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Quantification of Injection Fluids Effects to Mindanao Geothermal Production Field Productivity Through a Series of Tracer Tests, Philippines

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ABSTRACT

Tracer tests using napthtalene disulfonates were conducted in Mindanao Geothermal Production Field, Philippines in 2003 and 2006 to describe the extent of the re-injection fluids encroachment to the production sector and to quantify its effects to well-to-well performance and over-all field productivity. Brine fluids injected since late 1999 in Matingao and Kullay injection sinks were already observed in the Marbel production sector. Modeling was done to predict the effects of RI fluids in terms of output and temperature declines in each production wells using the Icebox® software package comprising of three sub-programs: TRMASS, TRINV and TRCOOL. Majority of the production wells drilled in this sector indicated positive tracer response with % tracer recovery ranging from 2% to as high as 40%. Well SK2D, APO3D, APO1D, and SP4D are wells identified that have significant RI fractions in their discharges that amounts to 0.41, 0.45, 0.21 and 0.186, respectively. These substantial amounts of injected fluid could lead to significant decrease in production temperature ranging from 13°C to as high as 39°C. The timing of the temperature decline (thermal breakthrough) is highly dependent in the matrix porosity which could be as early as 2 years (porosity = 60 %) or as long as 15 years (porosity = 5 %) in the case of SK2D. The declines in production temperatures were translated to loss in steam flow in each wells and the steam availability was recalculated to determine the impact. The re-injection fluids are being channelled mainly by the major faults identified in the geothermal field (mostly NW trending faults). The steam availability of the field has an average decline rate of 0.8 kg/month which is solely attributed to reservoir cooling. Changes in the reservoir management were implemented following the integrated information obtained from the tracer tests and geochemical monitoring of production wells resulting to thermal recovery of the Marbel production sector and sustained overall Mindanao field productivity.

1. INTRODUCTION

Mindanao Geothermal Production (MGP) field is geographically divided into three sectors from the northwest to southeast, namely: Kullay-Matingao, Marbel and Sandawa. Steam is produced from Marbel and the Sandawa sectors. There are three injection sinks in the field, namely: Kullay Matingao and Kanlas (Figure 1).

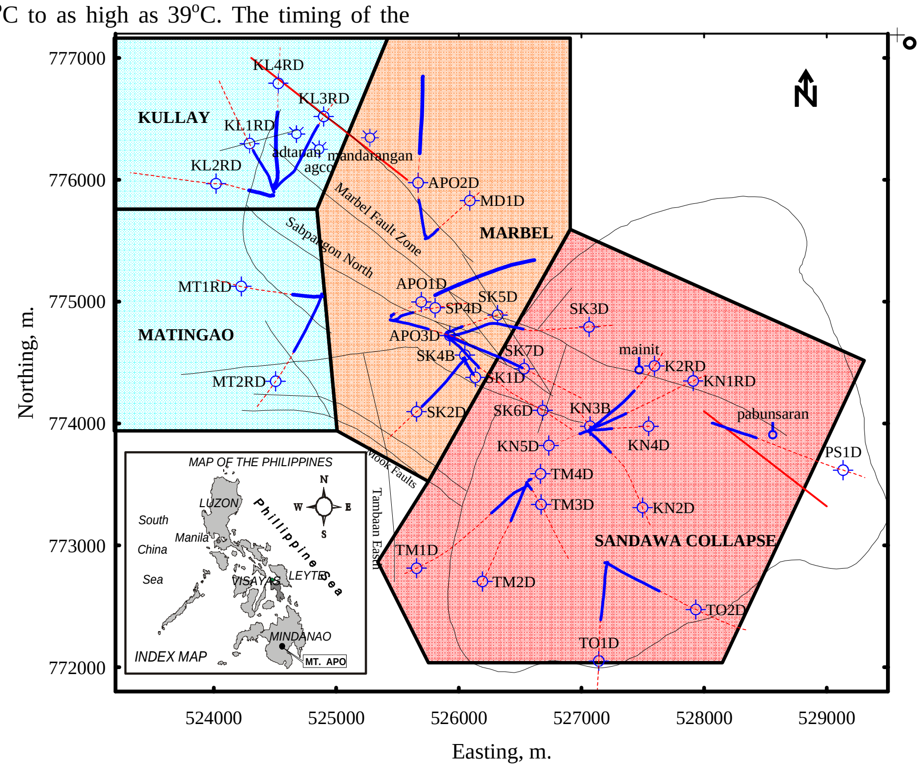

Figure 1: Map of Mindanao geothermal production field (MGPF) showing the geographical boundaries. Philippine map (insert) shows the regional location of the geothermal project (Mt. Apo)

Commercial production began two-fold with Mindanao-1 (M1) in 1997 and followed by Mindanao-2 (M2) in 1999. M1 draws steam from the Marbel sector and M2 from the Sandawa sector. Geochemical monitoring of the well discharges after nearly a year of production in M1 indicated that injection returns were affecting Marbel sector. Two tracer tests were conducted to establish injection breakthrough from well MT2RD.

The first and second tracer tests used ~20 kg of sodium flourescein dye in March 1998 and 1 curie of I131 in December 1998. The results of these tests are discussed in the reports of Malate *et al.* (1999) and Delfin *et al.* (1999).

In 2003 and 2006, tracer tests were conducted following marked geochemical changes in the well discharges. The tracer tests involved injection of naphthalene disulfonate/tri-substituted sulfonate (NDS/NTS) in injection wells located in Kullay, Matingao and Sandawa to define the transit time, volume or mass of injection returns, and verify structural connections to the production sectors. The tracer data were used to evaluate the effects of injection returns to the sustainability and management of the production field.

The 2003 tracer tests were conducted in two wells by injecting NDS-A into MT2RD on March 28, 2003 and NDS-C into KL1RD on April 8, 2003. Subsequently in October 2006, NDS-B and NTS were injected into MT1RD and KL4RD, respectively, and NDS-D into KN2RD, an injection well within Sandawa production sector. The tracer tests essentially evaluate the injected fluids coming from Matingao and Kullay due to high brine load injection into these sectors. This report presents an update of the tracer tests conducted in the Mindanao Geothermal Production Field. Nogara (2004) discussed the procedure and the preliminary results of NDS-A tracer to well SK2D.

2. STRUCTURAL CORRELATION

Detailed structural assessment by Pioquinto (1997) established that there are several structural routes connecting Matingao and Kullay injection sinks to the Marbel production sector. Even prior to commercial operation of the field, these geologic structures were inferred conduits of cooler in-situ fluids from these two sectors which showed temperature reversals in some of the production wells. Through time, injected fluids gradually displaced these cool fluids with continuous injection. The preferential flow of the injection fluids from Matingao and Kullay was further enhanced due to high extraction rate concentrated at the Marbel production sector since majority of the production wells (mostly with high total mass flow, e.g. APO3D, SK2D and SP4D were drilled and produce from this region (Figure 2).

The structures tabulated in Table 1 are used as the basis in determining the injection or tracer flow paths from the Matingao and Kullay injection sectors to Marbel and Sandawa production sectors. Figure 3 shows the detailed surface structural interconnections across the Mt. Apo geothermal field including welltrack location of the production and injection wells.

The probable route and structures included are identified using the following hierarchical criteria: 1) direct and shortest structural connection, 2) interconnection of faults, 3) average breakthrough time of tracer which is directly correlated to tracer concentration and 4) the location of major and minor feed zones within the respective wells.

