

LESSONS LEARNED AT THE MIRAVALLS GEOTHERMAL FIELD

Paul Moya

Instituto Costarricense de Electricidad, UEN Proyectos y Servicios Asociados
C.S. Recursos Geotérmicos, Apartado Postal 10032-1000
San José
COSTA RICA

1. INTRODUCTION

The following sections present an overview of the main lessons learned at the Miravalles geothermal field, which has been under exploitation for more than twelve years. In the Miravalles geothermal field there are four main issues of concern to ICE: optimization of the production-injection strategy for the production zone, an increase in non-condensable gases in the northern sector of the production zone, the best utilization of the brine (separated water coming from the separation stations) and the best location to produce from the wellhead generation unit. There have been “lessons learned” in all of these issues, which have modified the old procedures or strategies. In the following sections, these lessons will be described.

2. OPTIMIZATION OF THE PRODUCTION-INJECTION STRATEGY FOR THE RESERVOIR:

Several parameters have been monitored at each production well to evaluate the behavior of the reservoir over the first twelve years of its exploitation. These parameters are: enthalpy, temperature, pressure, flow rate, wellhead pressure, and certain chemical species such as chloride, sulfate, bicarbonate, sodium, potassium, calcium, magnesium, silica and non-condensable gases (Yock, 1998).

2.1 Chemical and Thermodynamic Changes with Time:

The production zone at the Miravalles geothermal field has been divided into three different sectors: northern, central, and southern (Figure 1). Each production sector contains a group of wells and, for each well, the non-condensable gases, enthalpy and chloride concentration parameters have been graphed versus time (Figures 2 to 4). Fluid injection has taken place mainly in two areas: to the west and south of the production zone (Figure 1).

The vertical lines in Figures 2 to 4 indicate the commissioning of Unit 1 (U-1), Unit 2 (U-2), Unit 3 (U-3) and Unit 5 (U-5). “IC” in these figures stands for “injection change”, corresponding to a significant change in the injection configuration.

Early in the year 2003, the injection rate in the western zone was increased by diverting some of the fluids that initially were sent to the southern zone (Moya, 2005).

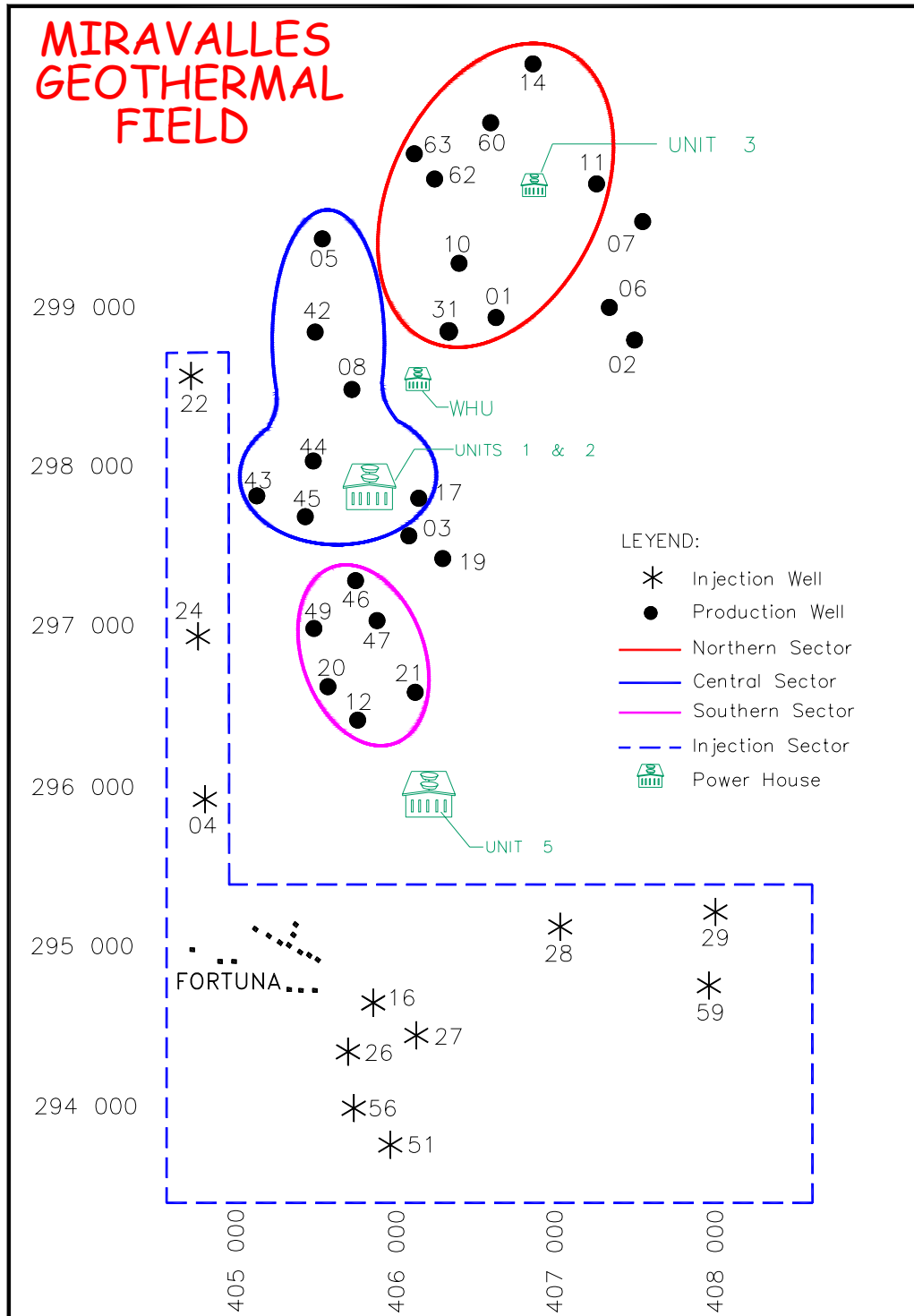


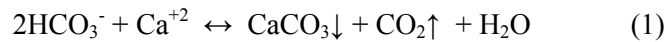
Figure 1 Production sectors at the Miravalles geothermal field.

2.1.1 Northern sector

Analyzing the northern part of the production zone (Figure 2), it can be observed that the majority of the wells (producing since 1994) were receiving a small fraction of the injected fluids until Unit 2 came online (in the middle of 1998). After that, the chloride content at the wells started to decrease and their non-condensable gases began to increase.

Wells PGM-01, PGM-10 and PGM-63 became non-productive, probably because fluid withdrawal rapidly lowered the flashing depth in these wells due to low permeability in this part of the reservoir. Lowering the flashing depth causes calcium carbonate deposition to take place, initially inside the production casing and then in formation fractures, reducing the permeability that allows the wells to produce.

While calcium carbonate deposition is taking place, CO₂ moves from the liquid to the steam phase, following the reaction indicated by Equation 1:



When the flash depth is lowered, this reaction causes the precipitation of calcium carbonate, and some shallow productive fractures may be affected.

2.1.2 Central sector:

In the central part of the production zone, it can be seen that the chloride concentration has increased or stayed constant in all the wells (Figure 3). The enthalpies in all the wells have decreased slightly, to values close to 1,000 kJ/kg, with the exception of well PGM-45, which presents a high-enthalpy anomaly due to a shallow steam zone. This steam zone was initially observed also in nearby well PGM-46, but it disappeared as the well produced. It was necessary to deepen well PGM-46 to recover its productivity.

The non-condensable gases have decreased in the majority of the wells in the central sectors. In PGM-17 the non-condensable gases fluctuated from 1994 to 2003, but began decreasing right after the western fluid injection was increased, and has continued to do so until the present. Of all the wells that are part of the Central Sectors, the only one that has shown an increase (since 1997) in non-condensable gases is PGM-45.

2.1.3 Southern sector

In the southern sector of the field, the chloride concentration has increased in all the wells since they began production (Figure 4). In all of these wells it is noticed that, due to the increase in the western fluid injection (with a corresponding decrease in the southern injection), less injected fluid is reaching these wells, causing the chloride content to stop increasing and be fairly constant. The enthalpies in the wells of this sector have decreased or stayed constant at values around 1,000 kJ/kg.

