

Evolution of the Miravalles Geothermal Field in Costa Rica after Ten Years of Exploitation

Carlos González-Vargas, Paul Moya-Rojas, Eddy Sánchez-Rivera, Osvaldo Vallejos-Ruiz, and Antonio Yock-Fung
Instituto Costarricense de Electricidad - C. S. Recursos Geotérmicos, Apartado Postal 10032-1000, San José, Costa Rica

cgonzalezv@ice.go.cr - pmoya@ice.go.cr - esanchezr@ice.go.cr - ovallejos@ice.go.cr - ayock@ice.go.cr

Keywords: Miravalles Geothermal Field, Costa Rica, Production, Field Management

ABSTRACT

The Miravalles Geothermal Field has been producing since 1994, and its installed capacity has now reached 163 MW. The field is a high-temperature liquid-dominated reservoir with temperatures reaching 230-255°C. Since exploitation began, the reservoir's chemical, hydraulic and thermal parameters have been carefully monitored to assess the changes produced by commercial exploitation. The reservoir response over a ten-year exploitation period has evolved notably due to massive production and injection in some sectors of the field. Further monitoring and modeling studies must address critical questions such as the proper design of production and injection policies, the strategies to be carried out and the future impact on the reservoir from commissioning a new power plant (Unit 5) in early 2004 and other possible developments.

1. INTRODUCTION

The Miravalles Geothermal Field is under exploitation in Costa Rica (Figure 1). Deep drilling started in 1979, when a high-temperature reservoir was discovered. Subsequent drilling has provided the steam supply needed for three flash plants commissioned in 1994, 1998 and 2000, a wellhead unit in 1995 and one binary plant commissioned in 2004, comprising an installed capacity of 163 MW. In addition, two 5 MW wellhead units from the "Comisión Federal de Electricidad" (Mexico) were in operation (1996 – 1998) while Unit 2 was being built, but these have been decommissioned.

As part of the management of the field, a monitoring program was set up after the first production tests and before the first power plant was commissioned. This provided baseline parameters for assessing the changes that would be caused by reservoir exploitation. The monitoring program includes well output testing, chemical sampling (for control of calcium, chloride and bicarbonate concentrations in production wells), downhole surveys (static temperature and pressure profiles, go devils and caliper logs) and a downhole pressure data gathering system which has been monitoring the reservoir continuously since June 1994, complemented by systematic hydraulic-level measurements (Vallejos et al., 2005). Several numerical models for forecasting the future behavior of the field have also been developed from the data collected (Vallejos et al, 1995, Mainieri et al, 2002) and Pham et al, 2000).

2. RESERVOIR CHARACTERIZATION

The Miravalles Geothermal Field (Figure 1) is a high-temperature liquid-dominated reservoir related to the nearby Miravalles Volcano (elevation 2028 m a.s.l). The reservoir is located at about 700 m depth, and its temperature naturally diminishes to the south and west. The estimated thickness of the reservoir is about 800-1000 m.

The field is associated with a 15 km wide caldera, which has been affected by intense neo-tectonic phenomena. The interior of the caldera is characterized in general by a smooth morphology. The main reservoir fluids have a sodium-chloride composition, with 5300 ppm TDS, a pH of 5.7 and a silica content of 430 ppm (under reservoir conditions). The fluids tend to deposit carbonate scale in the wells; this is prevented using an inhibition system that injects a chemical into the wellbores. The main aquifer is characterized by a 230-255°C lateral flow. A shallow steam-dominated aquifer located in the northeastern part of the field is formed by boiling of fluid from the main aquifer as it moves along fractures (Vallejos, 1996).

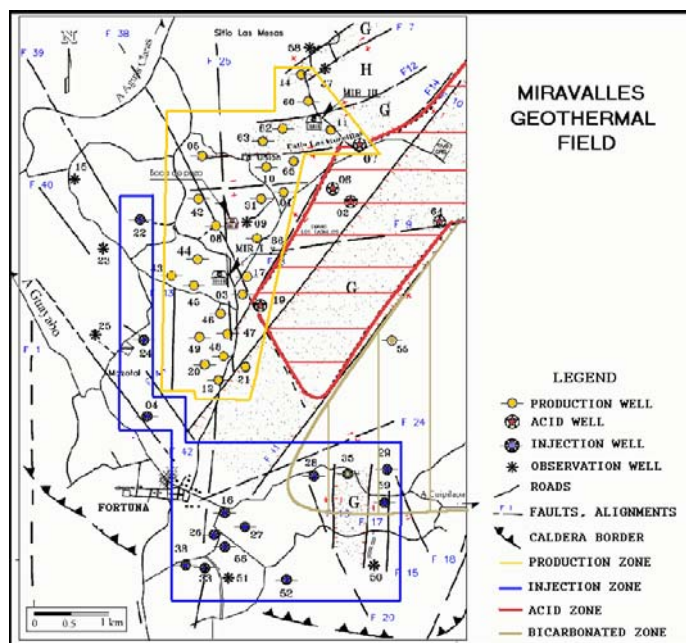


Figure 1. The Miravalles Geothermal Field.

There is an important sector where acid fluids are present, and so far five wells have been drilled that produce these kinds of fluids. Two of the acid wells have been successfully neutralized and used for commercial production (Sánchez et al., 2000). There are plans to test and later put online the rest of the acid wells.

3. CONCEPTUAL MODEL

The conceptual model of the Miravalles Geothermal Field is shown in Figure 2. The main features of the reservoir are:

- Heat source: a magmatic body located somewhere in the NE part of the field at an unknown depth.
- Caprock: its thickness is around 400-600 m and increases to the west and south. It is formed mainly by the upper part of the Volcanic-Sedimentary Unit.

- Main reservoir: volcanic units intensely fractured by neotectonic events within a graben structure. Its permeability is mainly secondary (fractures).
- Meteoric recharge: the structural conditions of the area assure an adequate recharge of the geothermal reservoir by meteoric water.
- Hydrothermal circulation: the main zone of recharge to the system is located in the NE sector of the field, near PGM-11 and possibly extending far from this well. The upflow comes through deep structures, and flows laterally through permeable formations in a SW direction. Near well PGM-10 the flow changes direction slightly towards the south, flowing preferentially along fractures and faults related to a N-S neotectonic system. This flow continues southward and discharges to the surface at a point located 7 km from the caldera border. This flow pattern applies to the main (neutral) aquifer. The acid aquifer is located in the E-NE part of the field, and its extent is not completely defined yet.

The proven reservoir area is about 13 km², and a similar area is classified as a sector for probable expansion. Another 15 km² area is identified as also having some possibilities for future development (ICE/ELC, 1995). These areas may increase as the reservoir is investigated further.

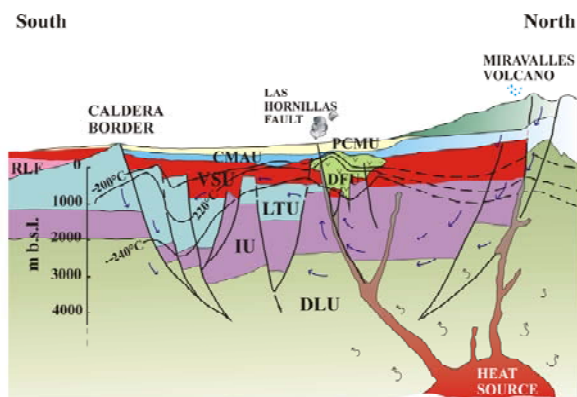


Figure 2. Conceptual Model of the Miravalles Geothermal Field (Vega et al., 2005)

4. PRODUCTION HISTORY

The Instituto Costarricense de Electricidad (ICE) commissioned the first 55 MWe power plant in March of 1994. Later that year the production was increased to 60 MWe. Subsequent field development led to the commissioning of a second 55 MWe unit in August 1998. Between these dates, three 5 MWe wellhead units produced an additional 15 MWe. Two of wellhead units, owned by Comisión Federal de Electricidad de México, were retired in August 1998 and January 1999; the other, which belongs to ICE, continues to produce sporadically. The wellhead units had a steam consumption rate about double that of the Unit 1 flash plant, so the equivalent mass extraction when these plants were operating was enough to produce almost 30 MWe. In March 2000, a 29 MWe power plant owned and operated under a build-operate-transfer (BOT) contract with Geoenergía de Guanacaste (a subsidiary of Oxbow-Marubeni) and known as Unit III was commissioned. The last power plant added, Unit V, is a 19 MWe binary plant that uses some of the residual heat of the injection fluids going to the south of the field. Under this scheme, ICE is the sole owner and operator of the field (Table 1).

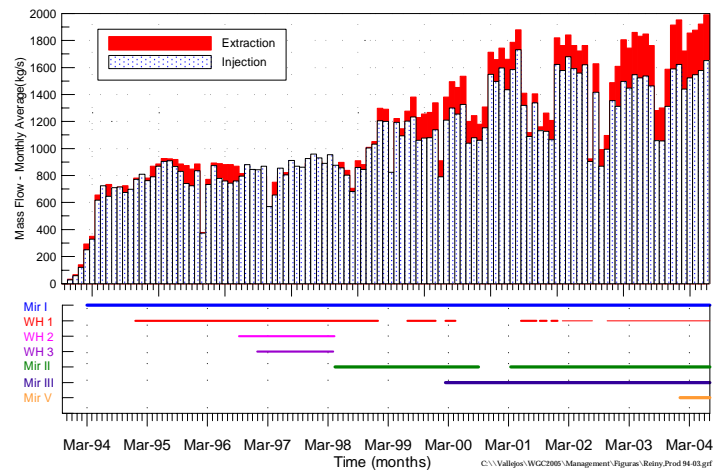


Figure 3. Production of the Miravalles Geothermal Field (November 1993 – June 2004).