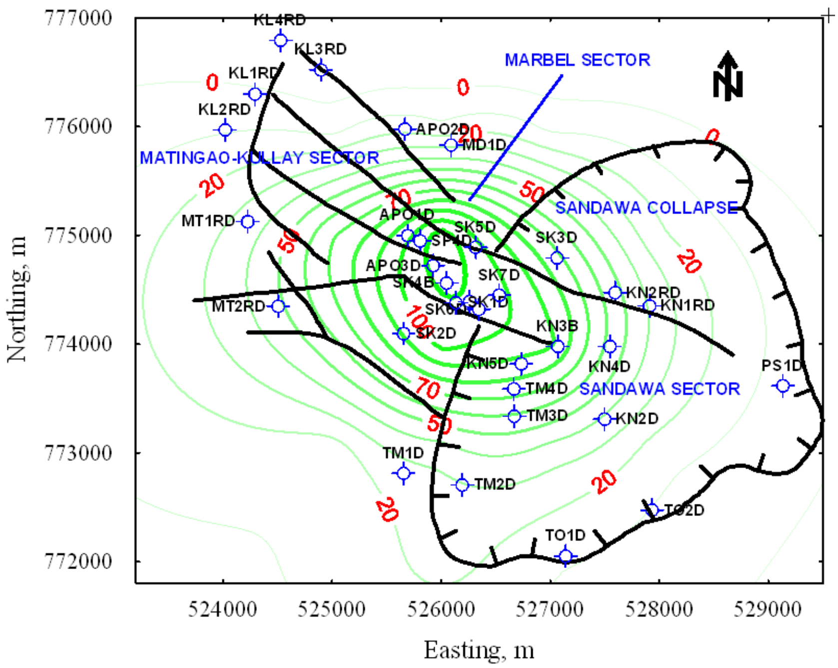

Figure 2: Iso-contour of mass extraction rate (kg/s-km2) in MGPF using 2 x 2 km grid

Table 1. Faults intersected by injection wells used in injecting the NDS tracers and production wells that showed positive response to the tracers. Depths of intersection including feed zones are referred to meter reduced sea level (mRSL) unless otherwise specified.

MGPF Wells	Structures Encountered	Depth, mRSL	Feed zone/s Depth, mRSL
Production Wells			
APO1D	Matingao Collapse	675 to 275	Feed Zone: 150
	Sabpangon North	450 to 400	
	Kanlas West	150 to 100	
APO2D	Mandarangan North	350 to 225	Feed zone: 300
APO3D	Matingao South	475 to 375	Feed zone: 275
	Sabpangon North	325 to 275	
	Sabpangon Central	225 to 150	
SP4D	Sabpangon North	675 to 425	Feed zone: 400
	Kanlas West	200 to 175	
SK1D	Sabpangon South	875 to 750	Feed zone: 775
SK2D	Sabpangon South	900 to 775	Major zone: 300
	Sungko	275 to 125	Minor zone: 100
	Mook East	75 to 0	
SK3D	Marbel Fault Zone	025 to -200	Feed zone: -500
	Sinupa Fault	-225 to -500	
	Sinupa South	-225 to -500	
	Little Apo Fault	-525 to -550	
SK4B	Sabpangon South	325 to 125	Feed zone: 300
SK5D	Sabpangon North	775 to 770	Feed zone: 400
	Kanlas West	700 to 675	
	Kanlas North	475 to 275	
	Marbel Fault Zone	400 to 325	
SK6D	Sabpangon South	475 to 100	Major zone: 350
	N-S Kanlas Fault	-75 to -175	Minor zone: -100
	Kanlas Gamay	-250 to -325	
	Kanlas Daku	-325 to -330	
	Tabaco Central	-425 to -500	
SK7D	Kanlas West	125 to -53	Major zone: 100
	Kanlas North	-4 to -468	Minor zone: -300
	Tabaco West	-381 to -543	
Injection Wells			
KL1RD (*2,6* NDS)	N-NW Sisiman	175 to 075	
	Sisiman Splay	-125 to -325	
	Sisiman Fault	-400 to -625	
KL4RD (*1,3,6* NTS)	Sudsuwayan Central	28 to -526	Major zone: -323
	Sisiman Splay A	-535 to -683	
MT1RD (*1,5* NDS)	Matingao Central Splay	200 to 100	Major zone
	Matingao Central	-150 to -250	Minor zone
	Kullay	-300 to -350	
MT2RD (*1,6* NDS)	Tambaan Central	250 to 175	Major zone: -300
	Tambaan West	125 to -25	Minor zone: 200
	Mook East	25 to -125	
KN2RD (*2,7* NDS)	Kambatan North	298 to 98	
	Marbel Fault	48 to -52	Minor zone
	Mainit Central	-102 to -302	Major zone

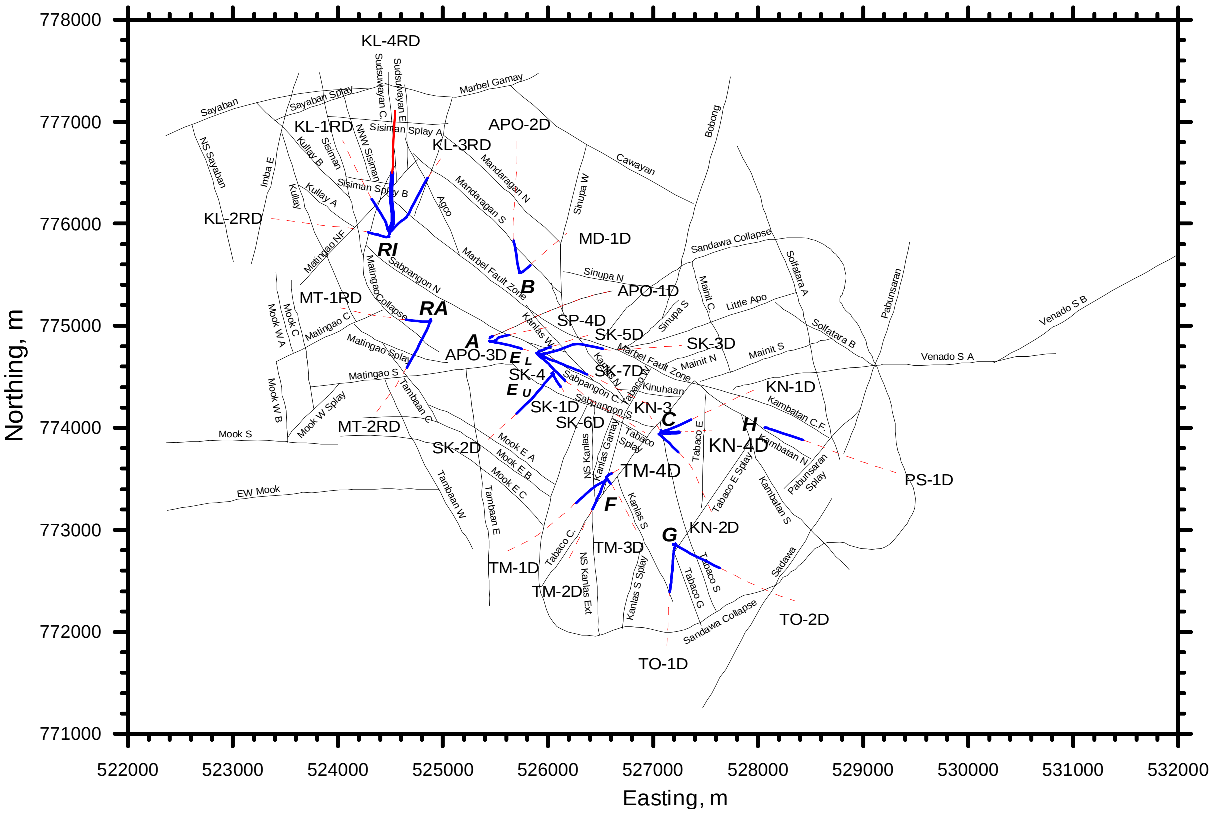

Figure 3: Detailed structural map of Mindanao Geothermal Production Field showing the intricate connections of structures