The non-condensable gases decreased in the majority of these wells, except for PGM-12 and PGM-46. The non-condensable gases have been increasing in PGM-12 since the middle of 2001, and in PGM-46 since late 1997. The deepening of PGM-46 caused the rate of increase to lessen, but it has continued nonetheless. From figures 2 to 4, it can be inferred that there must be permanent monitoring

of field-wide production and injection conditions, in order to establish the best production/injection strategy, and also to monitor the behavior of the non-condensable gases. It was learned that injection in the field should be distributed over several sectors of the field and with the appropriate balance of rates, in order to optimize the exploitation of the geothermal reservoir.

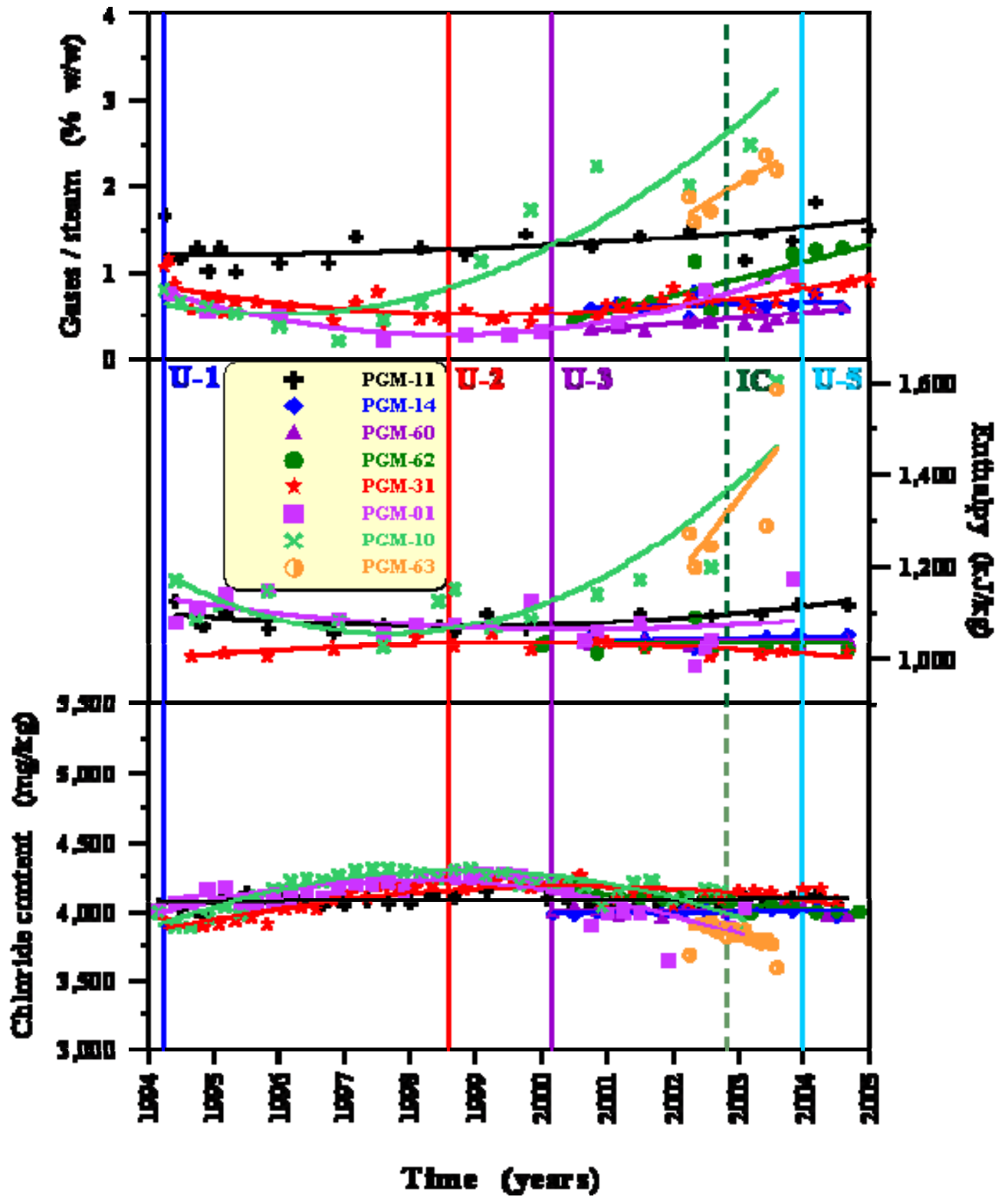


FIGURE 2: Northern sector

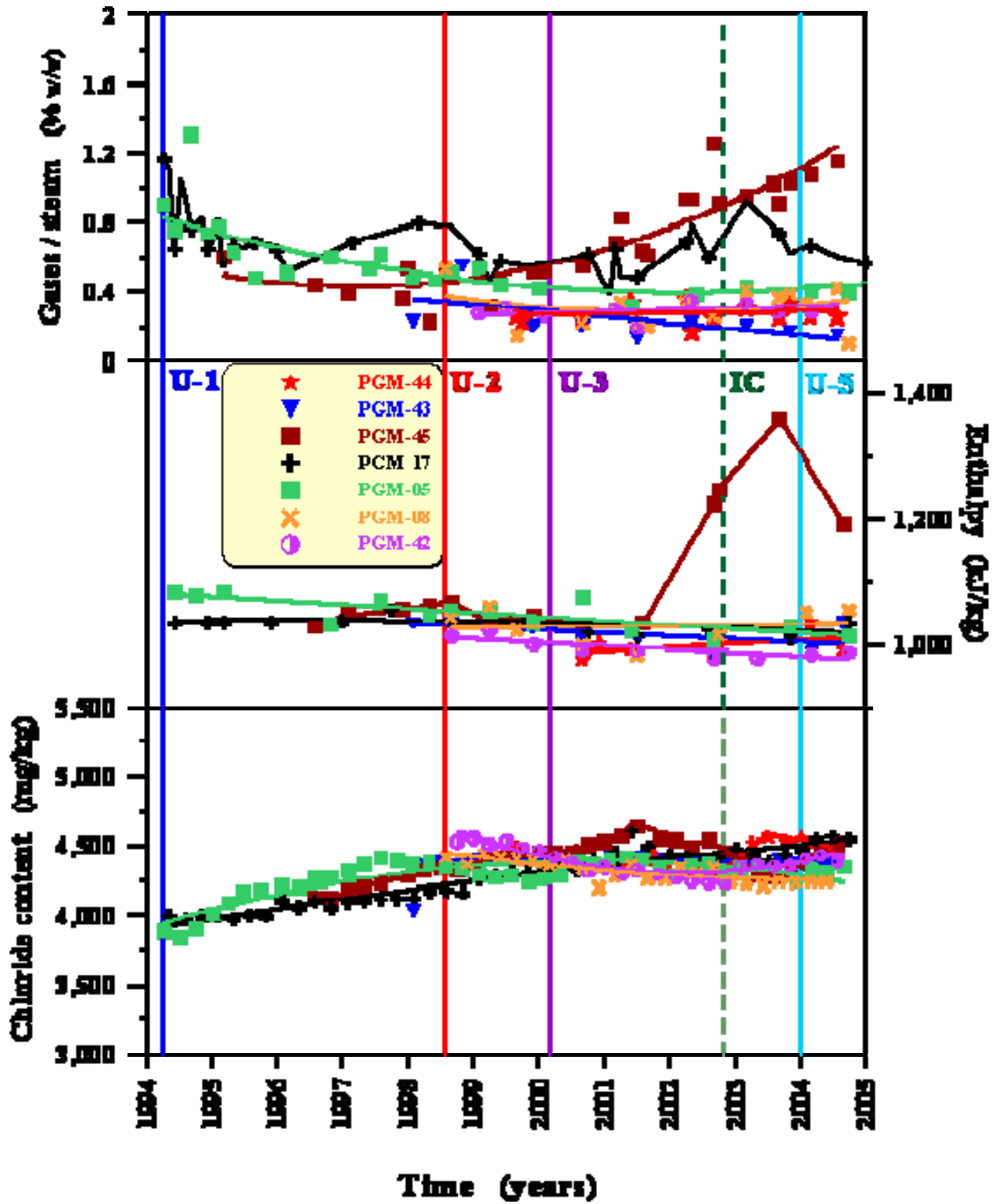


FIGURE 3: Central Sector

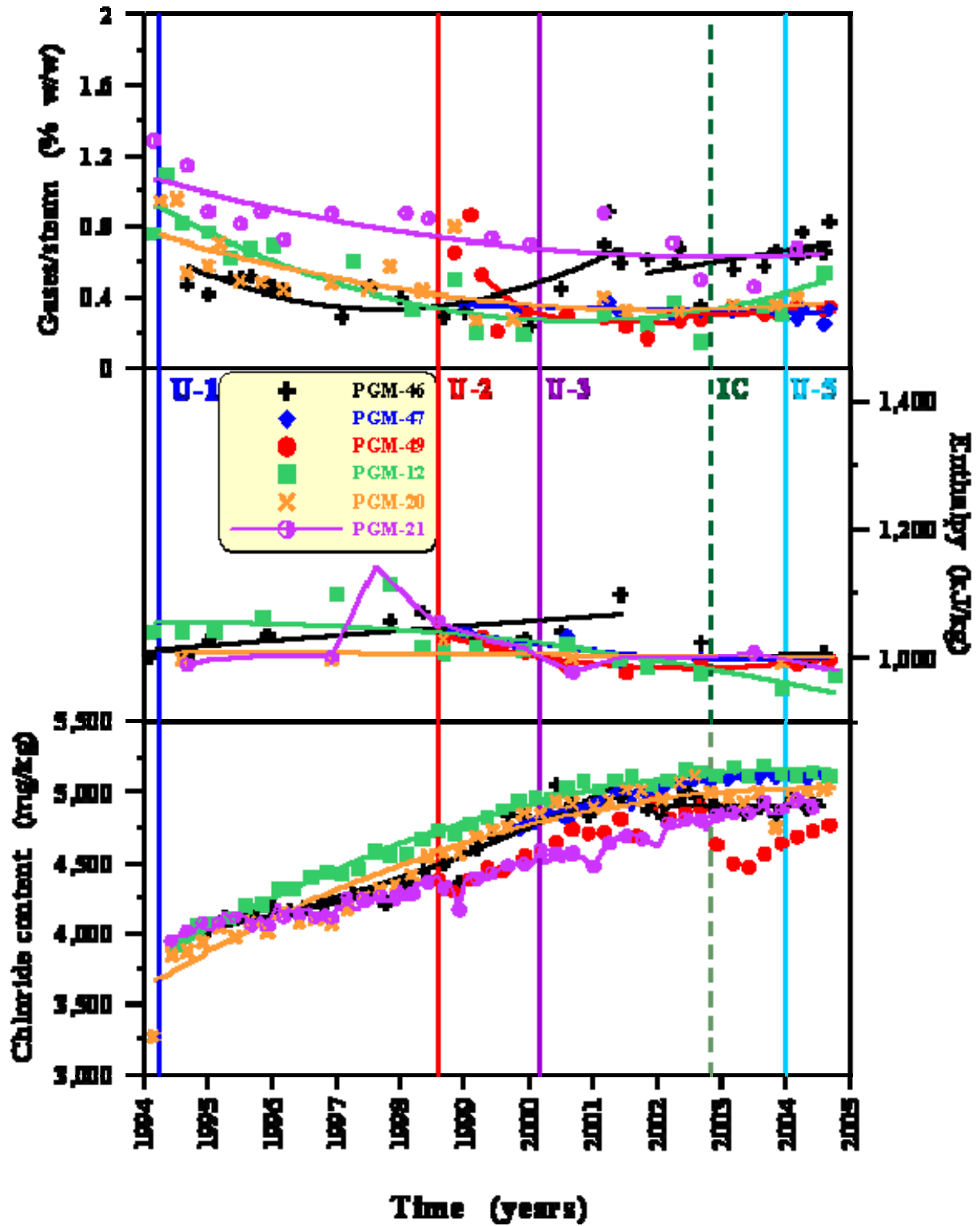


FIGURE 4: Southern Sector

3. NON-CONDENSABLE GASES

Continuous exploitation has tended to increase the concentration of non-condensable gases in the reservoir, which in turn has provoked the establishment of a program of detailed monitoring of the non-condensable gases at each well in order to determine the principal causes of the increase, and to select the best injection and production strategies to improve the current operating conditions.

Studies have indicated that the principal cause of the increase in non-condensable gases is pressure decline in the reservoir. In order to minimize this tendency, three different strategies have been or will be implemented. First, by increasing the volume of fluids injected in the western sector (wells PGM-22 and PGM-24), it has been possible to decrease the non-condensable gases in the vicinity of well PGM-45 and also in all of the wells of the western sector. Figure 5 shows that well PGM-45 had a trend of increasing non-condensable gases from early 1999 to late 2003. Diverting more fluid to the western sector caused an immediate decrease in the non-condensable gases reported in this well (a positive effect). Also, the enthalpy began to decrease as a consequence of the arrival of injected fluids in the reservoir near well PGM-45 (Moya, 2005b).

