviour is essentially a mirror image of the coarsening-up sand models except that gravity reduces the width of the cooled interval.

5.3 DISCUSSION

The reservoir is cooled by the injection of cold water. The degree of cooling primarily depends on how much cold water flows through the rock. The injected water is heated by the formation resulting in a temperature front which travels much more slowly than the water front.

Reservoir heterogeneity, which causes water channelling, may result in deeper penetration of the temperature front. This heterogeneity effect was apparent for both the 30 and 152 metre thick reservoir models. However, heat flow through the formation cools regions of the reservoir unswept by water. Where either the water swept or unswept regions are thin, this results in a fairly homogeneous temperature profile.

As described in Section 4.1, the depth of heat penetration can be estimated as $2\sqrt{\kappa t}$. This formula can be used to estimate reservoir/heterogeneity thicknesses where reservoir cooling may persist. For the examples modelled, the thermal diffusivity is 9.6×10^{-7} m^2/s and the depth of heat penetration is approximately 0.6 metres after 1 day, 11 metres after 1 year, 35 metres after 10 years and 110 metres after 100 years. Thus regions of thickness greater than 10 metres are likely to involve timescales longer than one year during reservoir reheating. Cases 1 and 2 have reservoir thickness less than 10 metres and persistent cooling is essentially limited to the near well region. Cases 3 and 4 are thicker than ten metres and show considerably longer lived temperature effects.

The heat flow through the base and cap rocks is limited by the thermal conductivity of the rock which is unable to transport the greater quantities of heat required to warm the increased injected water flowing through the thicker reservoir models. The reheating of the reservoir is further retarded by the regions of the base and cap rocks which are cooled during injection. Consequently, the cooled reservoir region grows with reservoir thickness for a given water throughput (in pore volumes). The time required to warm the reservoir is also increased.

The convection of cold water is much more effective at cooling the reservoir than conduction as can be seen by the fact that, for all cases considered, the temperature front advances approximately 7 times further into the reservoir than it penetrates into the base or cap rocks.

Similarly, following cessation of water injection, the reservoir is slow to warm. For thin reservoirs significant cooling may persist in the near well region (i.e. less than 140 metres) for at least two years. The size of the cooled region and the time required for it to warm increase with reservoir thickness. For thicker reservoirs, measurable temperature drops may still persist after 100 years.

6 Conclusions

The literature contained little information regarding the duration of reservoir cooling. However, data relating to thermal properties of reservoir rocks has been measured, but mostly in the context of thermal recovery processes such as steamflooding.

Analytic model calculations indicate that the rise in temperature following a period of water injection is very slow and significant cooling may remain for a few years even in very thin reservoir sections of approximately 3 metres. These results have been duplicated using numerical simulation.

The degree of reservoir cooling primarily depends on how much cold water flows through the rock. The injected water is heated by the formation resulting in a temperature front which travels much more slowly than the water front. Reservoir heterogeneity, which causes water channelling, may result in deeper penetration of the temperature front. However, heat conduction through the formation cools adjacent regions of the reservoir largely bypassed by water. Where either the water swept or unswept regions are thin, this results in a fairly homogeneous temperature profile.

The depth of heat penetration can be estimated. This allows the impact of heterogeneity on the temperature distribution to be estimated. For the examples modelled here, regions for which the thickness is greater than 10 metres are likely to have a significant impact on reservoir cooling and reheating. Conversely for thinner reservoir regions, the reservoir cooling is effectively limited to the near well region i.e. less than 200 metres from the well.

The heat conduction through the base and cap rocks is limited by the thermal conductivity of the rock which is unable to transport the greater quantities of heat required to warm the increased injected water flowing through the thicker reservoir models. The reheating of the reservoir is further retarded by the regions of the base and cap rocks which are cooled during injection. Consequently, the cooled reservoir region grows with reservoir thickness for a given water throughput (in hydrocarbon pore volumes). The time required to warm the reservoir is also increased.

The convection of cold water is more effective at cooling the reservoir than conduction as can be seen by the fact that, for all cases run, the temperature front advances approximately 7 times further into the reservoir than it penetrates into the base or cap rocks.

Following cessation of water injection, the reservoir is slow to warm. Even for thin reservoirs (~ 3 metres) significant cooling may persist in the near well region for at least two years. The size of the cooled region and the time required for it to warm increase with reservoir thickness. For thicker reservoirs, measurable temperature drops may still persist after 100 years.

This report shows that the persistent nature of reservoir cooling caused by the injection of cold water should not be a surprise. Such effects could be expected for a reservoir where an interval of 10 metres or more has been cooled by injected water.

