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FIRST SEVEN YEARS OF EXPLOITATION AT THE MIRAVALLES GEOTHERMAL FIELD

Paul Moya and Antonio Yock

Instituto Costarricense de Electricidad, UEN Proyectos y Servicios Asociados
C. S. Recursos Geotérmicos, Apartado Postal 10032-1000
San José, Costa Rica, Centro América
e-mail: pmoya@ns.ice.go.cr

ABSTRACT

The Miravalles Geothermal Field has been producing electric energy since March 1994. It has provided steam for Unit 1 (60 MWe) since 1994, a Well Head Unit (5 MWe) installed in 1995, Unit 2 (55 MWe) in 1998 and Unit 3 (27.5 MWe) in the year 2000. The total installed capacity in Miravalles is therefore 147.5 MWe. The reservoir response during the seven years of exploitation is described in the following sections. So far the field has successfully supplied the steam needed to maintain constant production over the first seven years of exploitation. A new development (consisting either of a second-flash unit or a binary plant, the so called Unit 5 or “bottoming cycle” unit) of 10-20 MWe is expected to be online by the end of year 2002.

INTRODUCTION

Costa Rica, located in Central America, has an area of about 51,100 km^2 and a population of 3.7 million. Most of the population lives in the Central Valley, where the capital San José is also located. The average temperature in San José is 22 °C ± 5° C . The climate has only two seasons, the dry season (from December to March) and the rainy season (from April to November).

Before 1994, Costa Rica supplied its electric energy needs with hydroelectricity (about 80%) and thermal (fossil fuel) energy (about 20%). During the international oil crisis of 1973-1974, the Costa Rican Institute of Electricity (ICE), which is the institution in charge of supplying energy for the country, realized the need to develop other sources of energy to reduce the country’s dependence on oil. After several studies were conducted, it was concluded that geothermal energy could have the potential to substantially reduce Costa Rica’s dependence on thermal energy, and therefore its consumption of oil.

There are four mountain ranges in Costa Rica, known as the Guanacaste, Tilarán, Central and Talamanca ranges. The Guanacaste range is a chain of andesitic Quaternary stratovolcanoes trending NW-SE. It is composed mainly of pyroclastic rocks, lava flows, fluvio-lacustrine deposits, and glowing avalanche deposits that have formed gently sloping plateaus on both sides of the range. The area is under constant regional stress due to the subduction of the Cocos Plate under the Caribbean Plate, and also due to regional uplift of the volcanic arc. The interaction between the two plates has created a complex system of faults with northwest, northeast and north as the predominant trends.

The Miravalles volcano, a stratovolcanic complex rising 2028 m above sea level, is part of the Guanacaste range. This volcanic massif (Lat. 10º 47’ N., Long. 85º 10’ W) was built after the formation of the “Guayabo Caldera” about 500,000 years ago, through at least three phases of collapse and rebuilding. Lava flows are andesitic to basaltic-andesitic with normal potassium contents. Six eruptive foci can be recognized; they are aligned NE-SW andshow a clear SW migration. The volcano has no record of historic eruptive activity, but there are many hot springs and fumaroles on its southwestern slopes.

The Miravalles geothermal field is also located on the southwestern slope of the volcano. The extent of the geothermal field already identified is greater than 21 km^2, of which about 16 km^2 are dedicated to production and 5 km^2 to injection. There are 50 geothermal wells, including observation, production and injection- wells, whose depths range from 900 to 3000 meters. The production wells produce between 3 and 12 MW each, and the injection wells each accept between 70 and 450 kg/s. The reservoir has a temperature of about 240 ºC and is water-dominated.

Seven separation stations (also called satellites) supply the steam needed for Unit 1, Unit 2, Unit 3 and the Well Head Unit (147.5 MWe). Normally, two or three production wells supply two-phase flow to each separation station. The total steam flow to the plants is about 300 kg/s, and the residual geothermal water sent to the injection wells is about 1,350 kg/s.

CHEMICAL AND THERMODYNAMIC CHANGES WITH TIME

Several parameters have been monitored at each production well to evaluate the evolution of the reservoir over the seven years of its exploitation. These parameters are chloride concentration, magnesium content, enthalpy, measured downhole temperature, Na/K ratio (Fournier geothermometer), silica content (Fournier and Potter geothermometer) and Cl/B ratio (Yock, 1998).

There have been three different production scenarios during the period of exploitation. From March 1994 to August 1998 steam was supplied to one condensing power plant and two backpressure power plants to produce approximately 65 MWe. From August 1998 to March 2000 the steam production was sent to the two condensing power plants (Units 1 and 2) and one backpressure power plant, generating about 120 MWe. Finally, from March 2000 to December 2000 steam was supplied to three condensing power plants to produce about 138 MWe.

During the first period 12 production wells (PGM-11, PGM-05, PGM-10, PGM-01, PGM-31, PGM-17, PGM-03, PGM-45, PGM-46, PGM-20, PGM-12 and PGM-21) and 6 injection wells (PGM-02, PGM-22, PGM-24, PGM-16, PGM-26 and PGM-04) were used. In the second period, 4 production wells (PGM-42, PGM-08, PGM-43 and PGM-49) and 3 injection wells (PGM-28, PGM-51 and PGM-56) were added. For the last period, 3 more production wells (PGM-14, PGM-60, PGM-62) were utilized; there was no need for additional injection wells (see Figure 1).