Since positive results have been obtained by injecting hot fluids in the western and southern parts of the production zone, hot fluids were injected into PGM-63 from July 2005 to August 2006, which may contribute to stopping the current pressure drop as well as decreasing the non-condensable gases in the northern zone. Wells such as PGM-01, PGM-10 and also PGM-63 were initially production wells (in 1994), but due to the pressure drop in the northern zone they have had to be taken out of production.

Figure 6 shows the amount of fluid injected into PGM-63. The surrounding wells were monitored, but it was not possible to establish any relationship between the water injected in that well and a decrease in the non-condensable gases.

Second, the studies carried out have indicated that non-condensable gases were increasing rapidly in the northern part of the production zone, that is, near wells PGM-11, PGM-60 and PGM-62. It has been necessary to produce these wells at a minimum flow rate (or even to close them) in order to reduce the pressure drop and consequently the non-condensable gas contents. The resulting deficit in steam supply for Unit 3 (located in the northern sector) is compensated for by steam from the central part of the field. This strategy has at least allowed the non-condensable gas content in that particular area to be kept constant. Third, two existing acidic wells (PGM-02 and PGM-06) were placed online by the end of March 2006, to extract fluids from the “acidic zone” instead of the main production zone. The production from the acidic zone will add to the steam supply in the northern zone (Unit 3), and has stabilized or slowed down the pressure decline and consequently moderated the increase in non-condensable gas content in that sector of the reservoir.

The strategies described in this section have allowed optimization of the available steam supply for the generating plants. A new strategy has been established for managing the steam supply from the field. Initially (in 1994) there was no particular strategy for supplying steam to the various units, but now it is important to manage the supply based on non-condensable gas contents, in order to maximize the final power output.