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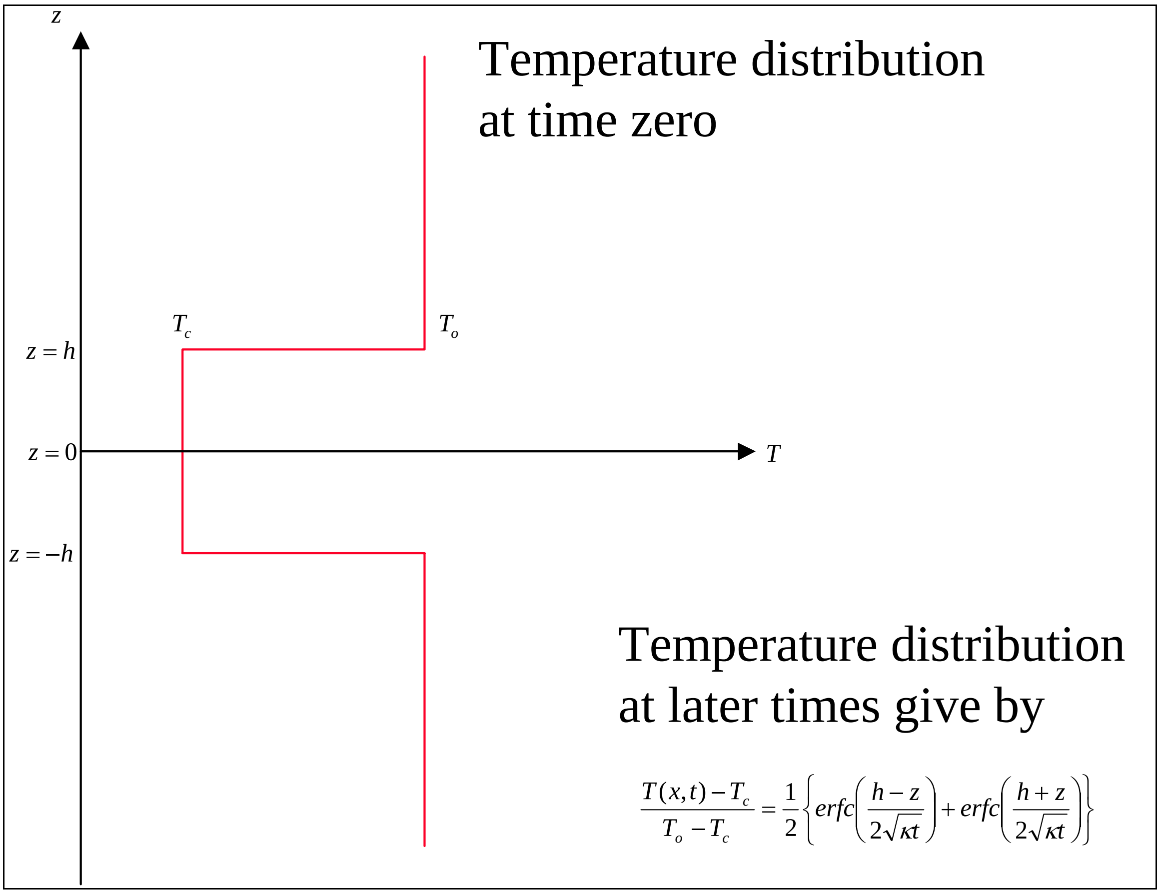

Figure 1: Initial Temperature Distribution in Analytic Model

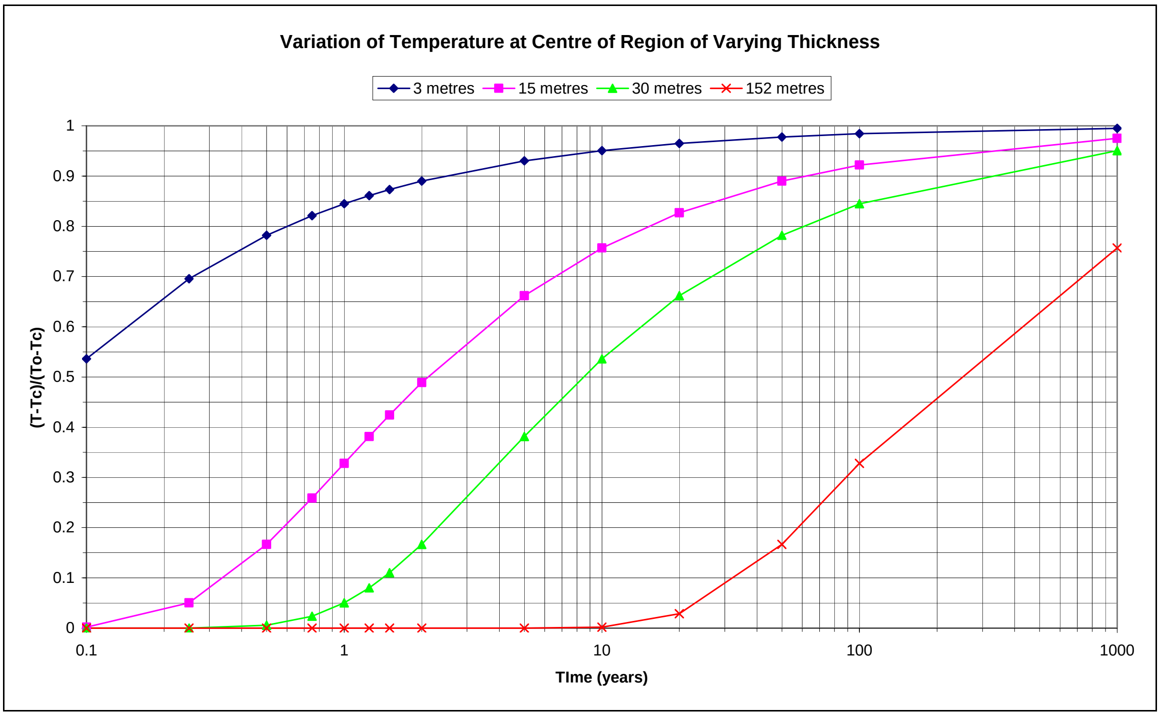

Figure 2: Analytic Prediction of Variation of Temperature with Time at the Centre of Reservoir