Parameters such as chloride concentration and enthalpy have been used to characterize variations in the behavior of the different geothermal wells during the seven years of exploitation. Contour maps of both parameters have been prepared to investigate the evolution of the Miravalles geothermal field in space and time. Chloride contents have been measured weekly since exploitation of the reservoir began. These data have been used to prepare the chloride contour maps described in this section.

Enthalpy data have been obtained from the well production curves, which have been measured once or twice per year since 1994. These data were used to prepare the enthalpy contour maps, which are also described in this section.

The 1994 chloride content contour map (Figure 2) and the 1994 enthalpy contour map (Figure 3) show the initial state of these parameters. These data were obtained two or three months after the commissioning of Unit 1 (55 MWe).

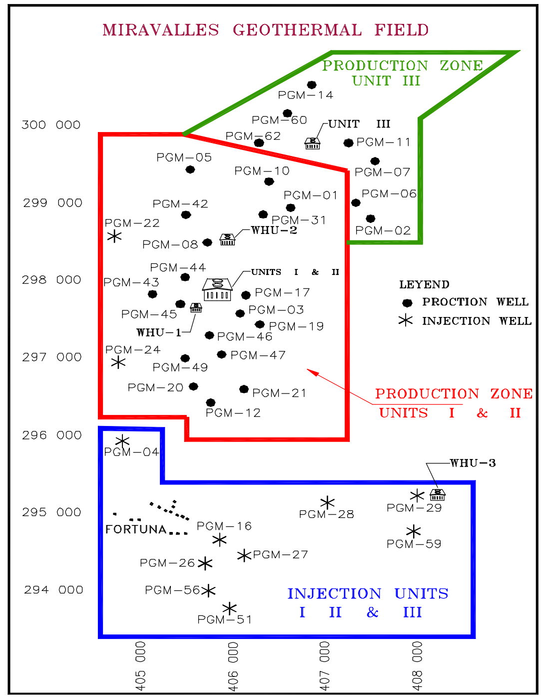

Figure 1. Miravalles Geothermal Field.

In Figure 2, it can be seen that the chloride concentration is very similar for all the wells. Lower values are found at the northern wells PGM-05, PGM-11 and PGM-10, the last having the lowest value of the three (2,585 ppm). Wells located in the center and southern parts of the geothermal field present higher concentrations (2,800 ppm). Well PGM-21 shows the highest chloride content (2,933 ppm) of all the wells.

Figure 3 shows enthalpy values as of 1994. Higher enthalpies (in excess of 1,050 kJ/kg) are present in the northern part of the field. The contour of 1,050 kJ/kg has been highlighted in all the enthalpy maps for comparison purposes. The wells with higher enthalpy values (above 1,100 kJ/kg) are PGM-10 and PGM-11. Of the wells located in the southern part of the field, PGM-20 and PGM-21 show the lowest enthalpy values (less than 1,000 kJ/kg).

Figures 4 and 5 show chloride concentration and enthalpy as of 1998; that is, four years after Unit 1 came online and immediately after the commissioning of Unit 2 (55 MWe).