Table 1. Generating Units at Miravalles.

Plant	Operator	Installed Capacity (MW)	Operation Time	
			Start	End
Unit I	ICE	55	03/1994	---
WHU 1	ICE	5	11/1994	---
WHU 2	CFE *	5	09/1996	08/1998
WHU 3	CFE *	5	04/1997	01/1999
Unit II	ICE	55	08/1998	---
Unit III	ICE**	29	03/2000	---
Unit V	ICE	19	01/2004	---

Notes: * CFE means Comisión Federal de Electricidad de México.

**This unit is privately operated under a BOT contract.

Table 2. Injection Rates at Miravalles (% of Total Mass Reinjected).

Start	End	South	PGM-22	PGM-24	PGM-04
03/1994	07/1998	38%	24%	22%	11%
08/1998	02/2000	69%	14%	10%	6%
03/2000	11/2002	76%	8%	8%	8%
12/2002	12/2003	64%	11%	17%	8%
01/2004	04/2004	68%	14%	14%	4%

Notes: Between 1994-2002 PGM-02 was receiving some quantities of fluid.

Over time there have been some changes in the production and injection rates and schemes in the field. From 1994 to 1998, a quart of the total injection was done in well PGM-22, another quart in well PGM-24 and the rest in the southern part of the field (wells PGM-16 and 26). From 1998 to 2000 the generation rate was doubled, as were the extraction and injection rates. Injection into wells PGM-22 and 24 decreased to about one half of the previous rate, and the balance was shifted to the southern wells (PGM-16, 26, 27, 51 and 56). From 2000 to the end of 2002, the production rate was again increased, and the injection was directed towards the south (Figure 3).

In late 2002 a portion of the water injected in the south was diverted back to the western sector of the field (Table 2), but with the commissioning of Unit V in early 2004 the injection temperature was lowered to from 165°C to 136°C.

5. RESERVOIR RESPONSE

5.1 Thermal & Chemical Evolution

Under natural (undisturbed) conditions, the NE sector of the reservoir presents the highest temperatures (Figure 4) and enthalpies (Figure 5) in the field; these decrease gradually towards the south. Some wells to the north (PGM-10 and 11) are in a boiling point with depth condition. Chloride (Cl⁻) contents were similar across the whole field (Figure 6), though the eastern wells had slightly higher values compared with the western-sector wells. The Ca/Cl ratio (Figure 7) is greatest in the northwest, showing that the fluids of this sector are richer in calcium.

A year later and over the following four years (1994-1998), the onset of massive production induced the hot fluids coming from the northwest to move more rapidly towards the center of the field, increasing the temperature and enthalpy (Figures 8 and 9). The effect of injection appears as an increase in the Cl⁻ content, due especially to the influence of the injection wells in the western sector. A tracer test done 11 months after the first plant was commissioned (Yock et al, 1995) confirmed the observed changes. The movement of fluids (Figures 8 and 10) coming from the northeast was also observed. These effects increased slightly with time until the end of 1996. By the middle of 1996 to early 1999, two wellhead units were producing an additional 10 MWe. The additional waste fluids were injected in the southeastern (PGM-28) and southwestern sectors (PGM-04). The combined effect of an increasing influence of reinjection coming from the west and the southeastern injection is seen as a slight variation in temperature (Figure 8) and enthalpy (Figure 9) near the western injector wells, and as a increase in the Cl⁻ content and Ca/Cl ratio (Figure 11). However, no noticeable thermal breakthrough had been seen by the end of 1997.

At the beginning of 1999, the influence of commissioning the second plant (in mid-1998) is noted. Injection was decreased in the western sector and the wellhead unit located at PGM-29 had operated for several months. These changes produced an increase in enthalpy and temperature near the western injection wells, and moved the fluid front from the southeastern sector toward the central zones of the field. The Ca/Cl ratio shows an advance toward the southwestern sector, while the northwestern sector maintains stable values. It should be emphasized that, even though the increase in this ratio from the west toward the center of the field is evident, the northeastern sector has not been influenced. This behavior indicates two possible fluid components, one of natural origin coming from the northeast and the other one induced coming from the injection zones, and composed largely of the local waters from these zones plus an injection component.

By the end of 1999, the wellhead unit at PGM-29 had been decommissioned, and well PGM-28 was still in use as an injector. At that time, the temperature decreased (Figure 12) towards the east as a consequence of the injected fluids coming from the south. The enthalpy does not show much change in the southwestern sector, but to the east of wells PGM-22 and PGM-24 a significant effect on the enthalpy (Figure 13) and Cl⁻ content (Figure 14) is noted. This could have originated from fluids in the southwest migrating northward, coming mainly from well PGM-24, which has a

greater influence than the southern injection wells PGM-16, 26, 56, 51 and 28. The Ca/Cl ratio (Figure 15) continues to be stable throughout the field, showing that the influence of the calcium-rich fluid component from the west has decreased considerably, possibly minimized by a more influential southern component. Another factor that could influence the stabilization of the Ca/Cl ratio is that the calcium content of the mass extracted from the west nearly equals the maximum calcium values present in that zone.

Unit 3 was commissioned in March 2000. Subsequently, a general decrease of temperature (Figure 16) and enthalpy (Figure 17) in the field was seen, especially to the northeast of well PGM-60. It must be noted that the local temperature decrease in wells PGM-10 and 11 was due to boiling in formation rather than the advance of fluids coming from the south, as can be observed in the enthalpy behavior of wells PGM-31, 01 and 05. However, the enthalpy decreased towards the north-northeast, due to the changes mentioned. Well PGM-03 represents an isolated, local enthalpy caused by well damage that affects the temperature. Other anomalies occur in the vicinities of wells PGM-60, 62 and 19 because these wells had been producing for only a few months and they had not totally recovered (Figures 16 and 17). The Cl⁻ content (Figure 18) continues to increase toward the northeastern sector, slightly in the northwest and west-central sectors, and substantially in the southwest and southern sectors, where the Cl⁻ front, which originated in the southern injection wells, is stronger. The Ca/Cl ratio (Figure 19) shows a slight increase due to a decrease in the calcium-rich component coming from the west, compared to the evolution shown in previous years. The increasing rate of exploitation led to a decline in the total field-wide mass flow rate, caused by the combined effects of the injection breakthrough and reservoir pressure decline. The wells most affected were PGM-08, 46 and 21. Decline trends are not well defined, but the more productive wells have lost between 6 and 8 MWe each over a 6-year period.

In November 2001 the production and injection scheme remained the same as in November 2000. Under this condition, the temperature did not show major changes (Figure 20), but the enthalpy seemed to be affected slightly (Figure 21). It must be considered that these two parameters showed this condition as of July 2001. The strong injection in the south can still be observed in the chloride pattern shown in Figure 22. The stability of the Ca/Cl ratio (Figure 23), compared with the changes observed earlier, shows that the advance of the more calcium-rich fluids coming from the west has stopped. The Ca/Cl ratio and Cl⁻ concentrations show the influence of the injected fluids coming from the west. A year later, a slight decrease in temperature is observed in the south-central sector of the field, which is an indication of the increasing influence of injection in the south. The enthalpy shows the same trend of decline; however, the development of a high-enthalpy sector in the northeastern part of the field is observed. This is possibly associated with pressure decline caused by reservoir exploitation, and also with the formation of steam caps in some sectors of the field.

Due to the increasing influence of injection in the south-central sector of the field and the general pressure decline in the reservoir, ICE decided to modify the injection scheme by reducing the amount injected in the southern wells and increasing it in the west (wells PGM-22 and PGM-24). This change was made in November 2002, so its effects were not observed at that time (Figures 24 to 27).