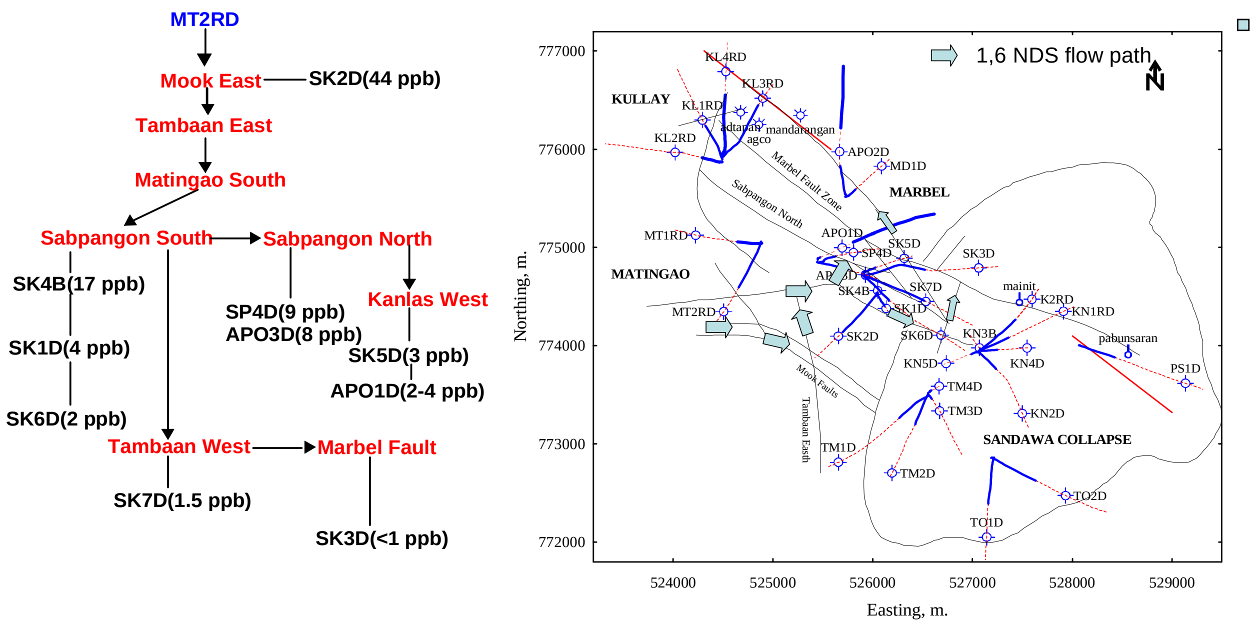

Figure 4: Most probable flow paths of injected brine in MT2RD to the production sectors

3. NAPHTHALENE DISULFONATE- A AND B

Two injection wells are located inside the Matingao injection sink namely: MT1RD and MT2RD. The combined load of these injection wells averages 220 kg/s. The Matingao sector accepts almost 70% of the total brine effluent obtained from the Marbel production sector. Positive tracer responses were detected in the following production wells in order of decreasing tracer concentrations: SK2D, SK4B, SP4D, APO3D, APO1D, SK1D, SK5D, SK6D, SK7D, SK3D and APO2D after injecting NDS-A and NDS-B in MT2RD and MT1RD, respectively.

Pioquinto (1997) established that well SK2D has a direct channel connection with MT2RD through Mook East. Both wells encountered this structure and coincidentally both intersection depths correspond to their major contributing zones that are located at the bottom section of the bores. It is inferred that the major feed zone is the highest accepting zone. Well SK2D showed the highest and immediate response to NDS-A. The tracer concentration reached as high as 44 ug/L (ppb) where the average breakthrough time is approximately five months. Initial assessment conducted on the well showed that the amount of tracer recovered is about 80 kg or about 20 % recovery (Nogara, 2003). Well APO3D on the other hand responded to NDS-B tracer injected in MT1RD with tracer concentration in excess of 40 ug/L (ppb) short of four months transit time.

Interconnection of fault structures explains the tracer response of the other production wells. The intricate network of faults provides numerous passageways. The most probable passageways of injected fluid from MT2RD as it moves to production sector are shown in Figure 4. The flow path distance and the corresponding maximum tracer concentration observed in each well are tabulated in Table 2.

4. NAPHTHALENE DISULFONATE-C AND D AND TRI-SUBSTITUTED SULFONATE

The Kullay sector has four injection wells namely KL1RD, KL2RD, KL3RD and KL4RD. Wells KL1RD and KL3RD with average acceptance of 60 kg/s are used for hot brine injection while KL2RD and KL4RD are used for the disposal of the power plant condensate amounting to 40 kg/s through cold injection. To test the hydrological connection of the Kullay sector to Marbel, NDS-C and NTS were injected in KL1RD (2003) and KL4RD in 2006, respectively. Samples collected from production wells were qualitatively evaluated for NTS following interference issues in the laboratory analyses. In over a year of monitoring since March 2003, the wells that showed positive tracer responses for NDS-C enumerated in order of decreasing tracer concentrations are APO1D, SP4D, SK5D, APO3D, SK4B, SK3D, SK2D, SK1D, SK7D, SK6D and APO2D. While the same wells in the Marbel production sector indicated NTS tracer response except for SK2D, SK6D and SK7D. The tracer remains undetected in Sandawa production wells as of this writing. Well APO1D due to its proximity to the Kullay sector yielded the highest and immediate tracer breakthrough. The maximum tracer concentration is about 36 ppb within ten months average breakthrough time.

Table 2. Estimated Flow Path Distance Against Maximum Tracer Concentration Obtained.

Well	Flow path distance, m	Highest tracer conc., ppb
SK2D	1,100	44.0
SK4B	2,350	18.0
SP4D	2,600	8.00
APO3D	2,650	7.00
SK5D	2,900	3.50
SK1D	3,050	4.00
APO1D	3,250	2.75
SK6D	3,450	2.00
SK7D	3,900	1.50
SK3D	4,650	0.80

Table 3. Estimated Flow Path Distance Against Maximum Tracer Concentration Obtained.

