UNITED NATIONS UNIVERSITY

GEOTHERMAL TRAINING PROGRAMME

LaGeo

Feb. 20. 2013 /LSG-GAx-BS-MMM-EdV

List of papers from:
SHORT COURSE ON CONCEPTUAL MODELLING OF GEOTHERMAL SYSTEMS

Organized by UNU-GTP and LaGeo,
held in El Salvador during February 24th – March 2nd, 2013

SUNDAY, 24 February

Participants and trainers arrive in El Salvador and register into a hotel.

19:00-22:00 Opening dinner

MONDAY, 25 February

08:30-09:00 **Registration**
09:00-09:20 **Opening ceremony – Lic. Julio Valdivieso, President of LaGeo**
09:20-09:30 **Aim of the short course – organization and practical matters**
Lúdvík S. Georgsson, UNU-GTP and Evelyn de Velis, LaGeo

Geothermal energy overview– Chairman: Roberto Renderos, LaGeo

09:30-10:30 **Geothermal energy in the world and the capacity building activities of the UNU-GTP**
Lúdvík S. Georgsson and Ingvar B. Fridleifsson, UNU-GTP
10:30-11:00 **IDB – supporting geothermal development and capacity building in Latin America**
Toshitaka Takeuchi, IDB
11:00-11:30 Coffee break
11:30-12:00 **Current status of geothermal resources development in Central America**
Francisco E. Montalvo, LaGeo
12:00-12:30 **Geothermal activity in South America: Bolivia, Chile, Colombia, Ecuador, Peru**
Ingimar G. Haraldsson, UNU-GTP
12:30-13:00 **Geothermal status, progress and challenges in the Eastern Caribbean Islands**
Anelda Maynard-Date, NEVLEC and Alexis George, MPWEP
13:00-14:00 Lunch

Introducing conceptual modelling – Chairman: Ingimar Haraldsson, UNU-GTP

14:00-15:00 **Geothermal systems in global perspective**
Kristján Saemundsson, Gudni Axelsson and *Benedikt Steingrímsson*, ÍSOR
15:00-15:45 **Conceptual models of geothermal systems – introduction**
Gudni Axelsson, ÍSOR
15:45-16:15 Coffee break
16:15-17:00 **Case history of Los Azufres - conceptual modelling in a Mexican geothermal field**
Abraham III Molina, CFE

TUESDAY, 26 February

Geoscientific mapping: Creating the foundation for conceptual models – Chairman: Gudni Axelsson, ÍSOR

09:00-09:25 **Geological mapping in volcanic regions – Iceland as an example**
Anette K. Mortensen, ÍSOR
09:25-09:45 **Geological surveys for geothermal exploration in Costa Rica**
Leyner Chavarria Rojas, ICE
09:45-10:30 **Geochemical surveying and conceptual model of Chilanguera geothermal system, El Salvador**
Roberto Renderos, Antonio Matus, José Tenorio, and Martín Cubías, LaGeo
10:30-11:15 **Resistivity methods used in El Salvador geothermal exploration**
Pedro Santos, LaGeo
11:15-11:30 Coffee break

Session continued – Chairman: Patricia Jacobo, LaGeo

11:30-12:15 **Seismic activity, gravity, and magnetic measurements**
José Rivas, LaGeo
12:15-12:40 **Geothermal well design options**
Benedikt Steingrímsson, ÍSOR
12:40-13:00 **Geothermal drilling**
Jaime Arévalo, LaGeo
13:00- 14:00 Lunch

Session continued – Chairman: Anelda Maynard-Date, NEVLEC

14:00-14:25 **Stratigraphic, tectonic, and temperature mapping through geological well logging: Icelandic experience**
Anette K. Mortensen, ÍSOR
14:25-14:45 **Stratigraphic, tectonic, and temperature mapping through geological well logging in El Salvador**
Luz Barrios, Elizabeth de Henríquez and Arturo Quezada LaGeo
14:45-15:30 **Geophysical well logging: geological wireline logs and fracture imaging**
Benedikt Steingrímsson, ÍSOR
15:30-16:00 **Geochemical characterization and integral analysis of data, Las Pailas geothermal field, Costa Rica**
Yalile Torres Mora and Hugo Fajardo Torres, ICE
16:00-16:15 Coffee break
16:15-17:00 **3D visualization of geothermal data – practical examples**
Anette K. Mortensen, ÍSOR

WEDNESDAY, 27 February

Estimating reservoir conditions and properties and monitoring reservoir changes: Physical basis of conceptual modelling – Chairman: Anette K. Mortensen, ÍSOR

09:00-09:45 **Temperature and pressure logging**
Benedikt Steingrímsson, ÍSOR
09:45-10:15 **Reservoir temperature and pressure models**
Benedikt Steingrímsson, ÍSOR
10:15-11:00 **Geothermal well testing**
Gudni Axelsson, ÍSOR
11:00-11:15 Coffee break

Session continued – Chairman: Benedikt Steingrímsson, ÍSOR

11:15-11:45 **Reservoir response monitoring during production**
Manuel M. Monterrosa, LaGeo and Gudni Axelsson, ÍSOR

11:45-12:00 **Reservoir changes during eighteen years of exploitation in the Miravalles geothermal field, Costa Rica**
Sergio Castro, ICE

12:00-12:30 **Chemical response monitoring during production**
Patricia Jacobo and Francisco Montalvo, LaGeo

12:30-12:45 **Micro seismic monitoring during production, utilization and case examples for Mexico**
Efrén Cruz-Noé, Cecilia Lorenzo-Pulido, Jorge Soto-Peredo and Saúl Pulido-Arreola, CFE

12:45-13:00 **Gravity and subsidence monitoring during production**
Gudni Axelsson, ÍSOR

13:00-14:00 Lunch

Developing conceptual models – Chairman: Luz Barrios, LaGeo

14:00-15:00 **Developing a conceptual model of a geothermal system**
Anette K. Mortensen and Gudni Axelsson, ÍSOR

15:00-15:30 **Conceptual models for the Berlin geothemal field, case history**
Pedro Santos and Manuel Monterrosa, LaGeo

15:30-16:00 Coffee break

16:00-16:30 **Conceptual model and resource assessment for the Olkaria geothermal system, Kenya**
Gudni Axelsson, ÍSOR, et al.

16:30-17:00 **The Miravalles geothermal system, Costa Rica**
Osvaldo Vallejos Ruiz, ICE

THURSDAY, 28 February

Field trip to San Vicente and Berlín geothermal fields.

FRIDAY, 1 March

Practical session on conceptual modelling – Chairman: Paul Moya, WestJEC

09:00-13:00 **Evaluation and processing of variable data for conceptual model development (participants split in 6 groups addressing different subjects)**
Gudni Axelsson, Anette K. Mortensen and Benedikt Steingrímsson, ÍSOR, Manuel M. Monterrosa, LaGeo, Osvaldo Vallejos, ICE

13:00-14:00 Lunch

Session continued – Chairman: Yalile Torres Mora, ICE

14:00-17:00 **Presentations of group-results and discussions**
Gudni Axelsson, Anette K. Mortensen and Benedikt Steingrímsson, ÍSOR Manuel M. Monterrosa, LaGeo, Osvaldo Vallejos, ICE

SATURDAY, 2 March

Resource assessment and reservoir modelling – Chairman: Abraham III Molina, CFE

09:00-09:30 **Geothermal drilling targets and well siting**
Gudni Axelsson, *Anette K. Mortensen* and Hjalti Franzson

09:30-10:00 **Volumetric resource assessment**
Zosimo Sarmiento, FEDCO, Gudni Axelsson
and *Benedikt Steingrímsson*, ÍSOR
10:00-10:30 **Dynamic modelling of geothermal systems**
Gudni Axelsson, ÍSOR
10:30-11:00 Coffee break
11:00-13:00 **Practical training in resource assessment based on a conceptual model**
Manuel Monterrosa, LaGeo, Osvaldo Vallejos, ICE
Benedikt Steingrímsson and Gudni Axelsson, ÍSOR
13:00-14:00 Lunch

Review and discussion – Chairman: Manuel Monterrosa, LaGeo

14:00-14:30 **Review** (Instructors and Trainees)
14:30-15:00 **Discussion and recommendations**
15:00-15:30 Coffee break

Conclusions and closing remarks – Chairman: Lúdvík S. Georgsson, UNU-GTP

15:30-16:00 **Summary of the discussion, conclusions, and recommendations**
16:00-17:00 **Final closing ceremony**

17:00-18:00 ***Course assessment and next steps in training courses for Central America***
Meeting and review by instructors

19:00-21:00 Closing cocktail hosted by LaGeo

SUNDAY, 3 March

All guests depart from San Salvador for their home countries

Presented at "Short Course on Conceptual Modelling of Geothermal Systems",
organized by UNU-GTP and LaGeo, in Santa Tecla, El Salvador, February 24 - March 2, 2013.

UNITED NATIONS UNIVERSITY
GEOTHERMAL TRAINING PROGRAMME

LaGeo S.A. de C.V.

GEOTHERMAL ENERGY IN THE WORLD AND THE CAPACITY BUILDING ACTIVTIES OF THE UNU-GTP

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ABSTRACT

The renewable energy sources are expected to provide at least 20% of the world primary energy in 2050. A key element in the mitigation of climate change is capacity building in renewable energy technologies in the developing countries, where the main energy use growth is expected. Based on the World Energy Assessment Report update on the status in 2001 (WEA, 2004), the primary energy consumption in the world was assessed to be in excess of 400 EJ, with about 80% coming from fossil fuels, but only 14% from renewable energy sources. The contribution of the renewables is discussed and their possibilities. Their current share in the energy production is mainly from biomass and hydro, followed by wind and geothermal energy. In a future envisioned with depleting resources of fossil fuels and environmentally acceptable energy sources, geothermal energy with its large technical potential is expected to play an important role.

Central America is one of the world´s richest regions in geothermal resources. Geothermal power stations provide about 12% of the total electricity generation of the four countries Costa Rica, El Salvador, Guatemala and Nicaragua, while hydro stations provide 46% of the electricity for the four countries, and wind energy 2%. The geothermal potential for electricity generation in Central America has been estimated some 4 GWe, and less than 500 MWe have been harnessed so far. With the large untapped geothermal resources and the existing significant experience there are still ample opportunities to take geothermal to a higher level in the area. South America also hosts vast resources of geothermal energy that are largely unexploited, estimated to be in the range of 4-9 GWe. Exploration and development is now on-going in countries like Bolivia, Chile, Colombia and Ecuador. Similarly, the 11 volcanic islands of the Eastern Caribbean have an estimated power potential of 16 GWe collectively, according to USDOE studies. Production is still limited to Guadeloupe, with 15.7 MWe, but exploration wells have been drilled in St. Lucia, Nevis and Dominica, and are expected to continue this year in Montserrat and Dominica.

Finally, the activities of the UNU Geothermal Training Programme are described, including the 6 month training and postgraduate academic studies in Iceland with reference to Latin America. Special attention is given to the "UN Millennium Development Goals Short Courses" given almost annually in El Salvador since 2006, at first for the benefit of Central America, but more recently reaching to a large part of Latin America, and some of the volcanically active Caribbean Islands. Further development of geothermal capacity building in the region is discussed.

1. INTRODUCTION

Geothermal energy is one of the renewable energy sources that can be expected to play an important role in an energy future where the emphasis is no longer on fossil fuels, but on energy resources that are at least semi-renewable and long-term environmentally acceptable, especially with regard to emission of greenhouse gases and other pollutants. For developing countries which are endowed with good geothermal resources, it is a reliable local energy source that can at least to some extent be used to replace energy production based on imported (usually) fossil fuels. The technology is proven and cost-effective. For developing countries that have good resources and have acquired the necessary local expertise it has become very important. A good example of this is Kenya, as well as the Philippines, El Salvador and Costa Rica where geothermal energy is providing for 10-20% of the electricity production. Iceland should also be mentioned as the only country where geothermal energy supplies more than 60% of the primary energy used.

Geothermal systems can be classified into a few different types but with reference to variable geological conditions each one is in principle unique, so that good knowledge is needed through exploration. Furthermore, development of a geothermal system for electrical production is a capital intensive undertaking, and thus requires financial strength, or at least access to good financing. Thus, for developing geothermal resources, good training and expertise are needed for the exploration and development work, and furthermore strong financial backup for the project is necessary.

Here, the role of geothermal energy in the world's energy mix is presented with some emphasis on its utilization in Latin America and the Caribbean region. Then capacity building activities will be discussed. The operations of the United Nations University Geothermal Training Programme (UNU-GTP) will be introduced and the need for further geothermal capacity building in the region discussed.

2. THE NEED FOR MORE ENERGY

Amongst the top priorities for the majority of the world´s population is access to sufficient affordable energy. There is a very limited equity in the energy use in the different parts of the world. Some 70% of the world´s population lives at per capita energy consumption level below one-quarter of that of W-Europe, and one-sixth of that of the USA (WEC, 1993). And two billion people, a third of the world´s population, have no access to modern energy services. A key issue to improve the standard of living of the poor is to make clean energy available to them at prices they can cope with. World population, now at 7 billion people, is expected to continue to increase to the end of the 21st century, and possibly double through the century. To provide sufficient commercial energy (not to mention clean energy) to the people of all continents during this century is thus an enormous task.

The renewable energy sources are expected to provide 20-40% of the primary energy in 2050. The technical potential of renewable energy sources is estimated 7600 EJ/year, and thus certainly sufficiently large to meet future world energy requirements (WEA, 2000). The question is how large a part of the technical potential can be harnessed in an economical, environmentally and socially acceptable way.

The main growth in energy use will certainly be in the developing countries. It is thus very important to support developing countries with fast expanding energy markets, such as China and India, to try as possible to meet their growing energy demands by developing their renewable energy resources. In some countries in e.g. Central America and the East African Rift Valley, the majority of the grid connected electricity is already provided by hydro and geothermal energy. It is necessary to assist them in developing their renewable energy resources further so they are not compelled to meet the fast growing energy demands by fossil fuels.

3. WORLD ENERGY SOURCES

With technological and economic development, estimates of the ultimately available energy resource base continue to increase. Economic development over the next century will apparently not be constrained by geological resources. Environmental concerns, financing, and technological constrains appear more likely sources of future limits (Fridleifsson, 2002). In all scenarios of the World Energy Council (WEC), the peak of the fossil fuel era has already passed (Nakicenovic et al., 1998). Oil and gas will continue to be important sources of energy in all cases, but the role of renewable energy sources and nuclear energy vary highly in different scenarios and the proposed level to which these energy sources can be expected to replace coal. In all the scenarios, the renewables are though expected to become significant contributors to the world primary energy consumption, providing at least 20% of the primary energy in 2050 and 30% in 2100. They are expected to cover a large part of the increase in the general energy consumption and the energy needed to replace coal.

But are these scenarios realistic? Table 1 (WEA, 2000) shows that there is no question that the technical potential of renewable energy resources is sufficiently large to meet future world energy requirements. The question is, however, how large a part of it can be harnessed in an economical, environmentally and socially acceptable way. This will probably vary between the energy sources. It is worth noting, that the present annual consumption of primary energy in the world is more than 400 EJ (Table 2).