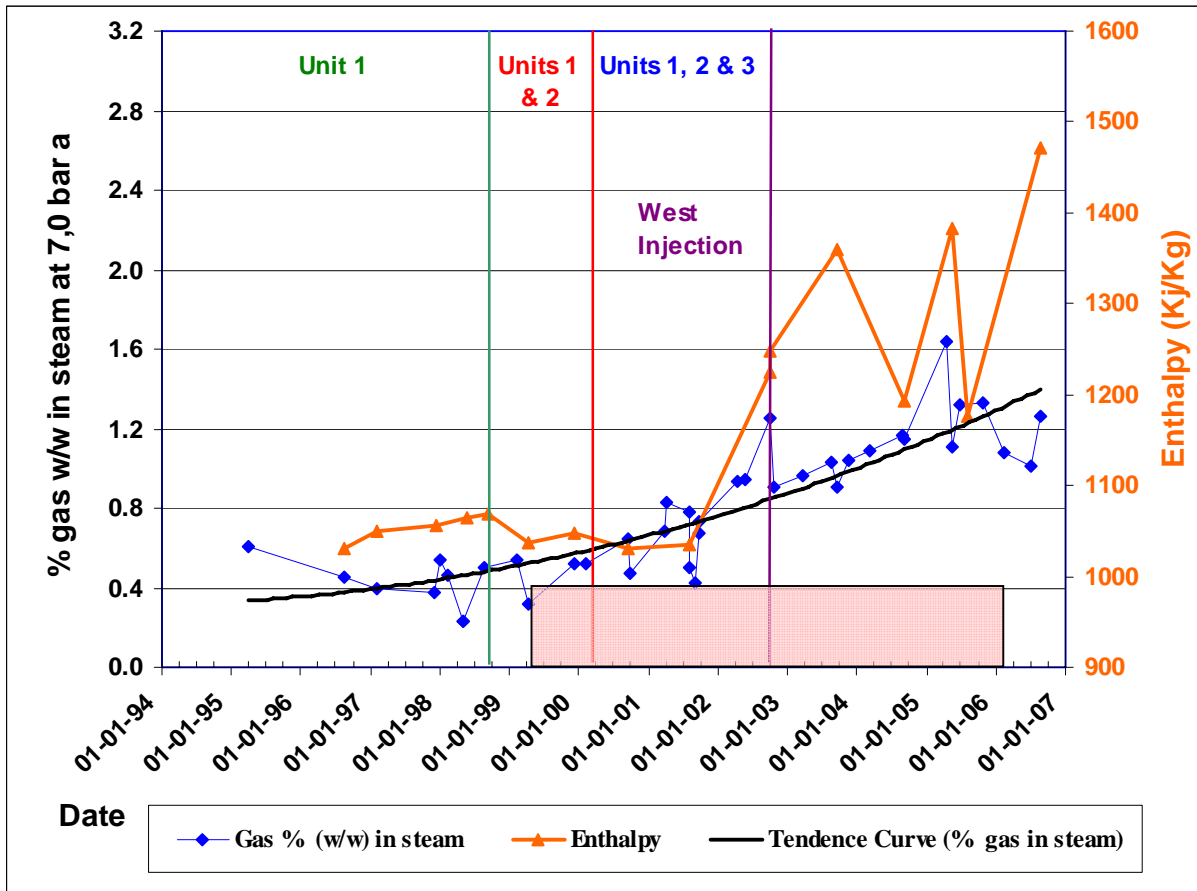


FIGURE 5: History of non-condensable gases in well PGM-45 (% w/w in steam separated at 7 bar a)

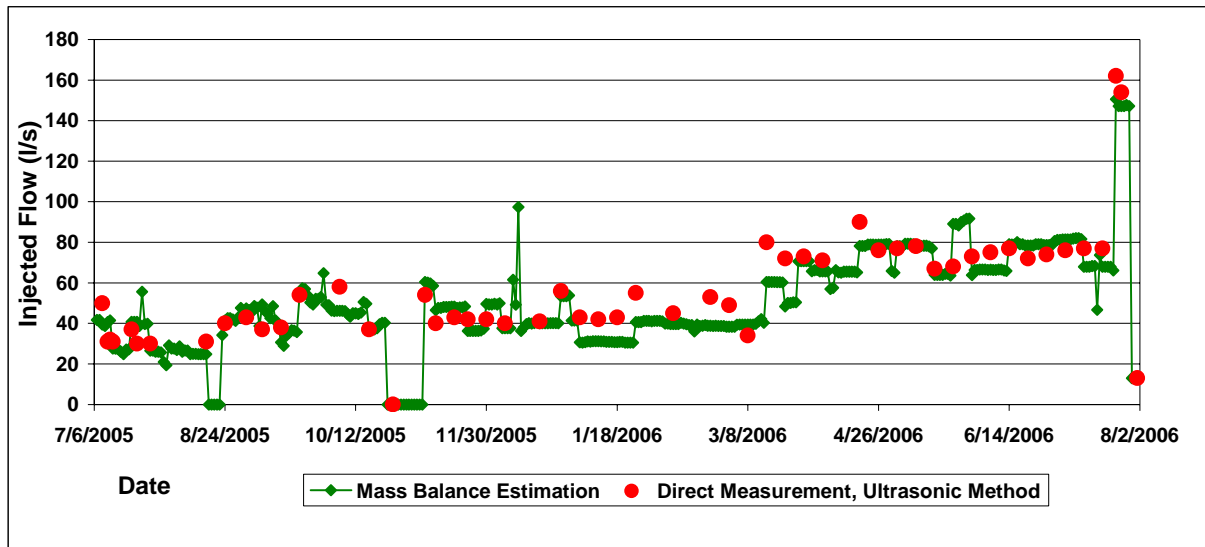


FIGURE 6: Mass injected into PGM-63

The compressor capacities for the main units are 0.66% (Unit 1), 0.88% (Unit 2) and 1.5% (Unit 3). If the non-condensable gas content is higher than the compressor capacity, then the ejectors provide the extra capacity needed to process the steam. Unfortunately, the ejectors require some of the supplied steam to operate, decreasing the efficiency of the energy generation.

Higher compressor capacities were specified for the new units coming online, but nevertheless those capacities are becoming too small to process the current levels of non-condensable gases being sent to the units.

Initially, separation stations 1, 2 and 3 supplied their steam to Unit 1, while separation stations 4, 5 and 6 supplied their steam to Unit 2. Separation station 7 supplies steam to Unit 3, but this unit can also receive steam from a pipeline coming from separation station 1.

Figure 7 indicates that, by the end of 2003, the compressor capacity of Unit 1 (0.66%) was insufficient for the non-condensable gases coming from separation stations 1 (1.66%), 2 (1.0%) and 3 (0.46%), with a weighted average of 0.94%. On the other hand, the compressor capacity of Unit 2 (0.88%) was much higher than the capacity required for the steam from separation stations 4 (0.37%), 5 (0.75%) and 6 (0.44%), with an average of 0.58%.

After studying the situation and looking for the best option, it was decided to interchange separation stations 1 and 4. Beginning in early 2004 the steam coming from separation station 1 was sent to Unit 2 and vice versa; that is, the steam from separation station 4 was sent to Unit 1. The interchange resulted in a better distribution of the non-condensable gases among the compressors (Figures 8 and 9).

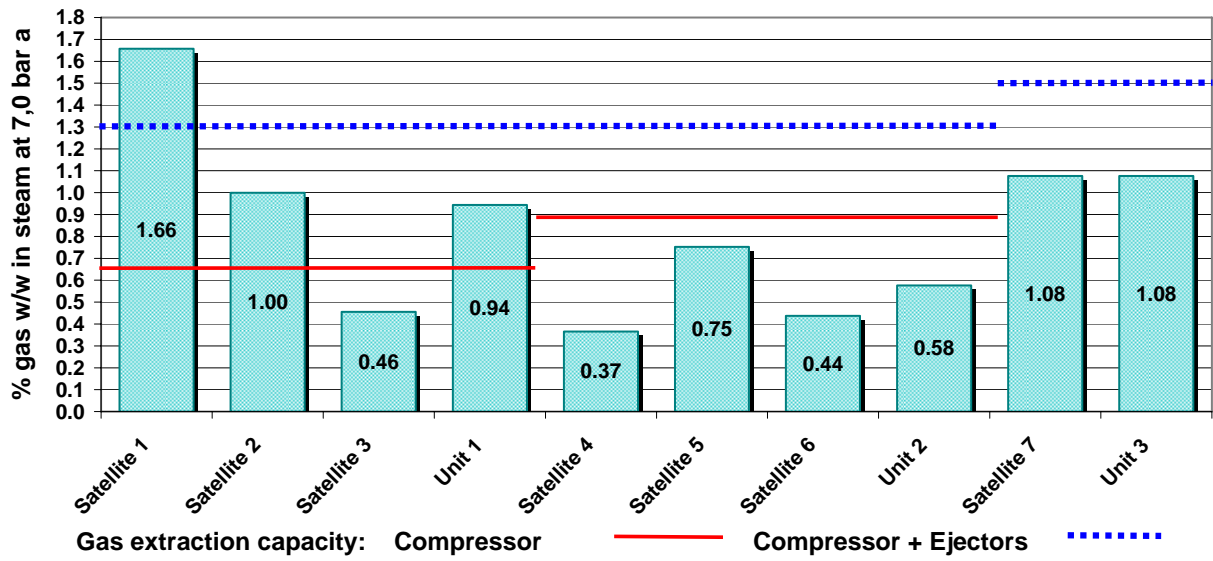


FIGURE 7: Non-condensable gases by satellite in 2003 (%w/w) in steam separated at 7 bar a)