Well	Flow path distance, m	Highest tracer conc., ppb
APO1D	2,400	36.0
SP4D	2,450	24.0
SK5D	2,600	15.0
APO3D	2,800	7.00
SK4B	2,900	4.00
SK3D	3,100	2.00
SK2D	3,300	1.00
SK6D	3,350	0.50
SK7D	3,450	0.50

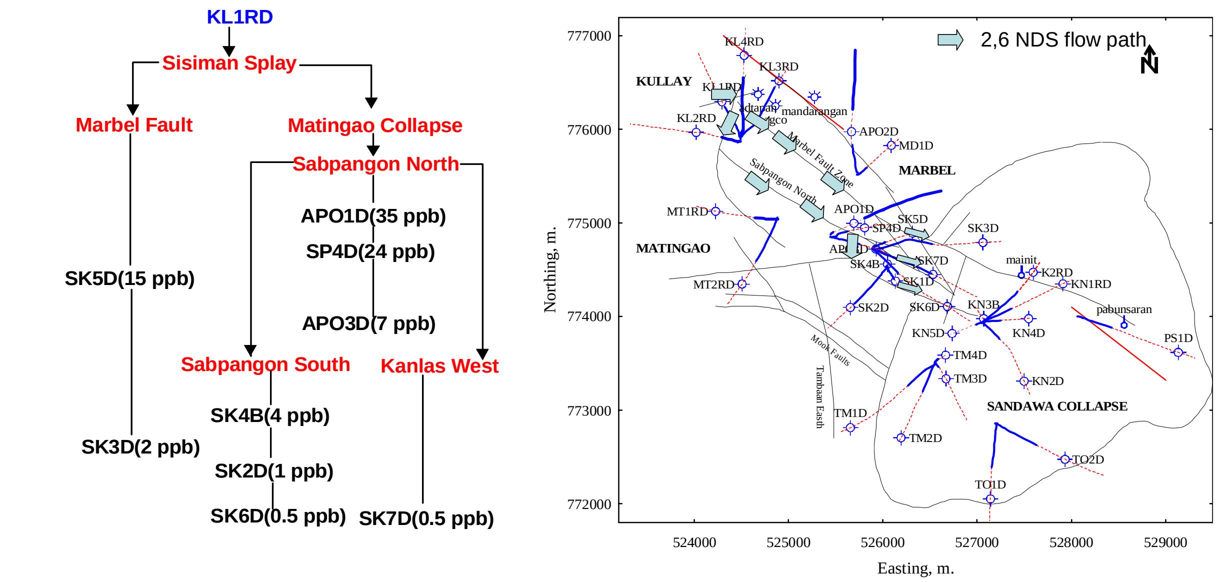

Figure 5: Most probable flow paths of injected brine in KL1RD to the production sectors

Compared to SK2D, the nearest well to the Matingao injection sector, the observed tracer concentration in APO1D is slightly lower and the breakthrough time is longer. It is implied based on this result that the tracer NDS-C injected in KL1RD traveled a longer distance than NDS-A injected in MT2RD before reaching the nearest production well. In this case, no direct connection is established from well KL1RD to APO1D. The possible structural flow path to this well from KL1RD is Sisiman Splay B to Matingao Collapse and through Sabpangon North. There is also a possibility that the injected fluid from Kullay is being channeled by Marbel fault zone as shown in the positive tracer response of well SK5D. However, for well APO1D this Marbel Fault Zone at the bottom section of the well was isolated through cement-plugging activity conducted on March 2, 1998 since it was inferred to be the conduit of cooler fluids.

The rest of the wells that indicated positive tracer response to NDS-C either intersected both the Sabpangon North and Marbel Fault Zone or one of these faults. The difference in the observed tracer concentration is attributed to the dilution effect brought by the in-situ fluid as the injected fluid progressed to the production sectors. Figure 5 summarizes the flow paths of the reinjected fluid coming from well KL1RD elucidated through the injection NDS-C. The calculated flow path distances with the corresponding observed tracer concentrations are tabulated in Table 3.

Significant tracer response is observed in well APO2D and MD1D in relation to NTS injected in KL4RD. These wells are located northeast of Marbel production sector at Mandarangan. Other wells indicating positive response with respect to NTS in order of proximity are SP4D, SK5D and APO3D. The possible structural flow path established is through Mandarangan North and Mandarangan South faults.

Tracer injected (NDS-D) in well KN2RD from within the Sandawa sector were observed in nearly all Marbel production wells except for SK3D at less than 1 per cent overall injected fluid returns. Well APO1D indicated the highest percentage returns at 0.7 % with respect to the NDS –D tracer suggesting a structural flow path through Kinuhaan fault to Marbel Fault Zone reaching as far as well APO1D. Well SK2D indicated the least transit time of 3.5 months through Tabaco East Splay and Sabpangon South fault. Notably the tracer is undetected as of this writing in nearby Sandawa wells, namely KN3B, KN2D, TM1D and TM2D.

5. TRACER DATA ANALYSIS AND MODELLING

Analysis of tracer data was done using a software package called ICEBOX® composed of three programs namely: TRMASS, TRINV and TRCOOL which were compiled by different authors from Iceland (United Nations University Geothermal Training Programme, 1994). As a generic data input, the unit of time when the sample was collected and the amount of tracer in ppb should be first converted into seconds and g/L, respectively. TRMASS was used to get the tracer mass recovered based on the actual data through integration of area under the tracer breakthrough curve (Arason, 1993). This is done using the following equation:

$$m_i(t) = \int_0^t C_i(s) Q_i(s) ds \qquad (1)$$

Where $m_i(t)$ indicates the cumulative mass recovered in production well number i as a function of time, C_i, is the tracer concentration and Q_i the production rate of the well. The accuracy of the estimation is dependent on the set of data obtained. The set of data should contain data that smoothly define the different sections of the breakthrough curve, e.g. on-set of breakthrough, the plateau concentration and the tail end of the curve. If one section of the curve is not well defined, the tracer mass recovered calculated by *TRMASS* is underestimated. This is the main problem encountered in analyzing the tracer data for Mindanao geothermal field. Some of the wells have no well defined breakthrough curves due to insufficient data brought by slow turn-over of analysis results and relatively longer transit time of tracer for some of the wells especially in the case of NDS-C injected into KL1RD. The minimum transit time observed for NDS-C in the nearest well (SK2D and SP4D) in Kullay is about a year, which requires longer monitoring duration for other wells to completely define the tracer breakthrough curves.

TRMASS gives tracer mass recovered (lumped amount) at the well head of the production well without resolving the contributions from different feed-zones in case the well has multiple feed-zones. To address this problem the TRINV program was used. This program calculates the mass tracer recovered based on a pre-defined model. The program generates best-fit curve that defines the behavior of the observed tracer values as a function of time. It provides a better approximation of the tracer mass recovered specific to the contributing feed-zone. The model used is a simple one-dimensional flow-channel tracer transport in simulating the return data from tracer test (Axelsson et al., 1995). The model assumes that the flow between the well pair (injection and production wells) may be approximated by one-dimensional flow in flow channels. These flow channels may be part of near-vertical fracture zones or parts of horizontal interbeds or layers. In some cases, more than one channel may be assumed to connect an injection well and a production well, i.e. connecting different feed-zones in the wells involved. The working equation for the model is shown in the following formula:

$$c(t) = \frac{uM}{2Q\sqrt{\pi Dt}} e^{-(x-u)^2/4Dt} \tag{2}$$

Where, velocity $u = q/\rho A\phi$, q = injection flow-rate in the channel, dispersion $D = \alpha_L u$ (diffusion neglected), α_L – is the longitudinal dispersivity, M is the tracer mass recovered, $c(t)$ is the tracer concentration in the production well fluid, Q is the production rate (kg/s) and x is the distance of the wells involved. Conservation of the tracer according to $c \times Q = C \times q$ has been assumed in this model.