TABLE 1: Technical potential of renewable energy sources
Source: World Energy Assessment (WEA, 2000)

	EJ / year
Hydropower	50
Biomass	276
Solar energy	1,575
Wind energy	640
Geothermal energy	5,000
TOTAL	**7,600**

Table 2 shows the world primary energy consumption in 2001 (WEA, 2004). Fossil fuels provide 80% of the total, with oil (35%) in first place, followed by coal (23%) and natural gas (22%). The renewables collectively provide 14% of the primary energy, mostly in the form of traditional biomass (9%) and much less by large (>10 MW) hydropower stations (2%) and the "new renewables" (2%). Nuclear energy provides 7% of the world primary energy.

TABLE 2: World primary energy consumption in 2001
Source: World Energy Assessment (WEA, 2004)

Energy source	**Primary energy EJ**	**Percentage %**
Fossil fuels	**332**	**79.4**
Oil	147	35.1
Natural gas	91	21.7
Coal	94	22.6
Renewables	**57**	**13.7**
Large hydro (>10 MW)	9	2.3
Traditional biomass	39	9.3
"New renewables" (biomass, geothermal, solar, small hydro (<10 MW), tidal, wind)	9	2.2
Nuclear	**29**	**6.9**
Total	**418**	**100**

If we only look at the electricity production, the role of hydropower becomes much more significant. The world electricity production was about 14,000 TWh in 1998 as compared with 6,000 TWh in 1973 (WEA, 2000). Most of the electricity was produced by coal (38%), followed by hydro (18%), nuclear (17%), natural gas (16%) and oil (9%). Only 2% of the electricity was provided by the "new renewables" (small hydro, biomass, geothermal, wind, solar and tidal energy).

Table 3 shows the installed capacity and electricity production in 2005 for the renewable energy sources, namely hydro, biomass, wind, geothermal, and solar energy (from Fridleifsson et al., 2008). The data for the table is compiled from "Tables" in the 2007 Survey of Energy Resources (WEC, 2007). It should be noted that the installed capacity for biomass is not given in the "Tables", but reported as "in excess of 40 GW" in the text. The capacity factor for biomass is thus uncertain. No figures are given for the installed capacity and electricity production of tidal energy in the survey. The table clearly reflects the variable capacity factors of the power stations using the renewable sources. The capacity factor of 73% for geothermal is by far the highest. Geothermal energy is independent of weather conditions contrary to solar, wind, or hydro applications. It has an inherent storage capability and can be used both for base load and peak power. The relatively high share of geothermal energy in electricity production compared to the installed capacity (1.8% of the electricity with only 1% of the installed capacity) reflects the reliability of geothermal plants which are commonly operated at capacity factors in excess of 90%.

TABLE 3: Electricity from renewable energy resources in 2005

	Installed capacity		**Production per year**		**Capacity factor %**
	GWe	**%**	**TWh/yr**	**%**	
Hydro	778	87.5	2,837	89	42
Biomass	40*	4.5	183	5.7	52*
Wind	59	6.6	106	3.3	21
Geothermal	8.9	1.0	57	1.8	73
Solar	4	0.4	5	0.2	14
Total	**890**	**100**	**3,188**	**100**	**41****

* Capacity factor is uncertain; **Weighted average.

Table 3 also serves to demonstrate that renewable energy sources can contribute significantly more to the mitigation of climate change by cooperating than by competing. It underlines that geothermal energy is available day and night every day of the year and can thus serve as a supplement to energy sources which are only available intermittently. It is most economical for geothermal power stations to serve as a base load throughout the year, but they can also, at a cost, be operated to meet seasonal variations and as peak power.

Geothermal energy is one of the renewable energy sources that can be expected to play an important role in an energy future where the emphasis is no longer on fossil fuels, but on energy resources that are at least semi-renewable and long-term environmentally acceptable, especially with regard to emission of greenhouse gases and other pollutants. For developing countries which are endowed with good geothermal resources, it is a reliable local energy source that can at least to some extent be used to replace energy production based on imported (usually) fossil fuels. The technology is proven and cost-effective. For developing countries that have good resources and have acquired the necessary local expertise it has become very important. A good example of this is Kenya, as well as the Philippines, El Salvador and Costa Rica, where geothermal energy has become one of the important energy sources providing for 10-20% of the electricity production. With Kenya's Vision 2030, geothermal is scheduled to become Kenya's main source of electricity, with plans for 5000 MWe on-line in the two next decades (Ngugi, 2012). Iceland should also be mentioned as the only country where geothermal energy supplies more than 60% of the primary energy used. This is done through direct use for space heating, bathing, etc., and through production of electricity (Ragnarsson, 2010).

In 2009, electricity was produced from geothermal energy in 24 countries, increasing by 20% in the 5-year period from 2004 to 2009 (Bertani, 2010). Table 4 lists the top sixteen countries producing geothermal electricity in the world in 2009, and those employing direct use of geothermal energy (in GWh/year). Figure 1 shows the top fourteen countries in the world with the highest percentage share of geothermal in their national electricity production. Special attention is drawn to the fact that El Salvador, Costa Rica and Nicaragua are among the seven top countries, and that Guatemala is in tenth place.

TABLE 4: Top sixteen countries utilising geothermal energy in 2009;
data on electricity from Bertani (2010) and on direct use from Lund et al. (2010)

Geothermal electricity production		**Geothermal direct use**	
	GWh/yr		**GWh/yr**
USA	14,974	China	20,932
Philippines	10,311	USA	15,710
Indonesia	9,600	Sweden	12,585
Mexico	7,047	Turkey	10,247
Italy	5,520	Japan	7,139
Iceland	4,597	Norway	7,001
New Zealand	4,055	Iceland	6,768
Japan	3,064	France	3,592
Kenya	1,430	Germany	3,546
El Salvador	1,422	Netherlands	2,972
Costa Rica	1,131	Italy	2,762
Turkey	490	Hungary	2,713
Papua – New Guinea	450	New Zealand	2,654
Russia	441	Canada	2,465
Nicaragua	310	Finland	2,325
Guatemala	289	Switzerland	2,143

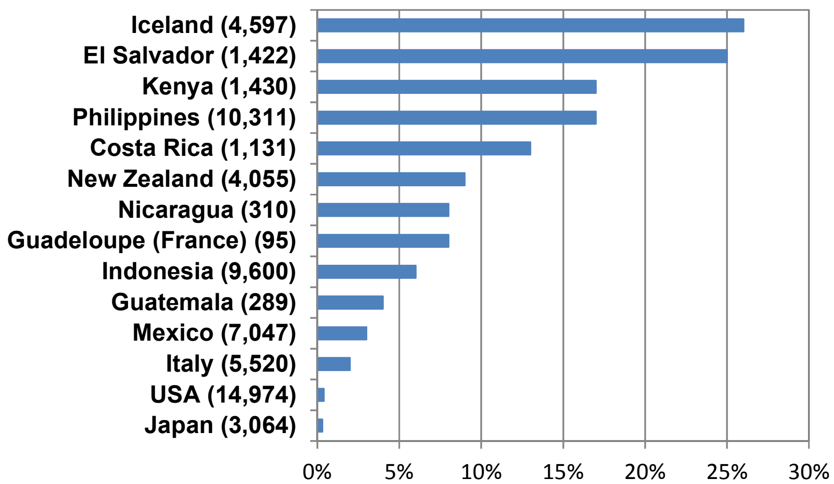

FIGURE 1: The fourteen countries with the highest % share of geothermal energy in their national electricity production. Numbers in parenthesis give the annual geothermal electricity production in GWh in 2009 (based on Bertani, 2010)

The largest geothermal electricity producer is the USA, with almost 15,000 GWh/yr, but amounting to only 0.5% of their total electricity production. It is different for most of the other countries listed in Table 4, with geothermal playing an important role in their electricity production. That certainly applies to the fourth country on the list, the Philippines, where the production of 10,300 GWh/yr means that geothermal supplies 17% of the total produced electricity. The same applies to Kenya, the total production of 1,430 GWh/yr puts the country in 9th place with regard to world production but constitutes 17% of the total electricity production in Kenya. For direct use (Lund et al., 2010), China heads the list followed by the USA, Sweden and Turkey. No Central American country is on the list of the 16 countries highest in direct use of geothermal energy.

4. GEOTHERMAL ELECTRICITY IN LATIN AMERICA AND EASTERN CARIBBEAN

Central America is one of the world´s richest regions in geothermal resources. Geothermal power stations provide about 12% of the total electricity generation of the four countries Costa Rica, El Salvador, Guatemala and Nicaragua, according to data provided from the countries (CEPAL, 2010; see also Table 4). In each of the 4 countries there are geothermal power plants in operation in two geothermal areas. The photo in Figure 2 is taken at the Ahuachapán geothermal power plant in El Salvador, while Figure 3 shows the Las Pailas binary power plant in Costa Rica. The electricity generated in the geothermal areas is in all cases replacing electricity generated by imported oil. The geothermal potential for electricity generation in Central America has been estimated some 4 GWe (Lippmann 2002), but less than 0.5 GWe have been harnessed so far. Exploration and production drilling has been ongoing in several new fields in the region with positive results, most recently in the San Vicente field in El Salvador.

FIGURE 2: Some lecturers and participants in the Short Course IV in 2012 visiting the Ahuachapán geothermal power plant in El Salvador

FIGURE 3: The Las Pailas binary geothermal power plant in Costa Rica

South America also hosts vast sources of geothermal energy that are largely unexploited. In 1999, the Geothermal Energy Association estimated the continent´s potential for electricity generation from geothermal resources to be in the range of 4-9 GWe based on available information and assuming technology available at the time (Gawell et al., 1999). These resources are largely the product of the convergence of the South American tectonic plate and the Nazca plate that has given rise to the Andes mountain chain, with its countless volcanoes. High-temperature geothermal resources in Bolivia, Chile, Colombia, Ecuador and Peru are mainly associated with the volcanically active regions, although low-temperature resources are also found outside them. Despite this, the only geothermal power plant which has been operated on the continent is the 0.7 MW binary demonstration unit in the Copahue field in Argentina, which was decommissioned in 1996 (Bertani, 2010). However, all of these countries have some history of geothermal exploration, and the interest has recently been reinvigorated with the changes in global energy prices and the increased emphasis on renewables to combat global warming (Haraldsson, 2013).

The 11 volcanic islands of the Eastern Caribbean lying on the inner arc have an estimated power potential of 16,310 MWe collectively, according to USDOE studies. Guadeloupe, as of 2004, has an operating facility of 15.7 MWe and is the only island in the region harnessing power from its geothermal resources. St. Lucia, Nevis and most recently Dominica have drilled exploration wells to analyse the resource for commercial exploitation. The recent most significant progress was the drilling of 3 deep vertical exploration wells in Dominica in 2012 (Maynard-Date, 2012; George, 2012). Further progress is expected in 2013 with the first deep exploration well being drilled in Montserrat, and additional trial wells in Dominica.

4. THE UNU GEOTHERMAL TRAINING PROGRAMME IN ICELAND

4.1 Introduction

The UNU Geothermal Training Programme (UNU-GTP) was established in Iceland in 1978. Its mandate is to assist developing countries with significant geothermal potential to establish groups of specialists in geothermal exploration and development by offering six month specialized training for professionals employed in geothermal research and/or development. More recently, the UNU-GTP also offers successful candidates the possibility of extending their studies to MSc or PhD degrees in geothermal sciences or engineering in cooperation with the University of Iceland. The UNU-GTP also organizes Workshops and Short Courses on geothermal development in Africa (started in 2005), Central America (started in 2006), and China (in 2008) (Fridleifsson, 2010).

During 1979-2012, 515 scientists and engineers from 53 countries have completed the annual six month courses. They have come from countries in Asia (40%), Africa (32%), Latin America (16%), Central and Eastern Europe (12%) and Oceania (0.4%). Since 2000, 33 have graduated with MSc degree (end of 2012). In January 2013, seven pursued their MSc and three PhD studies at the University of Iceland.

The UNU-GTP Short Courses are a special contribution of the Government of Iceland to the Millennium Development Goals of the United Nations. A part of the objective is to increase the cooperation between specialists in neighbouring countries in the field of sustainable use of geothermal resources. About 200 scientists/engineers and decision makers have participated in the 3 workshops that have each been a week, and more than 500 scientists/engineers have now been trained at the Short Courses, which have extended over 1-3½ weeks. Many former UNU Fellows are lecturers and co-organizers of the UNU-GTP Workshops and Short Courses. An offspring of the Millennium Short Courses has been the possibility of UNU-GTP to offer customer-designed geothermal short courses, which has now become an important part of the UNU-GTP operations (Georgsson, 2010, 2012a, b).

Since the start of the Workshops/Short Courses in 2005/6, the long term aim has been that the courses would develop into sustainable regional geothermal training centres. This is foreseen to happen in Kenya for the benefit of the African countries. And now, the Inter-American Development Bank (IDB) with the support of the Nordic Development Fund (NDF) is working towards establishing a model for a sustainable post-graduate university programme to be established in El Salvador for the benefits of the Latin American countries, with the cooperation of amongst others the UNU-GTP, LaGeo, and Salvadorian universities.

4.2 The 6 month geothermal training in Iceland

The main emphasis of the 6 month training is to provide the participants with sufficient understanding and practical experience to permit the independent execution of projects within a selected discipline in their home countries. Nine specialized lines of training are offered, *Geological exploration*, *Borehole geology, Geophysical exploration*, *Borehole geophysics*, *Reservoir engineering*, *Environmental studies, Chemistry of thermal fluids*, *Geothermal utilization* and *Drilling technology*. Each participant is meant to follow only one line of training, but within each line there is a considerable flexibility to allow for the needs of the individual.

The basic set-up of the 6 month training includes a 6 week introductory lecture course which aims to provide the individual with background knowledge on most aspects of geothermal energy resources and technology. It is followed by lectures and practical training in the field that individual is specializing in (6 weeks), Excursions are arranged to some of the main geothermal fields under exploration and utilization in Iceland, with seminars held and case histories presented on each field (2 weeks). The final phase is the execution of an extensive research project (10-12 weeks), under the guidance of an expert supervisor, which is concluded with a research project report. The trainees are encouraged to work on geothermal data from their home country if available. The reports are published in the annual yearbook "Geothermal Training in Iceland" (edited by Lúdvík S. Georgsson, international publishing code ISBN 978-9979-68). All research reports are also available on the home page of the UNU-GTP (*www.unugtp.is*). Figure 4 shows the recently revised time schedule and contents of the six month specialized courses at UNU-GTP in Iceland.