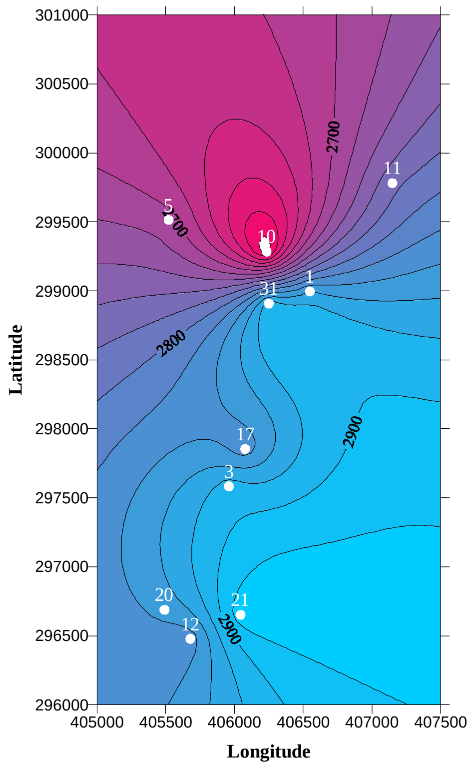

Figure 2. Contour Map of Chloride Content, 1994

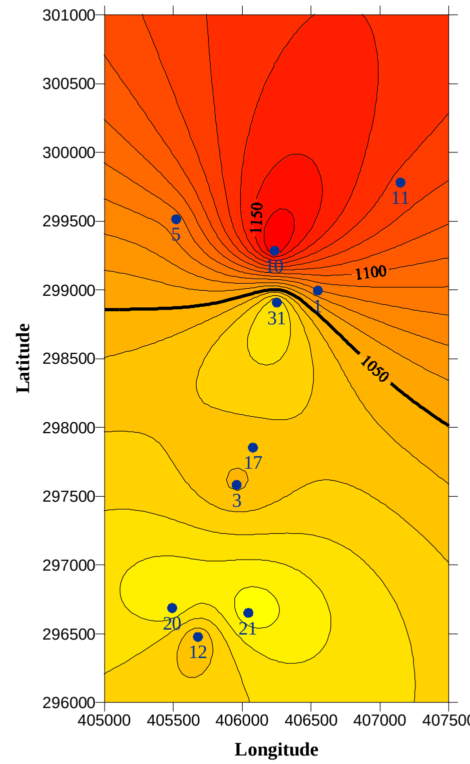

Figure 3. Contour Map of Enthalpy, 1994

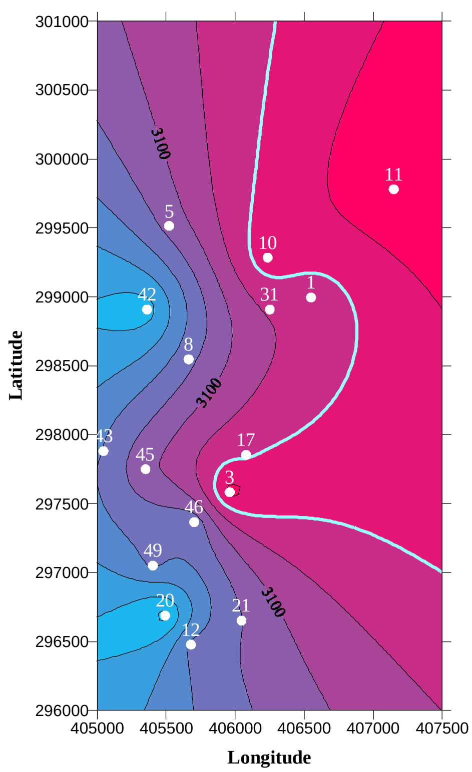

Figure 4. Contour Map of Chloride Content, 1998

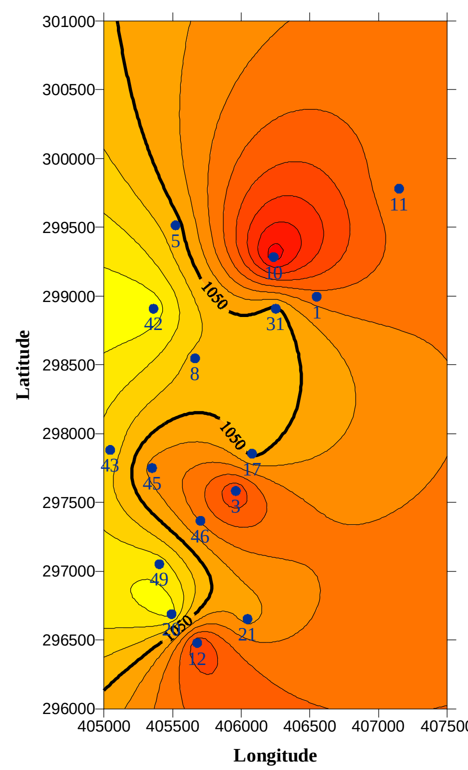

Figure 5. Contour Map of Enthalpy, 1998

The contour line of 3,000 ppm has been enhanced in order to follow the changes in chloride in the production zone of the field. The 3,000 ppm contour does not appear in Figure 2 because the collected data all have lower values.

In contrast, in Figure 4 wells PGM-03, PGM-10 and PGM-11 are the only wells with chloride levels below 3,000 ppm. Probably many of the chloride contents have been increased by flashing in the reservoir or by the return of injected fluids. In the western zone, two possible entries of injected fluid can be identified. The northern inflow is associated with injection in well PGM-22 (which receives fluid from Satellite No. 1) and is probably affecting wells PGM-05, PGM-08 and PGM-42 (see Figure 1). The southern inflow is probably related to injection in well PGM-24 (which receives fluid from Satellite No. 2) and also to the influence of fluids injected in the southern part of the field (from Satellite No.3). The southern entry is believed to be affecting wells PGM-12, PGM-20 and PGM-49 (see Figure 1).

When Figure 5 is compared with Figure 3, it is observed that the 1,050 kJ/kg contour line shows a major change in position. This is related to an increase in enthalpy in several of the wells, as a consequence of massive extraction of fluid. The same two entries shown in Figure 4 are also present in Figure 5. In this case, they indicate the entrance of fluids of lower enthalpy, which suggests that the injected fluid, at a temperature of about 165 ^{0}C, is returning to the production zone. Even though the injected fluids may have caused enthalpy declines in some of the nearby wells, it is not believed that the effect is severe enough to warrant reducing or eliminating the injection that is taking place in wells PGM-22 and PGM-24.

Figures 6 and 7 were prepared using the data collected up to March 2000, which is when Unit 3 (27.5 MWe) came online. Units 1 and 2 were online together for a year and a half prior the commissioning of Unit 3.

