Reinjection Scheme in Momotombo, Nicaragua, on the Basis of Reservoir Pressure Monitoring, Tracer Test Analysis and Numerical Modeling Study

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Momotombo, tracer test, reinjection, Nicaragua, numerical modeling

ABSTRACT

Reinjecting separated water back into the formation is one of the most important tasks for field management in the Momotombo geothermal field. A reinjection scheme has been operated in Momotombo since 1983. Most of the separated water, however, had been discharged to Managua Lake until 1999. The reinjection scheme was developed on the basis of the results of reservoir pressure monitoring, tracer test analysis and numerical simulation studies. Then improved reinjection scheme was initiated by Ormat in 1999. Tracer test analysis suggests that the southeastern part of the well field where reinjection wells locate is the most suitable area for injection. Shallow reinjection well RMT15 is strongly connected to the production zone, and thus cooling of the production zone due to injection in this well is expected. Numerical simulation studies suggests that steam production and enthalpy of the produced fluid in most of the production wells decline quickly by increasing steam production and injection rate in Well RMT15. If brine production increases, reinjection in RMT15 must be stopped and brine must be injected to the southeastern part of the field.

1. Introduction

The Momotombo area was started for power generation in 1983 with an installed capacity of 35 MWe. Six years later, in 1989, another 35 MWe unit was commissioned. An organic Rankine cycle Ormat® Energy Converter (OEC) unit was commissioned in 2002 with 7 MWe installed capacity increasing the total installed capacity to 77 MWe. At present, power output of the plant is only 35 MWe as of 2007, far below the installed capacity. The output, however, supplies about 10% of the total consumption of electricity in Nicaragua. Insufficient steam production is mainly due to decline in well productivity caused by either temperature and pressure drops of reservoir or scaling in wellbore and reservoir.

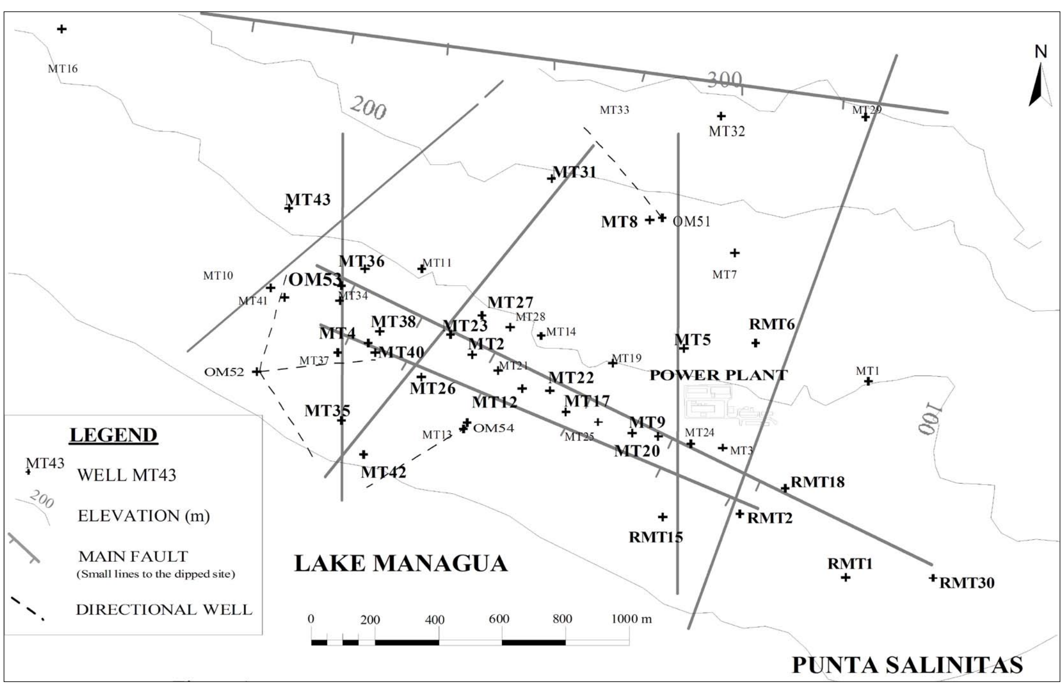

Figure 1.