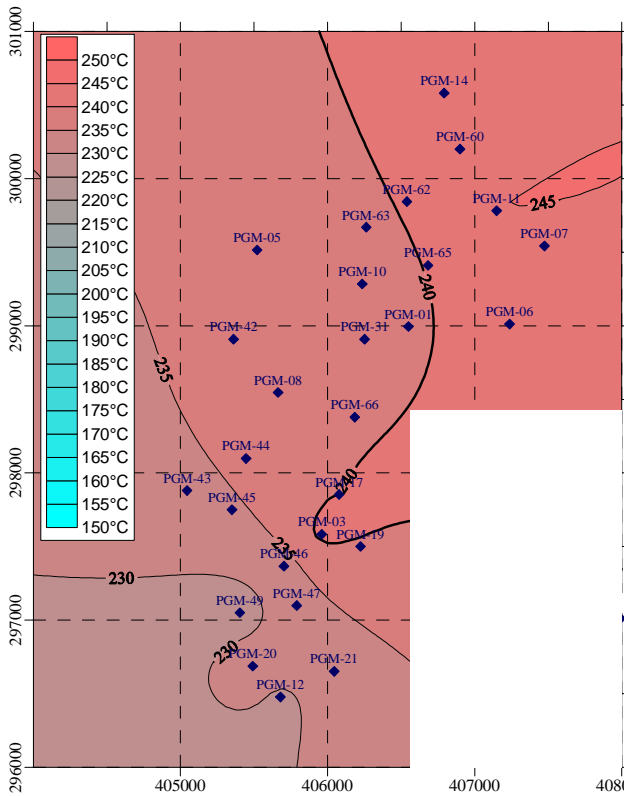


Figure 4. Temperature - March, 1994

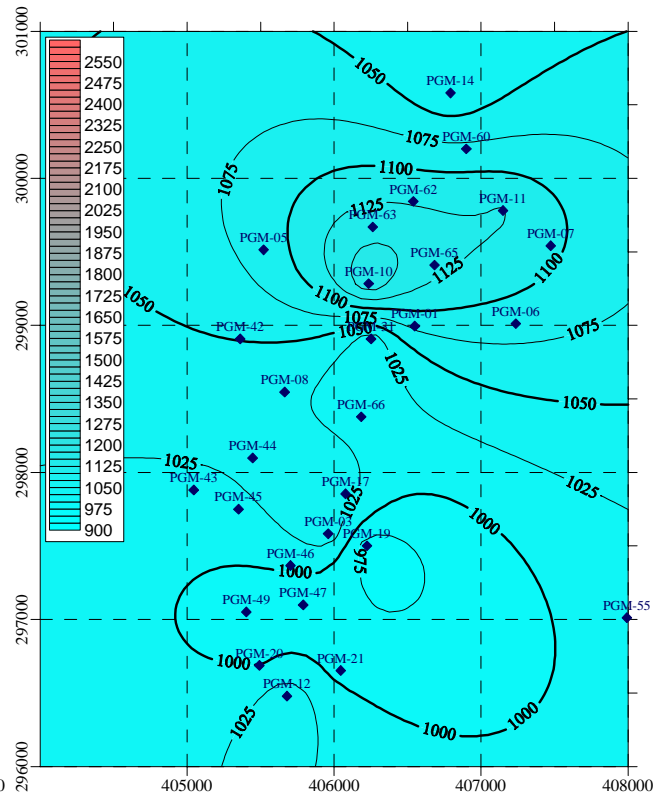


Figure 5. Enthalpy – March, 1994

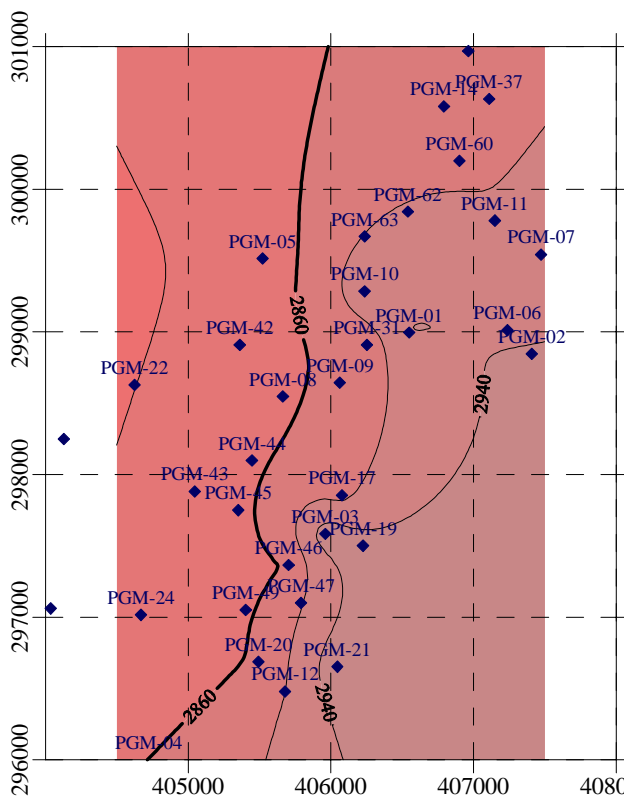


Figure 6. – Chlorides - March, 1994

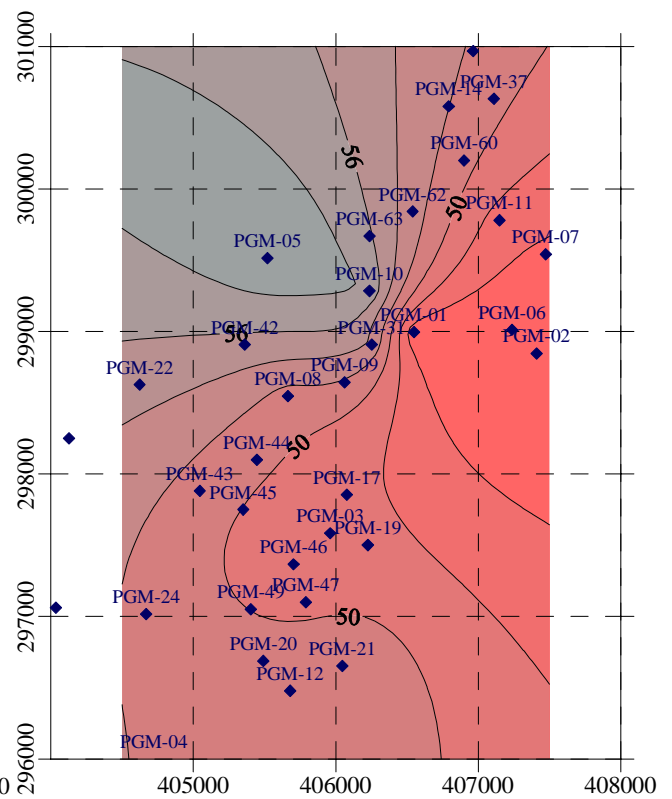


Figure 7. Ca/Cl*3000 Ratio – March, 1994

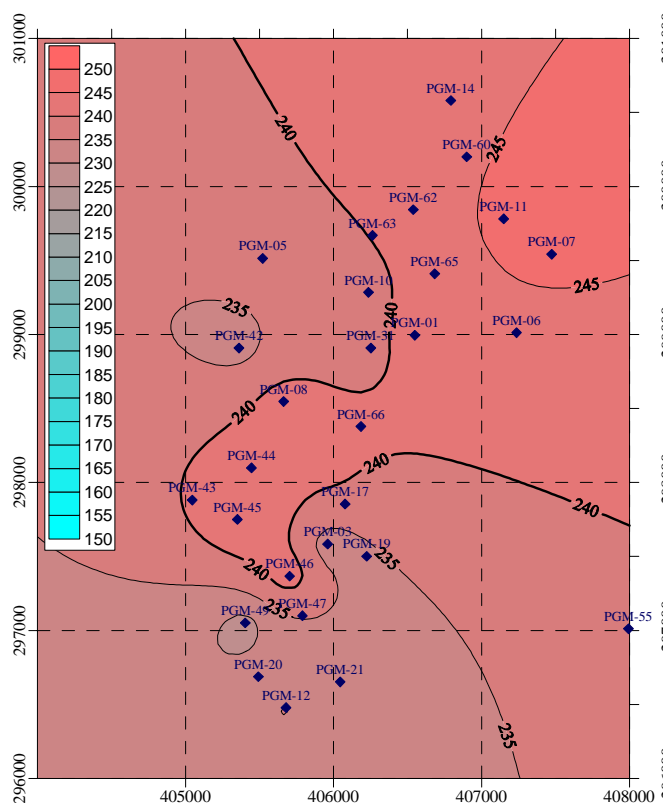


Figure 8. Temperature – August, 1997

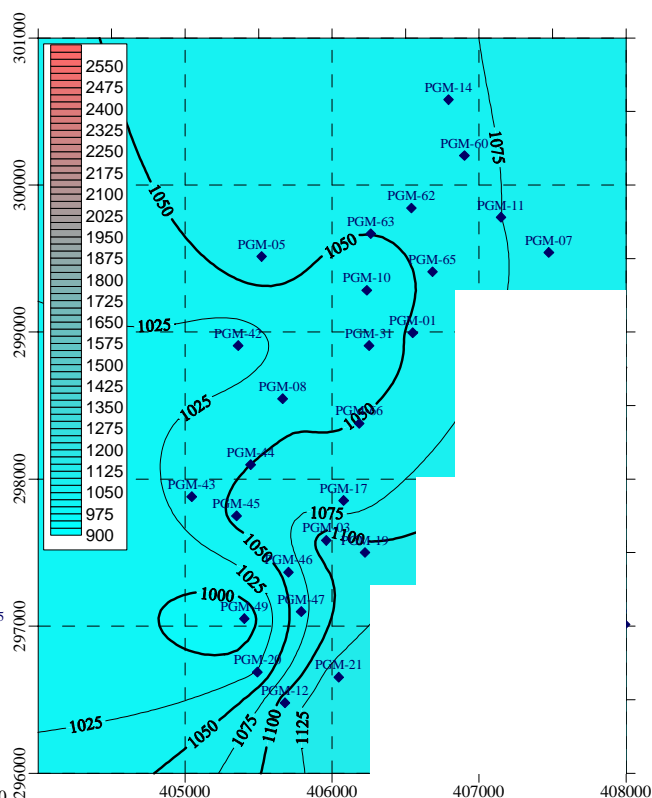