When Figure 6 is compared with Figure 4, it can be seen that the 3,000 ppm contour indicates a decrease in chloride content, probably due to declining chloride concentrations in wells PGM-01 and PGM-31. In this figure, three possible inflows with high chloride contents can be observed. The first (on the northwestern side) is also seen in Figure 4, but Figure 6 indicates that the amount of injected fluid is less than is indicated by Figure 4. This might be related to the associated normal decrease of the liquid phase of all the wells, mainly as a consequence of their productions, and also to a decrease in the amount of fluid injected into well PGM-22, because the liquid from PGM-05 has not been injected in PGM-22 since Unit 2 came online. The two-phase fluids from well PGM-05 were transferred to Satellite No. 4, so that the liquid from PGM-05 is now injected into well PGM-28 (in the southern part of the field; see Figure 1). Another reason for the decrease in the rate of injection in the northern zone is that not only wells PGM-05 and PGM-45 were producing in 1998 (Figure 4), but also wells PGM-08, PGM-42 and PGM-43 (when Unit 2 came online, Figure 6), which might have modified the fluid distribution within the reservoir.

The entry on the southwestern side is also observed in Figure 6. However, it is less distinct than in Figure 4, due to the influence of massive injection of fluids in the southern part of the field. In addition, the rate of injection in well PGM-24 decreased because the liquid from well PGM-46 was transferred to Satellite No. 6 (Unit 2), and well PGM-03 decreased its liquid phase contribution.

The third inflow observed in Figure 6 has the highest chloride content, and seems to originate from fluid injection in the south of the field. The rate of injection in this zone has increased considerably, from 310 kg/s (Figure 4) to 1,300 kg/s (Figure 6).

The 1050 kJ/kg contour line in Figure 7 shows a major change in the northern and southern parts of the field. The change in the northern part is associated with the incorporation of wells PGM-14, PGM-60 and PGM-62, which were needed to supply Unit 3 (27.5 MWe). The change in the southern part is related to enthalpy decreases in wells PGM-21 and PGM-46. Although PGM-47 came on line, this well did not help increase the overall enthalpy values in the southern zone because its enthalpy is just 1018 kJ/kg. The decrease in enthalpy in well PGM-21 seems to be associated with the injected fluids in the southern part of the field. The vicinity of well PGM-03 remains the zone where the higher enthalpy values are found, whereas the zone near well PGM-10 is less distinct.

Figures 8 and 9 represent reservoir conditions after 8 months of continuous operation of the three units.

As shown in Figure 8, the 3,000 ppm contour line changes southward, mainly as a consequence of increasing chloride concentrations in the wells located in the southern part of the production zone (PGM-12, PGM-17, PGM-20, PGM-21, PGM-45 and PGM-47). At the same time, the chloride contents in some wells located in the northern part of the production zone (PGM-01, PGM-05, PGM-10 and PGM-11) have remained constant. The wells that supply Unit 3 (PGM-14, PGM-60 and PGM-62) show a trend of increasing chloride, which is normal during the first months of production. In this figure, it is hard to identify clearly the northwestern inflow, which is well defined in Figures 4 and 6.