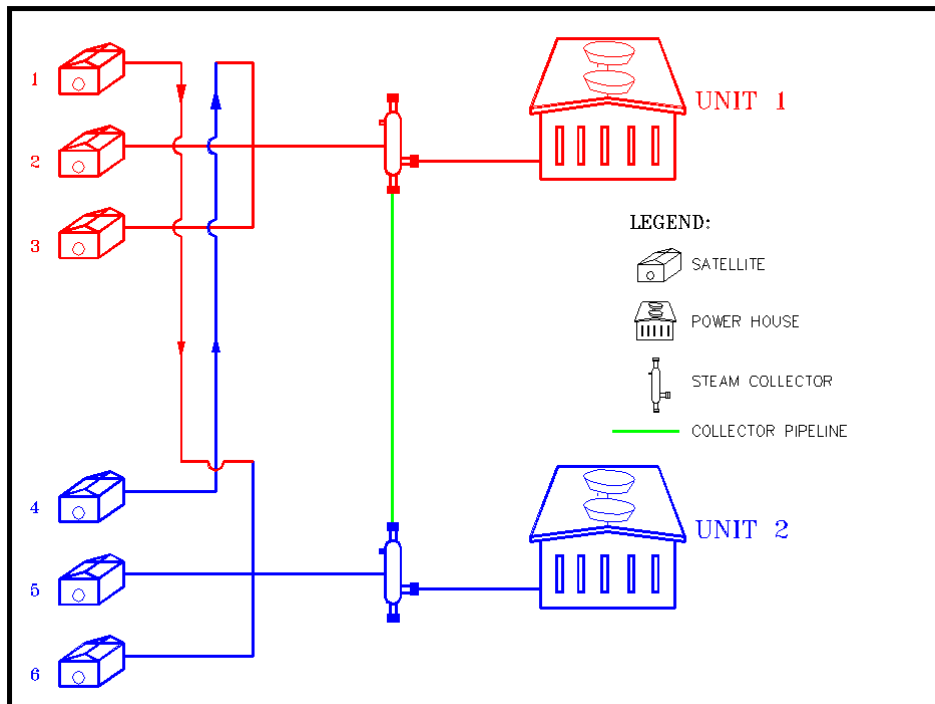


FIGURE 8: Interchange separation station 1 and 4

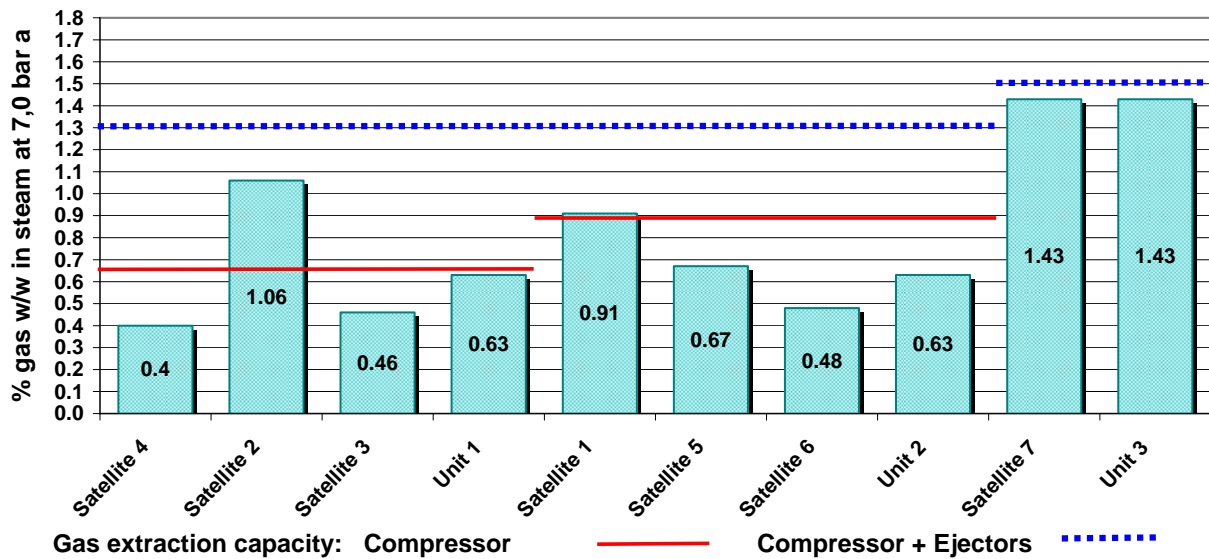


FIGURA 9: Non-condensable gases by satellite in 2004 (%w/w in steam separated at 7 bar a)

The effect of the switch can be observed in Figures 10 and 11. Figure 10 shows the measured non-condensable gas data, the average curve for the measured data and the maximum compressor capacity at Unit 1. Once the interchange was made, a decrease in the total non-condensable gas content was observed (Figure 10). In contrast, Figure 11 shows an inverse effect, that is, an increase occurred after switching the non-condensable gases from the separation stations 1 and 4. Since the non-condensable gas content in the reservoir keeps increasing, due to continuous exploitation, the gas content at the three units has consequently increased (Figures 10, 11 and 12).

Even though interchanging the separation stations has had a positive effect, at present the non-condensable gas contents are getting close to or have exceeded the maximum compressor capacities at Units 1, 2 and 3 (Figure 13).

It is necessary to increase the non-condensable extraction capacity of the main units. This can be achieved by: a) increasing the current capacity of the compressor (improving it), b) adding a vacuum pump to the system, c) increasing the existing ejectors (increasing the amount of steam required per ejector), or d) buying a new compressor with the required capacity.

As a summary, Figure 14 shows the geothermal wells whose non-condensable gas concentrations have been increasing. Figure 15 shows the wells that have experienced decreases in non-condensable gases.

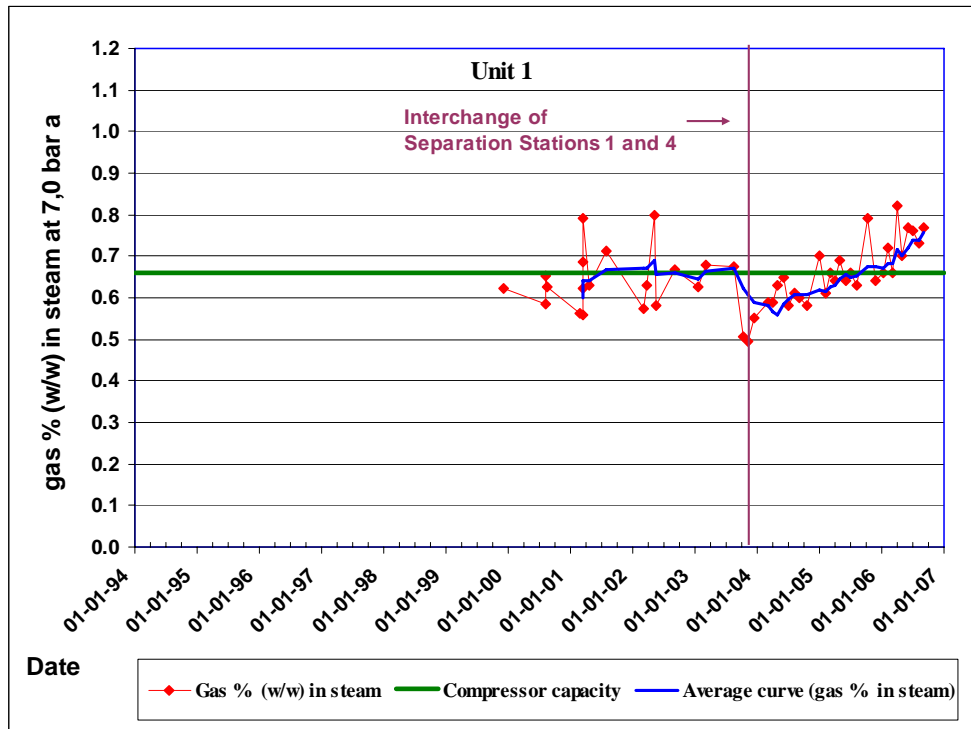


FIGURE 10: History of non-condensable gases at Unit 1 (%w/w in steam separated at 7 bar a)