Week	Geological Exploration	Borehole Geology	Geophysical Exploration	Borehole Geophysics	Reservoir Engineering	Chemistry of Thermal Fluids	Environmental Science	Geothermal Utilization	Drilling Technology
1 2 3 4 5 6	Introductory Lecture Course Main aspects of geothermal energy exploration and utilization Practicals and short field excursions								
7 8 9 10	Field geology Lithological, tectonic & hydrothermal mapping Temperature surveying	Sample preparation Cutting analysis Petrography - Lithological & alteration logs	Thermal methods - Magnetics Gravity - Seismic methods Resistivity of rocks - Resistivity methods: DC, TEM & MT	Well logging & testing - theory & practises Logging and testing demonstrations Reservoir physics & well/reservor modelling Monitoring response to exploitation		Sampling of fluid & gas - Wet steam wells - Analytical methods Thermodynamics - Data processing and interpret.	EIA project planning Chemistry - Physics Biology - Monitoring Revegetation - Safety	Thermal design of power plants & source systems - Direct use of geothermal heat - Scientific modelling of utilization systems	Drilling equipment & procedures - Well design Rig operations - Safety Management - Cementing
11 12	Excursion to some of the main geothermal fields of Iceland, geothermal power plants and direct use facilities								
13 14	Gradient wells Remote sensing - GIS	XRD - Fluid inclusions Logging software	Processing & modelling resistivity data - GPS	Resource management & reinjection Data processing & software applications		Water-rock interaction Corrosion & scaling	Gas dispersion & abatem. Corrosion & scaling	Power plant components - Control systems - Corrosion & scaling	Completion - Testing Problems - Drilling software
15 16 17 18 19 20 21 22 23 24 25 26	**Project and report writing**	**Project and report writing**	**Project and report writing**	**Project and report writing**	**Project and report writing**	**Project and report writing**	**Project and report writing**	**Project and report writing**	**Project and report writing**

FIGURE 4: Approximate time schedule and contents of the 6 month specialized courses at UNU-GTP

The largest groups of UNU Fellows have come from China (80), Kenya (72), El Salvador (34) and Philippines (33). Figure 5 shows the UNU Fellows who completed the 6 months training in 2012.

For the past several years, regular funding of the UNU-GTP has allowed financing of six months training of about 20 UNU Fellows per year, with extra 1-3 Fellowships per year being financed through other sources, at least partially. However, the last three years have seen a dramatic increase in this. Improved set-up and new facilities in Iceland have made it possible for UNU-GTP to accept additional fellows if financed through external sources. This is reflected in the large groups in 2010-2012, with the largest group to date trained in 2012, including 33 UNU Fellows, 11 of whom were mainly financed through other agencies. Especially Kenya has utilized this opportunity as possible. Figure 6 shows the development of the training capacity of the UNU Geothermal Training Programme in Iceland from the beginning in 1979 to 2012. For a more detailed description of the general operations of the UNU-GTP see Fridleifsson (2010) or the UNU-GTP webpage, *www.unugtp.is*.

FIGURE 5: UNU Fellows in Iceland for the 6 month training in 2012

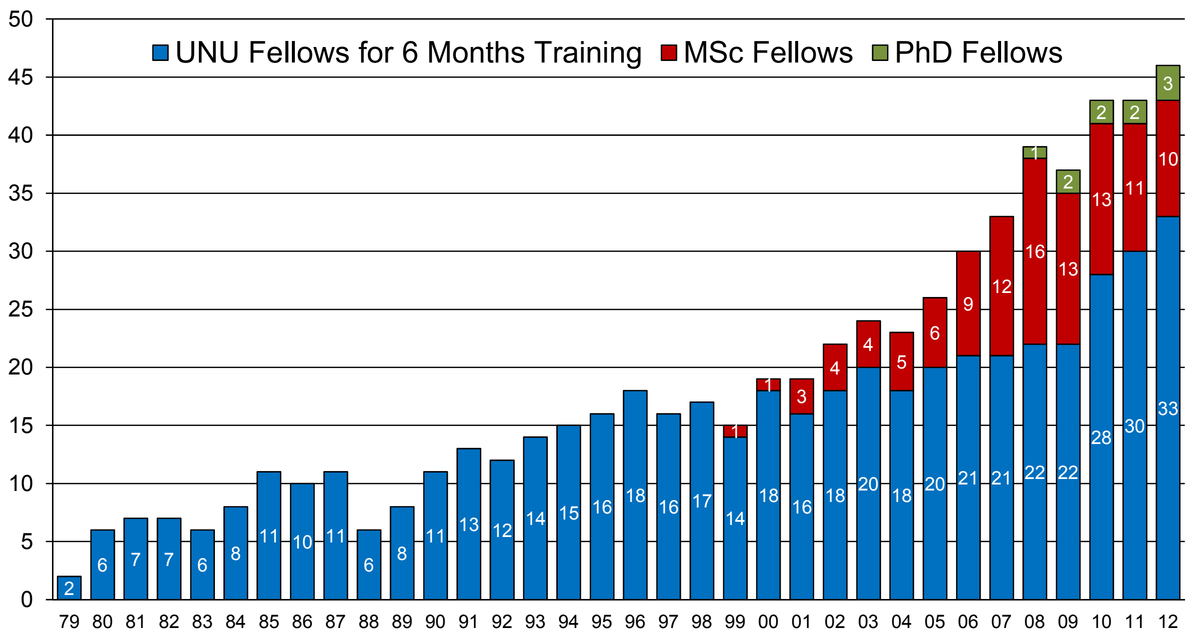

FIGURE 6: The gradual development of the training capacity of the UNU Geothermal Training Programme in Iceland from 1979 to 2012

4.3 The MSc and PhD programme

The aim of establishing an MSc programme in cooperation with the University of Iceland (UI) was to go a step further in assisting selected countries to strengthen their specialist groups even further and increase their geothermal research capacity, through admittance and support for postgraduate academic studies. The six months training at the UNU-GTP fulfils 25% of the MSc programme credit requirements (30 of 120 ECTs). Since 2001, 33 former UNU Fellows (China 2, Costa Rica 1, Djibouti

1, El Salvador 4, Eritrea 2, Ethiopia 2, Indonesia 4, Iran 3, Jordan 1, Kenya 8, Mongolia 1, Philippines 2, Rwanda 1 and Uganda 1) have completed an MSc degree in geothermal science and engineering (December 2012) through the UNU-GTP MSc programme, with 5 or 15% from Latin America. At the beginning of 2013, 7 are doing their MSc studies in Iceland, 1 of whom comes from El Salvador, and 1 from Nicaragua. The MSc theses have been published in the UNU-GTP publication series, and can also be obtained from the UNU-GTP webpage (*www.unugtp.is*). All of the MSc Fellows have been on UNU-GTP Fellowships funded by the Government of Iceland.

Finally, three former UNU Fellows, all coming from Africa, have now (end of 2012) been admitted to PhD studies at the University of Iceland on UNU-GTP Fellowships, with the first ones starting in the academic year 2008-2009. On February 15, 2013 a new milestone was reached in the operations of the UNU-GTP with the first one of these defending her PhD thesis. Dr. Pacific F.Achieng Ogola from Kenya was in fact the first person from Africa to graduate with a doctoral degree from the UI.

4.4 Workshops and Short Courses

The Short Courses/Workshops are set up in a selected country in the target region through cooperation with local energy agencies/utilities and/or earth science institutions, responsible for exploration, development and operation of geothermal facilities in the respective countries. In implementation, the first phase has been a week long workshop during which decision makers in energy and environmental matters in the target region have met with the leading local geothermal experts and specially invited international experts. The status of geothermal exploration and development has been introduced and the possible role of geothermal energy in the future energy mix of the region discussed. The purpose has, on one hand, been to educate key decision makers in the energy market of the respective region about the possibilities of geothermal energy, and increase their awareness of the necessity for more effort in the education of geothermal scientists in the region, and, on the other hand, to further the cooperation between specialists and decision makers in the different countries.

The workshop is followed by "annual" specialized Short Courses for earth scientists and engineers in surface exploration, deep exploration, production exploration, environmental studies and production monitoring etc., in line with the type of geothermal activity found in the respective region, and the needs of the region. Material presented and written for these events has been published on CDs and is also available on the website of the UNU-GTP (*www.unugtp.is*).

4.4.1 The African Series of Millennium Short Courses

During the planning of the first Workshop, the priority region was East Africa with its huge and to a large extent unused potential for geothermal power development, and urgent need for electric power. Cooperation was sought with Kenya, which has been the leading African country in geothermal development. The cooperation has generally meant that the costs of all invited foreign participants (travels and accommodation) and non-local lecturers (salaries, travels and accommodation) are covered by the UNU-GTP and the Icelandic Government, while the costs of the local Kenyan participation and some of the local arrangements are born by the Kenyan geothermal companies.

The first event in Africa, "*Workshop for Decision Makers on Geothermal Projects and their Management*", was held in Kenya in November 2005. At the Workshop, high-level decision makers from five countries met to learn about and discuss the main phases of geothermal development and what kind of manpower, equipment, and financing was needed for each phase, and analyse what was available in the region (Fridleifsson et al., 2005).

The result of the Workshop was that the Short Courses in East Africa should to begin with focus on surface exploration which was the field acutely needed for most countries in the region. The first Short Course was the ten day "*Short Course on Surface Exploration for Geothermal Resources*" held in November, 2006. The purpose was to give "a state of the art" overview of the methods used in surface geothermal exploration, and discuss the status and possibilities of geothermal development in East Africa. During the last 6 years, the annual Short Course in Kenya gradually developed into a more general course on geothermal exploration: "*Short Course on Exploration for Geothermal Resources*", which is now 3½ week long.

Participation in the Short Courses in Kenya has increased every year, not least due to the big pressure on capacity building in Kenya itself, which is needed for its intended fast-tracking of geothermal development in the next two decades. New countries have also been added to those invited most years, and in many cases, they have been participating for the first time in geothermal meetings in the UNU-GTP events. In total, 19 countries of Africa have now participated, the majority of them on a fairly regular basis. The highest number of participants in a single event is 61 in the 2012 Short Course, and the total number of participants in the Workshop/Short Courses is now over 360 persons. The Short Courses in East Africa have certainly proven to be a valuable addition to the capacity building activities of the UNU-GTP in Africa. They are now established as a good first training opportunity for young African scientists and engineers engaged in or being groomed for geothermal work, who are given an introduction to state-of-the-art exploration techniques for geothermal resources and the possible development of this valuable renewable energy source.

The UNU-GTP foresees a further development of the Short Courses in Africa, and expects that in the near future they will develop into a permanent regional school for geothermal training. The Kenyan cooperation partners are now preparing building of facilities which can make this possible, and if current plans hold, this should turn into a reality soon. For a further description of the UNU-GTP Workshops and Short Courses in Africa see Georgsson (2010; 2011; 2012a) or the UNU-GTP webpage (*www.unugtp.is*).

4.4.2 The Central-American Series of Millennium Short Courses

Similar to East Africa, in Central America geothermal resources are now playing an ever increasing role in the power production of countries like El Salvador, Costa Rica, Nicaragua and Guatemala, with considerable untapped potential. And Mexico has certainly been one of the world's largest producers of geothermal electricity for many years. The UNU-GTP has since its early years supported this region through training of many staff members of geothermal institutions, especially in El Salvador and Costa Rica. Hence, Central America was selected as the region for the second Series of Millennium Short Courses, with LaGeo S.A de C.V. in El Salvador chosen as a cooperation partner for this task. LaGeo (with its predecessors) has been responsible for geothermal development in El Salvador since the 1970s, and has all the know-how necessary to be an active and strong partner in hosting this series of courses, as it has certainly proven to be.

The "*Workshop for Decision Makers on Geothermal Projects in Central America*" was held in San Salvador in late November 2006 (Fridleifsson and Henriquez, 2006). The fifty participants in the 6 day event were mainly from the four countries in Central America most active in geothermal development, i.e. Costa Rica, El Salvador, Guatemala, and Nicaragua, and some of them were from the highest level. The Workshop was a sound success. In its conclusions, it said "*the importance of local geothermal energy resources and their possible potential in increased power production in the region is emphasized, along with the minimal environmental impact of geothermal, and the need for increased training and regional technical cooperation in this field.*" Figure 7 shows most of the participants of the workshop.

With geothermal development in Central America at a more advanced stage compared to East Africa, it has not been necessary to put the same emphasis on surface exploration in the Short Courses. So the topics have differed from one event to another. The first one was titled "*Short Course on Geothermal Development in Central America: Resource Assessment and Environmental Management*", a week-long event held in El Salvador in late November 2007 (Fridleifsson et al., 2007). Regional participants were 45 + 17 lecturers, with additional international lecturers coming from Iceland, Kenya and the Philippines (Tables 5 and 6).

FIGURE 7: Participants in the first UNU-GTP Workshop in Central America in 2006

TABLE 5: Participants in the Millennium Short Courses in Central America 2007-2012

Country	2007	2009	2011	2012	Total
Bolivia				1	**1**
Chile				5	**5**
Colombia			5	2	**7**
Costa Rica	6	7	6	1	**20**
Dominica		2	2	2	**6**
El Salvador	22	9	23	28	**82**
Ecuador			1	2	**3**
Guatemala	1	1	2	1	**5**
Honduras	2	2	5	2	**11**
Mexico	1		3	6	**9**
Nevis		2	2	1	**5**
Nicaragua	13	7	13	11	**44**
Others		2		3	**5**
Total	**45**	**32**	**62**	**65**	**203**

TABLE 6: Lecturers in the Millennium Workshops and Short Courses in El Salvador in 2006-2012

Short course / Workshop	Total	Home country	Neighb. countries	Intern.	Iceland	UNU-Fellows
El Salvador 2006	25	8	9	5	3	9
El Salvador 2007	16	3	5	3	5	7
El Salvador 2009	19	12	4	0	5	11
El Salvador 2011	25	12	6	1	6	14
El Salvador 2012	26	10	8	3	5	11

The third event in Central America was delayed to 2009. The two week long "*Short Course on Surface Exploration for Geothermal Resources*" was held in October 2009 in El Salvador. It was a shorter version of the courses that had been held in East Africa in 2007-2009, with the main emphasis on geophysics and chemistry of thermal fluids, and aimed at young earth scientists in the region (Georgsson et al., 2009). The last day consisted of participation in the "Central American Geothermal Workshop", a cooperative event between LaGeo, the International Geothermal Association (IGA) and UNU-GTP, intended to highlight geothermal development in Central America. The Short Course reached a broader audience than the first two with participation from the East Caribbean Region. The third Short Course was the "*Short Course on Geothermal Drilling, Resource Development, and Power Plants*", a week long course given in January 2011. Here, the UNU-GTP reached for the first time to countries in South America (Georgsson et al., 2011). The topic also proved to be very interesting to many private companies in the geothermal business in the region, reflected in their increased participation, even at their own cost. This is a trend we saw continue in last year's event, the week long *Short Course IV on Geothermal Development and Geothermal Wells*" (Georgsson et al., 2012) and progressing even further with the current event. Tables 5 and 6 show the number of participants and lecturers. Figure 8 shows the participants of the Short Course in 2012.