Figure 9. Enthalpy – August, 1997

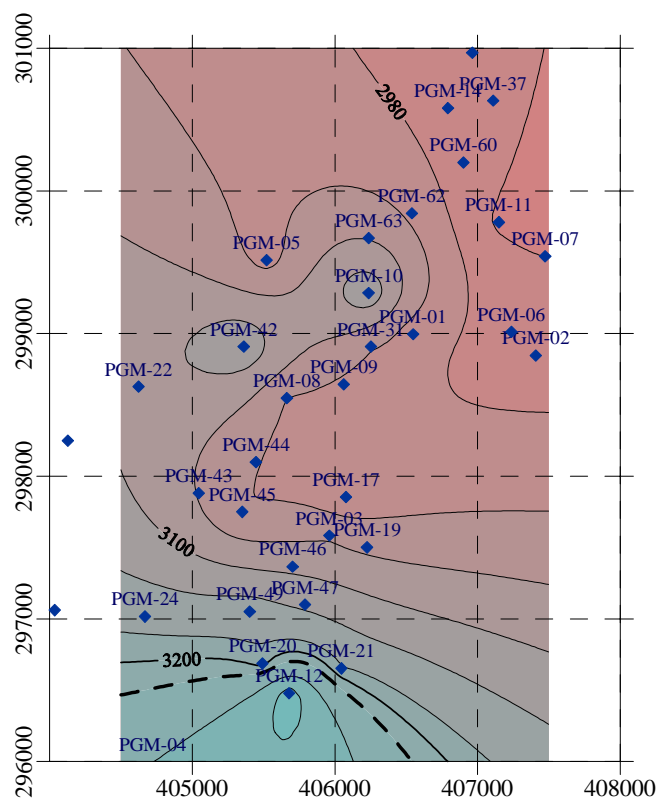


Figure 10. Chlorides – August, 1997

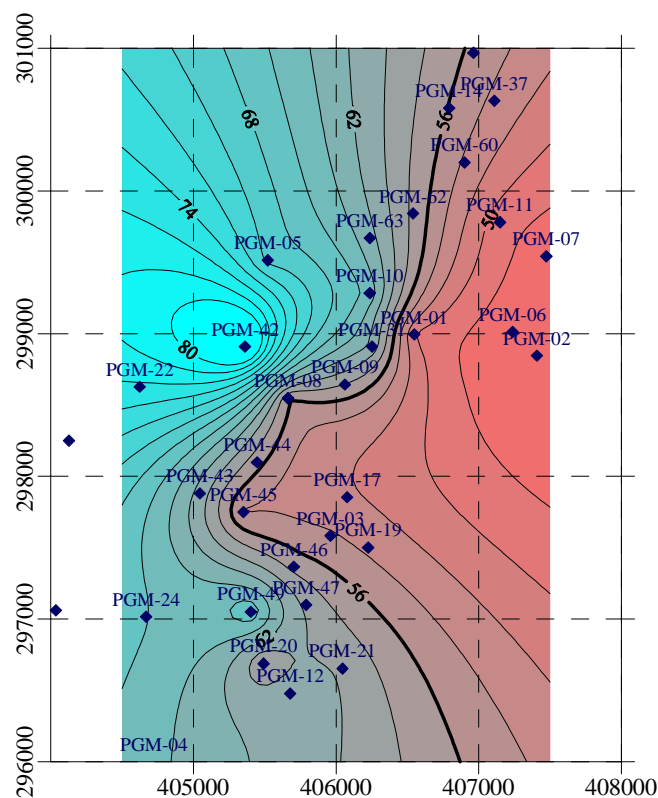


Figure 11. Ca/Cl*3000 Ratio – August, 1997

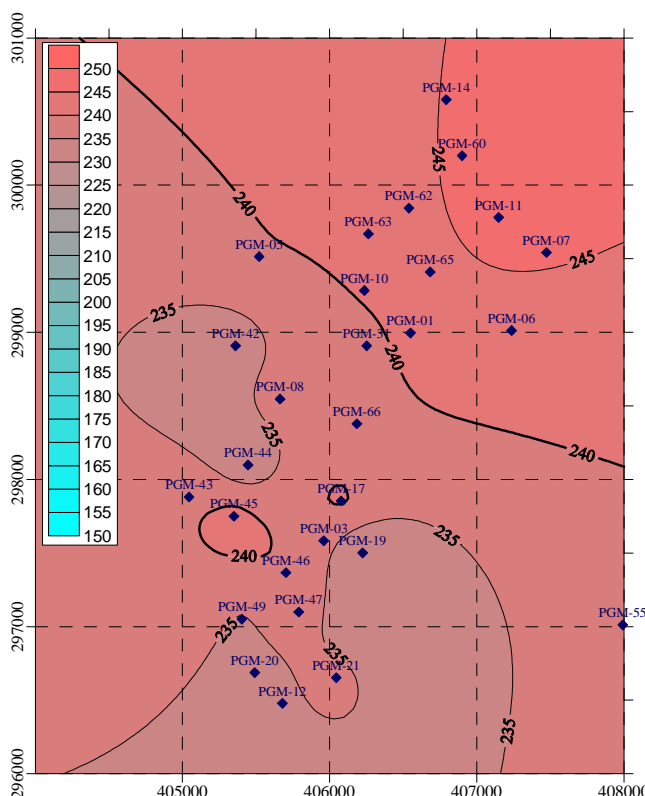


Figure 12. Temperature – November, 1999

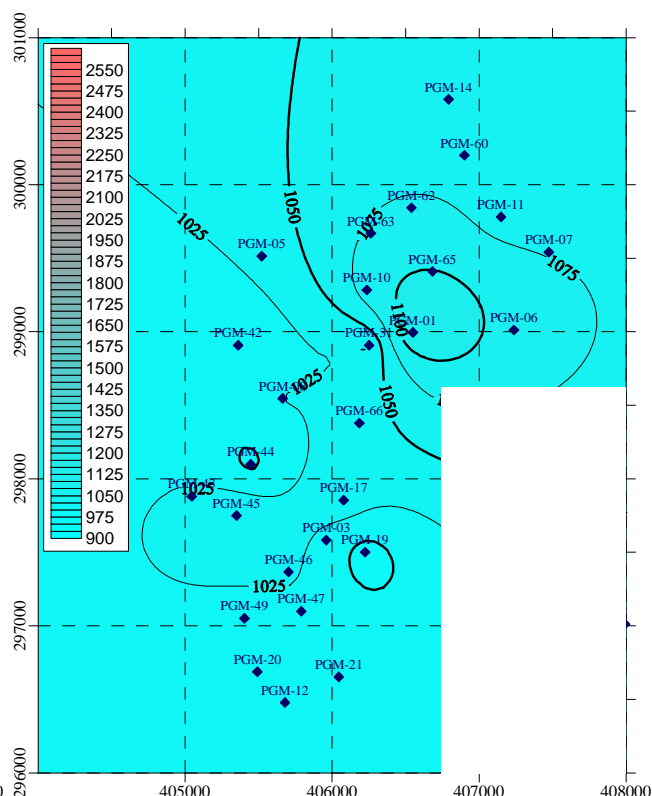


Figure 13. Enthalpy – November, 1999

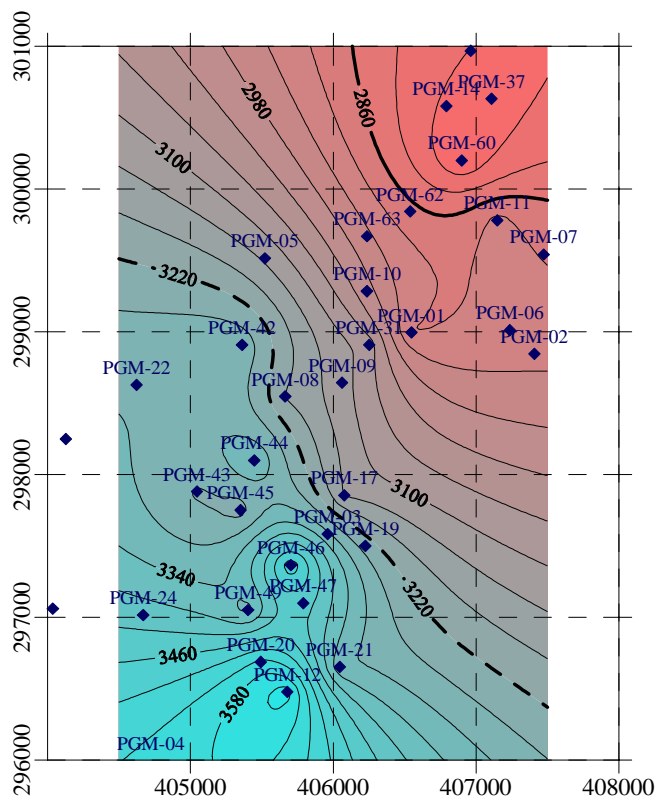