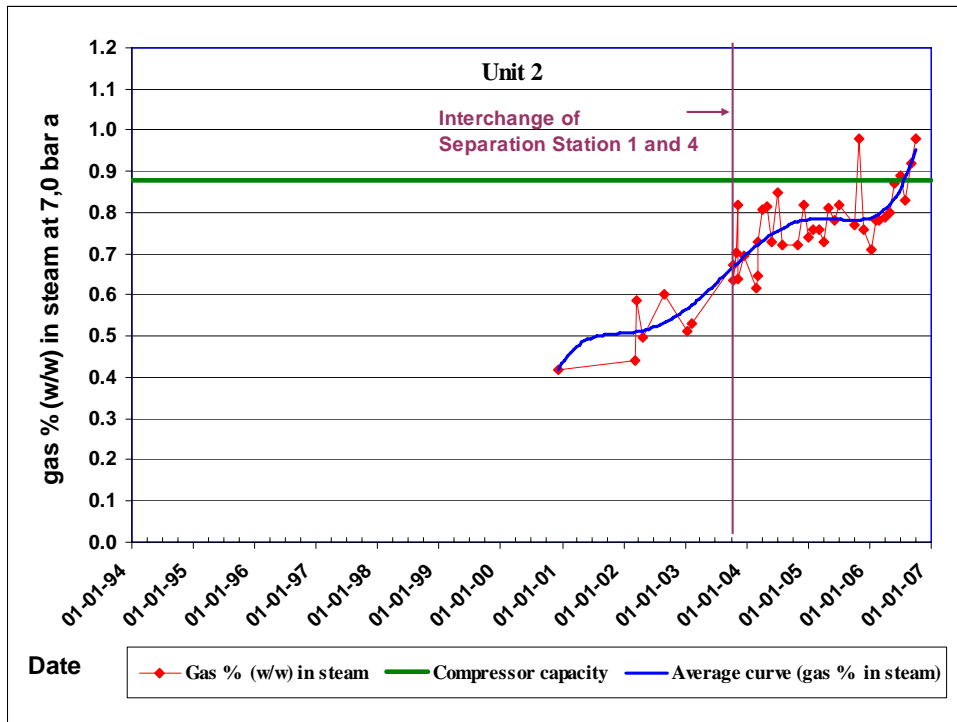


FIGURE 11: History of non-condensable gases at Unit 2 (%w/w in steam separated at 7 bar a)

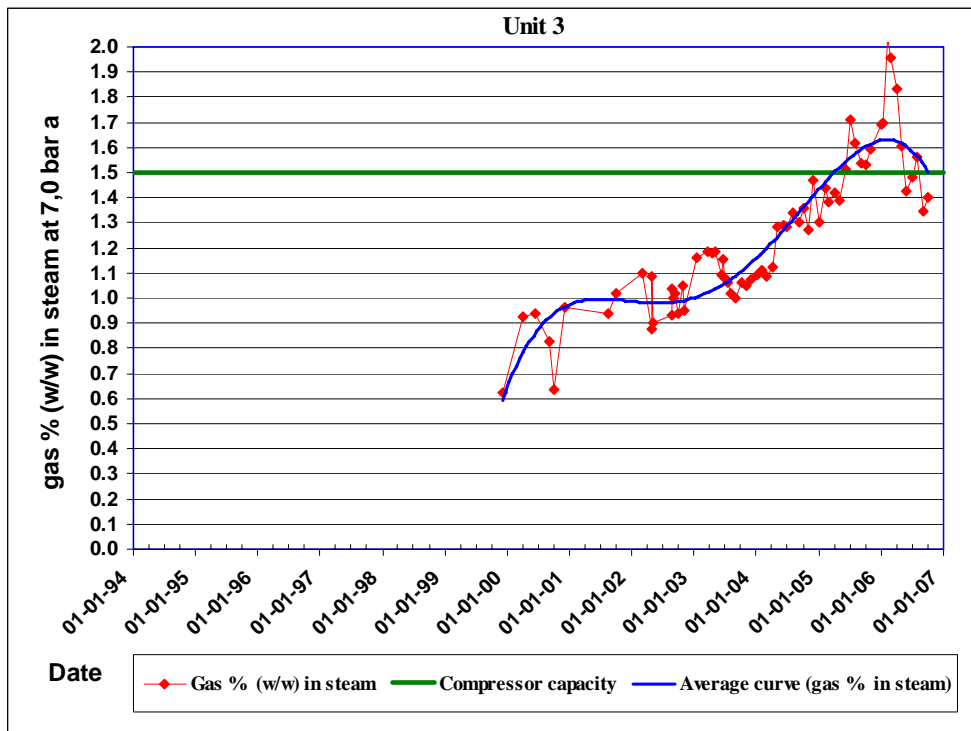


FIGURE 12: History of non-condensable gases at Unit 3 (% w/w in steam separated at 7 bar a) (Sánchez, 2004b)

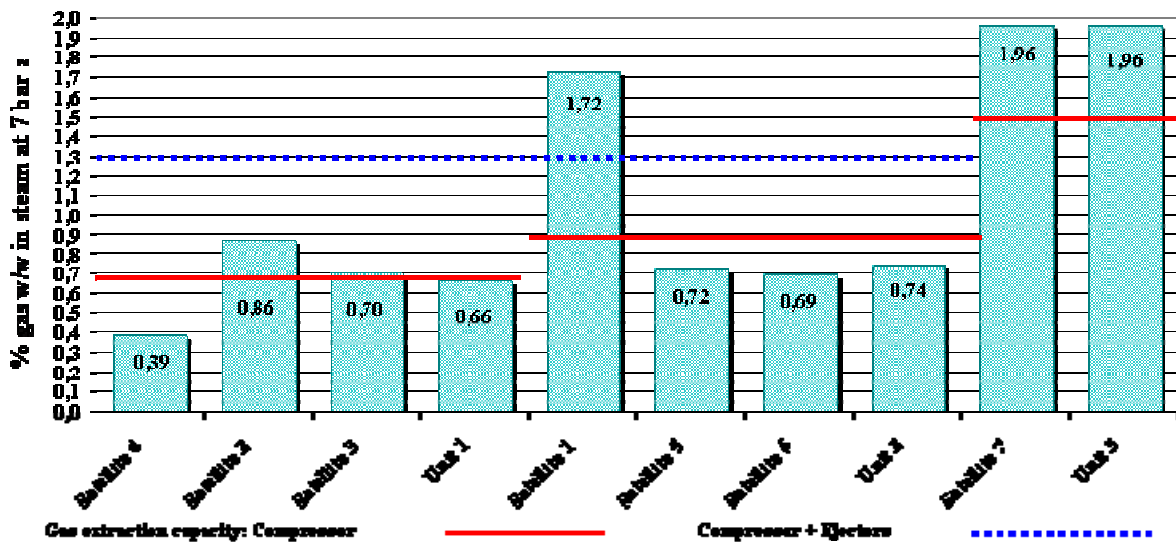


FIGURE 13: Non-condensable gases by satellite in 2006 (%w/w in steam separated at 7 bar a) Eddy Sánchez, personal communication