Finally the results of the *TRINV* program (tracer inversion) are used to predict the effect of the injection fluid to the production temperatures. The decline in production temperature is not uniquely determined by the flow-path volume but also depends on surface area and porosity of flow channel. Assuming equal flow-path volume, large surface area leads to slow cooling and vice versa. The surface area is dependent on porosity that defined by an inverse relationship. The cooling effects of injection fluid to the production wells were calculated by TRCOOL program (Axelsson, 1993). This program incorporates the following equations:

$$T(t) = T_0 - \frac{q}{Q}(T_0 - T_i)\left[1 - erf\left\{\frac{kh}{c_w q\sqrt{t - \left(\frac{x}{\beta}\right)}}\right\}\right] \tag{3}$$

$$\beta = \left(\frac{q\, c_w}{(\rho\, c)_f\, hb}\right) \tag{4}$$

$$(\rho c)_f = \rho_w\, c_w\, \phi + \rho_r\, c_r\, (1-\phi) \tag{5}$$

Where: $T(t)$ = production temperature, T_0 = initial reservoir temperature, T_i = injection temperature, q = injection rate, Q = production rate, h = channel width, b = channel thickness, k = thermal conductivity of reservoir rock, K = thermal diffusivity of rock, ρ and c are density and heat capacity of water (w) and rock (r).

The cooling predictions were calculated using a worst case scenario wherein the flow-channel dimension and its physical property consisted of high porosity, small surface area and pipe-like flow channel. This pessimistic scenario was done by assuming equal dimension both in the width and height of the flow channel.

6. RESULTS AND DISCUSSION

6.1 Transit Time, Tracer Recovery and Injection Fraction

Model parameters used for the subsequent simulations are not presented in this report and discussions will focus on the 2003 tracer tests results. However, selected updates may be included for the 2006 tracer tests.

Both tracers (NDS-A and NDS-C) injected separately to MT2RD and KL1RD were observed in all production wells (APO1D, APO2D, APO3D, SK1D, SK2D, SK4B and SP4D) except MD1D inside Marbel and 3 wells (SK3D, SK6D and SK7D) inside the Sandawa. Tracers injected in 2006 were also detected in nearly all wells in Marbel production sector and NDS-D tracer remains undetected in the nearby Sandawa productions wells. These confirmed and validated the hydrological connections between Matingao-Marbel, Kullay-Marbel and the in-field injection well (KN2RD) to Marbel which has been consistent with the geochemical trends observed from the production wells proximal to the injection sectors such as steady increase in Clres and cooling of cations and quartz geothermometers with corresponding decline in gas discharges (CO_2 and H_2S). The model parameters used in the tracer inversion and the result of the simulations for NDS-A and NDS-C tracers are tabulated in Tables 4 and 5, respectively.

Table 4. Model parameters used to simulate NDS-A recovery of wells and results of the tracer inversion, where x = flow path distance, ABT = average breakthrough time, A = cross-sectional area, ϕ = porosity, Mr = percent tracer mass recovered and RIFrac, fraction of the injection fluid in the total mass flow of the well.

Well	x, m	ABT, month	$A\phi$, m^2	M_r, %	RI_{Frac}
APO1D	3250	12	42.4	2.9	0.053
APO3D	2650	10.4	52.3	4.6	0.066
SK2D	1100	4.7	727	31.2	0.41
SK4B	2350	8.4	84.1	4.9	0.11
SK5D	2900	12	9.7	0.7	0.02
SK6D	3450	12	14.3	1.1	0.022
SP4D	2600	11	31.9	2.3	0.042

Table 5. Model parameters used to simulate NDS-C recovery of wells and results of the tracer inversion, where x = flow path distance, ABT = average breakthrough time, A = cross-sectional area, ϕ = porosity, Mr = percent tracer mass recovered and RIFrac, fraction of the injection fluid in the total mass flow of the well.

Well	x, m	ABT, month	$A\phi$, m^2	Mr, %	RI_{Frac}
APO1D	2400	11	142	15.0	0.154
SP4D	2450	12	146	14.4	0.149

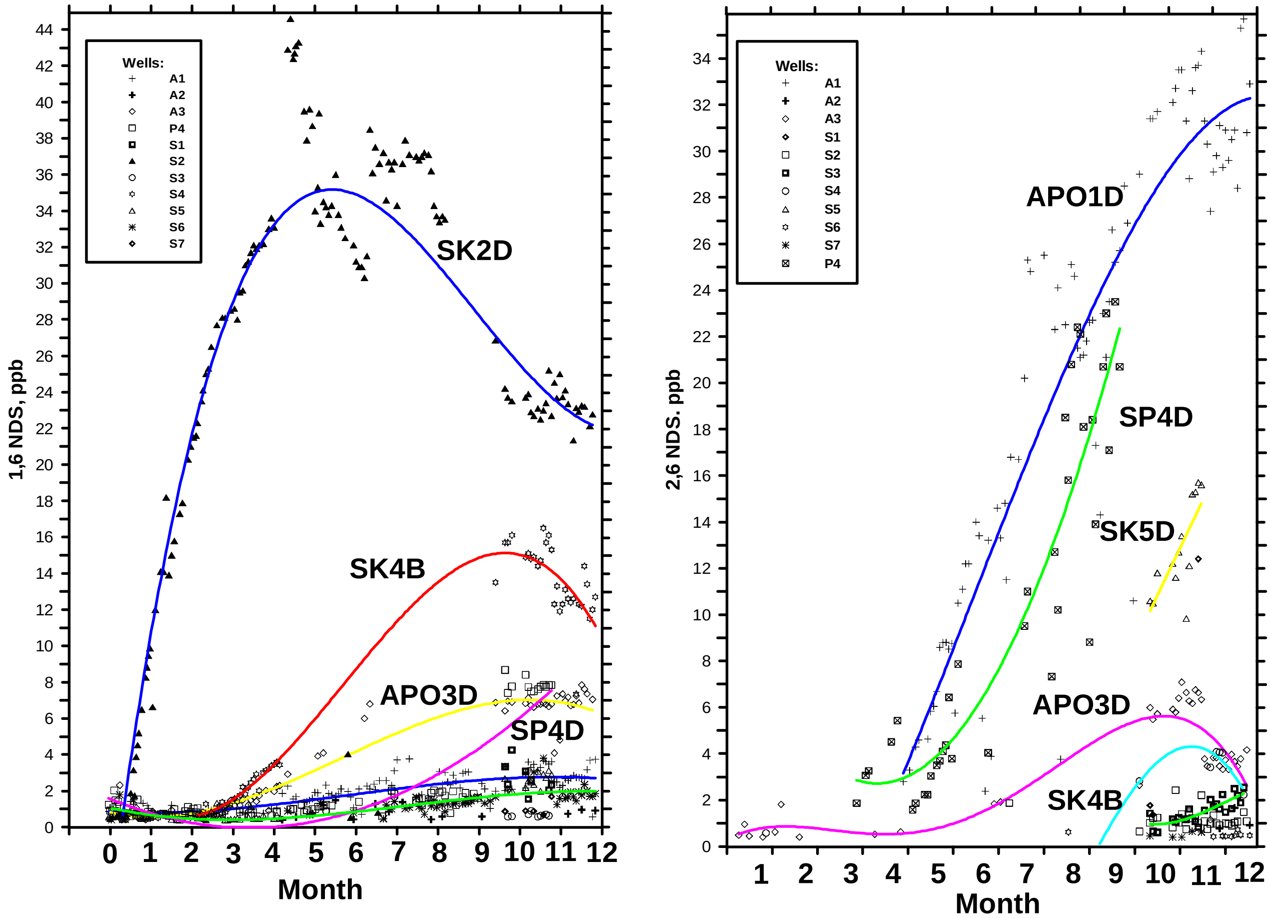

Figure 6: Composite plots of tracer recovery profiles bothe for NDS-A and NDS-C tracers as observed in MGPF production wells

The injection fractions in the last column of the foregoing tables were calculated using the following equation.

$$RI_{Frac} = \frac{q\,M_r}{100\,Q} \tag{6}$$

Where: q = stable injection rate of injection well, M_r = % tracer recovered, and Q = stable production rate.