Figure 14. Chlorides – November 1999

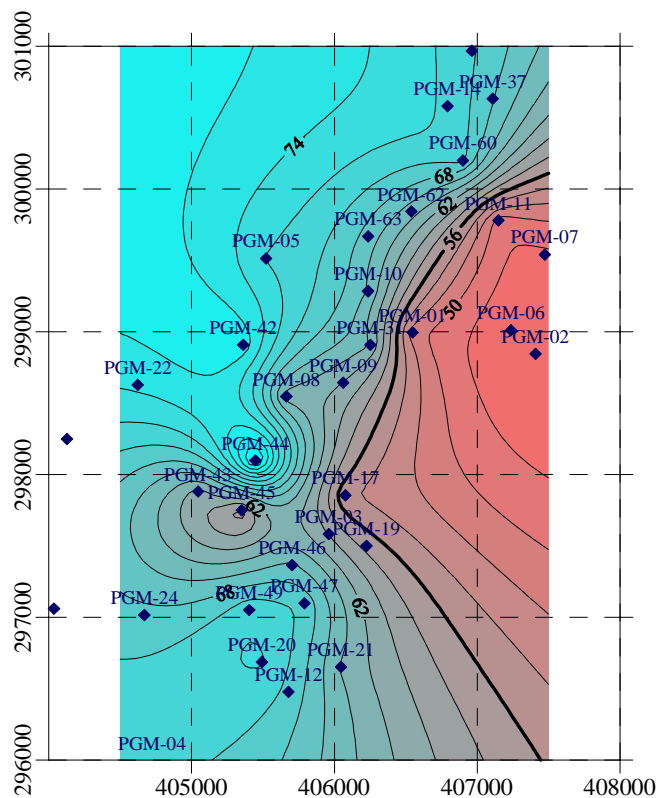


Figure 15. Ca/C*3000l Ratio – November, 1999

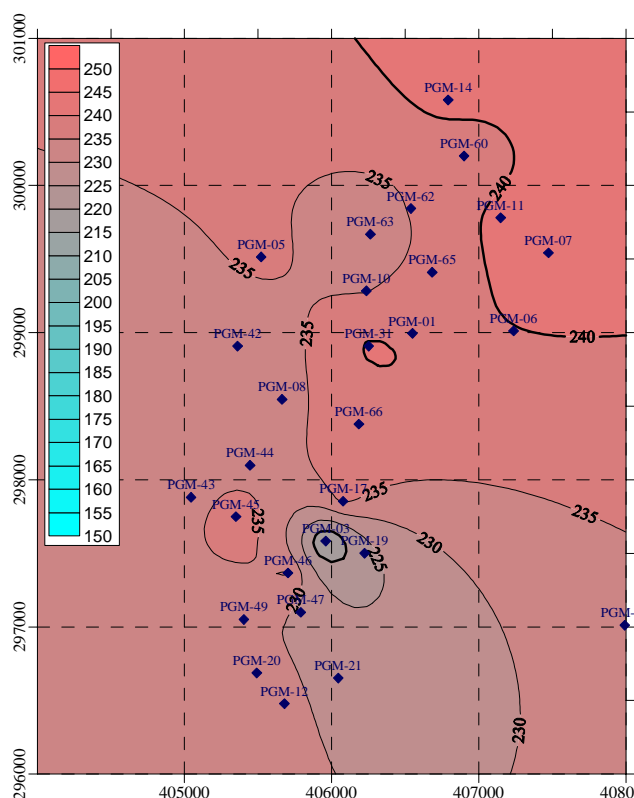


Figure 16. Temperature – November, 2000

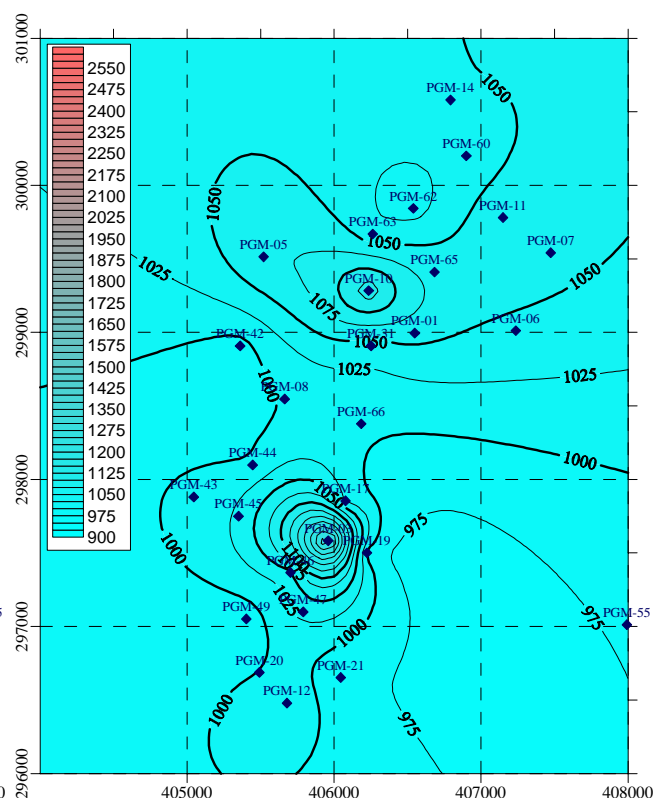


Figure 17. Enthalpy – November, 2000

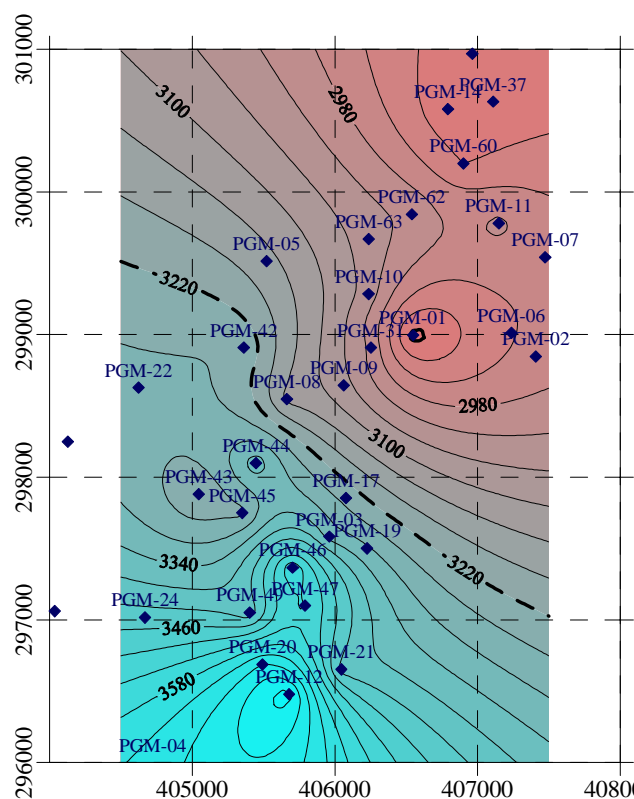


Figure 18. Chlorides – November, 2000

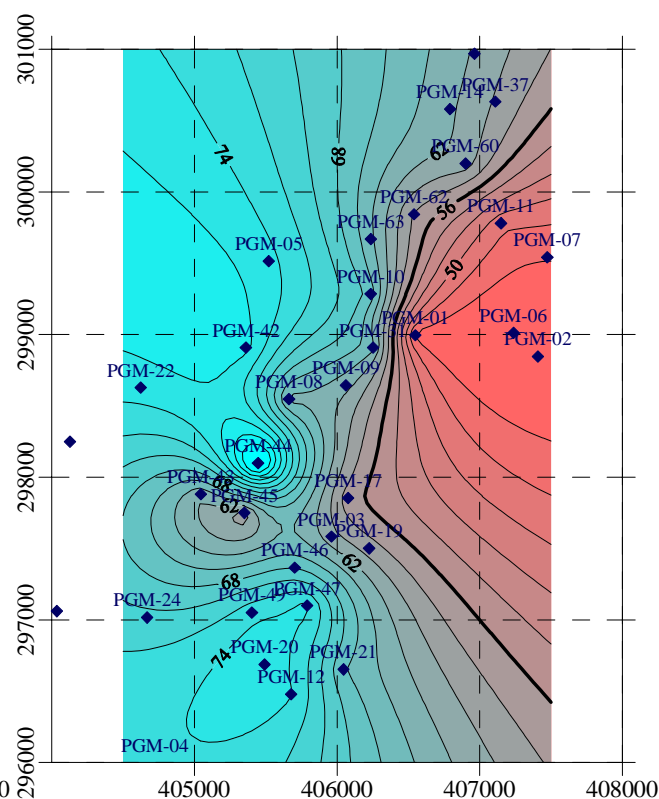


Figure 19. Ca/Cl*3000 Ratio – November, 2000