Rehabilitation project was started in 1999 as a 15 year Concession, when the power output dropped down to 9 MWe. In this project, Ormat drilled additional four production wells, and implemented a full reinjection scheme for maintaining reservoir pressure. The results, however, were unsuccessful. As an alternative, Ormat installed a bottoming OEC to increase output. Total investment by Ormat reached about US$ 40 Million and resulted in an electricity cost lower than US5.22 cents/kWh. This makes the Momotombo plant the lowest cost electricity producer in Nicaragua.

2. Reinjection History at Momotombo

Forty-seven wells in total have been drilled within the area of about 2 km^2 in Momotombo. Separated water has been reinjected into the reservoir since the start of development, but the scheme has been changed in terms of the magnitude of the amount of reinjection as well as reinjection water temperature.

Locations of wells and main faults are indicated in Figure 1 with names that start with R such as RMT15. Reinjection wells are located mainly in the eastern part of the well field. Wells have different injection capacity: RMT6 and RMT15 have the largest ones, exceeding 450 t/h whereas wells RMT1, 2 and 30 the lowest such as below 100 t/h.

A reinjection system has been operating in Momotombo since 1983. The separated water has been sent to the wells either pressurized by pump or as gravitational flow. Before commissioning the 7 MWe OEC unit, temperature of reinjected water was originally 170°C, but it has gradually decreased to 155°C in 2003.

Figure 2 presents the histories of reinjection and separated waters at Momotombo. As can be seen, between 12% and 30% of the separated water was reinjected between 1984 and 1996. Reinjection rate has been increased to more than 90% of the separated water after 1999. This difference becomes even smaller in 2003 and 2004 when most of the separated water had been reinjected. In 2002 all production wells were connected to the reinjection system and two reinjection wells, RMT1 and RMT30, were connected to the system in early 2003 as reinjection capacity of wells became insufficient.

The rehabilitation program mentioned above also includes reinjecting 100% of the separated water for some pressure support from the 7 MWe OEC was commissioned in 2002, using brine which was disposed for years to Lake Managua. This brine cools down as it flows through the vaporizers of the OEC from 155ºC to 100ºC before being reinjected.

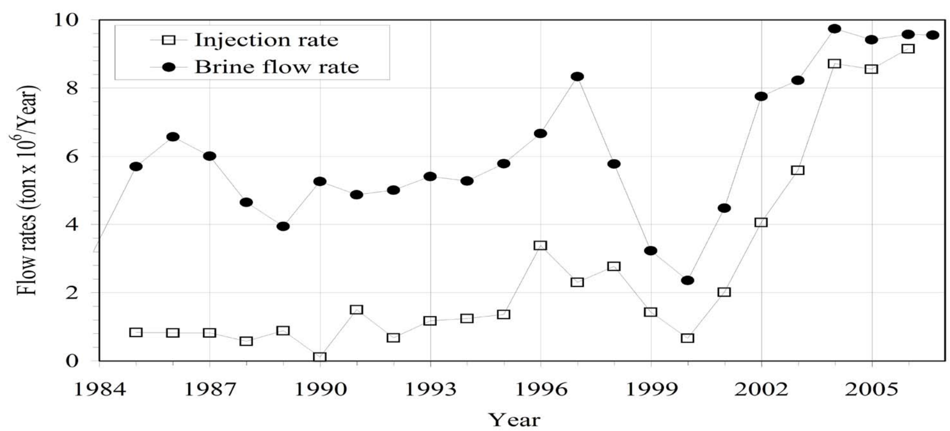

Figure 2.