The profile of the tracer recovery curves (breakthrough curves) is best approximated and simplified using a single channel communication between the injection and production wells both for NDS-A and NDS-C tracers. The composite tracer recovery curves for NDS-A and NDS-C tracers are summarized in Figure 6. Some of the wells like SK1D, APO2D, SK3D and SK7D for NDS-A and APO2D, APO3D, SK1D, SK2D, SK3D, SK4B, SK5D, SK6D, SK7D for NDS-C gave positive tracer responses but the data sets obtained are insufficient to give a well defined breakthrough curves such that no simulations were completed. But the initial results of these wells helped in defining the spatial encroachment of the injection fluids migrating from Matingao and Kullay towards the two production sectors.

The tracer breakthrough for NDS-A injected in MT2RD (Matingao) is relatively faster and more pronounced compared to NDS-C injected in KL1RD (Kullay). The earliest average breakthrough time is 4.7 months with a distance of 1100 meters and maximum tracer concentration of 44 ppb as given by well SK2D. While in NDS-C, the earliest average breakthrough time is 11 months having a distance of 2400 m and maximum tracer concentration of 35 ppb as observed in well APO1D. The data seem logical because of the proportionate spatial differences of the two well pairs. In comparison to other geothermal fields that conducted similar tracer activity, e.g. Mahanagdong, the tracer transit times in both injection sinks are relatively longer since in Mahanagdong field some wells have tracer breakthrough within a month after tracer injection (Herras, 2004).

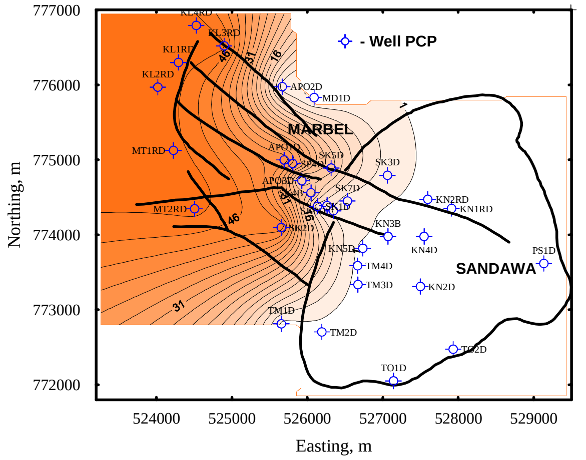

Figure 7: Iso-contour of combined maximum NDS-A and NDS-C tracers concentration as observed in MGPF production wells

The total mass of tracer recovered for NDS-A is about 48% or 192 kg injected (combined mass tracer recovery on all wells affected by NDS-A). The residual 52% of the tracer injected possibly dispersed to the reservoir. The bulk of the tracer recovered was obtained in well SK2D amounting to 31% of the tracer mass injected (124 kg) or 65% of the total tracer recovered. Presence of direct structural connection between MT2RD and SK2D through Mook East and proximity of the two wells to each other explain this observation. Wells located at the margin of the Marbel production sector opposite to Matingao injection sink such as SK5D and SK6D gave minimal tracer recovery of < 2.0%. This implies that the tracer has vastly dispersed upon reaching the northeastern region.

The total amount of tracer recovered for NDS-C cannot be calculated because of the insufficient (available) data sets obtained for most of the wells monitored. Data insufficiency is due to the generally longer transit time for NDS-C requiring extended periods of monitoring. Based on the profiles of incomplete breakthrough curves, the monitoring period is being extended for at least another six months to fully define the tracer recovery curves. So far, wells APO1D and SP4D were simulated and gave combined tracer mass recovery of about 30% or 120 kg of NDS-C.

Likewise, the amounts of injection present in the discharges of the wells affected by injection fluids are proportional to the combined amount of tracer recovered. Well SK2D has the highest injection fraction in the fluid discharge amounting to at least 0.41 or 31 kg/s mass flow based on 76 kg/s current mass flow output of the well. This injection fraction value was verified by calculating the weighted chloride value using the baseline reservoir chloride concentration of 4250 mg/kg in SK2D and injection fluid injected chloride of 6000 mg/kg. Surprisingly, the calculated weighted chloride value of 5283 mg/kg is comparable to the current reservoir chloride of well SK2D at ~5500 mg/kg. Wells APO1D and SP4D having similar combined injection fraction coming from MT2RD and KL1RD of around 0.20 are the next wells that have substantial amount of injection fluids. This is followed by SK4B giving 0.11 injection fraction, which is based only in NDS-A and not taking into account the possible contribution of KL1RD since the data set available is inadequate. The injection fractions for the rest of tracer-positive wells have values < 0.10, e.g. APO3D (0.07), SK5D (0.02) and SK6D (0.02).

Figure 7 shows the combined iso-contours of NDS-A and NDS-C maximum concentrations of both tracers in Mindanao geothermal field. These contours reflect the spatial encroachment of both tracers to the production sectors which mimic the injected fluid coming from the two injection wells (MT2RD and KL1RD). Again, the wells that are immediately affected by the injected fluid are SK2D for MT2RD and APO1D/SP4D for KL1RD.