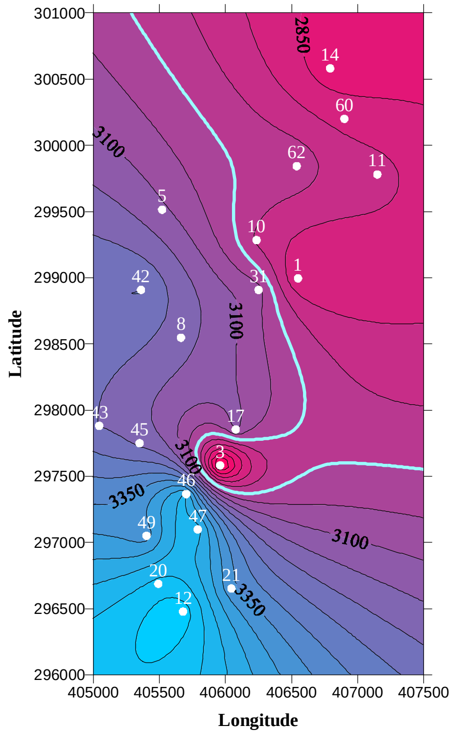

Figure 6. Contour Map of Chloride Content, March 2000

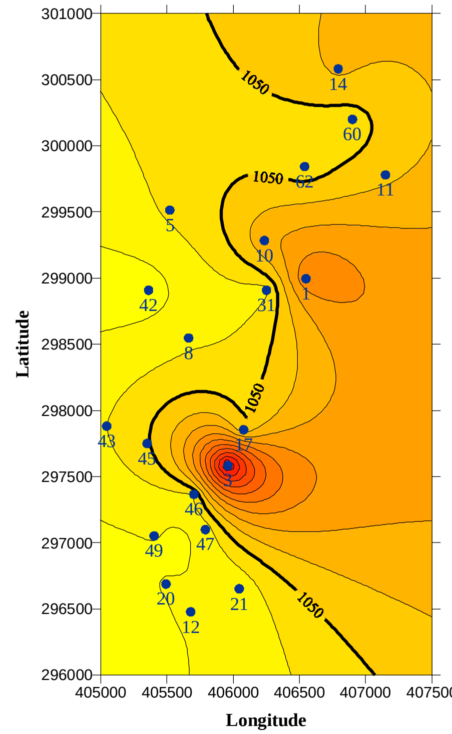

Figure 7. Contour Map of Enthalpy, March 2000

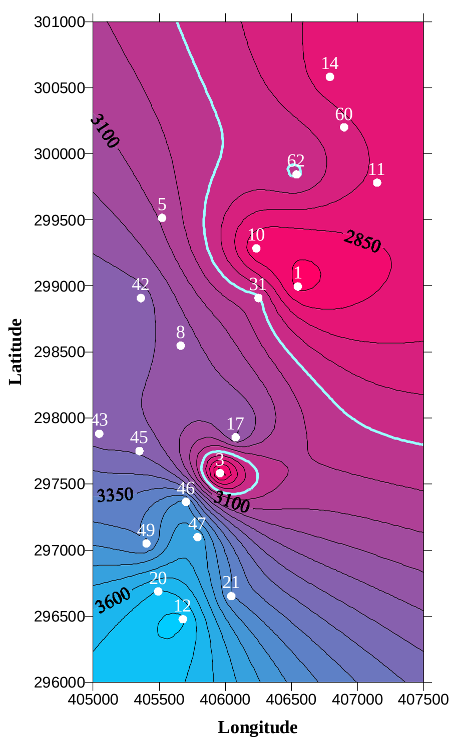

Figure 8. Contour Map of Chloride Content, November, 2000

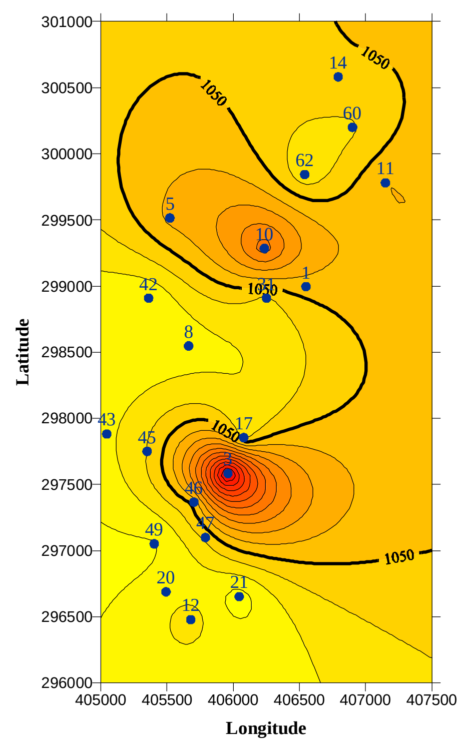

Figure 9. Contour Map of Enthalpy, November, 2000

Figure 9 is similar to Figure 7. The principal difference is that in wells PGM-10 and PGM-05 the enthalpy values have tended to increase, but in the majority of the wells the enthalpy has decreased. Wells such as PGM-21, PGM-42, and PGM-49 show enthalpy values below 1,000 kJ/kg, while enthalpies at wells such as PGM-11 and PGM-45 have remained constant.

In Figure 10 the variation of the monitored parameters for well PGM-12 can be observed. This well is located in the southern part of the production zone, and it has been used to supply Unit 1. PGM-12 shows the largest variation in chloride concentrations (884 ppm). During the first four years of production the enthalpy of this well gradually increased to 1,114 kJ/kg; it then decreased to 1,016 kJ/kg in early 1998, and has been constant since then. PGM-12 and PGM-46 are the only wells that have shown an initial magnesium concentration that is a bit higher than the reservoir average concentration (0.2 ppm vs. 0.05 ppm). During the last three years, the magnesium concentration in these wells has stabilized at about 0.07 ppm.

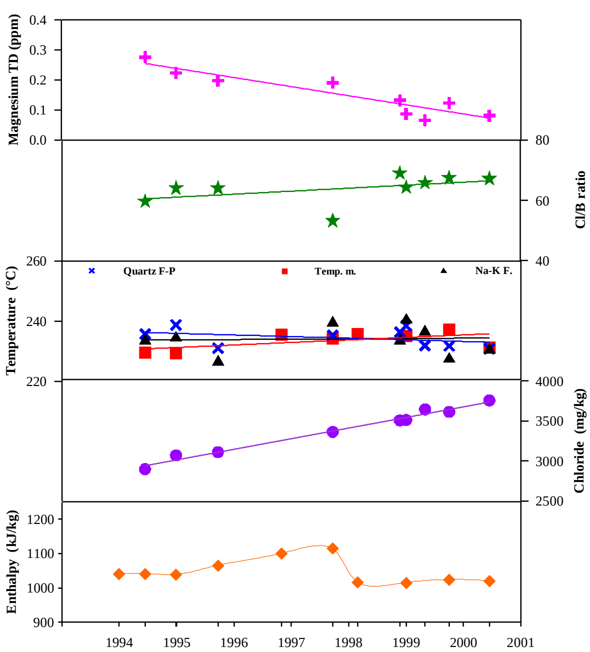

Figure 10. Parameters of well PGM-12.