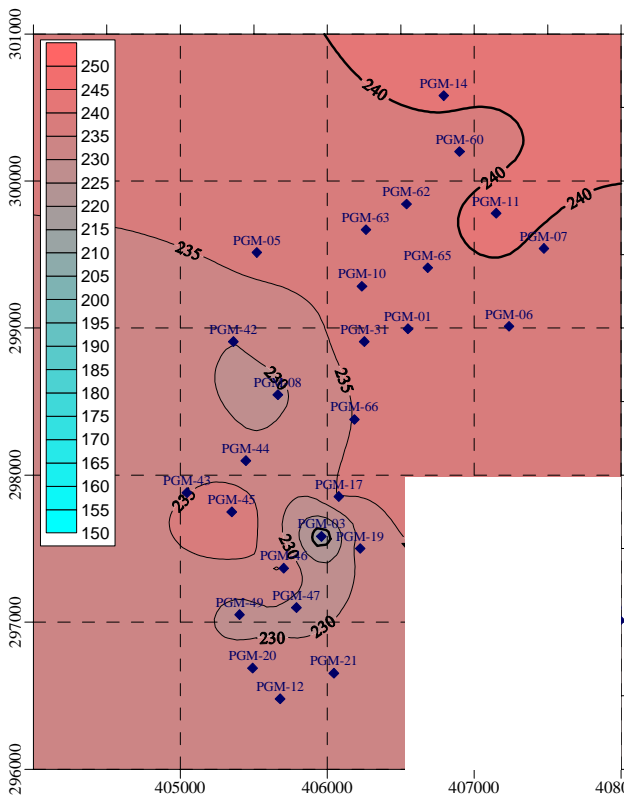


Figure 20. Temperature – July, 2001

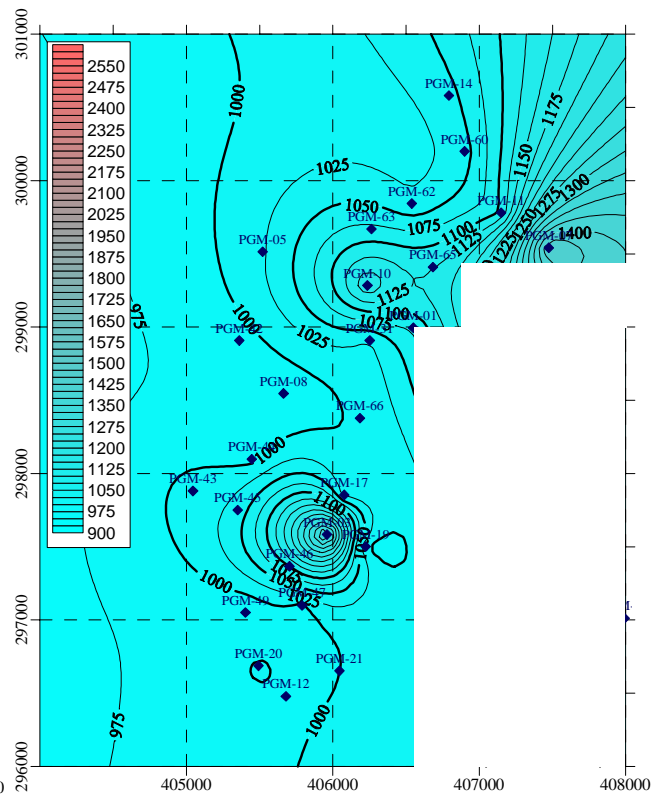


Figure 21. Enthalpy – July, 2001

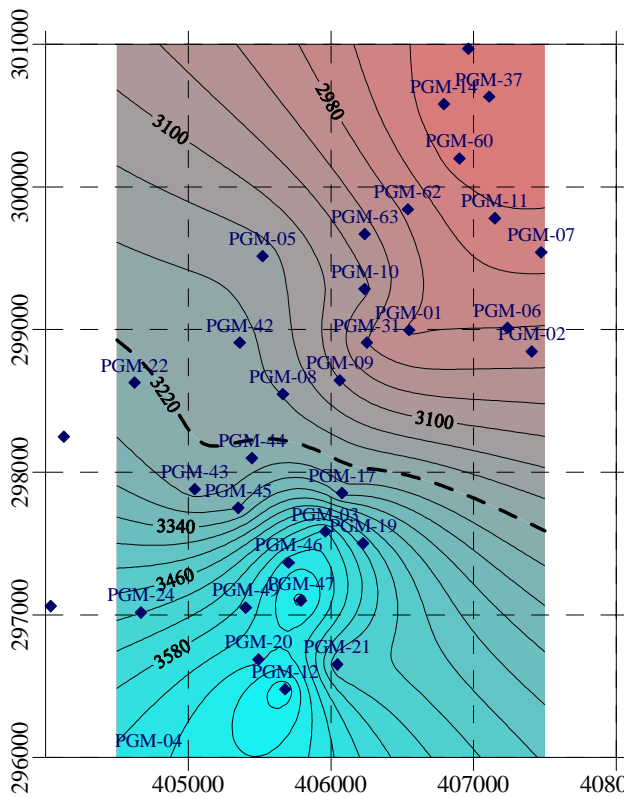


Figure 22. Chlorides – November, 2001

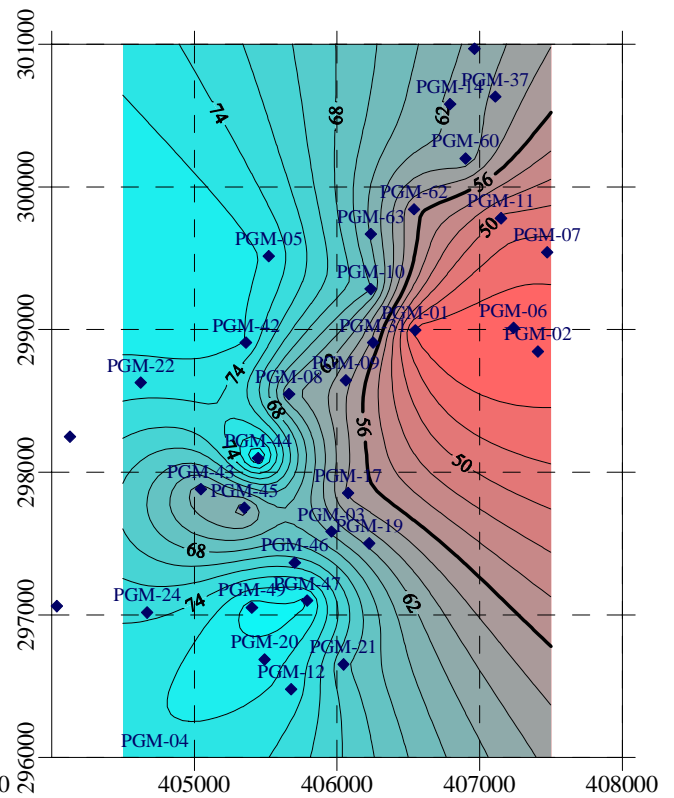


Figure 23. Ca/Cl*3000 Ratio – November, 2001

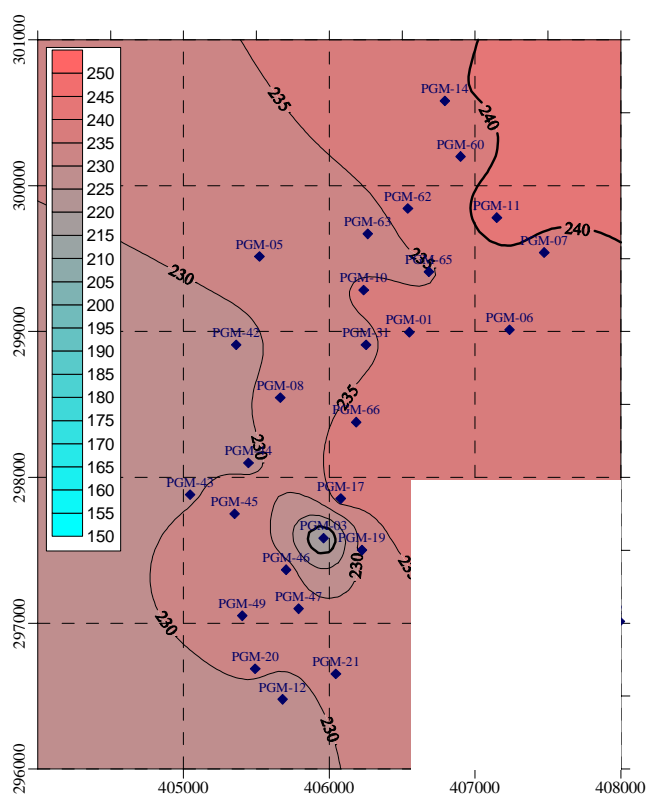
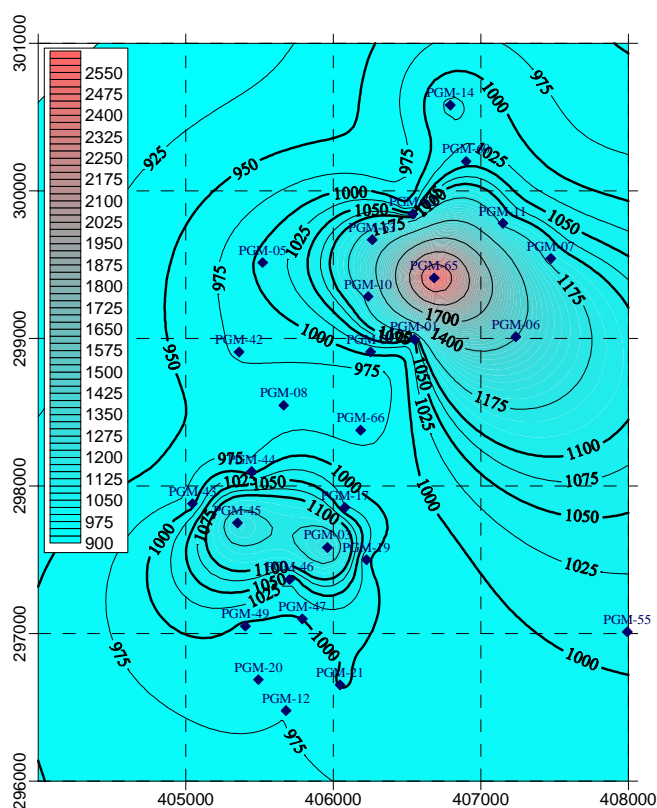