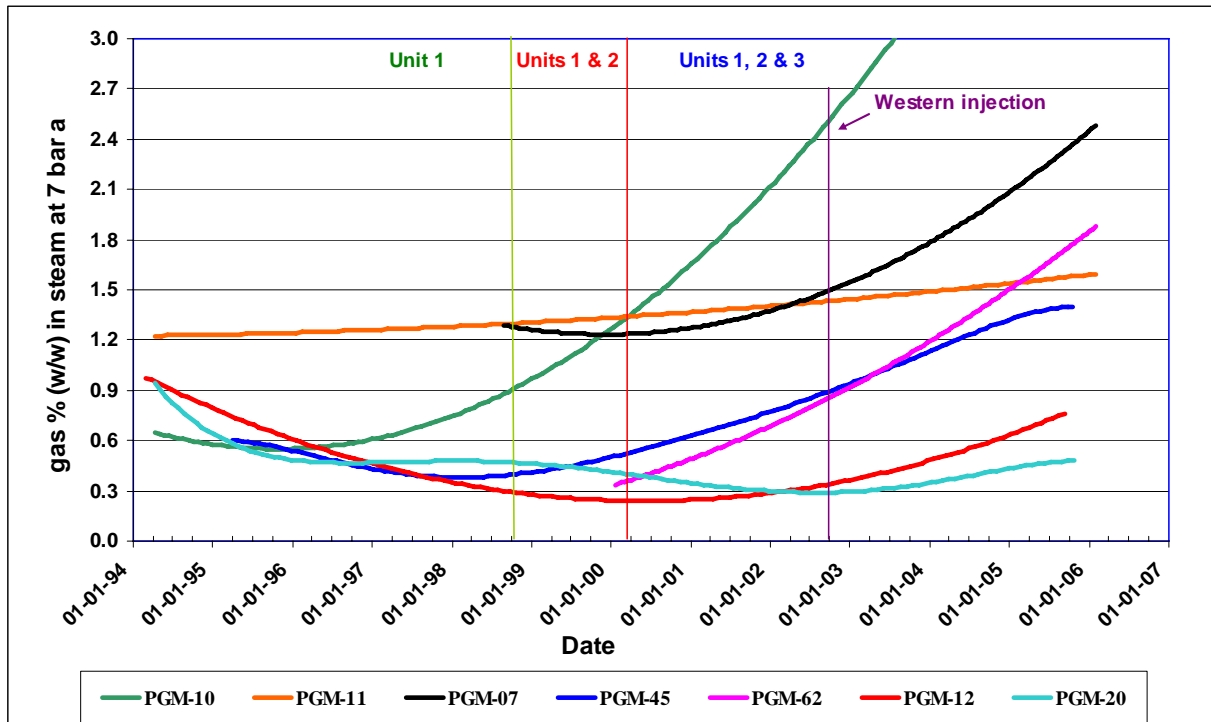


FIGURE 14: Wells showing increases in non-condensable gases

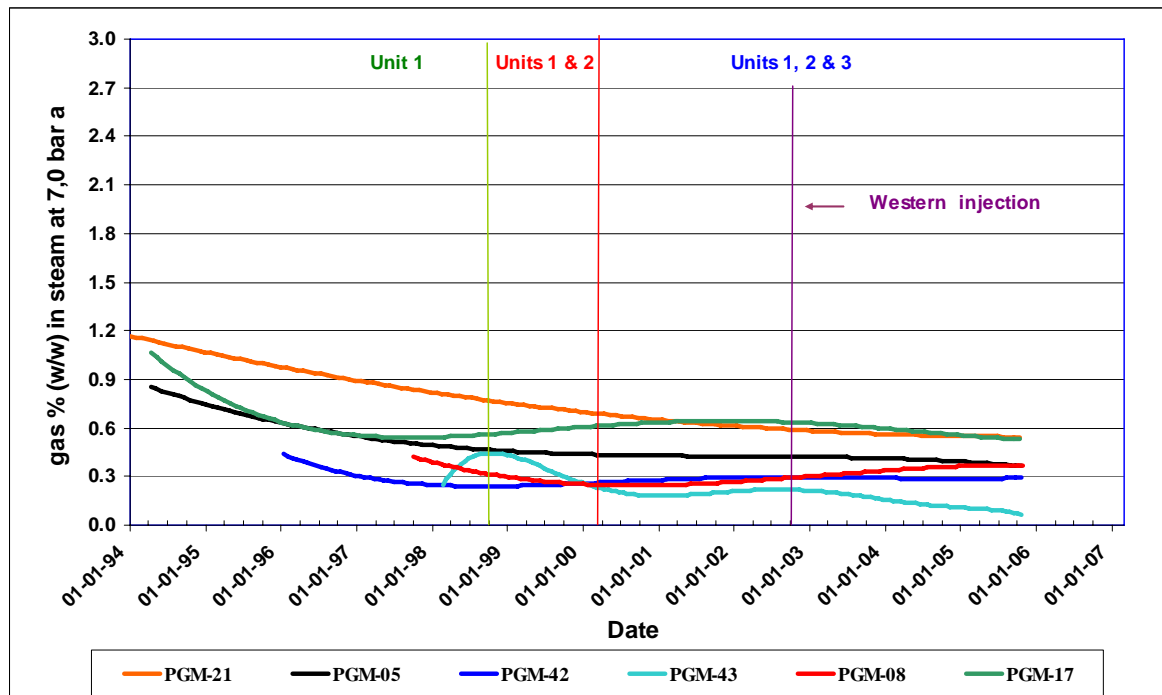


FIGURE 15: Wells showing decreases in non-condensable gases

The main lesson learned regarding non-condensable gas contents is that the power plants should be designed in such a way that the non-condensable gas extraction capacity can be expanded easily. In order to allow for increases in the gas extraction capacity, some provisions should be made when designing and constructing a new power plant, so that, after operating the plant with its initial non-condensable gas extraction capacity (for some years), the gas extraction capacity can be easily modified to adjust it to the new gas extraction requirement.

4. UNIT 5 (A BINARY PLANT)

The characteristics of Unit 5 (Figure 16), as well as the characteristics of the residual and working fluids, are shown in Table 1 (Moya, 2003b).

The powerhouse consists of two modules or energy converters (Figure 17), with a capacity of about 7.75 MWe each. The modules are mounted on a skid and composed of primary equipment (two turbines and a generator) and auxiliary equipment (two vaporizers, two separators, two preheaters, two recuperators, four condensers and two cycle pumps). There is also a conveyor belt hoist for each of the modules. The thermodynamic cycle used by the modules is the Rankine cycle.

Construction of the binary plant started in November 2002 and was finished by December 2003, including the commissioned final tests.

Even though Unit 5 works properly, its installation has caused some inconvenience when operating the field. The operation conditions are very sensitive to changes; that is, changes in pressure at Unit 5 are reflected immediately in the different satellites and vice versa, especially in Satellite 3. The temperatures downstream of Unit 5 for Collectors 1 and 2 are not optimal. It was thought that the wellhead temperature at the injection wells was going to be at least 140°C, but direct measurements indicate that such temperatures cannot always be achieved. ICE had asked Ormat to design the heat exchangers for 110% of the normal discharge, and, therefore, the heat exchangers extract a large amount of heat from the brine. It was suggested to plug some of the tubes in the heat exchanger to increase the outlet temperature from Unit 5. This modification is still being studied.

The pressure downstream of Unit 5 for Collector 3 is low. Because Satellite 3 is very close to Unit 5, the elevation difference is small and therefore the separation pressure at Satellite 3 is very close to the inlet pressure at Unit 5. The highest inlet pressure in collector 3 is close to 8.5 bar g, and its outlet pressure is close to 6.5 bar g. Pressures under 6.6 bar g will cause flashing inside the pipelines, and consequently unstable brine conditions can occur along Collector 3.

A study is currently being carried out to improve the outlet temperatures from Collectors 1 and 2 at Unit 5 as well as to improve the inlet and outlet pressures from Collector 3. The main idea is to divert all of the liquid entering the three collectors to Collector 3, then to split it evenly and send it back into the two modules at Unit 5. By doing this, the flow from Collector 3 can be combined with that of the other two collectors, increasing the outlet pressure of Collector 3. If this modification is made, the overall performance of Unit 5 could be improved.

Since it was necessary to divert some injected brine to the western sector of the field, less brine was available to be sent to the southern sector and consequently to Unit 5. Therefore, at present, there is a lack of brine for Unit 5, which prevents the plant from operating at full capacity. The lesson learned here is that, even though there was an estimate made of the amount of brine available to feed Unit 5, this estimation proved incorrect when it became necessary to distribute the injection in the geothermal field. The brine was needed to improve the pressure support and to decrease non-condensable gas contents in some sectors of the reservoir.

Characteristics of	Item	Unit	Value	IN	Out
RESIDUAL FLUID	Waste geothermal water	kg/s	885		
	Pressure range	bar a		8.04 – 7.25	5
	Temperature range	°C		167.6 – 163.1	136
WORKING FLUID (Pentane)	C ₅ H ₁₂				
	<u>Boiling Point</u>	°C	36.1		
	Flash point	°C	-49		
	Flux	kg/s	242.4		
	Pressure range	bar a		16.4	1.25
	Temperature range	°C		147.4	38
	Losses	kg/month	880		
BINARY PLANT	Total power	MWe	18.07		
	Net power	MWe	15.5		
	Internal Service	MWe	2.57		
	Construction period	month	17		