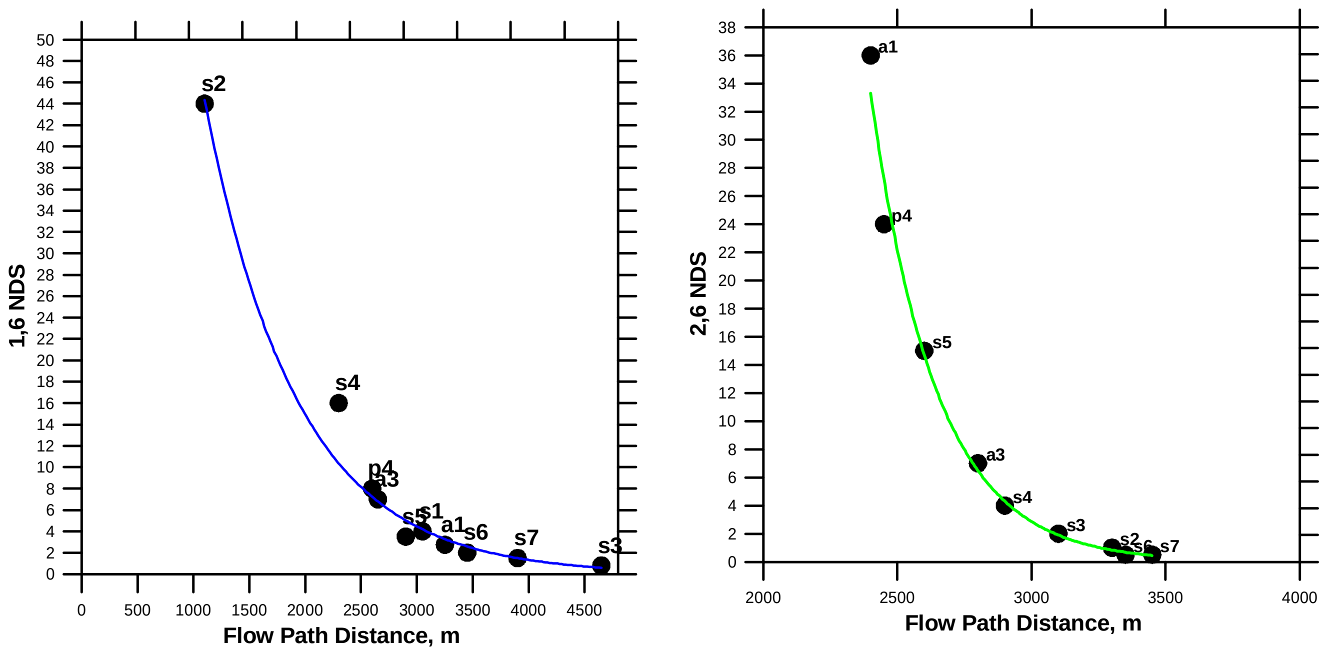

Figure 8: Correlation of flow-path distances and maximum tracer concentrations observed in MGPF production wells

Similar curve behavior was obtained when plotting the flow-path distance against the maximum tracer concentration for NDS-A and NDS-C as shown in Figure 8. It appears that the maximum tracer concentration observed in the wells is a function of flow-path distance rather than the linear distance between the pressure-control-points (PCP) of the well pair. This proves that the migration of the injection fluids from the injection sinks towards the Marbel production sector is primarily controlled by structures and not by lateral migration through a permeable horizon e.g. paleosol, formational contact between the Upper and Lower volcanics and lava flow.

6.2 Cooling Prediction

The tracer inversion program after simulating the best curve that fits the individual well recovery tracer curve profile provided the following important parameters: the product of the porosity (ϕ) and the surface area of the channel (A). These parameters are needed in the cooling prediction and the essential input values for the TRCOOL program.

Table 6 shows the calculated product of porosity and channel surface area for each well. The only variable left for the cooling calculation is the porosity of the flow channel. The effect of the porosity to the cooling calculation is shown in Figure 9 using data obtained in well SK2D for NDS-A. The figure clearly shows that decreasing the porosity will prolong the induction time for the logarithmic decline in the reservoir temperature. The porosity used has insignificant effect to the minimum reservoir temperature at infinite time or steady state condition. The effect of decreasing the porosity can be visualized by imagining an expanding flow channel with increasing brecciated rocks at the slit of the channel. These '*filler*' rocks have definitely higher thermal capacity and abundant stored heat and in effect these rock '*fillers*' delayed the induction time of thermal decline in the reservoir through thermal buffering.

The worst scenario for the cooling model is a flow channel having equal dimensions in the height and width; and porosity equal to 100 %. This is a true flow-pipe model. However, in reality the structural fault has filler rocks and mineral deposits at the cavity due to accumulated debris from grinding action when the fault moves and possible silicification or mineral deposition when the fluid boils as it flows through the channel. The channel matrix porosity values were determined based on the reservoir temperature responses (TQtz) of SK2D and APO1D representing the two different tracers and routes. SK2D gave % porosity value of 10 which is similar to the upper range used in the volumetric stored heat assessment while APO1D gave a higher porosity of 15 % (Figure 10).

The cooling prediction is ascertained by the amount of decline in reservoir temperature caused by injection returns; however the uncertainty is in the timing of the decline due to unrefined values for channel matrix porosity. The cooling prediction calculation in this case, concentrates mainly in the lowest temperature that the well will experience at a reservoir life span of 25 years. The timing of thermal decline can be known when good estimate values of channel porosity are available. Table 7 shows the results of the cooling predictions using 10% and 15% porosity for NDS-A and NDS-C, respectively.

Table 6. Product of Porosity and Channel's Surface Area Dimension (ϕA) for Tracer-Positive Wells.

Well	ϕA for 1,6 NDS (m^2)	ϕA for 2,6 NDS (m^2)
APO1D	42	142
APO3D	52	-
SK2D	727	-
SK4B	84	-
SK5D	10	-
SK6D	14	-
SP4D	32	146

Table 7. Results of the Cooling Prediction for Wells with Well Define Curves.

Well	TMF kg/s	T_{RES} (Tqtz)	Min. Predicted Temp., °C (onset time in yrs)		ΔTemp., °C			
			1,6 NDS (Φ=0.10)	2,6 NDS (Φ=0.15)	1,6 NDS	2,6 NDS	Total	Actual @ 8 yrs
APO1D	55	236	234 (12)	225 (6)	2	11	13	3
APO3D	70	241	237 (7)	-	4	-	4	3
SK2D	76	248	209 (5)	-	39	-	39	3
SK4B	45	245	238 (9)	-	7	-	7	2
SK5D	32	251	250 (11)	-	1	-	1	12
SK6D	49	272	271 (12)	-	1	-	1	9
SP4D	55	240	238 (9)	227 (7)	2	11	13	3

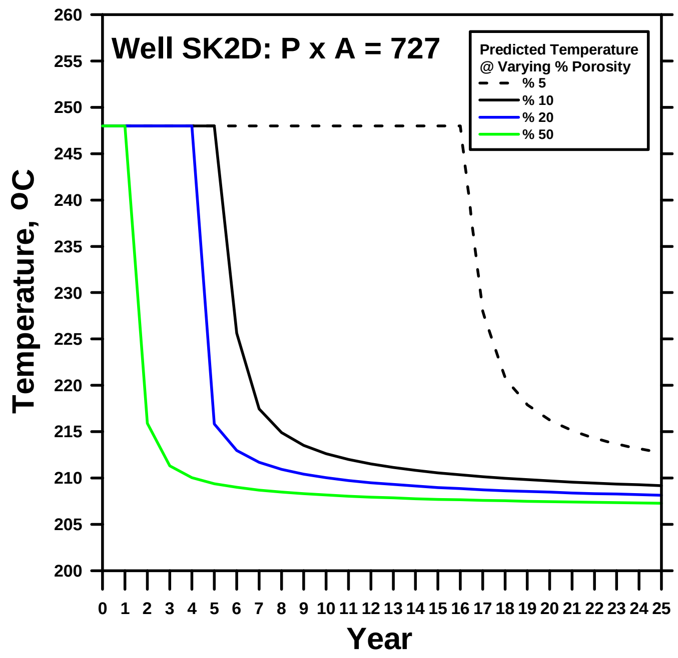

Figure 9: Plot showing the effect of porosity used for the flow channel in the profile of the predicted reservoir temperature through time. Decreasing porosity value prolongs the induction time for the thermal declines