The monitored parameters of well PGM-45 are shown in Figure 11. This well is located in the center of the field and has been utilized to feed Unit 2. Most of the parameters have remained constant over time, except for the chloride content, which has increased by 242 ppm since August 1996. Well PGM-17 behaves similarly to well PGM-45; in this case, the increase in the chloride concentration has been 386 ppm since June 1995.

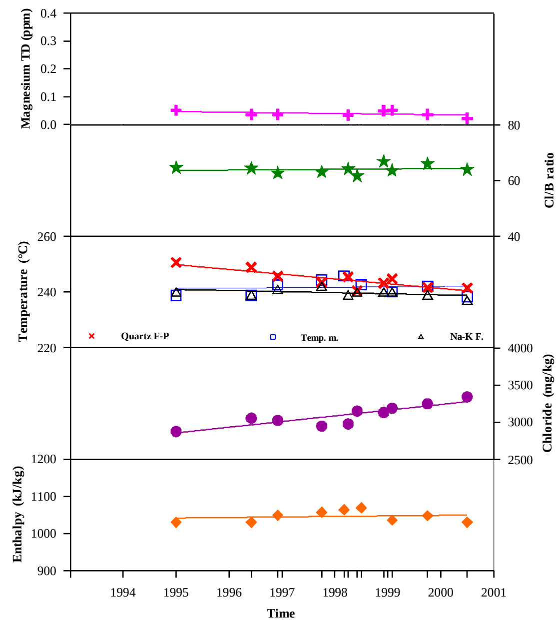

Figure. 11. Parameters of well PGM-45.

In Figure 12 the monitored parameters of well PGM-11 can be observed. This well is located in the northern part of the production zone and it was used to supply Unit 1 until February 2000. Since March 2000 the well has been used to supply steam to Unit 3. Even though PGM-11 has been producing since 1994, its parameters have remained constant. The behavior of well PGM-11 is similar to that of wells PGM-01 and PGM-31.

The monitored parameters of well PGM-21 are shown in Figure 13. PGM-21 is located in the southern part of the production zone and it has been used to supply Unit 1 since 1994. The enthalpy began to rise until it reached 1,147 kJ/kg by the middle of 1997; it then decreased to 979 kJ/kg. The chloride concentration increased by 88 ppm in the three years up to June 1997, then stayed constant for the following nine months. It then increased by 504 ppm during the last three and a half years.

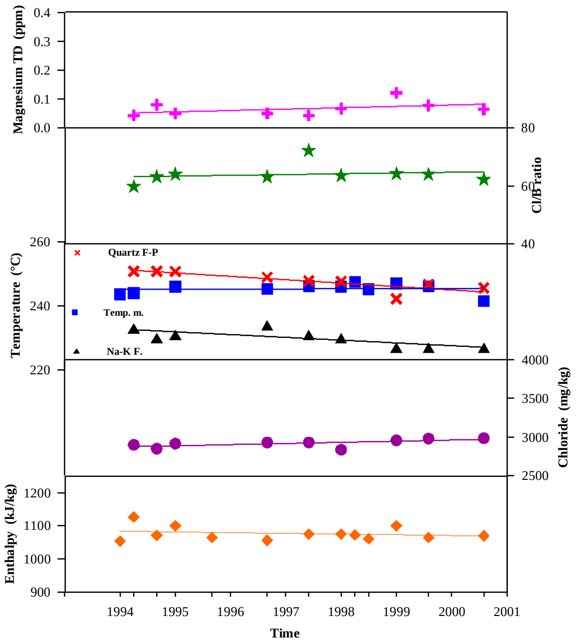

Figure. 12. Parameters of well PGM-11.

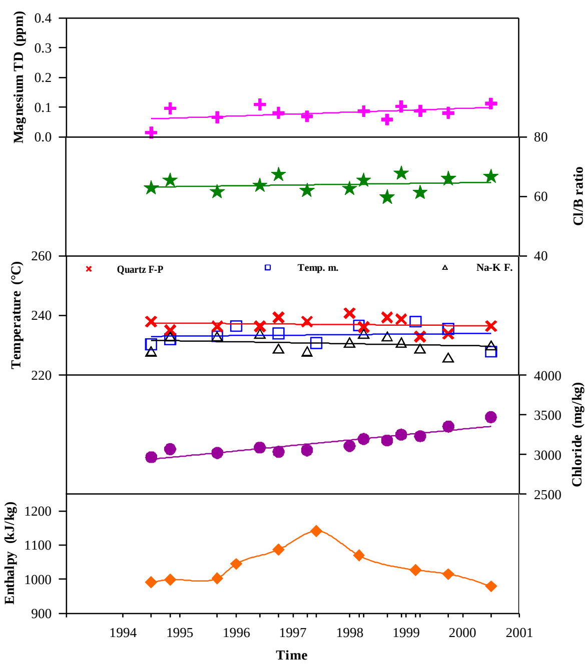

Figure. 13. Parameters of well PGM-21.