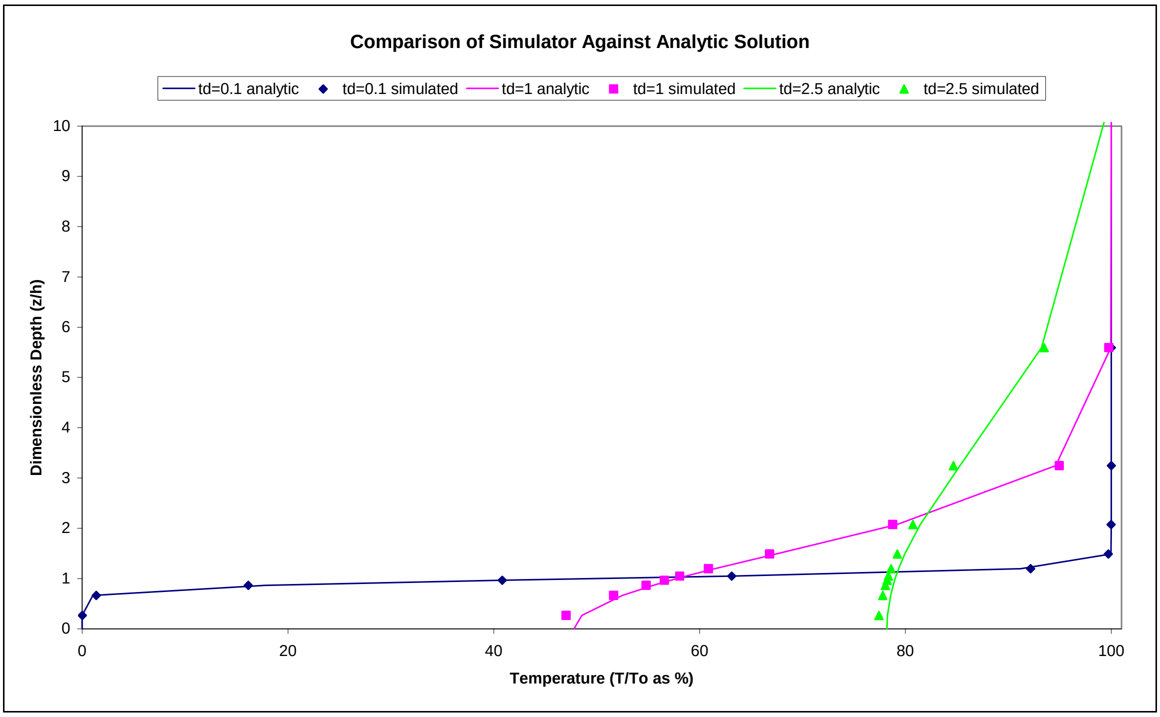

Figure 3: Comparison of Analytic and Simulated Solutions

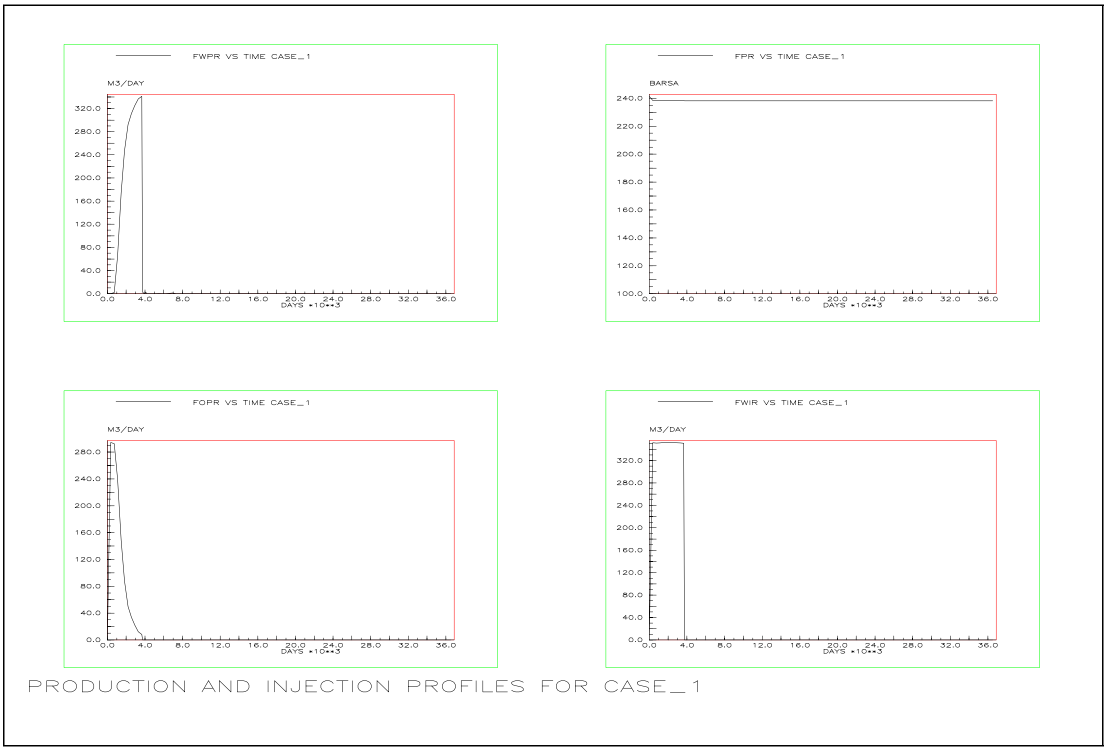

Figure 4: Production and Injection Profiles - Case 1

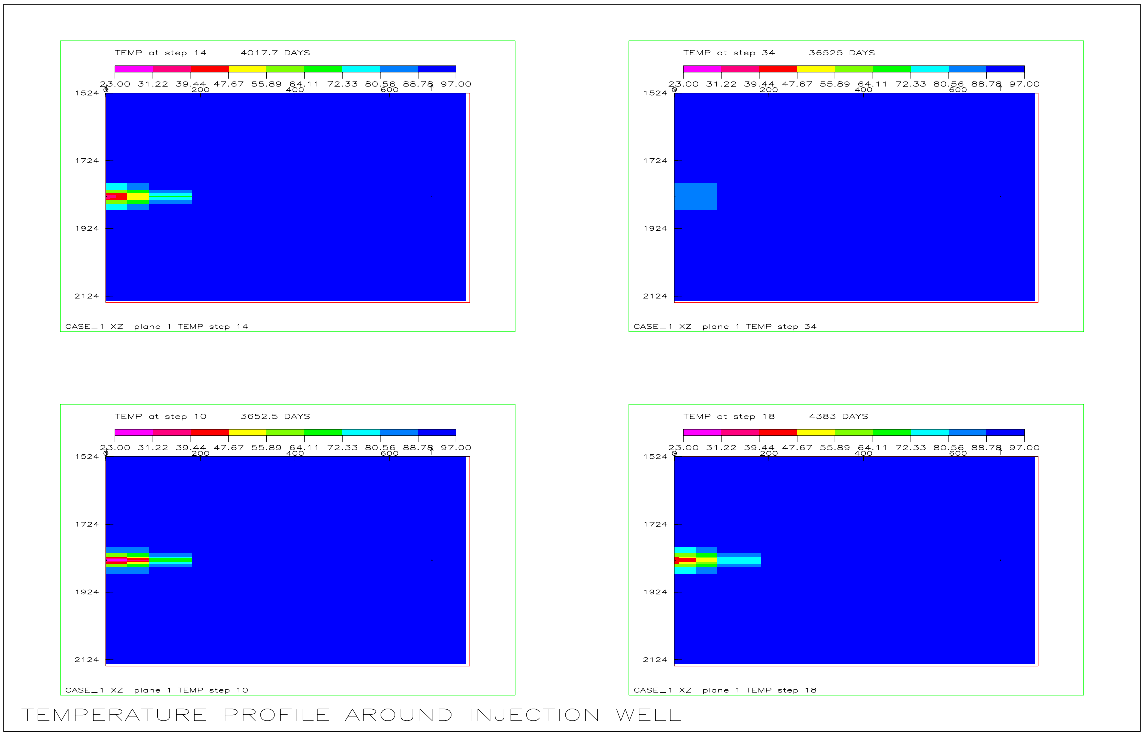

Figure 5: Temperature Profile Around Injection Well - Case 1:

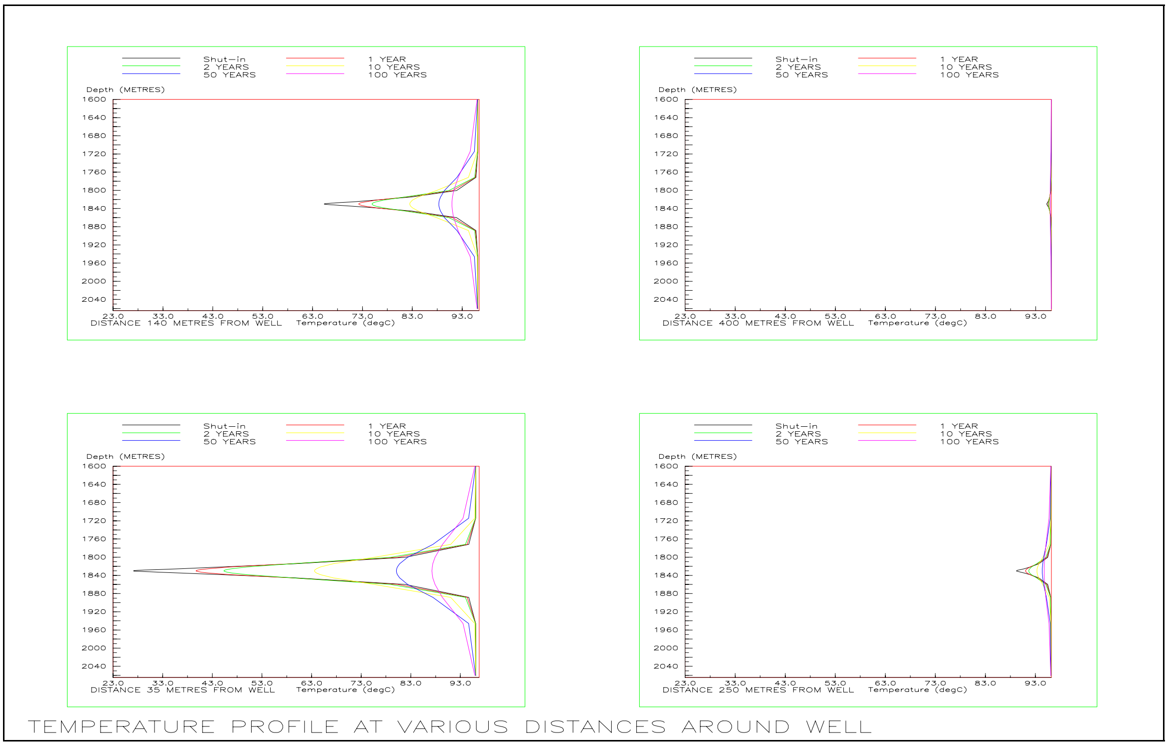

Figure 6: Temperature Profile Through Formation - Case 1

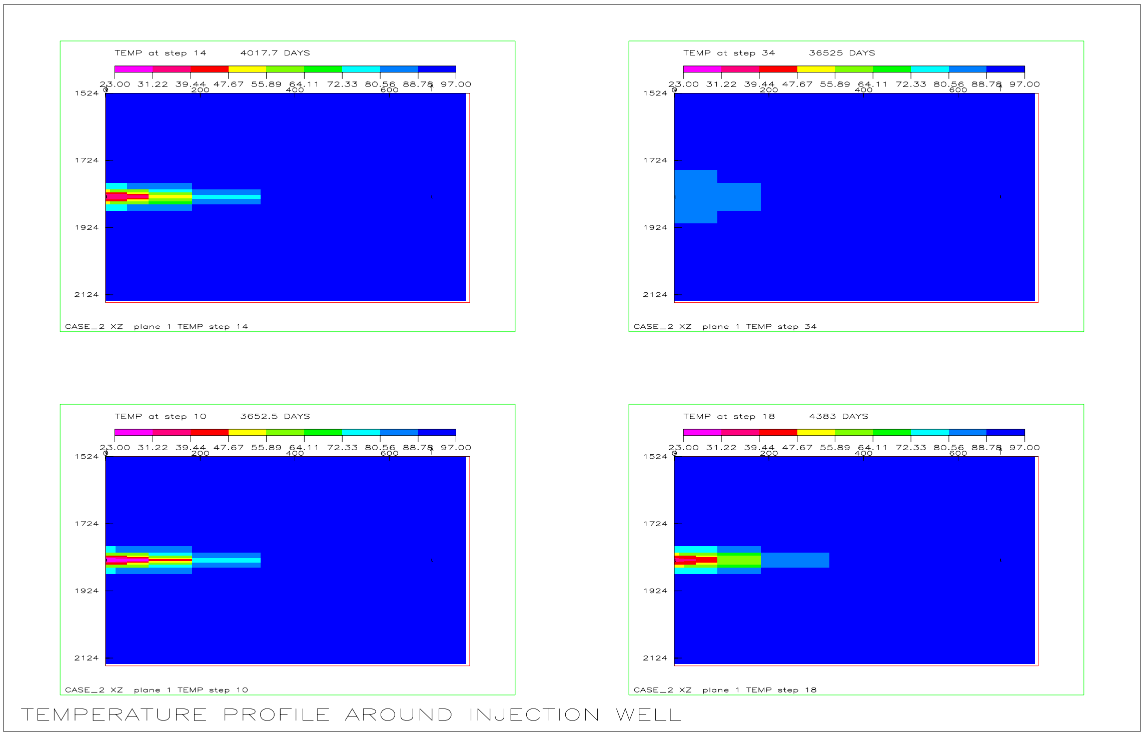

Figure 7: Temperature Profile Around Well - Case 2

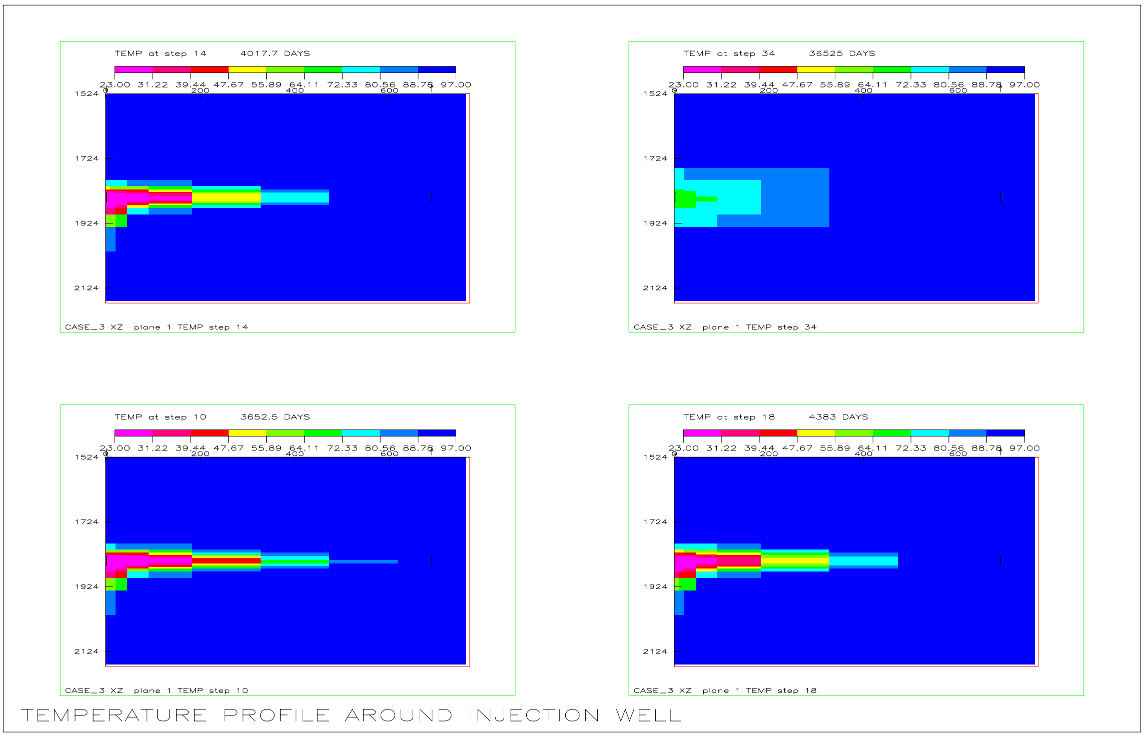