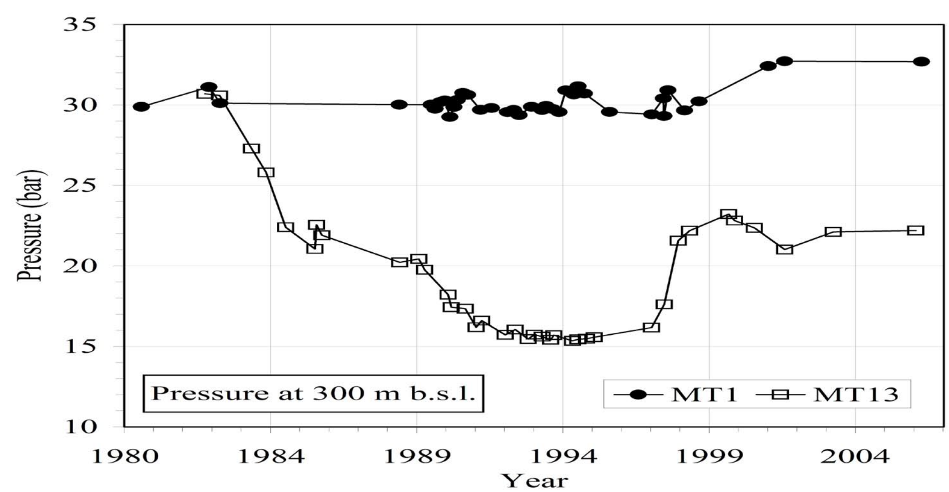

Figure 3.

3. Pressure Drawdown

Down hole pressure histories of two wells, MT1 and MT13, are presented in Figure 3. A shallow well MT13 located in the center of the production zone (Figure 1), and then may represent the pressure of the shallow reservoir. Well MT1 is located in the eastern part of the well field near the reinjection area.

Total pressure drawdown in Well MT13 reaches about 20 bar in 20 years. Relatively constant pressure of 16 bar between 1989 and 1996 implies that two-phase zone was formed in the shallow reservoir during this period and supported by discharged fluids of high specific enthalpy at shallow wells such as MT12 and MT20 located near MT13 (Porras, 2005).

Pressure history for Well MT1 is relatively constant throughout the measurement period implying that Well MT1 does not receive any pressure drawdown due to production. However, there is a pressure decline and a gradual recovery between 1996 and 1998 that may correspond to a decrease in reinjection rate at nearby wells suggesting a good hydrological communication.