FIGURE 8: Participants and lecturers in the El Salvador Short Course in 2012

The Short Courses in El Salvador have brought new and important components to geothermal development in Central America. They have not only increased the available training capacity for the region, but also furthered cooperation between the countries of the region in geothermal development. The geothermal development in Central America is on average at a higher level than in East Africa, which means that the future need in capacity building is more varied. We foresee the need for Short Courses covering topics ranging from surface exploration to development, field management, production monitoring, environmental aspects, and even techniques for direct use. However, participation can also be expected to cover a wider geographical area where geothermal resources have not been developed to the same extent. Many of the small nations of the Eastern Caribbean region have important geothermal resources to be developed. Participants from this region can be expected to become a significant factor in the Short Courses in the near future. Similarly, participation from South America is also expected to increase, as interest in the development of high-temperature resources in this part of the world grows.

From a more general perspective, the Short Courses have become a new channel to the more advanced training in Iceland with the strongest participants showing their ability and strength, and thus opening the possibility to be selected for training in Iceland. There are now many examples of good participants in the Short Courses being selected for the 6 month training in Iceland. And in a few cases it has even led to MSc studies in Iceland, first of whom completed his MSc in April 2010. The Short Courses have also been an important element towards increased cooperation between the countries within the region.

4.5 Customer-designed Short Courses

The latest capacity building service of the UNU-GTP are the customer-designed Short Courses in developing countries, given for the first time in 2010. This new service of the UNU-GTP was triggered by an urgent need for training in countries planning fast-tracking of geothermal development, while it has also been an offspring of the regular training and Short Courses and the material prepared there. This has proven a good opportunity for some countries/ institutions in need of a rapid capacity building process, beyond what UNU-GTP can service under its conventional operations, and which have themselves the strength or the support of external sources (e.g. multilateral or bilateral aid agencies) to finance such events. The paying customer defines the outline of the Short Course, while UNU-GTP is a guarantee of the quality of the contents.

In 2010-2012, 9 such Short Courses or Advanced Training have been held for five different customers in three continents. The contents have varied from general geoscientific courses to more specialized ones, such as on geothermal drilling, as well as scaling and corrosion in geothermal installations. Similarly, the length has varied from one week to 6 months, based on the need and target. An example is the week long "Short Course on Geothermal Exploration and Development" held in El Salvador in November 2011. The Short Course was sponsored by the Organization of American States (OAS) for the benefit of three South-American countries, Ecuador, Colombia and Peru, all of which have consequently been invited to send participants to the UNU-GTP Millennium Short Courses.

4.6 The strength of the internet

Open publications has always been the motto of the UNU-GTP, which is in line with the general policies of the United Nations University, supporting free access of scientific material for the developing nations. The reports of the UNU Fellows in Iceland have been distributed free of charge to geothermal institutions worldwide, and the same has applied to publications of study material. The annual report book "Geothermal training in Iceland" is also sent to all active former UNU Fellows, and to geothermal institutions worldwide. With the coming of the internet, from the early 2000s, the reports have also been published open-file in a pdf-version at UNU-GTP's website. More recently, all older reports have also been made available there. The same applies to the UNU-GTP Workshops and Short Courses, and the UNU-GTP Anniversary Publications. Papers written for these events and published in books and/or on CDs, are all also available for downloading at the website: *www.unugtp.is.*

It is safe to say that with all the material now accessible on the UNU-GTP website, the UNU-GTP has created one of the largest open databases in the world available on geothermal exploration, development and utilization. This is easy to verify by searching for material on geothermal on the internet, through one of the large search machines, where material published by the UNU-GTP will inevitably score high in possible views. It is therefore interesting to look at some statistics in this. Table 7 shows the most viewed publications in 2012 and their numbers of views. The Short Courses in El Salvador are obviously attracting much attention as papers presented there are in 3 of the 4 top seats. The number of views can also be considered very high for such specialized literature.

Additionally, it is interesting to see the geographic distribution of the website's visitors who viewed the publications of the UNU-GTP (including the website of Orkustofnun (*www.os.is*)). With 23,698,449 visits, Iceland was at the top, but Figure 9 shows the number of visits from other countries. Here it must be noted that for this purpose, it is only possible to see which countries view publications on the UNU-GTP and Orkustofnun websites, but not which publications are being viewed. What is unexpected here are the high number of visits from countries that are not known for access to significant amount of geothermal resources, like the Netherlands and Germany. However, here another factor must be considered which is how "computerized" the country is, and how general access is to the internet. This would be expected to increase the share of the developed countries, which the figure seems to support.

TABLE 7: Most viewed publication of the UNU-GTP on the internet in 2012

No.	No. views	Title and author of publication	Publication year and type/event
1	365,303	*Piping design: the fundamentals*, by José Luis Henriquez and Luis Agurirre	2011 - ESSC
2	114,520	*Absorption refrigeration system as an integrated condenser cooling unit in a geothermal power plan*, by Tesha	2009 – MSc thesis
3	85,575	Gravity and magnetic methods, by José Rivas	2009 - ESSC
4	42,226	*Geothermal power plant cycles and main components*, by Páll Valdimarsson	2011 - ESSC
5	29,473	*Analysis of management methods and application to maintenance of geothermal power plants*, by Clety Kwambai Bore	2008 – MSc thesis
6	22,885	*East African Rift System –an overview,* by Kristjan Saemundsson	2010 - KSC

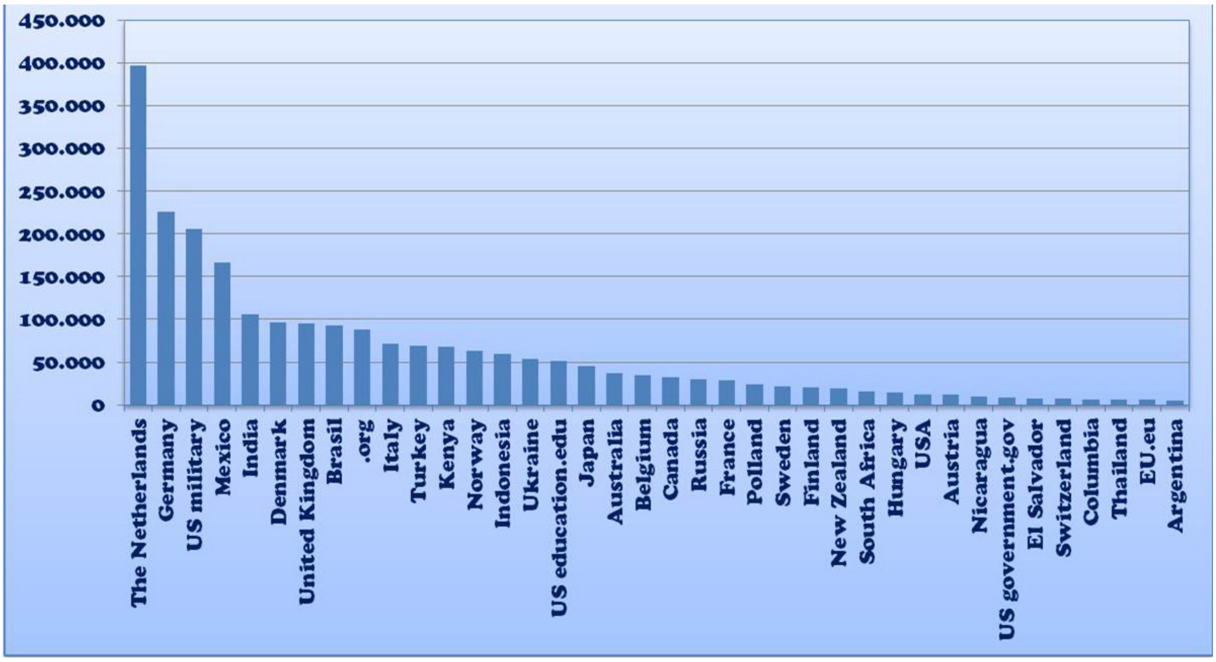

FIGURE 9: Number of views of the UNU-GTP and Orkustofnun websites by country (made by M. Ómarsdóttir)

5. DISCUSSION

One of the major concerns of mankind today is the ever increasing emission of greenhouse gases into the atmosphere and the threat of global warming. It is internationally accepted that a continuation of the present way of producing most of our energy by burning fossil fuels will bring on significant climate changes, global warming, rises in sea level, floods, draughts, deforestation, and extreme weather conditions. One of the key solutions to avoid these difficulties is to reduce the use of fossil fuels and increase the sustainable use of renewable energy sources. Geothermal energy can play an important role in this aspect in many parts of the world.

Using indigenous renewable energy resources is an important issue and a possible solution for many countries, not least from the third world. This applies very much to Latin America and the eastern Caribbean Islands. The volcanic systems of Central America and along the Andes mountain chain, as well as the volcanoes of the eastern Caribbean Islands, are a powerful heat source for the numerous high-temperature geothermal systems found in the region. These renewable energy resources have the potential to supply clean and sustainable energy to countries in dire need for energy and at the same time reduce their dependence on fossil fuels. When considering the wealth of these resources, it can be argued that it is surprising, how slow the development has been in S-America and the Caribbean region.

Capacity building and transfer of technology are key issues in the sustainable development of geothermal resources. Many industrialised and developing countries have significant experience in the development and operations of geothermal installations for direct use and/or electricity production. It is important that they open their doors to newcomers in the field. We need strong international cooperation in the transfer of technology and the financing of geothermal development in order to meet the Millennium Development Goals and the threats of global warming.

The UNU-GTP is intent on assisting the Latin American and Caribbean countries in geothermal capacity building as best it can, so geothermal power can play a bigger role in the energy future of the region. This we will continue to do both through offering UNU Fellowships for 6 month training and postgraduate academic studies in Iceland, and through Short Courses in the region itself. Here, we especially hope to be able to intensify our effort with regard to countries in the early stages of development.

A *Geothermal Diploma Course* in Spanish and open for all the C-American countries has been given twice in El Salvador in the last 4 years with both financial and educational support from Italy (Caprai et al., 2012). This initiative has now come to an end. However, the Inter-American Development Bank (IDB) with the support of the Nordic Development Fund (NDF) has now pledged support for the continuation of this, and is working towards establishing a model for a sustainable post-graduate university programme, which could even progress to an MSc programme, to be established in El Salvador for the benefits of the Latin American countries, with the cooperation of amongst others the UNU-GTP, LaGeo, and Salvadorian universities. This can prove an important basis for taking geothermal development in the region to a new level. The annual UNU-GTP Short Course could be foreseen to become an integral part of this diploma course. Hopefully, we will see the realisation of this in 2014.

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UNITED NATIONS UNIVERSITY
GEOTHERMAL TRAINING PROGRAMME

LaGeo S.A. de C.V.

CURRENT STATUS OF GEOTHERMAL RESOURCES DEVELOPMENT IN CENTRAL AMERICA

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ABSTRACT

Central America is rich in geothermal resources, however only a small portion has been developed and is currently used for electricity generation. In countries like El Salvador, Nicaragua, Costa Rica and Guatemala, the geothermal exploration led to the first resource evaluation and the beginning of commercial exploitation of some areas such as Ahuachapán in 1975, Momotombo in 1983, Berlin in 1992, Miravalles in 1994, Zunil in 1998, San Jacinto Tizate in 2005, Amatitlán in 2006 and recently Las Pailas in 2011. Currently, the region has a gross installed capacity of 625.3 MWe, generating an annual average of 454.9 MWe. From the existing geothermal potential in Central America, the electricity generated provides an average of 13%, which seems to be significant in countries like El Salvador, Costa Rica and Nicaragua contributing 23.45%, 13.59% and 12.11% respectively of the total electricity consumption in each country for the year 2012. Geothermal generation capacity in Central America in 2012 was 3429 GWh which is equivalent to 7.9% of total electricity generated by different sources. The potential resource in Central America has been estimated very close to the total amount currently used in electric power, that is, about 5105 MWe.

1. INTRODUCTION

Central America belongs to the so-called Pacific Ring of Fire and has been affected throughout its history by intense seismic and volcanic activity, resulting in catastrophic events that have impacted negatively on economic, social and cultural development of the region. The geodynamic situation of the isthmus and the occurrence of these natural phenomena can be attributed mainly to the subduction of the Cocos plate beneath the Caribbean plate (whose limits are known as Middle America Trench, which are within the Pacific Ocean), and the presence of faults (fractures of the crust) that are active in the Motagua-Chamalecón Polochic fault system, thus separating the Caribbean plate from the North American plate.

In Figure 1, the Cocos and the Caribbean tectonic plates collide, about 100 km parallel to the Pacific coast of Central America. The black arrows indicate the direction of movement. Volcanoes are formed in a narrow strip parallel to the shock zone. The process of subduction occurs when the Cocos plate disappears beneath the continental crust producing fusion of mass and extensional faulting. Along the trench, the subduction of the Cocos oceanic plate beneath the Caribbean plate is given at a rate of 73-84 mm/year (De Mets, 2001). The convergence movement of the Cocos plate is to the northeast. Some of the material melted by the high temperatures of Earth's mantle Cocos plate, rises almost vertically and enters the Caribbean plate along a nearly straight line, forming the Central American volcanic chain that runs northwest -southeast.

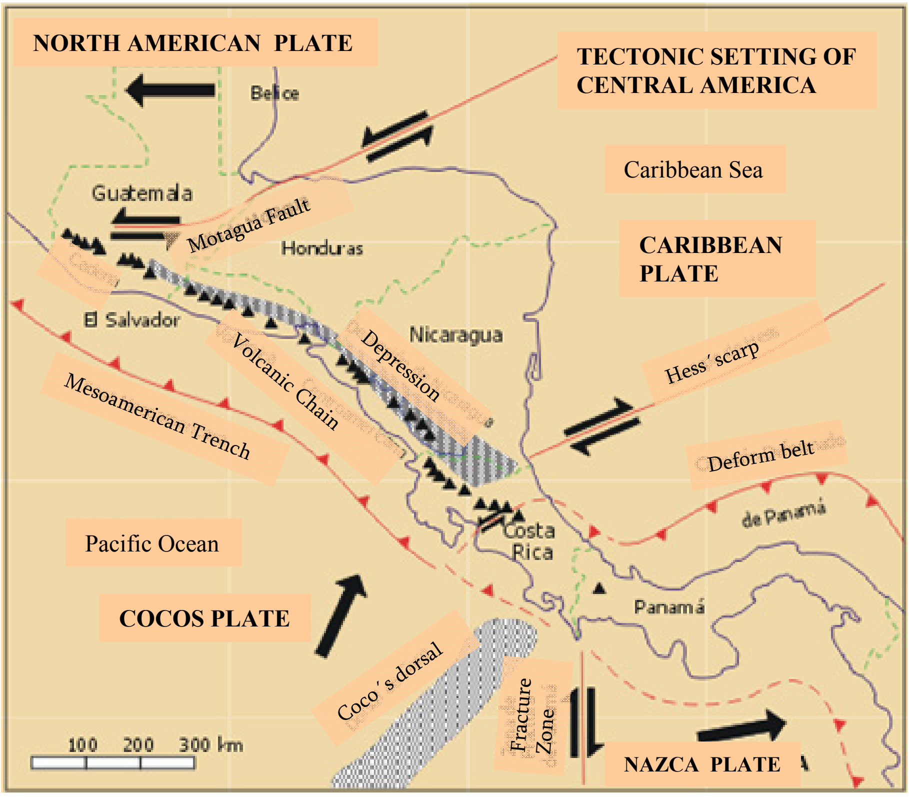

FIGURE 1: Subduction of the Cocos plate over the Caribbean plate and the volcanic chain (Source: modified from CEPREDENAC)

2. GEOTHERMAL RESOURCES IN CENTRAL AMERICA

Central America is rich in geothermal resources, however only a small portion has been developed and is currently used for electricity generation. The subduction process as mentioned above is responsible for the creation of the volcanic chain in the region which provides a potential source of energy because the exploited geothermal fields, are located in areas of anomalous heat flow in the vicinity of shallow magma chambers associated with volcanoes, producing temperatures between 200-300 °C at depths between 500 and 3,000 m, where the heat is transported by conduction in the rocks and convection in the geothermal fluids.