FIELD PRODUCTION

As mentioned above, the Miravalles Geothermal Field has been producing since 1994. Table 1 shows the increments of generation during these first seven years, and also the expected future development. As indicated in Table 1, the wellhead units from the Comisión Federal de Electricidad (Mexico) were in operation while Unit 2 was being built.

Plant Name	Start-up Date	Final Date	Power (MW)	Belongs to
Unit 1	3/1994	--	55.0	ICE
WHU-1	1/1995	--	5.0	ICE
WHU-2	9/1996	4/1999	5.0	CFE
WHU-3	2/1997	4/1998	5.0	CFE
Unit 2	8/1998	--	55.0	ICE
Unit 3	3/2000	--	27.5	ICE
Unit 5	9/2002	--	10 - 20	ICE

Notes:
ICE: Instituto Costarricense de Electricidad
CFE: Comisión Federal de Electricidad (México)
WHU: Well Head Unit

Table. 1. Geothermal units at Miravalles Geothermal Field.

Unit 1 is currently capable of generating 60 MWe; therefore at present there is a need to supply enough steam to generate 60 MWe (Unit 1), 5 MWe (Wellhead Unit 1), 55 MWe (Unit 2) and 27.5 MWe (Unit 3), for a total of 147.5 MWe. This capacity will be increased to 157.5 - 167.5 MWe when a second-flash unit or a binary plant comes online by the end of year 2002.

Figure 14 shows the rate of mass extraction from the Miravalles Geothermal Field since production began. The steam extraction rate increased gradually from May 1994 (350 thousand tons/month) until August 2000 (820 thousand tons/month). Liquid mass and total mass extraction have behaved in basically the same way: there was an increase from March 1994 (1 million tons/month) to May 1995 (2.5 million tons/month); they then fluctuated within a narrow band (1.7 to 2.5 million tons/month) until April 1998. Thereafter, the total mass extraction increased from 3.4 to 4.9 million tons/month and the liquid mass also increased from 2.9 to 4.1 million tons/month. This last increment has been due to the start-up of Units 2 and 3. The behavior of the extraction curves matches quite well the increases in generation over these years as the different new units were commissioned.