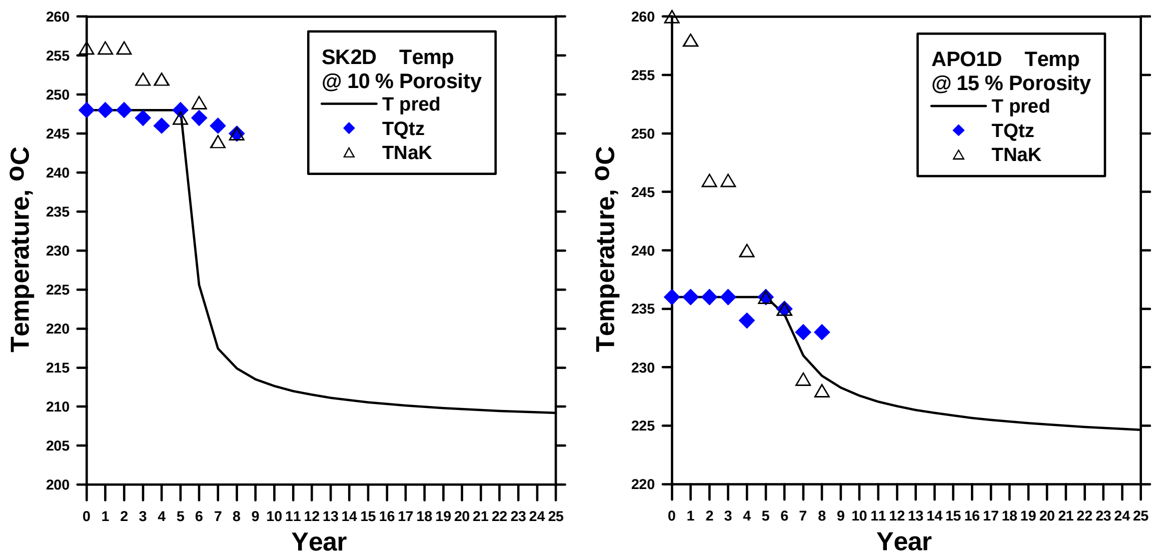

Figure 10: Graphical determination of porosity by matching the predicted temperatures of wells SK2D and APO1D to the actual cooling response of the production temperatures

Wells with direct communication and closer to the injection sinks have the highest predicted decline in temperatures like SK2D (32^{o}C), APO1D (13^{o}C) and SP4D (13^{o}C). The measured decline in temperatures for these wells based on silica geothermometer in 8 years of utilization is generally lower amounting to 3^{o}C. As mentioned earlier, the timing of decline is uncertain due to unknown porosity value and the 3^{o}C decline observed in these wells could possibly be the signal of the actual onset of thermal decline. Thus, further declines in the production temperatures are expected in the near future if the current injection scheme will be maintained.

In contrast, wells with low predicted reservoir temperature declines like SK5D and SK6D yielded higher actual values in 8 years of utilization. The actual temperature decline observed for SK5D and SK6D are 12^{o}C and 9^{o}C, respectively, but the maximum predicted temperature decline is about 1^{o}C in both wells. The faster decline rates observed for these two wells cannot solely be attributed to injection returns but possibly to other reservoir and well-bore processes like interplay of feed-zones, formation of scales, e.g. calcite that blocks the contribution of the hotter feed, and movement of other neighboring fluids that are relatively cooler but with comparable reservoir chloride to the wells involved.

SUMMARY

Similar amounts of NDS-A and NDS-C tracers amounting were injected separately into wells MT2RD and KL1RD on March 28 and April 8, 2003. Subsequently in October 2006, NDS-B and NTS were injected into MT1RD and KL4RD, respectively and NDS-D into KN2RD, an injection well within Sandawa production sector. Positive tracer responses were noted in nine (9) production wells located inside the Marbel and three (3) production wells inside the Sandawa. This confirmed and validated the hydrological connections between the injection sinks and the two production sectors as well as the total sectoral effect of the Matingao injection sink to the production sector. Furthermore, negligible tracer mass is observed in Sandawa production wells correlated to tracer injected in the in-field injection well, KN2RD. The impetus of injected fluid from the in-field injection wells in Sandawa prevents hot recharge to the Marbel production sector.

The injected fluids coming from Matingao and Kullay sectors travel at similar velocities. However, well SK2D yielded immediate and more pronounced tracer breakthrough coming from Matingao due to its proximity and presence of direct connection to MT2RD.

As predicted, large reservoir temperature declines will be observed in the production wells that have structural connections and located immediately at the two injection sinks. Well SK2D has the highest decline value of around 39^{o}C followed by wells APO1D and SP4D with similar decline value of 13^{o}C. The timing of decline is greatly dependent on the actual porosity of the flow-channel where lower porosity value will prolong induction time for thermal decline.

The observed discrepancy of temperature declines in wells SK5D and SK6D after eight years of utilization to the predicted values could also be attributed to other reservoir and well-bore processes, e.g. interplay of feed-zones, scaling and inflow of other neighboring cooler fluids.

Assumptions drawn from the tracer tests conducted in 2006 yielded the following:

a. The NTS injected in KL4RD validated the cold injection in-flow in APO2D which resulted to the continuous decline in the salinity of the well.

b. Wells MD1D and SK5D are significantly affected by injected fluids from well KL4RD.

c. The tri-substituted sulfonate (NTS) is not suitable in a multi-tracer test since quantification procedure and analyses are affected by interference from the other naphthalene disulfonate structure.

d. Injected fluids in KL4RD return to the Marbel production sector despite its distant location from the production wells. It is imperative for reservoir management to develop an outfield injection well to allow sufficient heating of the injected fluids thereby reducing, if not eliminating cooling effects to the Marbel production sector.

e. Brine load reduction in well MT1RD should precede MT2RD since MT1RD has significantly affected well APO3D which has marginal production temperature at ~220^{o}C.

f. Brine inflow towards the Marbel production sector from the in-field injection well, KN2RD resulted to abnormal temperature declines in SK3D, SK7D and SK6D which could not be attributed to Matingao and Kullay injection sectors.

g. Tracer test in KN2RD implied more of a permeability barrier rather than limited sectoral capacity which is evident by the positive tracer response of the Marbel production wells.

h. Permanent utilization of the in-field injectors may be detrimental in the long term as it affects to the sustainability of the Marbel sector since it blocks the hot recharge towards this sector by creating fluid barrier. This lead to drilling of new injection well at Pad H.

CONCLUSIONS

i. Positive tracer responses were noted in nine (9) production wells located inside the Marbel and three (3) production wells inside the Sandawa.

ii. Well SK2D has the highest decline value of around 39^{o}C followed by wells APO1D and SP4D with similar decline value of 13^{o}C. The timing of decline is greatly dependent on the actual porosity of the flow-channel where lower porosity value will prolong induction time for thermal decline.

iii. Temperature declines are also attributed to other reservoir and well-bore processes, e.g. interplay of feed-zones, scaling and inflow of other neighbouring cooler fluids.

iv. The NTS injected in KL4RD validated the cold injection in-flow in APO2D which resulted to the continuous decline in the salinity of the well.

v. Wells MD1D and SK5D are significantly affected by injected fluids from well KL4RD.

vi. Brine load reduction in well MT1RD should precede MT2RD since MT1RD has significantly affected well APO3D which has marginal production temperature at ~220^{o}C.

vii. Brine inflow towards the Marbel production sector from the in-field injection well, KN2RD resulted to abnormal temperature declines in SK3D, SK7D and SK6D which could not be attributed to Matingao and Kullay injection sectors.

viii. Tracer test in KN2RD suggests a permeability barrier rather than limited sector capacity which is evident by the positive tracer response of the Marbel production wells.

ix. Permanent utilization of the in-field injectors may be detrimental in the long term as it affects the sustainability of the Marbel sector since it blocks the hot recharge towards this sector by creating a fluid barrier.

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