In countries like El Salvador, Nicaragua, Costa Rica and Guatemala, the geothermal exploration began in the late fifties and early sixties, resulting the identification of several promising areas for the start of drilling that led to the first resource evaluation and the beginning of commercial exploitation of some areas such as Ahuachapán in 1975, Momotombo in 1983, Berlin in 1992, Miravalles in 1994, Zunil in 1998, San Jacinto Tizate in 2005, Amatitlán in 2006 and recently Las Pailas in July 2011 and San Jacinto Tizate in January (U3) and December 2012 (U4).

In Figure 2, shows the location of the geothermal fields currently in operation and main geothermal areas that have been subject to exploration in Central America. Those with high temperature (> 200°C) have been utilized for generating electricity and very low application of low temperature resources have been done.

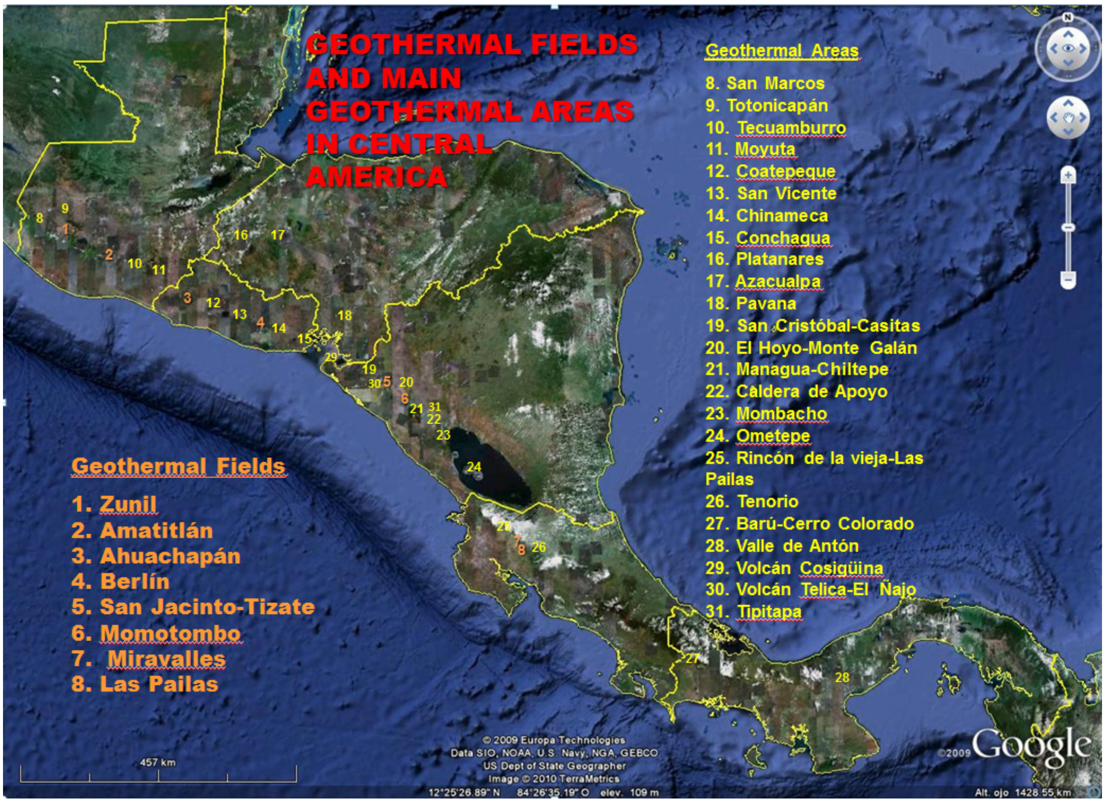

FIGURE 2: Location of the geothermal fields in operation and main geothermal areas in Central America (modified from Google)

Since the mid 90's to early 2003, the energy development in the region was focused mainly on production sustainability of existing power plants, with significantly reduction of the exploration studies of new geothermal areas.

The main reasons for this were:

- Priority of government investment to other sectors of their economies.
- Low oil prices (in the range of 10-20 dollars per barrel).
- Private companies preferred power generation investment in "traditional" electricity generation schemes (such as hydro and thermal plants).
- The geothermal projects had difficulty obtaining long-term loans as Banks and private investors had become less willing to take the risks associated with this industry.
- Support for geothermal exploration and development by local and international governments had fallen.

Today, governments in the region show more interest in developing renewable energy resources in their countries, especially in the geothermal energy. This change is probably the result of high oil prices, instability in this market, uncertainties in future climate conditions (which could affect the output of hydroelectric projects), the need of reducing CO_2 emissions by overriding the environmental impacts associated with burning wood and fossil fuels to generate electricity.

3. GEOTHERMAL RESOURCES AND CURRENT ESTIMATED POTENTIAL

Geothermal resource development in Central America should contribute significantly to achieving the Millennium Development Goals, generating electricity based on geothermal fluids that are clean, renewable, sustainable and indigenous source of energy.

Their use can provide several advantages:
- offset the price of electricity,
- protecting the Central American countries against future rises in the oil market,
- contributing to reduced environmental pollution,
- creating more job opportunities especially in rural areas where the developing of the geothermal projects are carried out.

Lippmann (2002) reports the total electricity generation capacity that can be achieved in Central America from geothermal resources, could be in the range of 2000 to 16.000 MW, giving a most likely value around 4.000 MW.

Table 1 shows the estimated geothermal potential of different sources including the geothermal potential to be developed given the current installed capacity. It can be seen that the total estimated potential for the region by the various sources is about 3500 MWe (average of the estimated potential for various publications in Table 1).

TABLE 1: Estimated geothermal potential (MWe) for electricity generation

Geot. Pot. (Mwe)	Total	Develop.	Total	Develop.	Total	Develop.	Total	Develop.	Total	Develop.	Total	Develop.
Nicaragua	1750	1662.5	1200	1112.5	992	904.5	1000	912.5	345	257.5	1519	1431.5
Costa Rica	1000	834.3	235	69.5	750	584.3	235	69.3	1059	893.3	865	699.3
Guatemala	1000	950.8	1000	950.8	480	423	1000	950.8	993	943.8	400	350.8
El Salvador	500	295.6	333	128.6	362	157.6	450	245.6	595	390.6	644	439.6
Honduras	130	130	120	120	122	122	126	126	677	677	116	116
Panama	50	50	40	40	42	42	40	40	719	719	0	0
Total	4430	3923.2	2928	2421.4	2748	2233.4	2851	2344.2	4388	3881.2	3544	3037.2
Source:	Lippmann 2002		CEPAL 2004		JICA 2005		SICA 2006		EPI 2007		IILA 2009	

4. GEOTHERMAL RESOURCES AND CURRENT ELECTRICAL GENERATION

Currently from the existing geothermal potential in Central America only a relatively small amount has been used to generate electricity providing an average of 13%, but seems to be significant savings fossil fuels, especially in countries like El Salvador, Costa Rica and Nicaragua contributing 23.45, 13.59 and 12.1% respectively of total electricity consumption in each country (Table 2).

The data in Table 2 is from 2012, including information regarding the installed capacity for the new power plants in Costa Rica and Nicaragua (Las Pailas and San Jacinto Tizate respectively), hovewer, only the data for 2011 is available for Guatemala.

TABLE 2: Geothermal power generation in 2012. * Data from 2011

Country	Installed Capacity (MWe)	Available Capacity (MWe)	Annual Energy produced (GWh/y)	National participation rate (%)
El Salvador	204.4	179.1	1420.2	23.45
Costa Rica	207.2	180.0	1280.0	13.59
Nicaragua	164.5	68.8	491.8	12.11
Guatemala	*49.2	*27.0	*237.1	*2.91
Total	625.3	454.9	3429.1	

By the year 2009, the region has installed capacity of 506.6 MW, generating an annual average of 417.5 MWe. In 2010, the installed capacity remained the same and the annual generation was 357.4 MWe. Currently, the installed capacity has increased in 2012 up to 625 MW, generating annually 455 MWe and 3429 GWh which is equivalent to 7.9% of total electricity generated by different sources. As shown in Figure 3, the geothermal generation is the third in importance as a percentage compared to other types of energy used in Central America. Figure 4 shows the percentage of each country of the total generated from geothermal resources in 2012.

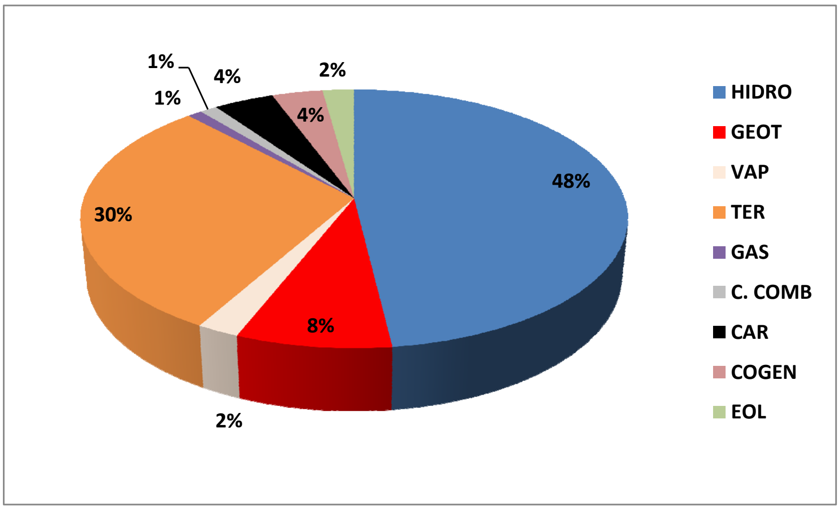

FIGURE 3: Electrical generation by energy source in Central America 2012

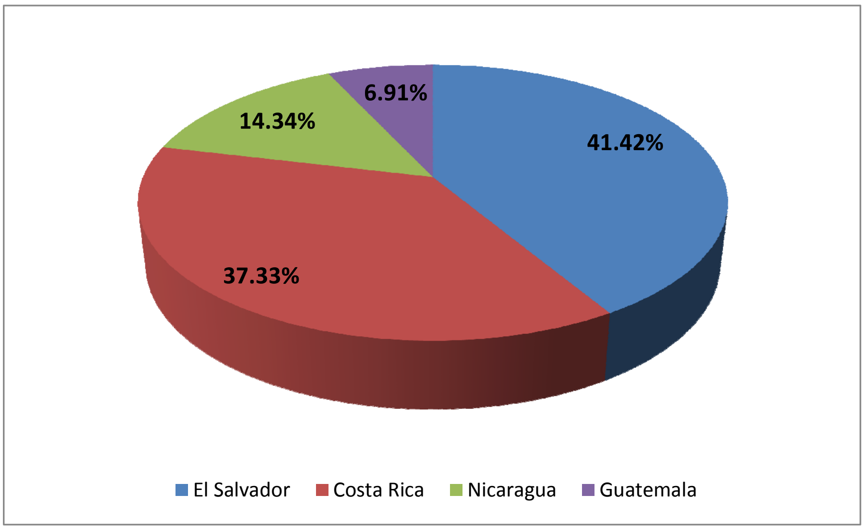

FIGURE 4: Electrical generation by geothermal resources in Central America 2012

Figure 5 shows the percentage of the different geothermal fields on the total generated from geothermal resources in 2012.

Table 3 shows the detailed number of units installed by each country, the available capacity in MW and annual average generation in 2012. It should be noted that a 10-MWe wellhead unit in Berlin and 5-MWe unit in Amatitlán have been shut down since 1999 and 2007 respectively. In the table the installed capacity is included, available capacity and the annual generation. Among the companies only the ICE (Instituto Costarricense de Electricidad) is the only government institution and LaGeo that is semi-private, the rest are private companies.

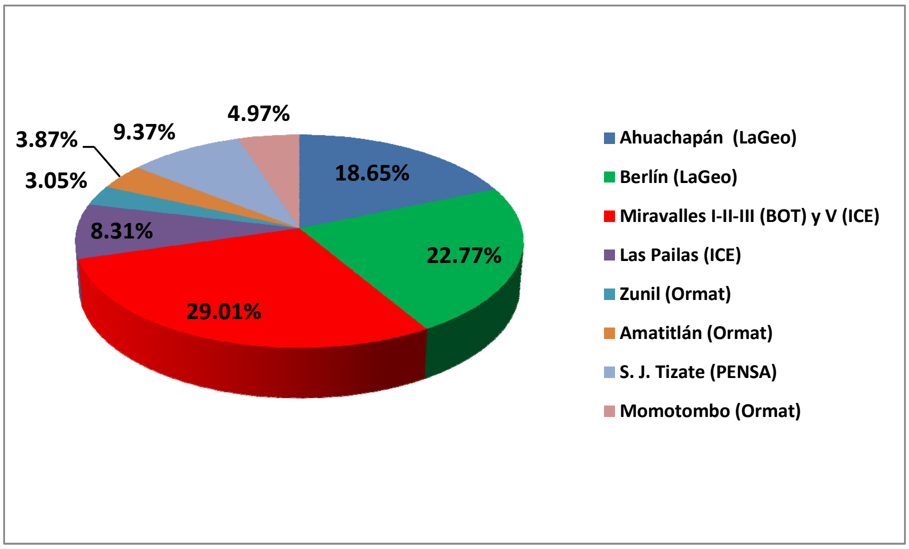

FIGURE 5: Percentage of geothermal production for each field in Central America by 2012

TABLE 3: Details of the Central American geothermal plants

Country	Geothermal Power Plant	Initial Operation	End of Operation	Installed Capacity (MWe)	Available Capacity (MWe)	Annual Generation (GWh)
El Salvador				**204.4**	**179.1**	**1420.4**
	Ahuachapán I-II-III	1975	***	95.0	74.1	639.5
	Berlin Boca Pozo	1992	1999	-10.0	0.0	0.0
	Berlin I-II	1999	***	56.2	53.6	422.0
	Berlin III	2007	***	44.0	42.6	308.0
	Berlin CB	2009	***	9.2	8.8	50.9
Guatemala				**49.2**	**27.0**	**237.1**
	Zunil (8)	1998	***	24.0	11.4	100.0
	Amatitlán	2006	***	25.2	15.6	137.1
	Amatitlán	2006	2007	-5.0	0.0	0.0
Costa Rica				**207.2**	**180.0**	**1280.0**
	Miravalles I	1994	***	55.0	50.0	370.0
	Miravalles II	1998	***	55.0	50.0	350.0
	Miravalles Boca Pozo	1998	***	5.0	5.0	15.0
	Miravalles III (BOT)	2000	***	29.5	25.0	150.0
	Miravalles V	2003	***	21.0	15.0	110.0
	Las Pailas	2011	***	41.7	35.0	285.0
Nicaragua				**164.5**	**68.8**	**491.8**
	Momotombo (3)	1983	***	77.5	30.3	191.8
	San Jacinto Tizate (2)	2005	***	10.0	38.5	300.0
	U3	2012	***	38.5		
	U4			38.5		

Note: Data available for Guatemala in 2011(CEPAL)

The contribution of geothermal power to the national grid of each country in Central America contains the updated data for 2012 both in geothermal generation (GWh) and percentage (Figure 6 and 7).