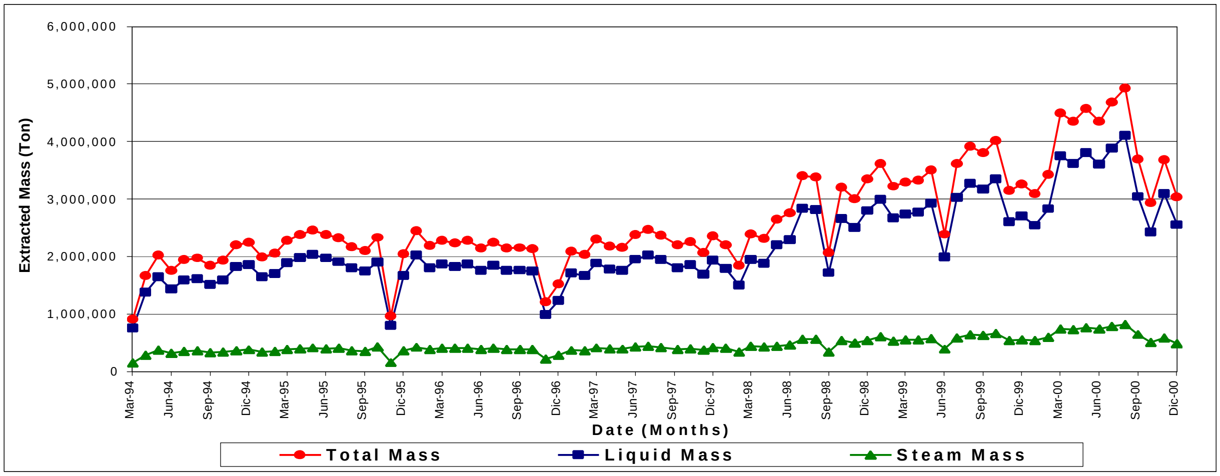

Figure 14. History of Mass Extraction

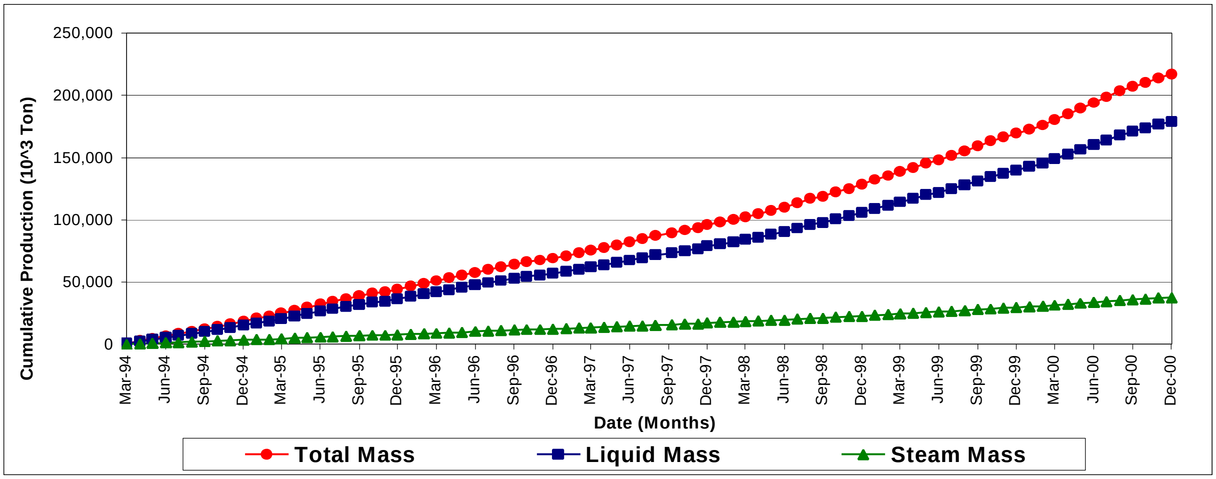

Figure 15. Cumulative Mass Extraction

Figure 15 shows the cumulative production of total, liquid and steam masses from the geothermal field. All of these masses increase linearly from March 1994 up to May 1998. When Units 2 and 3 started production the slope of the curves became steeper, but the increases were still nearly linear over those periods (from April 1998 to March 2000 and from April 2000 to December 2000). By December 2000, the accumulated production was approximately 38 million tons of steam, 180 million tons of liquid and 215 millions tons of total mass.

RESERVOIR MODELING

ICE contracted GeothermEx, Inc. (the consulting company for Unit 2) to perform numerical modeling of the reservoir behavior. The modeling effort consisted in simulating the initial state of the reservoir and matching historical production data. The model was then used to predict reservoir behavior under various future production and injection scenarios (ICE/GeothermEx, Inc., 1998).

For a numerical model to be fully calibrated, the observation-well pressures, flowing enthalpy, and flowing pressure or temperature transients must be matched. Although ICE has collected such data, only the observation-well pressures were usable for model calibration. The model matched all available observed pressure data. For wells in the main production zone, the difference between observed pressure and the pressure calculated by the model was less than 1 bar. The difference between observed and calculated pressures for wells outside the production area ranges from 1 to 2 bars. The reasonable agreement between the observed and calculated pressures suggests that the numerical model has been calibrated successfully. (ICE/GeothermEx, Inc.)

No flowing enthalpy data were matched in the numerical model because it was not possible to clearly identify the enthalpy trends. The flowing pressure trends were defined for most of the available production wells, but in most cases the corresponding temperature trends contradicted the trends of measured enthalpy (i.e., enthalpy declined while temperature increased). Therefore, neither flowing enthalpy nor flowing temperature trends could be used reliably to calibrate the model. Since the Miravalles numerical model has not been fully calibrated, the results from the forecast runs can be considered only as a general indication of the reservoir behavior under different production and injection scenarios. Generally, the model results indicated that the fluid enthalpy should remain stable and that the pressure drop should range between 0.73 to 1 bar/year, depending on the scenario under consideration, over a 25 year period (ICE/GeothermEx, Inc., 1998).

Current exploitation scenarios differ somewhat from the ones considered by the numerical model, and therefore the general model results cannot be compared to the actual performance of the reservoir. The actual pressure data show that the average pressure drop was about 1.5 bar/year before Unit 2 came online. A year after the commissioning of the second unit, the average pressure drop increased to 2.1 bar/year, which is reasonable considering that the total generation increased from 75 to 120 MWe. Finally, nine months after the commissioning of the third unit, the average pressure drop has increased to 2.7 bar/ year for a total generation of 147.5 MWe.

ICE has now contracted the services of GeothermEx, Inc. to incorporate the newly collected data into the numerical model of the Miravalles field, in order to predict the reservoir behavior under the current and future production and injection scenarios. The final results of this study are expected to be available by March 2001.

CONCLUSIONS

1. Wells PGM-01, PGM-11 and PGM-31 are the most chemically and physically stable boreholes at present.
2. Most of the wells show a tendency toward increased reservoir chloride content. The largest increase (884 ppm) appears in well PGM-12.
3. The northern inflow observed in Figures 4 and 5 shows a tendency to become less distinct; the chloride concentration in PGM-05 decreased since April 1998 and in PGM-42 since December 1999.
4. Injected fluids are present in the western and southern parts of the production zone. In the southern production zone, the enthalpies measured in November 2000 have decreased with respect to the measured enthalpies in 1998 (see Figure 5 and 9).
5. Tracer tests should be carried out in the southern part of the field to establish the origin of the injected fluids.
6. The commissioning of Units 2 and 3 can be identified as an increase of the mass extraction rates since May 1998 (see Figures 14 and 15).
7. The average reservoir pressure decline increased from 1.5 bar/year (75 MWe) to 2.1 bar/year (120 MWe) as a result of the commissioning of the second unit. Nine months after Unit 3 came on line, the average pressure drop increased to 2.7 bar/year.
8. The results of the new reservoir modeling studies are expected to be available by March 2001. With those results, it will be possible to predict reservoir behavior under the current and future production and injection scenarios.
9. So far the Miravalles Geothermal Field has been able to supply the steam required to feed all the units installed in the field.

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