4. Tracer Test

Two tracer tests were conducted to identify hydrological flow paths and the

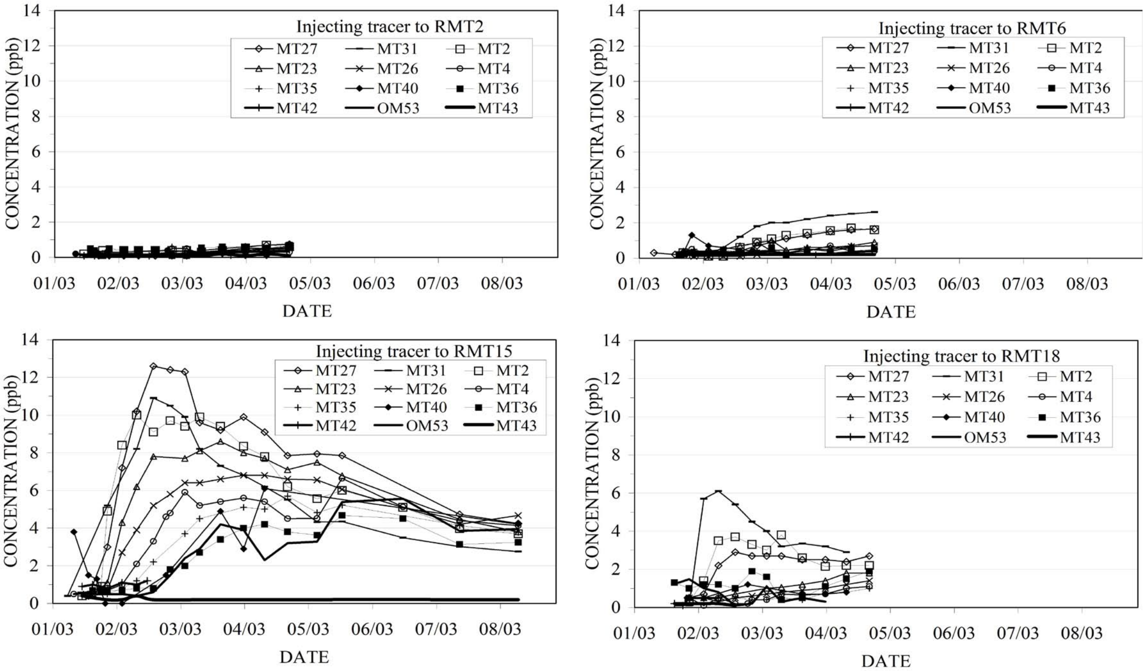

Figure 4.

rate of return prior to installation of the OEC. During the first test, tracer solution of 10wt% of 2,6 Naphthalene Disulfonate Acid was pumped into Well RMT15 on November 1st, 2002. Produced fluids were sampled with intervals of a declining frequency such that two samples/day to 1 sample/week. Fluids were collected at 12 production wells (MT2, 4, 23, 26, 27, 31, 35, 36, 40, 42, 43 and 53) over a period of 205 days. Figure 4 shows tracer concentrations at production wells in the second test.

The figure shows that tracer injected in Well RMT2 was not detected in any production well during the test. Tracer injected in Well RMT6 was detected in Wells MT31, 2 and 27 with maximum concentration in Well MT31. On the other hand, tracer from Well RMT15 was found in all production wells except MT43 and the highest peak concentrations were obtained at production wells MT27, 31, 2 and 23. The earliest first arrival can be seen in Well MT31 where the tracer arrived less than ten days after tracer injection. Peak concentrations appear in the time range from 32 to 127 days when tracer was injected at RMT15. Tracer injected in Well RMT18 was also detected in production wells at the second highest peak concentration after after the detection of the tracer injected in RMT15. The tracer injected in RMT18 first arrived in Well MT31 four days after injection, and the highest concentrations were measured in Well MT31 followed by the concentrations in MT2 and MT27.

The tracer test analysis reveals that there present flow channels connecting reinjection wells RMT15 and RMT18 with the main production zone of RMT15 which is better connected than RMT18. Continuous reservoir pressure monitoring suggests that spontaneous pressure response exist in well MT13 (Figure 1) when injecting brine in Well RMT15, on the other hand, pressure response is not clearly detected when injecting in Well RMT18.

TRINV and TRCOOL (Axelsson et al., 1995) computer software were used to estimate reservoir parameters and temperature predictions respectively for Wells MT27 and OM53. Figure 5 shows comparison of observed and calculated concentrations in wells MT27 and OM53 during the first tracer test and Table 1 summarizes the analyzed results. We can say that the magnitude of the estimated volumes of flow channel are relatively large compared with those of other geothermal fields, for example Ahuachapan (Axelsson et al., 2005). The dispersivity values appear reasonable suggesting that the fluid flow within the Momotombo reservoir can be a flow along sedimentary layers rather than along narrow fractures. Results also suggest that less than 10% of injected water into RMT15 was recovered in Well MT27 during the first tracer test, and less that 5% in Well OM53 .

Two prediction scenarios were considered for cooling analysis, 1) here we simulate a flowpath along a permeable layer with a rectangular cross-sectional area. This optimistic scenario is for well doublet MT27 and RMT15. It assumes injection into a flow channel embedded in an average rock temperature of 180ºC and 90ºC injected water with two possibilities, one having a thin layer (2 m thick) and wide flow channel, and a second possibility with a 16 m x 16 m cross-sectional area. 2) this assumes a simple model of the field as a whole, which is considered as a pessimistic model that takes into consideration a sedimentary layer of 800 m long that is approximately the distance between production and injection wells, 600 m