It should be noted that El Salvador, Costa Rica, Nicaragua and Guatemala are considered among the first 10 countries in the world producing a good percentage of total electricity consumption in each country (Figure 8).

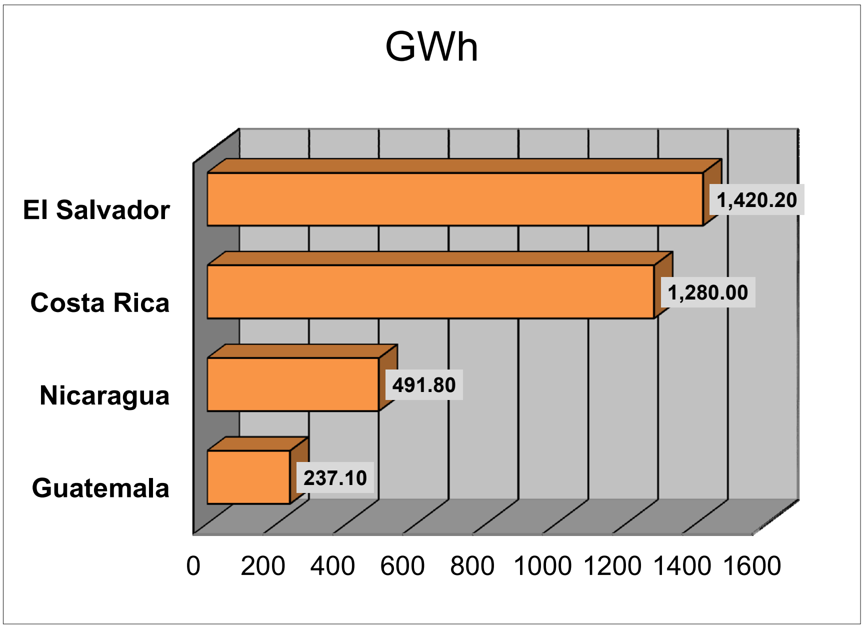

FIGURE 6: Geothermal energy production for electrical uses in 2012

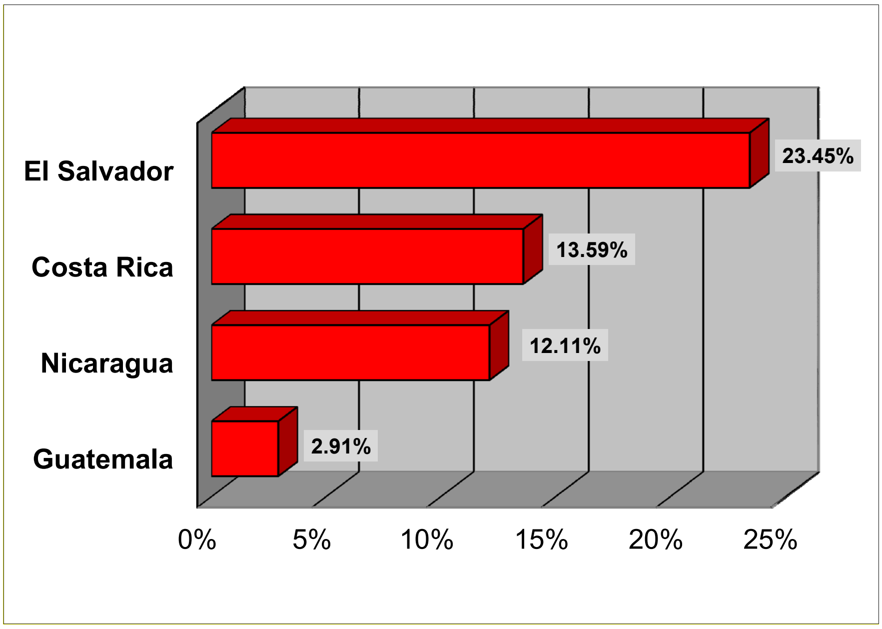

FIGURE 7: Percentage of contribution and electrical generation for 2012

5. GEOTHERMAL DEVELOPMENT HISTORY

The geothermal development in Central America since 1975 is shown in Figure 9. The increasing in installed capacity was faster in the first twenty five years, with an increment of around 400 MWe, after that, developing projects seemed to be of minor importance. Similar behavior was reported for the geothermal generation increasing from 72 to 3429 GWh in 37 years.

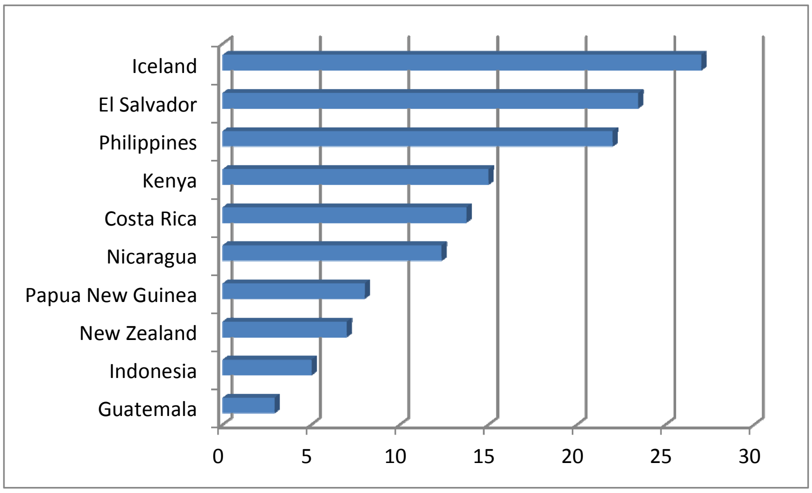

FIGURE 8: Top 10 countries with the highest percentage contribution of geothermal power to the national grid (modified from Bertani, 2007)

Worldwide, only 25 countries use geothermal power for electricity production (IGA). In 2010, total global capacity was 10,717 megawatts (Figure 10).

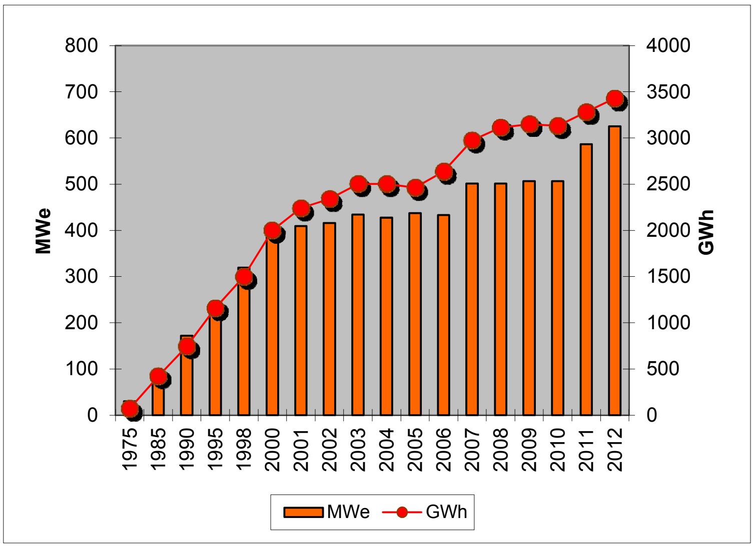

FIGURE 9: Geothermal development history and generation in Central America.

Even if Larderello (Italy) started the first commercial geothermal plant in the first part of twenty century, within the last 50 years of commercial electricity generation, several plants installed in different countries, have established and proven the geothermal industry as a cost-competitive renewable power generation technology. The majority of generation capacity is concentrated in some few countries: the U.S., the Philippines, Indonesia, Italy, Mexico, Iceland, Japan and New Zealand (Figure 11). After the first experiment of geothermal exploitation was carried out at Larderello in 1904, the first industrial power plant (250 kW) was put into operation in 1913, and geothermal power production has since increased continuously up to the present value of 810 MW installed capacity (711 MW running capacity). The first geothermal power plants in the U.S. were built in 1962 at The Geysers dry steam field, in northern California. It is still the largest producing geothermal field in the world, with a peak capability of nearly 1,100 MW enough electricity to supply a city of over a million inhabitants. The largest field that generates the most electricity in Latin America is Cerro Prieto, Baja California, Mexico (720 MW).

While these established markets will continue to account for the geothermal growth in the short term, several regions, including Central America, the Caribbean and East Africa, and others countries like Chile, Argentina, Turkey, Russia and Canada are looking to exploit robust geothermal resource potential as power generation demand and global fuel price increasing (Stephure, T., 2009; Figure 11).

The Figure 11, also shows other countries like Hungary, Germany, India, China and Australia exploring low enthalpy resources technology or with Enhance Geothermal system (EGS). Geothermal exploration is increasing, mostly due to improved technology and techniques. Several projects are underway around the world, but face financing, drilling risk, skilled labor shortages and other factors like environmental regulations mainly related to the location of geothermal resources in national parks could be limited the development over the next decade.

Figure 12 shows the geothermal-electric installed capacity by 2012. The countries of Costa Rica, El Salvador and Nicaragua are currently placed in position ten, eleven and twelve in the geothermal world, respectively.

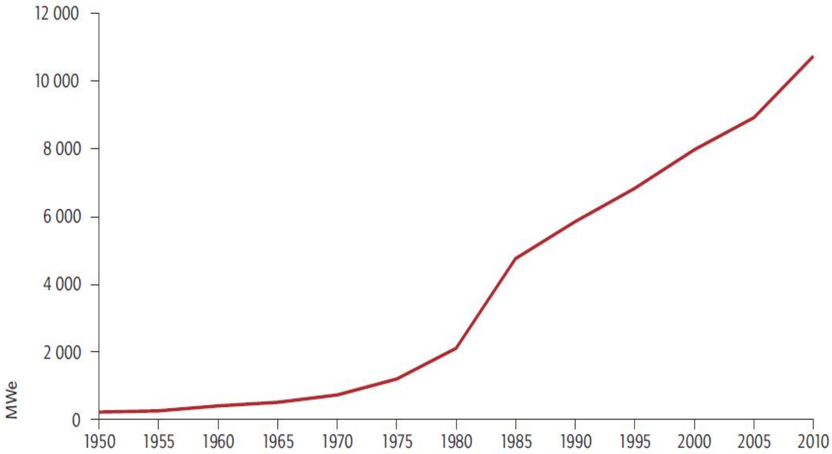

FIGURE 10: World geothermal development – Installed capacity

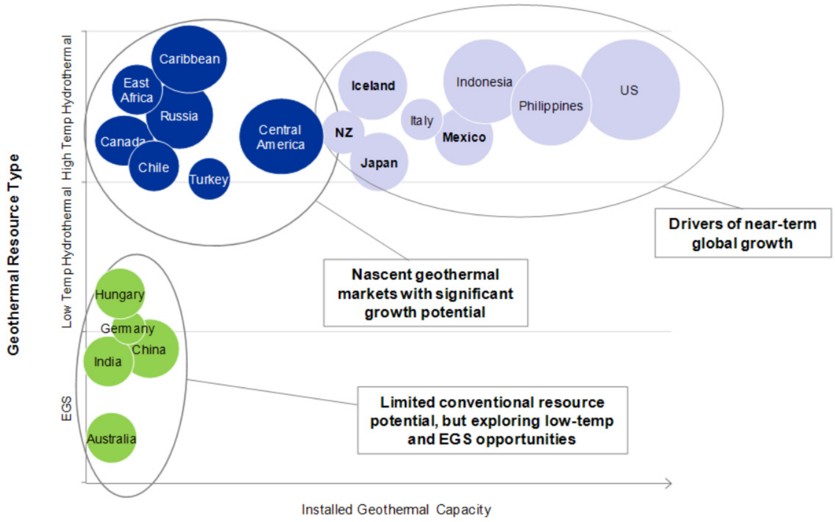

FIGURE 11: Global geothermal country rankings by installed capacity and pipeline
Note: Bubble size reflects MW resource potential (Stephure, T., 2009)

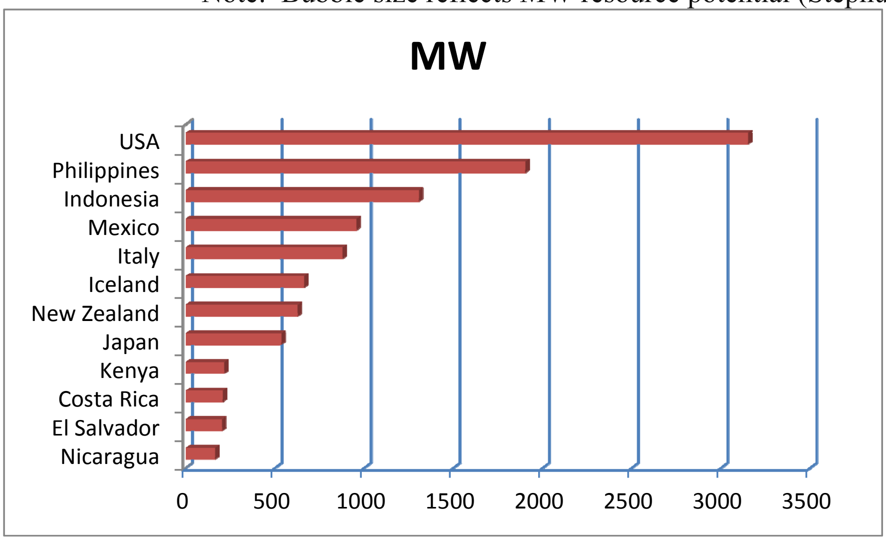

FIGURE 12: World geothermal installed capacity (modified from IGA News 90)

6. FUTURE DEVELOPMENT IN CENTRAL AMERICA

According to Earth Policy Institute (EPI) estimates 2007 (www.earthpolicy.org), the MW required to meet the total demand for electricity in each country for 2010 are shown in Figure 13.