Figure 24. Temperature – September, 2002



Figures 25. Enthalpy – September, 2002

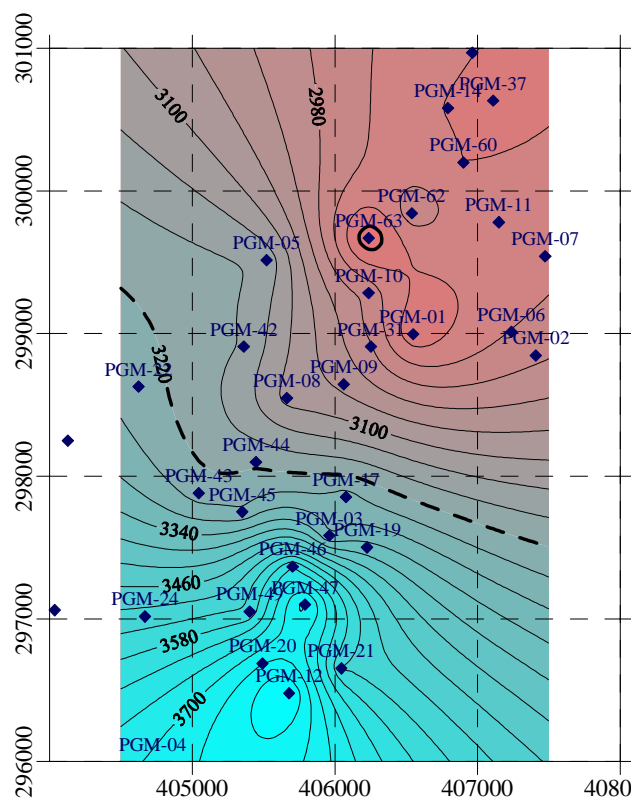


Figure 26. Chlorides – November, 2002

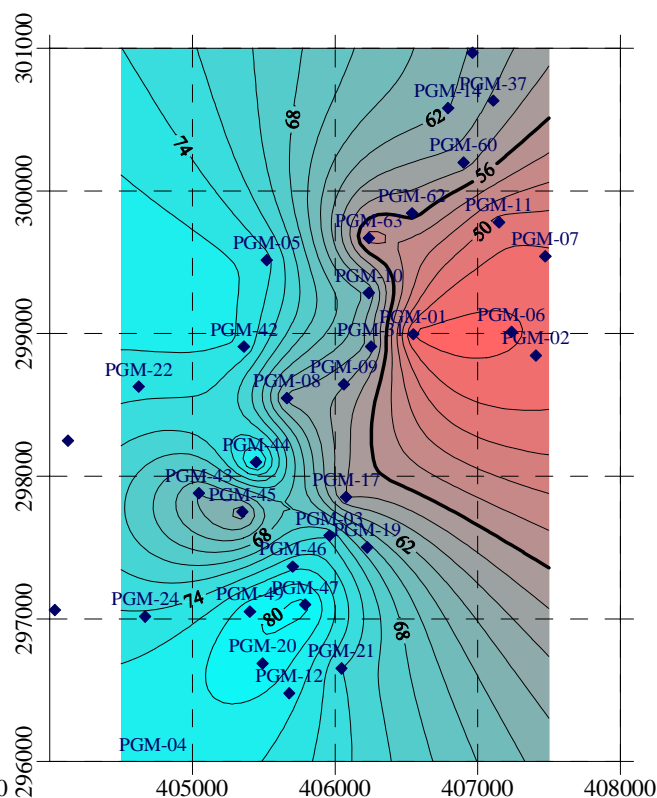


Figure 27. Ca/Cl*3000 Ratio – November, 2002

10

A year after this injection change took place, the effects are noticeable. An advance of the chloride front near PGM-22 is observed. There is also injection return in the central part of the field, appearing as a chemical front but not as a thermal breakthrough, and no noticeable cooling has occurred in this part of the field (Figures 28 to 31).

The changes made to the reinjection scheme during the period of reservoir exploitation (1994-2003) are reflected in the temperature behavior. The static temperature measured at the feed zones of the different wells showed a tendency to increase from 1994 until reaching a maximum between 1998 - 1999, right after the mass extraction rate increased due to the start-up of Unit II. After this point, a temperature decline began to be noticed in the majority of the wells.

5.2 Reservoir Pressure Evolution

Figure 32 shows the pressure decline trends measured in some wells around the field. The reservoir pressure has decreased continuously with time, the most affected zones being in the vicinities of wells PGM-47, 11 and 42, with a pressure drop on the order of about 2.0 bars per year (Moya and Castro, 2004). The northern and central zones are the most affected by exploitation. The wellhead pressure at most wells has dropped 1 to 3 bars, due to the reservoir changes described previously. An exception is well PGM-10, which has increased its maximum wellhead pressure with time.

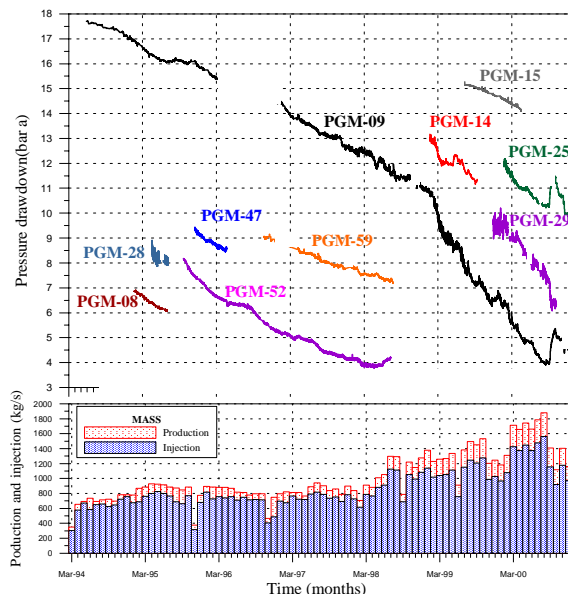


Figure 32. Pressure Decline Trends in different monitoring wells (from Castro, 2001).

A good correlation between the reservoir pressure drop and the commissioning of each power plant is observed, as the increase in extracted mass is reflected in an increase in the rate of pressure drop. Also, when the different power plants have been in maintenance and the mass extraction rate is decreased, an immediate response in the pressure measured in wells PGM-09 y PGM-25 has been seen. This clearly indicates a hydraulic connection between the wells located in the central-western part of the field. These short periods of maintenance have reduced the pressure drop, and in some cases the reservoir pressure has increased. However, this recovery has not been great enough to compensate for the total pressure drop observed over the production history of Miravalles (Castro, 2001).

5.3 Changes in Well Injection Capacity

During the 10 years of exploitation, the injection wells have changed their behavior as the steamfield has evolved. Prior to 1994, the injection wells were tested and an injection capacity was determined for each. Since commercial production of the field began, an obvious increase of injection capacity has been observed in most of the wells. Ten year later, it has been observed that the wells which originally had very large injection capacities (380-450 l/s) have not shown any decrease, and wells with an intermediate or low injection capacity (114-160 l/s) have shown an average increase in capacity between 175% and 333%.

6. DISCUSSION

Four stages in the evolution of the Miravalles Field have been observed:

a) First period: the initial condition of the field, with similar chloride concentrations over the entire field and calcium-enriched fluids in the western sector. Higher temperatures were present the northeast, and diminished naturally toward the southwest.

b) Second period: from the start of commercial exploitation of the field until April of 1999. The arrival of injection fluids coming from the west (wells PGM-22 and 24) toward the center of the field is noticed. This injection return is mixed with more calcium-rich waters belonging to this sector. A general temperature increase along a northeast-southwest trend is observed, indicating that the established exploitation regime could be supported by the natural recharge of the field. The existing injection returns did not show any negative thermal breakthrough.

c) Third period: from May 1999 to October 2002. The increasing influence of the injection return in the southern zone of the field is noticed, as chemical breakthrough is evident. A temperature and enthalpy decline along a southwest-northeast trend is observed, indicating not only the arrival of the chemical front but also mixing with colder fluids. A production decline in some of the wells is also

d) Fourth stage: starting in November 2002, a steady production decline is observed in some of the wells located in the northern sector of the field, in association with a reservoir pressure decline and a strong drop in wellhead pressures (PGM-01, 10 and 63, all of which are connected to Satellite 1). PGM-01 can no longer produce and PGM-10 is seriously affected. A remarkable steam cap has formed in the northern part of the field due to the massive exploitation. This steam cap seems to be extending to the rest of the field. The effect of the relocation of reinjection toward the western part of the field in late 2002 (to mitigate the pressure drop) has been noticed chemically, but it is still too soon to quantify its effect on the pressure of the reservoir. The effect of this action is less than expected, because of a lack of reinjected water coming from Satellite 1 (at present only one of five wells connected to this satellite is producing).