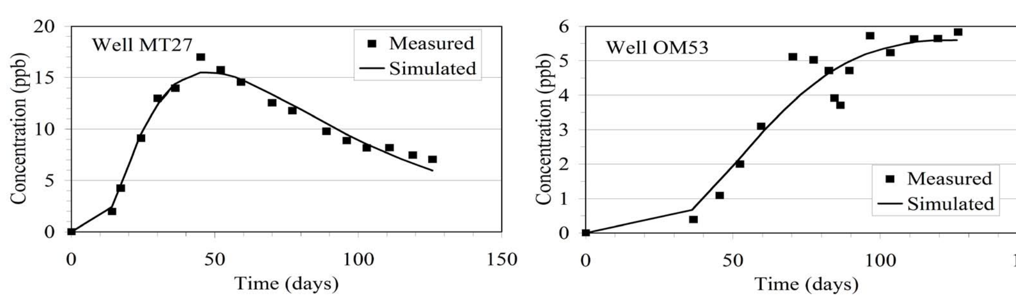

Figure 5.

wide and 100 m thick with 20% porosity. A heat flow is also considered from 180ºC hot rock below. The injection rate is given as 270 kg/s at 90ºC and a production rate is given as 360 kg/s. Figure 6 presents the results of the simulations for Case 1) with the two possibilities. Figure 6 shows the cooling effects are significant for the case of a rectangular flow channel of a transversal area of 16 m x 16 m. Mixture temperature drops from 180ºC to 161ºC in less than 10 years. Figure 7 shows simulation results for Case 2 where temperature drops from 180ºC to 120ºC in less than a year starting to decline about two years after injection started.

Table 1.

Well	Distance from Well RMT15 x (m)	Water flow rate (kg/s)	Flow channel volume, xAϕ (m^3)	Dispersivity, α_L (m)	Flow ratio (%)
MT27	850	61	45,000	220	8.5
OM53	1200	29	46,000	270	3.4

A: average cross-sectional area of the flow channel (m^2)
ϕ: flow-channel porosity
α_L: Longitudinal dispersivity of the channel (m)

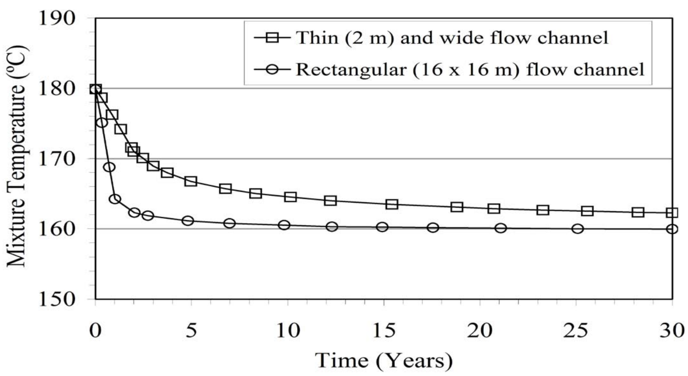

Figure 6.

5. Numerical Modeling Study

A three-dimensional, porous-medium, numerical model was developed for the liquid-dominated Momotombo geothermal reservoir. The model has a rectangular prism 13.8 km long, 9.4 km wide and 3 km deep with nine horizontal layers ranging in thickness between 150 and 1000 m. The boundary conditions at the top of the model are specified using an infinitely large boundary saturated with water at 1 bar and 15°C, the model assumes inflow of low-temperature groundwater from the east, and high- temperature mass recharge at depth (below 3000 m b.s.l), other lateral boundaries are given as close for heat and mass.