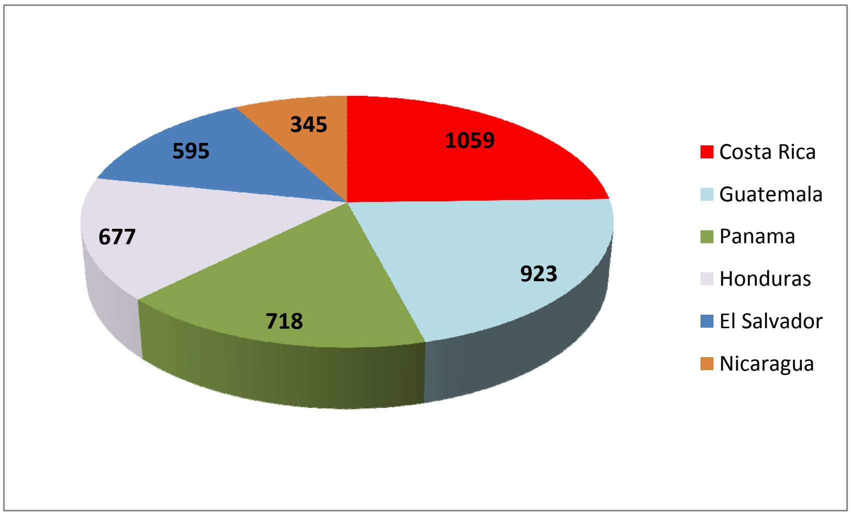

FIGURE 13: MWe required from geothermal resources in the Central American countries for achieved the annual current total demand of electricity by 2010 (EPI, 2007)

Should be noticed the importance for the governments and private companies to accelerate research and development of geothermal resources in the region. As has been mentioned the potential resources in Central America has been estimated very close to the total amount currently used in electric power that is about 4317 MWe (5104 MWe for the year 2012).

The Figure 13, shows the MWe required from geothermal resources in the Central American countries for achieved the annual current total demand of electricity by 2010 (according to EPI). See Table 1.

Bertani (2010) presents a forecasting for the geothermal installed capacity in Central American countries by the year 2015 as shown in Table 4.

TABLE 4: Geothermal installed capacity forecasting by the year 2015 (Bertani, 2010)

Country	MWe
Costa Rica	200
El Salvador	290
Guatemala	120
Nicaragua	240
Honduras	35
Total	885

These estimations gave an increase in installed capacity of 260 MWe (considering the total installed capacity by 2012 of 625 MWe) for the next years.

Some new projects that are underway and will be developed in the near future are described in Table 5, which would imply an increase in geothermal capacity in the region of about 325-375 MWe for the next few years.

Currently, in Costa Rica there are two operating geothermal fields, Miravalles in which are operated five power plants units with an a total installed capacity of 165.5 MWe. In the second half of 2011 (25^{th} July) the first plant in Las Pailas geothermal field was commissioned, located on the Pacific side on the slopes of Rincón de la Vieja Volcano in Guanacaste province, with a gross capacity of 41.6 MWe (35 MWe net power). The power plant is formed by two ORMAT binary Units with a net generation of 150,6 Gw/h in 2011 and 285 GWh in 2012 (Mainieri, ICE 2012; Castro ICE, 2013). Instituto Costarricense de Electricidad (ICE) is also exploring two steam fields in the country's west, financed by the Japanese government, under an agreement of understanding between the Costa Rican Electricity Institute (ICE) and the International Cooperation Agency of Japan (JICA) in order to install two new geothermal plants, called Las Pailas II and Borinquen.

The company GTherm is negotiating with ICE for a pilot project using the SWEGS system (Single-Well Engineered Geothermal System), which is a closed loop system, which doesn't require a water reservoir. GTherm is reported to be involved in negotiations for a 12 MW geothermal power project in Costa Rica. The technology uses underground infrastructure and the system generates next to no pollution at all. This so called "dry geothermal power" has a significant advantage against traditional enhanced geothermal systems. This project is also the starting point for expanding "dry geothermal power" technology to other countries in the region.

TABLE 5: Future development projects in Central America

Country	New geothermal development
Costa Rica	Las Pailas II 35-55 MW; Borinquen 55 MW; Tenorio; Arenal
El Salvador	Chinameca 50 MWe, San Vicente 10 MWe; Quinta U 28 MWe + Segunda Binaria 5.7 MWe; Optimization Ahuachapán Fase III 5 MWe
Guatemala	Amatitlán 20 - 50 MWe Tecuamburro; Moyuta ; San Marcos Concesiones: La China; La Gloria; Joaquina; Atitlán
Nicaragua	San Jacinto Tizate I y II 38.5 MWe + 38.5 MWe + BC 10 MWe; Casitas-San Cristóbal 33 MWe; El Hoyo-Monte Galán ; Managua-Chiltepe; Mombacho ; Caldera de Apoyo
Honduras	GeoPlatanares 35 MWe Azacualpa (20 MWe); Pavana (20 MWe)

El Salvador has increased its total geothermal power since 2007 from 151.2 MWe to 204.4 MWe, building two new units in the area of Berlin and the project of optimization in Ahuachapán which has reached levels of up to 85% of total capacity installed. El Salvador is continuing to develop geothermal energy projects in the areas of San Vicente and Chinameca, where drilling to confirm the resource and exploitation is scheduled to continue in 2012-2013 in San Vicente and in Chinameca where temperatures of about 250°C and 230°C respectively have been recorded in the recently drilled wells in both fields.

For Guatemala, the potential of geothermal energy has been estimated at 400 MWe, has been successful in use so far in the fields of Zunil and Amatitlan. Feasibility studies are conducted in geothermal fields Tecuamburro, San Marcos and Moyuta. In addition, expansion of 30 MWe are planning in Amatitlán. The government of Guatemala has granted four concessions in 2011, which will focus on analyzing the potential for possible development. The concessions are Atitlan, Joaquina, La Chinita, El Ceibillo and La Gloria project.

In Nicaragua, in addition of Momotombo, has begun the exploitation of the geothermal field of San Jacinto-Tizate property of Polaris Energy Nicaragua (PENSA), with the installation of two wellhead units with a total installed capacity of 10 MWe. Actually, two more units have started in operation by 2012, expanding the gross installed capacity to 87 MWe. It has recently been given to PENSA the Mombacho volcano and Caldera de Apoyo concessions.

Honduras will develop its first geothermal power plant in Platanares geothermal field, located in a different geological structure of the typical features of high-temperature fields associated with volcanic structures. Geoplatanares, the company that holds the concession is starting in the next future to drill exploration wells to confirm the feasibility and proceed to commercial development. Exploration activities are on the way in Azacualpa and Pavana geothermal areas. In the future, the completion of feasibility studies, environmental and financial, exploration drilling, production drilling, infrastructure adequacy of access, connection to the national transmission system, supply of equipment, plant construction and commercial operation are programmed.

In Central America, geothermal constitute the second most important renewable energy source in the region. To date, there has been progress such as the exploration, development and exploitation potential of this resource estimated in the order of 3000-4000 MW distributed among Costa Rica, Guatemala, El Salvador and Nicaragua; in the case of Panama and Honduras, there are only preliminary estimates, but the geological-tectonic point of view, indicates that there are also potential resources for electricity generation, but probably at limited scale compared with the others related to the volcanic activity.

The Figure 14 shows the total estimated geothermal potential (from Table 1, IILA, 2010) and the geothermal potential that could be developed in the future. If we can assume an average of the total estimated geothermal potential of 3544 MWe and taking into account the installed by 2012, the geothermal potential to be developed in the future reach about 3000 MWe (84 % of the total estimated). Although currently the geothermal energy in Central America has been successfully developed in several countries, there is still much work to do according to estimates of existing geothermal potential in the region.

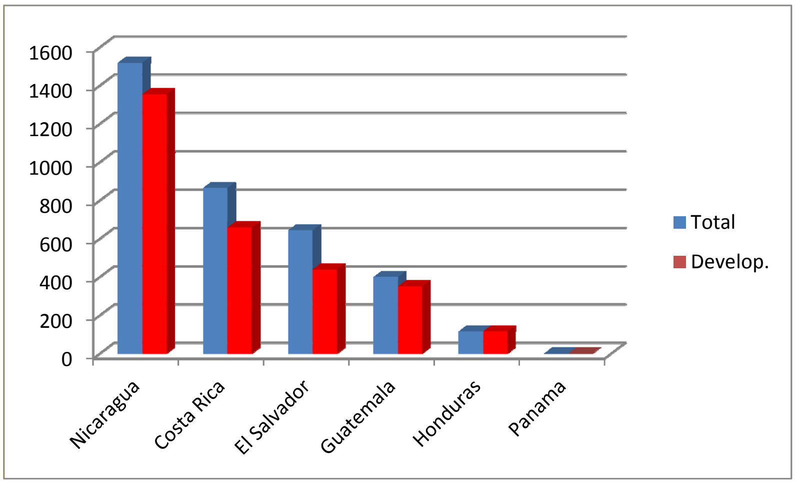

FIGURE 14: Total estimated geothermal potential and to be developed in MWe (IILA, 2010)

The potential resource in Central America, has been estimated very close to the total amount currently used in electricity power generation, which is about 4808 MWe (Cepal, 2011) and 5105 MWe (Paper, 2012).

7. DIRECT USES OF GEOTHERMAL ENERGY IN CENTRAL AMERICA

Direct use of geothermal energy is well known in ancient times, in Central America pre-Columbian cultures using the hot springs for medicinal purposes, culinary, religious or social. Some of the sites currently geothermal areas in El Salvador, were known to the Indians who inhabited these areas as "ausoles". The word according to some historians, comes from the Nahuatl "atl" (water) and "Soloni" (loud boiling sound) as the Dictionary of the Royal Academy of Spanish Language (RAE) which considers salvadoreñismo means loud boiling water, because the soil water boiling springs forming impressive fumaroles (Jose Perez Bouza: Spanish Influences on the Nahuatl of El Salvador 1994).

In general, direct uses of geothermal energy currently used in Central America include mostly the drying of fruits, cement blocks and pools or hot springs.

Due to the warm temperate climate of Central America currently does not apply the use of heating systems of buildings and greenhouses, but few research studies for cooling spaces have been made.

More specifically, some studies have been performed and are using the resource for moderate to low temperature as follows:

• Costa Rica, practically limited to the use of thermal pools, although there are technical studies for drying fruits and grains in the geothermal field of Miravalles.

• El Salvador has thermal baths and some tests in domestic application in the drying of fruits in the Berlin geothermal field in a natural dehydration process.
• Guatemala has thermal baths at different sites also applies to industrial drying of fruits and concrete blocks in the geothermal field of Amatitlán.
• Honduras has several places with hot springs in Copan and Gracias.

Lund et al (2010) has estimated that in Central America there are currently a total installed capacity of 7.2 MW thermal, with a total amount of energy used of 162.5 TJ / year equivalent to 45.1 GWh per year (Table 6).

TABLE 6: Direct uses in Central American countries (Lund et al, 2010)

Country	**Capacity MWt**	**Annual TJ/año**	**Annual GWh/año**	**Capacity factor**
Costa Rica	1.0	21.0	5.8	0.67
El Salvador	2.0	40.0	11.1	0.63
Guatemala	2.3	56.5	15.7	0.78
Honduras	1.9	45.0	12.5	0.74
Total	7.2	162.5	45.1	0.71

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UNITED NATIONS UNIVERSITY
GEOTHERMAL TRAINING PROGRAMME

LaGeo S.A. de C.V.

GEOTHERMAL ACTIVITY IN SOUTH AMERICA: BOLIVIA, CHILE, COLOMBIA, ECUADOR, AND PERU

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ABSTRACT

South America holds vast stores of geothermal energy that are largely unexploited. These resources are the product of the convergence of the South American tectonic plate and the Nazca plate that has given rise to the Andes mountain chain. High-temperature geothermal resources in Bolivia, Chile, Colombia, Ecuador and Peru are mainly associated with volcanically active regions, although low temperature resources are also found outside them. All of these countries have a history of geothermal exploration, which has been reinvigorated with recent world-wide attention to the utilization of environmentally benign and renewable resources. The paper provides an overview of their main regions of geothermal activity and recent developments in the geothermal sector are reviewed.

1. INTRODUCTION

South America has abundant geothermal energy resources. In 1999, the Geothermal Energy Association estimated the continent's potential for electricity generation from geothermal resources to be in the range of 3,970-8,610 MW, based on available information and assuming the use of technology available at the time (Gawell et al., 1999). Subsequent studies have put the potential much higher, as a preliminary analysis of Chile alone assumes a generation potential of 16,000 MW for at least 50 years from geothermal fluids with temperatures exceeding 150°C, extracted from within a depth of 3,000 m (Lahsen et al., 2010). In spite of this enormous potential, the only geothermal power plant which has been operated on the continent is the 670 kW binary demonstration unit in the Copahue field in Argentina, which was decommissioned in 1996 (Bertani, 2010).

Global warming and the global energy market have among other factors led to a renewed global interest in clean indigenous energy sources, and several South American countries are currently pursuing the development of their geothermal resources. Among these are Bolivia, Chile, Colombia, Ecuador and Peru. The following sections are intended to give a basic overview of geothermal activity and the state of geothermal development in these countries.