Figure 8: Temperature Profile Around Well - Case 3

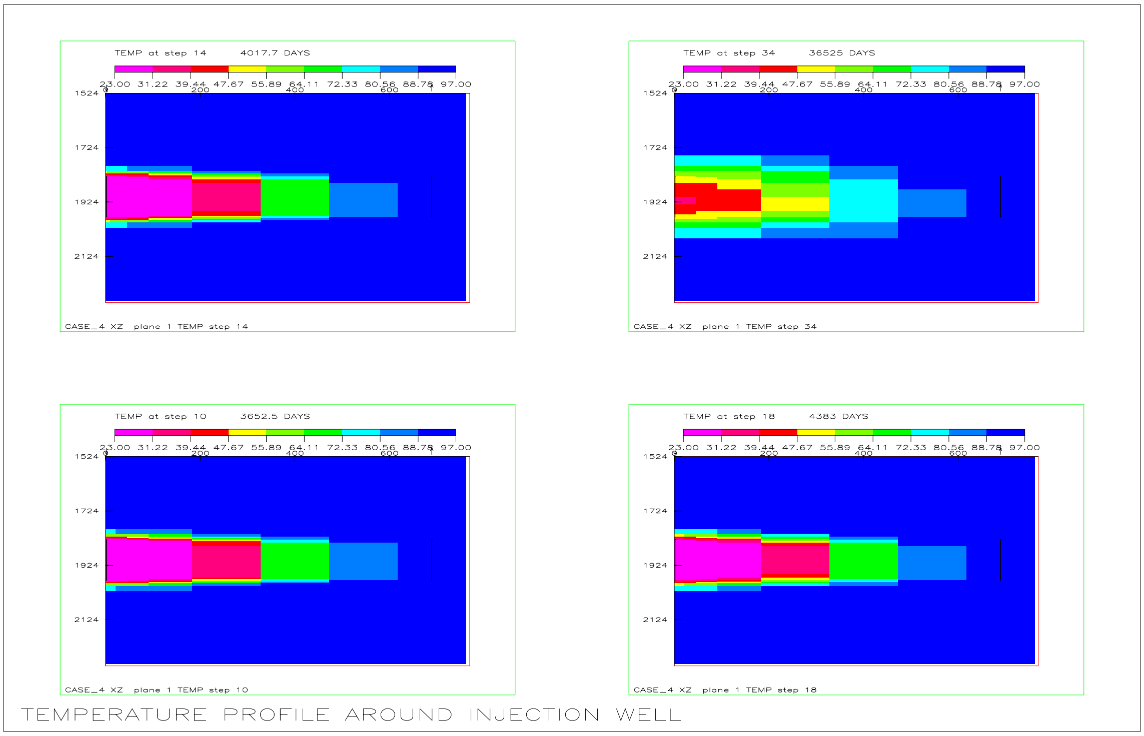

Figure 9: Temperature Profile Around Well - Case 4

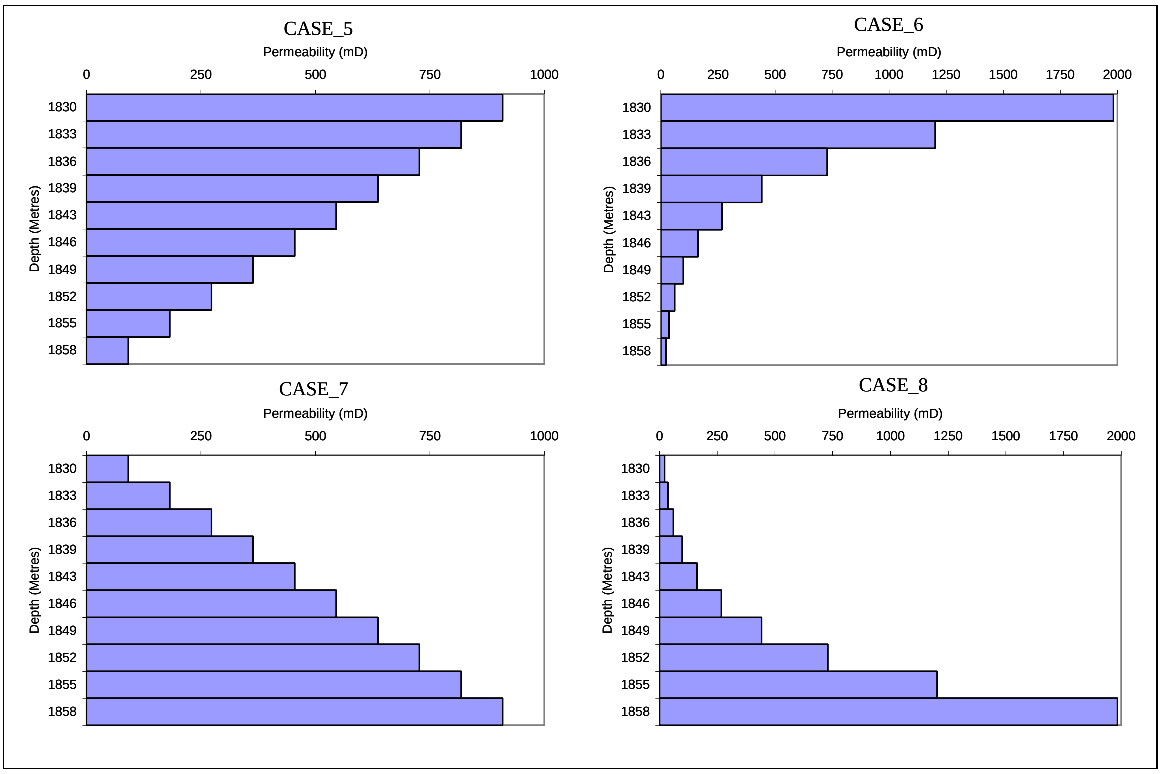

Figure 10: Permeability Distributions