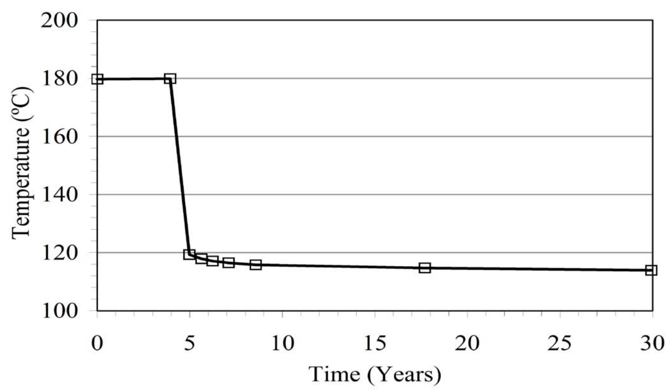

Figure 7.

The natural-state model was calibrated by matching the temperature profiles of 31 wells and initial reservoir pressures at the main feed zones for five selected wells. Twenty-one years of production and reinjection data were used in history matching. The iTOUGH2 simulator (Finsterle, 1999) was utilized in the natural-state and the history-matching simulations. The AUTOUGH2 code (O'Sullivan, 2000) was used to for predictions scenarios directed mainly at evaluating the effects of the reinjection on production zones, and at maintaining steam production. Two of the scenarios, I and II, have as objective to investigate the effects of increasing steam production and injection rate.

In scenario I the production and reinjection scheme as of 2004 is maintained, when ten wells were producing steam and four wells were used for injecting brine at 100ºC. For scenario II, it is assumed that steam production is increased in four shallow production wells and three new wells are drilled and put on-line. Reinjection amount for this scenario increases with production, with the result that the injection rate into Well RMT15 is higher than in Scenario I since it is assumed that no new reinjection well will be drilled.

The results for the two scenarios (i.e. computed specific enthalpy and steam flow rate for Well MT23) are presented in Figure 8. Well MT23 is located in the center of the well field with its feed zone at 850 m b.s.l. (Figure 1). Figure shows that simulated specific enthalpy decreases with time for the two scenarios, with a faster decline for scenario II, which is due to a decrease in the temperature of the grid block containing the feedzone of Well MT23 (Figure 8). The lower temperature results in a drop in steam production rate. The faster decrease in temperature and produced fluid enthalpy in scenario II is related to its injection scheme (short distance to production area and high injection rates).

6. Conclusions

On the basis of this work we concluded:

1) A reinjection system has been operating in Momotombo since 1983; however it was from 1999 that the percentage of brine mass injected back into formation started to increase and as currently more than 96% of the produced brine is being injected.
2) Reservoir pressure monitoring data suggest that the southeastern part of the well field is not hydraulically connected to the production zone.
3) Tracer test analysis revealed that flow channels present and connect between reinjection well RMT15 and the main production zone. Therefore, if cooling effects due to injection are detected in production wells, it is most probably

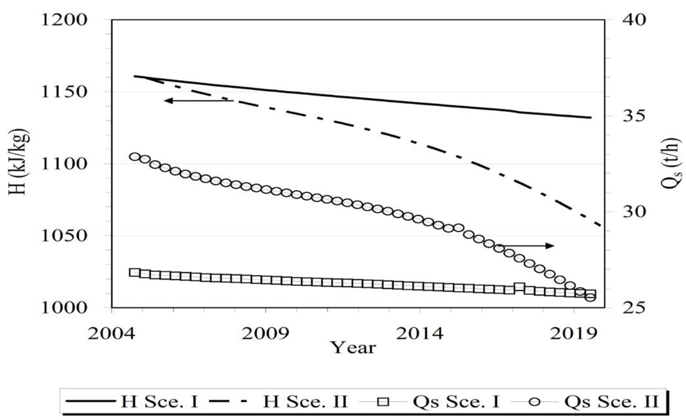

Figure 8.

due to reinjection operation at Well RMT15. Reinjection wells located to the eastern edge of the field are most suitable for injection without causing any significant cooling in production wells.

4) Based on a cooling analysis using the results of tracer tests, temperature drop ranges from 20ºC in 10 years to 60ºC within a year.

5) Numerical simulation studies for predicting reservoir performances suggest that increases both in steam production and injection rates using production and reinjection scheme as for 2004 lead to decreases in steam rate and enthalpy of produced fluid from most of the production wells.

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