Numerical modeling to forecast future reservoir behavior has shown that, under the current exploitation scheme, injection returns should mostly affect the temperature of the southern production area and the nearby wells. The overall pressure in the field seemed to be seriously affected when injection was shifted to the south in 1998, and it appeared to be necessary to relocate some of the injection back to the west, in order to reduce the reservoir pressure drops to

reasonable values (GeothermEx, Inc., 2002). This action has been partly completed, but changes in the production rates of wells connected to Satellite 1 have made it impossible to achieve the original rate of the fluid injection into well PGM-22 (Moya and Yock, 2004). This poses a special problem, since it was planned that the pressure drop in the northern and central part of the field was to be reduced by injection in this part of the field.

The operation of Unit V appears possible at this point, based on forecasting results that show that the colder injection returns should not seriously affect the temperature of the field, and to date no thermal breakthrough has been seen (GeothermEx, Inc., 2002). Monitoring of the field must be strengthened to avoid future problems that might occur if lowering the temperature of the reinjection waters (from 165 to 136 °C) impacts the reservoir more than predicted by the numerical modeling. Another possible impact of the commissioning of the binary plant is silica deposition in pipes, production casings, and fractures in the reservoir, due to an increase in silica oversaturation. This effect has not yet been quantified.

The most recent numerical model, developed in May 2002, forecasts the sustainability of the exploitation of the Miravalles reservoir under the conditions described below:

UNIT I:	generating up to 60 MW.
UNIT II:	generating up to 55 MW.
UNIT III:	generating up to 27.5 MW.
UNIT V:	generating up to 15 MW (injection temperature 136 °C.)
Wellhead unit:	installed in well PGM-29 (generating up to 5 MW).

The modeling runs clearly indicate the need to transfer the back-pressure unit from its current location to well PGM-29, in order to reduce the pressure drop observed in the center of the field.

Currently, the northern zone of the field most strongly affected by the continuous exploitation of the reservoir. Specific actions must be implemented in this part of the field to restore some of the seriously affected wells and to avoid future problems in wells that have not been affected yet. Among the actions to be considered are the possible injection of controlled quantities of water (at 165 °C) into the northern part of the field, the transfer of the backpressure unit to well PGM-29, and other possible production schemes (such as reducing the extraction during certain periods of the year).

7. CONCLUSIONS

The Miravalles Geothermal Field has successfully supplied steam for 10 years to the different generating units installed.

During this time the geothermal reservoir has evolved in response to changes in production and injection rates and the different exploitation strategies used as the different generation units have entered into operation. This evolution has been reflected in changes of several chemical and physical reservoir parameters, compared to the phase previous to the beginning of commercial exploitation.

A plan to monitor these parameters continuously was implemented to ensure the correct utilization and sustainability of the geothermal resource. This plan includes

the development of numerical models in association with external consultants, to help plan and maintain the production needed for the generating units installed so far.

It appears possible to operate Unit V without creating any big impacts on the reservoir. However, the real impact of this unit has not yet been seen, because it has been in operation for only a few months. It will be necessary to maintain continuous monitoring to prevent any negative effects, such as thermal breakthrough due to lowering of the reinjection temperature, and silica deposition in surface facilities and the reservoir. The latter impact has not been quantified, but its risk is increased by the commissioning of the binary plant.

Since November 1999 a general temperature decline in the field has been observed. The temperature decline in some wells is not due to the arrival of injection waters, but rather to boiling in the formation, as is the case at wells PGM-62, 11 and 10. This is probably related to the formation of a steam cap.

The steam cap that is forming progressively in the northern sector of the field is caused by the massive exploitation of the reservoir over its production history. The exploitation has caused a pressure drop that has caused steam to form in the shallow parts of the reservoir, as evidenced by an increase in the wellhead pressure of some monitoring wells.

The highest reservoir pressure drop has occurred in the vicinity of wells PGM-47, 11 and 42, where a pressure decline rate of about 2.0 bars per year has been detected.

Except in a few cases, the most productive wells have shown a greater decline in steam flow rate and therefore in power output. This is the case for wells PGM-08, 46 and 21.

It is advisable not to expand the generation capacity of Miravalles beyond 163 MW, which includes moving the wellhead unit at well PGM-29.

Among the conclusions derived from data analysis and numerical modeling was the urgency of redirecting part of the water injected in the southern sector toward the western sector of the field (wells PGM-22 and 24). This action was necessary to give pressure support to the center of the field, and to reduce the drop in production observed. This recommendation was implemented in part in November 2002, when the injection rate into PGM-24 was increased by 150 kg/s. A similar planned increase in well PGM-22 was not possible, due to a lack of available water coming from Satellite 1. The amount of separated fluid injected into well PGM-22 should be increased in order to support the pressure in the central part of the reservoir.

Implementing new injection schemes to improve pressure support to the field without affecting the temperature of the reservoir fluids is an obligatory task to be done in the near future. It is necessary to continue reservoir monitoring in order to determine if injection will cause temperatures to decline in one of the following ways: a) the injected fluids thermally equilibrate at a temperature lower than that of the productive zone, since the southern injection zone is cooler than the central and northern sectors of the field. In this case, production temperatures would stabilize at levels similar to those of the injection zone; b) the volume and speed of injection return are too great to allow thermal recovery. This would cause a gradual and continuous temperature decline, and enthalpy declines would be expected in the production wells.

ACKNOWLEDGEMENTS

The authors would like to thank Mr. Edward Hakanson for his help in reviewing the English writing of this paper and Mr. Roger Henneberger (GeothermEx, Inc.) for editing and improving the manuscript.

REFERENCES

- Castro, Sergio. 2001. Comportamiento de la presión del yacimiento en el Campo Geotérmico Miravalles, Informe semestral II-2001. *Internal report*. Instituto Costarricense de Electricidad, C. S. Recursos Geotérmicos. Costa Rica. 16 pp.
- GeothermEx, Inc. 2002. Updated Numerical Simulation of the Miravalles Geothermal Field, Guanacaste, Costa Rica. Richmond, California. USA. May 2002.
- ICE/ELC, 1995. Proyecto Geotérmico Miravalles: Informe de factibilidad 3ª. y 4ª. unidad. Instituto Costarricense de Electricidad and ELC Electroconsult. Report GMV-2-ELC-R-12400(R01). San José, Costa Rica.
- Mainieri, A., González, C., Moya, P., Sánchez, E., Yock, A., Pham, M., Granados, E., and Klein, C. W.: Updated Numerical Simulation of the Miravalles Geothermal Field, Costa Rica. *Geothermal Resources Council Transactions*, 26, (2002), 835-840.
- Moya, Paul and Castro, Sergio. 2004. Pressure Response to Production and Injection at the Miravalles Geothermal Field. *Proceedings*, 29th Workshop on Geothermal Reservoir Engineering. Stanford University, California. January 26-28, 2004.
- Moya, Paul and Yock, Antonio. 2004. Injection Management at the Miravalles Geothermal Field. *Proceedings*, 29th Workshop on Geothermal Reservoir Engineering. Stanford University, California. January 26-28, 2004.
- Pham, M., Sanyal, S., Granados, E., Manieri, A., And González, C.: Numerical Modeling of the Miravalles Geothermal Field, Costa Rica, *Proceedings*, World Geothermal Congress 2000, Kyushu-Tohoku, Japan (2000), 2797-2802.
- Vallejos, Osvaldo; Sánchez, Eddy and González, Carlos. 2005. Reservoir Management at the Miravalles Geothermal Field, Costa Rica. *Proceedings*, World Geothermal Congress 2005 (in press). Turkey.
- Vallejos, Osvaldo; Acuña, Jorge and González, Carlos. 1995. Monitoring of Reservoir Pressure at Miravalles. *Miravalles Geothermal Field 16th Advisory Consultant Panel Meeting*. Costa Rica.
- Vallejos, Osvaldo. 1996. A Conceptual Reservoir Model and Numerical Simulation Studies for the Miravalles Geothermal Field, Costa Rica. *Geothermal Training in Iceland 1996*. UNU G.T.P. Report 18. Iceland. Pp. 418-456.
- Vega, Eduardo; Chavarría., Leyner; Barrantes, Manuel; Molina, Fernando; Hakanson, Edward; Mora, Oscar. 2000. Geologic Model of the Miravalles Geothermal Field, Costa Rica. *Proceedings*, World Geothermal Congress 2005 (in press). Turkey.
- Yock, Antonio; Vives, Eulalia and Acuña, Jorge. 1995. Tracer Test with Injection at PGM-24 and Observation at Producing Wells of Satellite 3 Performed in 1995. *Miravalles Geothermal Field 16th Advisory Consultant Panel Meeting*. Costa Rica.