for Heterogeneous Cases with Reservoir Thickness of 30 metres (100 feet)

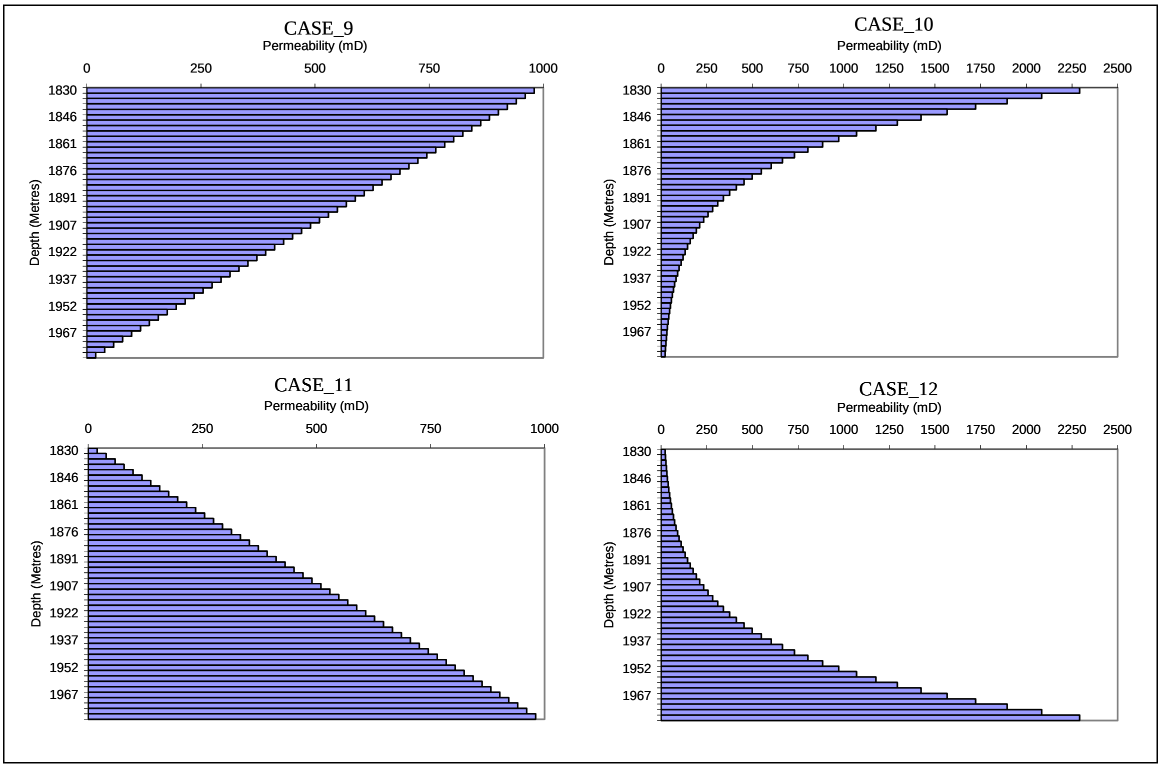

Figure 11: Permeability Distributions for Heterogeneous Cases with Reservoir Thickness of 152 metres (500 feet)