TABLE 1: Characteristics of the Unit 5 binary plant, residual and working fluids

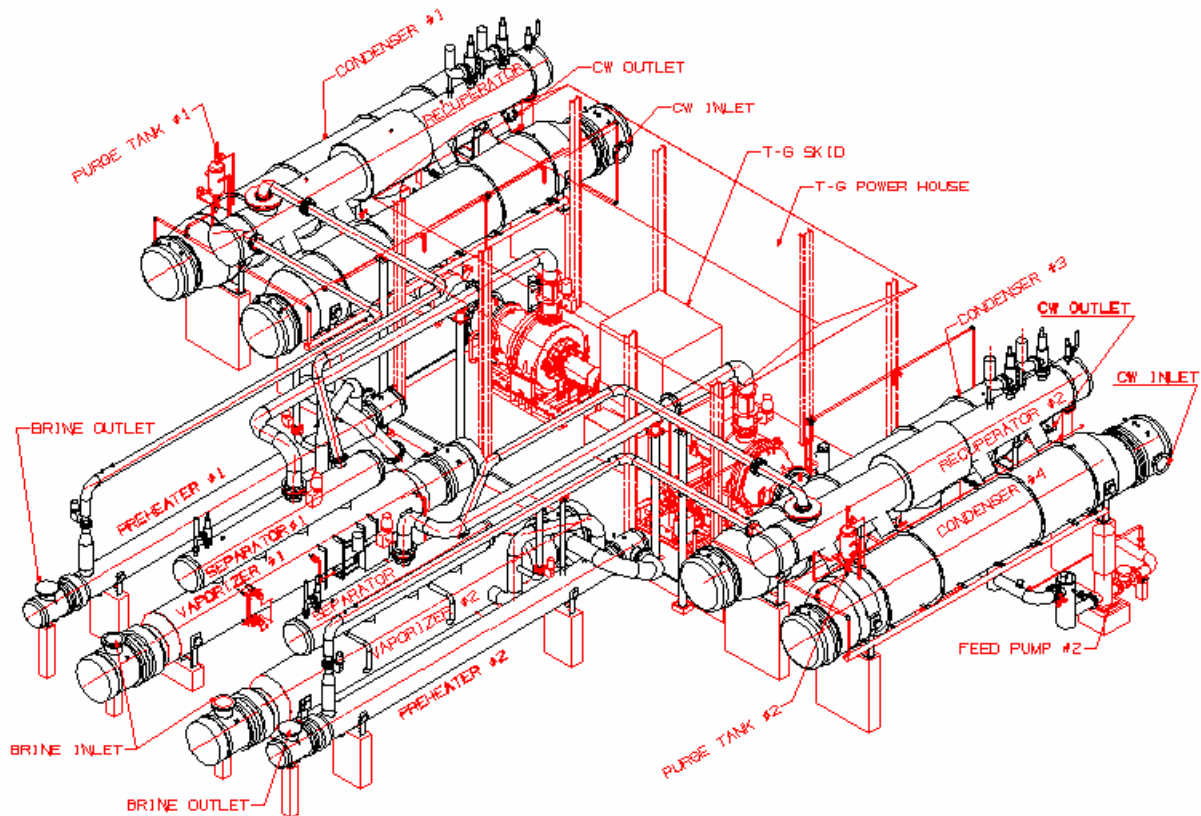


FIGURE 17: Unit 5 Energy Converters

5. WELLHEAD UNIT

The wellhead unit came online in early 1995. Since then, it has been working intermittently; that is, it is online mainly during the dry season in Costa Rica (from January to May). Because its specific steam consumption is greater than that of the main plants (Units 1 & 2), the wellhead unit is not operated throughout the year. It is understood that steam from the central zone of the production zone could be better utilized if it is saved for Units 1 & 2.

The idea of moving the wellhead unit to the southern sector of the field has been considered for the past several years; however, due to financial limitations, ICE has not been able to move the unit. During the second half of the present year (2006) ICE began to move the wellhead unit to well PGM-29, located in the southern part of the field. In the past, a wellhead unit from the Comisión Federal de

Electricidad (CFE) was installed (1997) and disassembled (1998) in the same site, using well PGM-29 as production well. Following that example, ICE is planning to have the wellhead unit online by early 2007, to help meet the energy demand during the next dry period.

ICE will use PGM-29 as a production well and PGM-28 or PGM-35 as an injection well to generate electricity from the WHU. This is the same arrangement that was used when the WHU from Mexico was in operation.

Wells PGM-28 and PGM-35 have been tested for only short periods of time (hours) because there are no production facilities (ponds) in this area. ICE plans to install a set of valves to test these wells while generating at the WHU. For example, PGM-29 could be a production well and PGM-59 an injection well, while simultaneously producing from PGM-28 and injecting into PGM-35, or vice versa. There is strong communication between PGM-29 and PGM-59, so these types of tests could only be carried out for short periods of time.

Non-condensable gases are very high in this part of the reservoir. ICE has measured 12-13% in PGM-29, but this is expected to decrease to about 4-5% after the well has produced for a period of time. That was the case when the WHU from Mexico operated during 1997-1998.

After testing the wells (PGM-28, PGM-29 and PGM-35), the possibility of installing a separation station in this zone may be analyzed. If there is enough production from the wells, their two-phase flow could be sent to this new separation station, with the steam sent to the center of the field and the brine to any of the wells in the southern sector (PGM-16, PGM-26, PGM-27, PGM-33, PGM-38, PGM-51 or PGM-56) where there is still available injection capacity. Wells PGM-50 and PGM-52 do not have significant injection capacity.

With the WHU in place, and having the final test results from wells PGM-28 and PGM-35, ICE will have the necessary scientific information to decide if it should: a) forget about the production of these wells, b) build a separation station in this zone or c) have a spare production (and /or injection) well for the WHU.

Regarding the WHU, the lesson learned is that wellhead units should not utilize steam that can be used for generation in an existing single-flash plant (or any major plant such as double-flash plant, etc.) In the case of Miravalles, the specific steam consumption for the wellhead unit (4 kg/MW) is almost double the steam consumption of a single-flash unit (2.2 kg/MW).

6. FINAL REMARKS

On September 25, 2006, the Miravalles geothermal field completed 12.5 years of continuous exploitation. During all these years, the field has been able to supply the steam and the separated brine required by the generating units, even though the installed capacity and the generation have increased repeatedly since 1994.

At present, wells PGM-01, PGM-10 and PGM-63 are non-productive. It is probable that the natural low permeability in their part of the reservoir, combined with some calcium carbonate deposition in the reservoir fractures, has caused these wells to stop producing.

Injection into PGM-63 was performed from July 2005 to August 2006, in order to evaluate the possibility of recovering the production within the northern sector of the field. So far the data collected do not show any communication between the monitored wells.

Chloride concentrations increased in wells PGM-01, PGM-10 and PGM-31 until Unit 2 came online, then decreased and remained constant. On the other hand, the chloride content has shown a tendency to increase in the central and southern parts of the field. The northern sector of the reservoir benefits the least from return of injected fluids. The increase in the western fluid injection has had an impact mainly on the central and southern parts of the production zone. At present, no cool front has been detected, and therefore effect of the arrival of the injected fluids at some wells has been positive so far.

Enthalpies have tended to decrease slightly in the northern, central and southern parts of the field ever since production began.

Non-condensable gases have increased in the northern sector and in some wells of the central part of the production zone. In the southern part of the field, the non-condensable gases have been decreasing.

Since the northern sector of the reservoir has experienced the strongest productivity declines, the wellhead unit is being relocated to well PGM-29 in the south. By doing so, the steam requirements will decrease for the northern and central sectors of the production zone.

The generating units should be kept at their nominal capacities. Extra generation from these units will tend to over-exploit the reservoir, and might not be sustainable over the long term.

ACKNOWLEDGEMENT

The author thanks Roger Henneberger (GeothermEx, Inc.) for editing and improving the manuscript.

REFERENCES

- Moya, P., Pérez, D. (2003b), "Unit 5: A Binary Plant at the Miravalles Geothermal Field", *Geothermal Resources Council Transactions*, Vol. 27, October 12-15, 2003.
- Moya, P., Yock, A. (2005), "First Eleven Years of Exploitation at the Miravalles Geothermal Field", *PROCEEDINGS, Thirtieth Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California*, January 31-February 2, 2005.
- Moya, P., Sánchez, E. (2005b), "Non-condensable Gases at the Miravalles Geothermal Field", *PROCEEDINGS, Thirtieth Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California*, January 31-February 2, 2005.
- Sánchez, E. (2004b), "Evaluación del contenido de gas en el vapor entregado a la Unidad 3 de Miravalles y pozos del Satélite 7, causas y consecuencias," *ICE Internal Report*, Equipo de Geoquímica, Area de Geociencias, 31 de octubre de 2004.

Yock, A., (1998), "Chemical and Isotopic Studies in the Miravalles Geothermal Field, Costa Rica," *The United Nations University, Geothermal Training in Iceland, 1998*, Reports 1998, Number 17, pages 461-499..