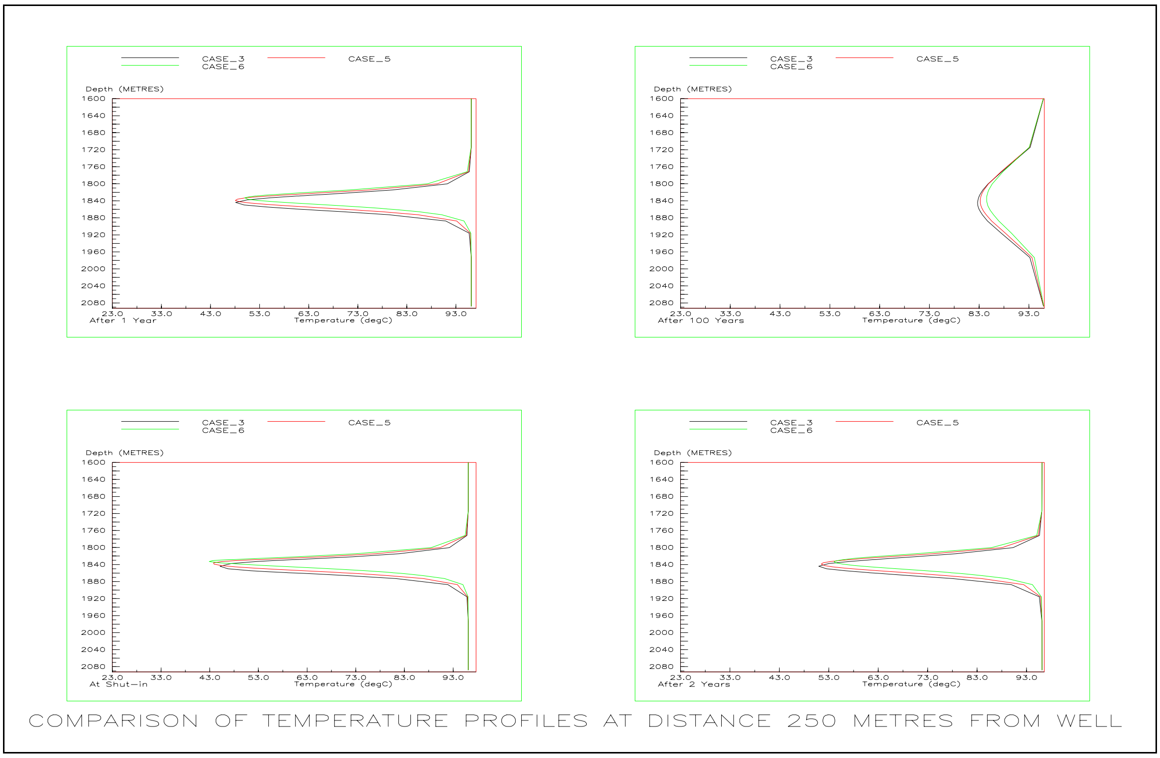

Figure 12: Comparison of Homogeneous and Coarsening-up Temperature Profiles - 30 metre Reservoir

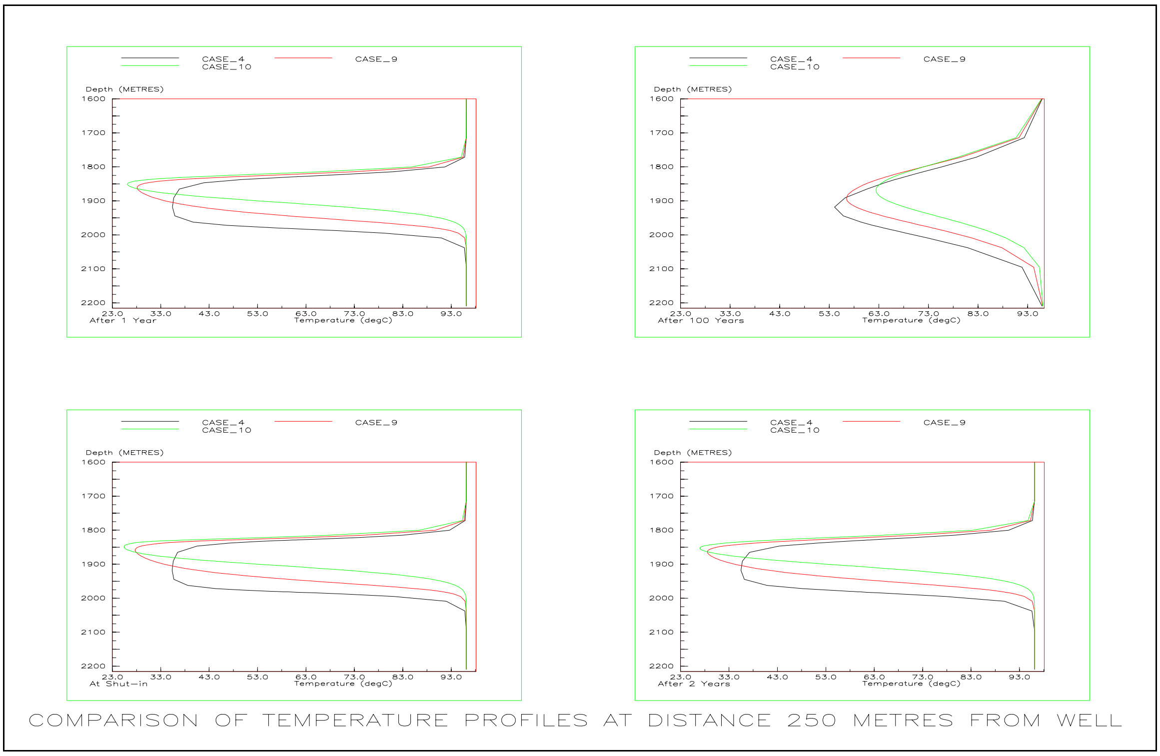

Figure 13: Comparison of Homogeneous and Coarsening-up Temperature Profiles - 152 metre Reservoir

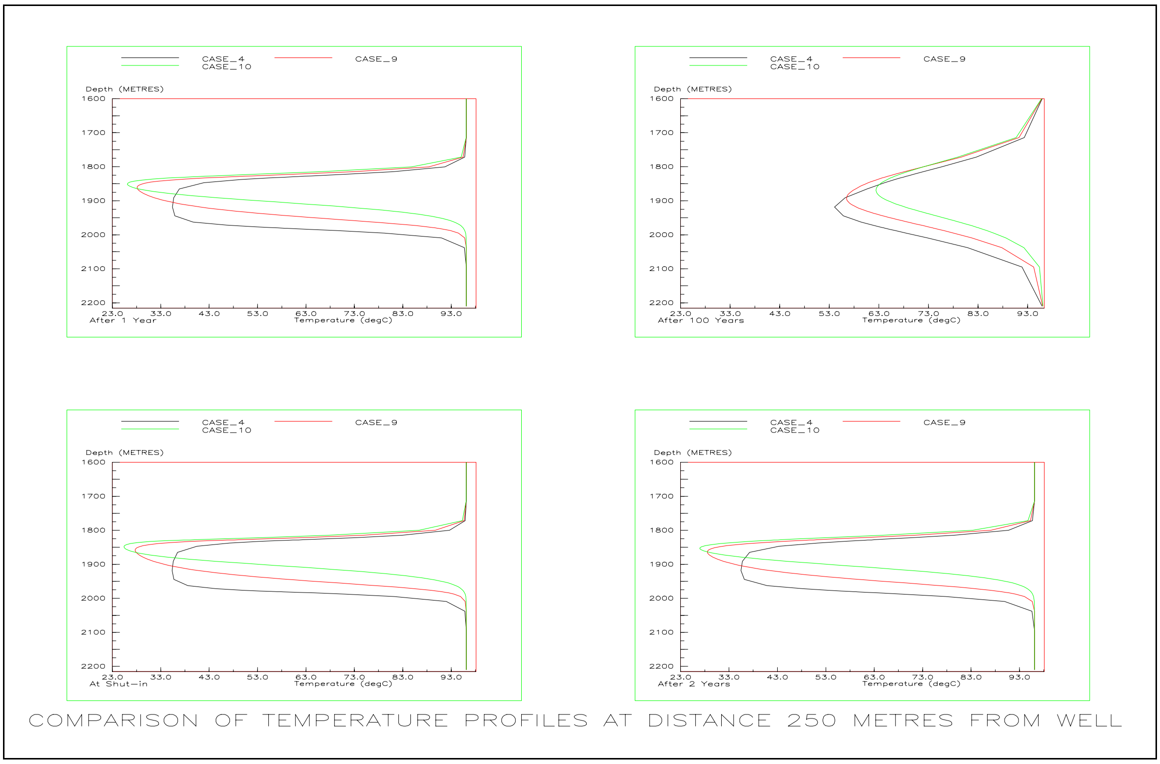

Figure 14: Comparison of Homogeneous and Fining-up Temperature Profiles - 30 metre Reservoir

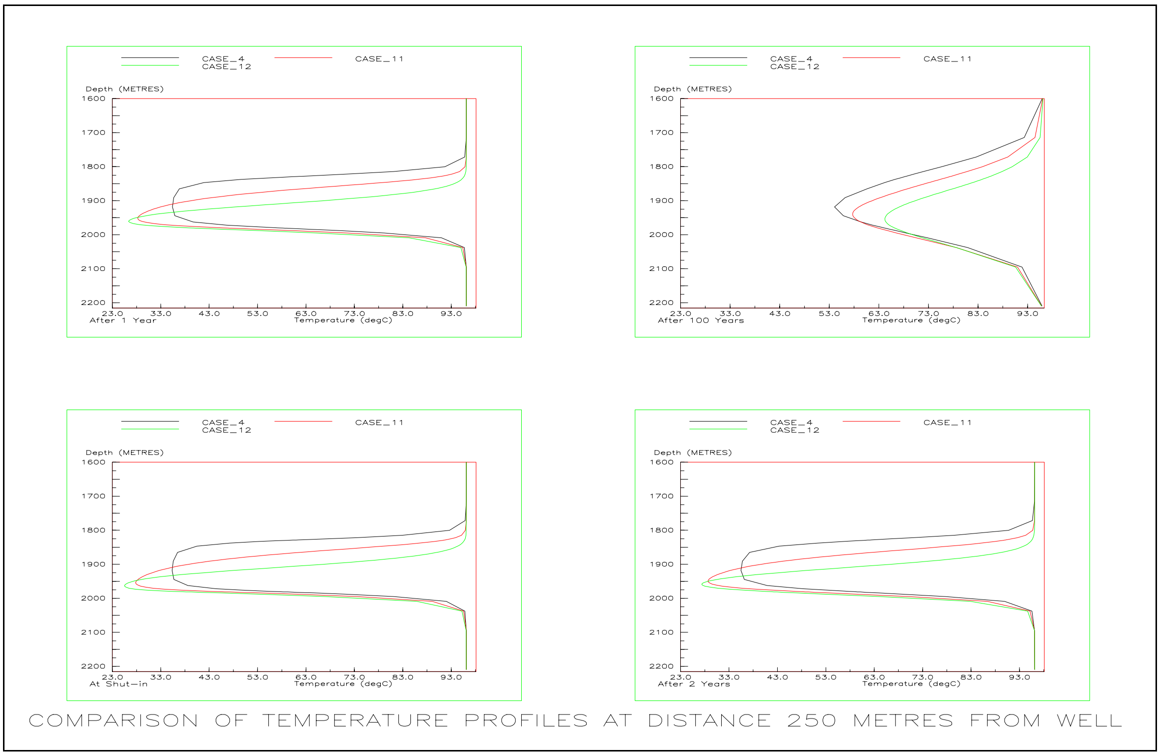

Figure 15: Comparison of Homogeneous and Fining-up Temperature Profiles - 152 metre Reservoir