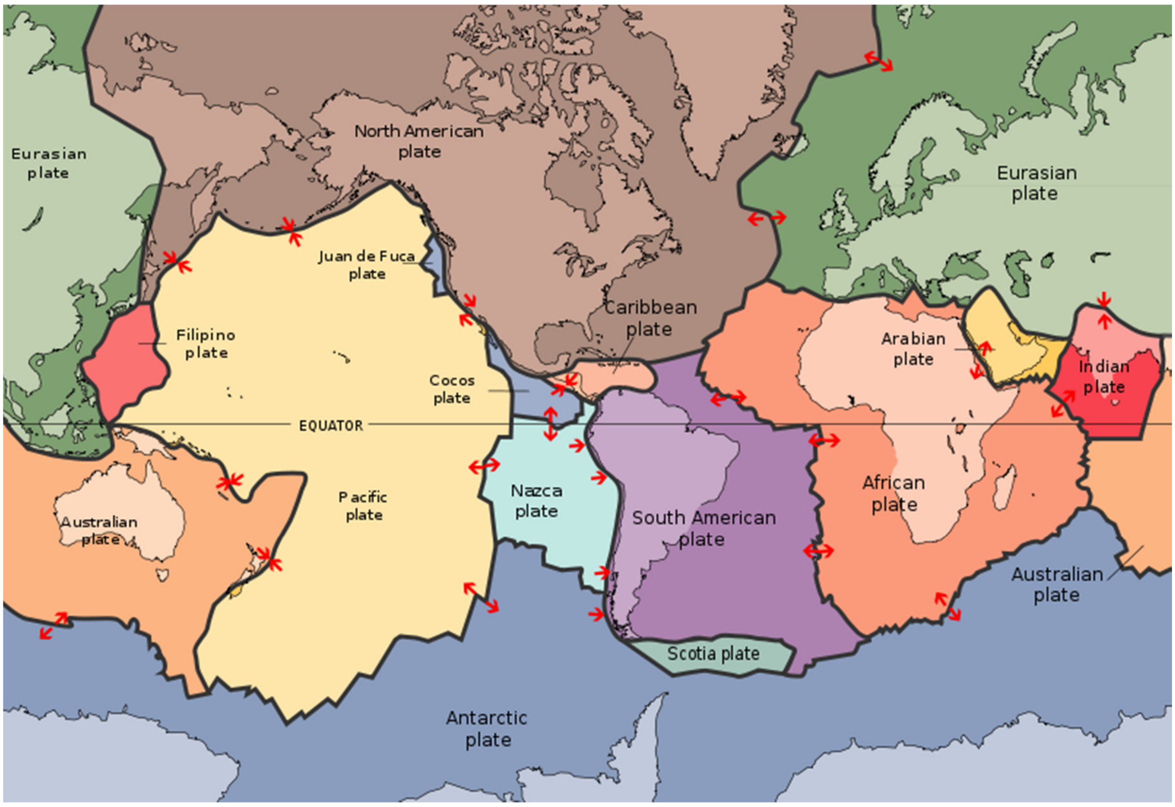

FIGURE 1: The tectonic plates of the world (USGS, 2011)

2. BACKGROUND

The South American tectonic plate, on which the South American continent rests, is bordered by the Nazca and Antarctic plates to the west (Figure 1). These three plates meet at the Chile triple junction. The Caribbean plate also borders the South American plate to the northwest, which in addition to the Nazca plate form another triple junction. The Nazca plate subducts under the South American plate in a convergent boundary (Figure 2) that manifests in the Peru-Chile trench that runs along the western coast of the continent, approximately 160 km from shore and reaches a maximum depth of over 8,000 m. Part of the Antarctic plate also subducts under the South American plate. The friction and pressure created by the sliding plates and the melting of the subducting plate cause earthquakes and volcanic activity, which are both conducive to the formation of geothermal reservoirs. Earthquakes produce faults and fissures through which water can flow and volcanic activity and shallow magma chambers provide heat sources.

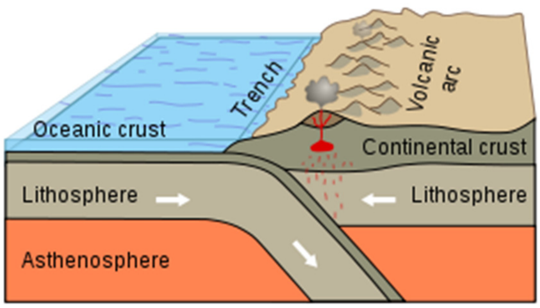

FIGURE 2: Oceanic-continental convergent boundary (USGS, 2012)

The convergence has given rise to the Andes mountain range that runs from Venezuela in the north to Patagonia in the south and reaches maximum altitude of 6,962 m at Aconcagua peak in Argentina, which is entirely the result of uplift. The Andes are the longest continental mountain chain in the world, spanning 7 countries, and the highest outside of Asia. They are split into several ranges (cordilleras) that are separated by intermediate depressions. They are widest at the Altiplano plateau, the most extensive high plateau outside of Tibet, and are home to many important cities, such as Bogotá, Quito, La Paz, Sucre and Santiago de Chile.

In a recent study, Cardoso et al. (2010) employed updated data sets on crustal seismic velocities, gravity anomalies, radiogenic heat production, terrestrial heat flow and thermal springs to produce a heat flow map of South America (Figure 3). Their results indicate that most of the continent's high temperature resources occur within:

- Well known sectors of magmatic activity in Chile;
- The Altiplano region of Bolivia;
- Isolated pockets along the western Andean belt in Peru; and
- Several localities along the magmatic arc covering western Ecuador, central volcanic belt of Colombia and southern Venezuela.

While many of these regions have long been known for volcanic and geothermal activity, the heat flow map is helpful for visualization on a continental scale.

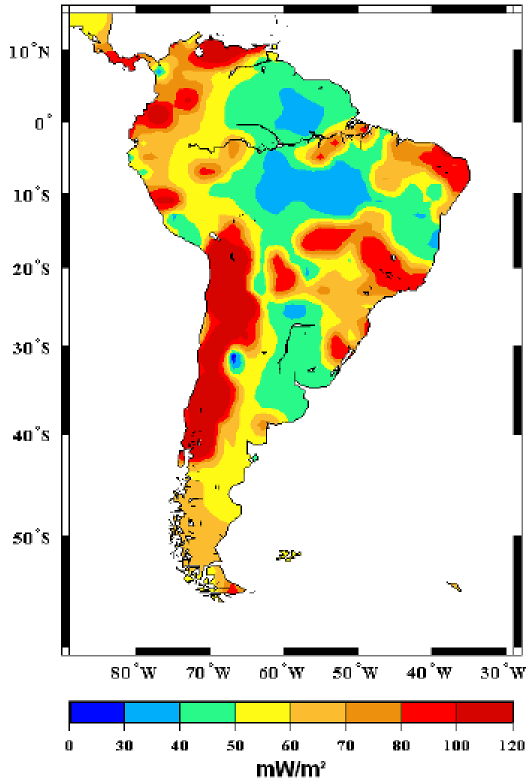

FIGURE 3: Heat flow map of South America (Cardoso et al., 2010)

3. BOLIVIA

3.1 Geographical/Geological setting

Bolivia is divided between the Andes to the west and lowlands of platforms and shields to the east. The Bolivian Andes are comprised of three main ranges (Figure 4):

- Cordillera Occidental to the west on the border with Chile, which is characterized by volcanoes and geothermal areas;
- Cordillera Central, the northern section of which is referred to as the Cordillera Real, and is rich in minerals; and
- Cordillera Oriental to the east, which is a fold and thrust belt lower than the other two.

FIGURE 4: Geographical visualization of Bolivia

In addition to these mountain ranges, the Altiplano extends over a large area between the Cordillera Occidental and the Cordillera Central. The plateau is around 700 km long and has a maximum width of approximately 200 km. The average elevation is close to 3,750 m.

3.2 Geothermal manifestations

In 1984, Aliaga reported on more than 70 areas with geothermal manifestations in Bolivia, including hot pools, mud pools, fumaroles and steaming ground (Aliaga, 1984). They are found on the eastern slopes of the Cordillera Occidental, in the southern part of the Cordillera Oriental and in the eastern central part of the Altiplano. In the Cordillera Oriental, geothermal activity is associated with faults, fractures and volcanic bodies and in the Altiplano it is related to igneous bodies and probably faults. Temperatures of many surface manifestations are as high as 85°C, but most do not exceed 50°C. The largest flow measured at the time was 67 l/s at Lanza (Figure 5). The waters vary from acidic to alkaline and most of them are used for bathing.

3.3. Geothermal exploration

According to Terceros (2000), geothermal exploration in Bolivia began in the 1970s. These early efforts established the existence of high enthalpy resources, mainly along the Cordillera Occidental. Pre-feasibility studies were carried out in the Salar de Empexa and Laguna Colorada fields between 1978 and 1980, after which interest was mainly concentrated on the Sol de Mañana field of Laguna Colorada. Feasibility studies were carried out between 1985 and 1990, including the drilling of new wells, which allowed the quantification and evaluation of the geothermal reservoir. The goal was to proceed with the installation of an experimental 4-10 MW power station. To that end a new well was drilled successfully and another one deepened between 1991 and 1992, although the installation of the experimental power station was not realized.

3.4 Laguna Colorada project

Terceros (2000) reports that the Laguna Colorada prospect is located in the Cordillera Occidental in the far southwest of Bolivia, near the Chilean border (Figure 5). The area consists of high plains constituted by deposits of lava and glacier material at an elevation of 4,900 m, which are dominated by the presence of volcanic structures. In 2000, 6 wells had been drilled with an average depth of 1,500 m. Reservoir studies and numerical simulation indicated a potential for at least 120 MW for 20 years and a possibility for up to 300 MW for 25 years.

FIGURE 5: Modified physical map of Bolivia showing some geothermal sites mentioned in the text

The state power company Empresa Nacional de Electricidad (ENDE) intends to construct a 100 MW power plant at Laguna Colorada. The project is comprised of three parts (URS Corporation Bolivia S.A., 2010):

- Resource development, including the drilling of new production and reinjection wells;

- The construction of a 100 MW power plant; and
- The construction of a single circuit 230 kV transmission line with a length of 170 km to connect the plant with the national grid.

3.5 Electricity generation

Electricity generation capacity in Bolivia is divided between thermal (60%) and hydro (40%). The total installed generation capacity in 2010 amounted to 1,655 MW and the gross generation was 6,589 GWh, which indicates a capacity factor of 0.45 (EIA, 2013). In 1999, GEA estimated Bolivia's geothermal electricity generation potential at 510-1,260 MW (Gawell et al., 1999), which is 31-76% of the installed capacity in 2010. Electricity availability in rural areas is among the lowest in Latin America.

4. CHILE

4.1 Geographical/Geological setting

Andean orogeny has shaped three main features in Chile parallel to the subduction zone (Figure 6):

- Cordillera de la Costa (the Chilean coastal range) to the west, which runs from the very north to the triple junction;
- The Andean cordillera to the east; and
- Valle Central (Intermediate Depression) in between the other two features, consisting of a fertile graben which has been filled with the by-products of volcanic activity and erosion of the surrounding mountains.

FIGURE 6: Terrain map of Chile

According to Lahsen et al. (2010), Chilean geothermal resources occur in close spatial relationship with active volcanism. There are two main volcanic zones. The northern one extends from 17°S to 28°S and is characterized by Quaternary volcanism along the high Andes and the Altiplano. Volcanic vents and hydrothermal manifestations occur within the small grabens associated with fault systems with an approximate N-S trend that have been created by differential uplift. The southern zone extends from 33°S to 46°S and is also characterized by Quaternary volcanism that is restricted to the Andean Cordillera. This activity has given rise to stratovolcanoes, pyroclastic cones, and calderas that have covered extensive areas of the Valle Central with Lahar type flows. All the Chilean high temperature thermal springs are associated with the Quaternary volcanic zones.

4.2 Geothermal resources (Lahsen et al., 2010)

Lahsen et al. (2010) report that geological, geochemical and geophysical surveys have been carried out in many geothermal areas in Chile and a preliminary assessment of the geothermal potential of the country indicates an electricity generation potential of the order of 16,000 MW for 50 years from geothermal fluids with temperatures exceeding 150°C, withdrawn from a depth less than 3,000 m.

The northern geothermal/volcanic zone (Figure 7) encompasses approximately 90 geothermal areas. Exploration has been carried out at Surire, Puchuldiza, Lirima, Apacheta and El Tatio. At Apacheta and El Tatio, 4 wells have been drilled up to a depth of 1,700 m. A preliminary estimate for these areas puts their electricity generation potential at 400-1000 MW, with a contribution of 5-10 MW_e per well.

The southern geothermal/volcanic zone (Figure 8) encompasses more than 200 geothermal areas. In late 2009, the prospects of Tinguiririca, Calabozos, Laguna del Maule, Chillán, Tolhuaca, Sierra Nevada, and Puyehue-Cordón Caulle were under exploration by ENG, Universidad de Chile, and some private companies. Exploration slim holes have been drilled at Calabozos, Laguna del Maule, Chillán, and Tolhuaca. Preliminary estimates for electricity generation from these areas vary from 600 MW to 950 MW, with a contribution of 3-10 MW_e per well.

4.3 Grid systems and electricity generation

The Center of Renewable Energy in Chile reports on several grid systems in the county (CER, 2012):

- The Northern Interconnected System (SING): Covering the northern part of the country, this grid concentrates around 24% of the demand for electricity in the country, mainly coming from mining companies;
- The Central Interconnected System (SIC): Covering the central part of the country, this grid provides about 75% of the electricity consumed, supplying the largest part of the population, industry, mining, farming and services; and
- The Aysén and Magallanes systems: Covering the southern part of the country, these grid systems are formed by several medium-sized systems.

Lahsen et al. report that the Northern Interconnected Power Grid is mainly supplied by fossil fuel based power plants, while the Central Interconnected Power Grid supplies 90% of the population with electricity and as of 2010, 52% were provided by hydropower and the rest from fossil fuel based power plants.

The total installed capacity for electricity generation in 2010 was 16,206 MW, producing approximately 62,863 GWh, with a capacity factor of 0.44 (EIA, 2013). The total projected capacity for 2015 is 19,568 MW, of which anticipated geothermal capacity is 75 MW_e. These numbers can be placed into context with the estimated 16,000 MW_e geothermal potential of the country.

4.4 Legal environment

The Non-Conventional Renewable Energy Law requires energy providers in systems of an installed capacity of 200 MW or greater to demonstrate that 10% of the energy provided comes from non-conventional renewable energy resources by 2024 (OECD/IEA, 2010). A Geothermal Law was enacted in 2000, providing a framework for the exploration and development of geothermal energy (Lahsen et al., 2010).

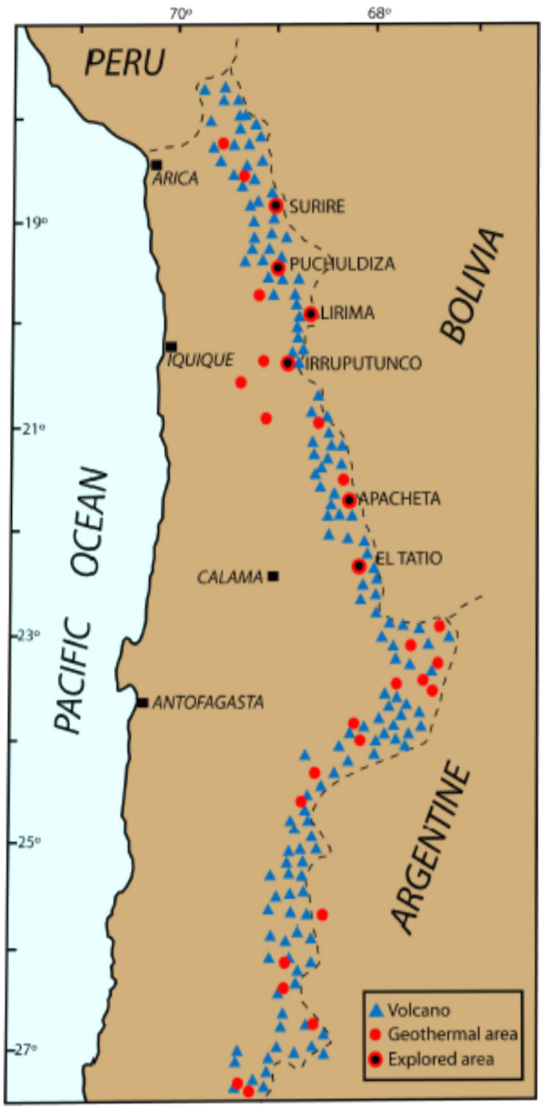

FIGURE 7: Geothermal areas of Northern Chile (Lahsen et al., 2010)

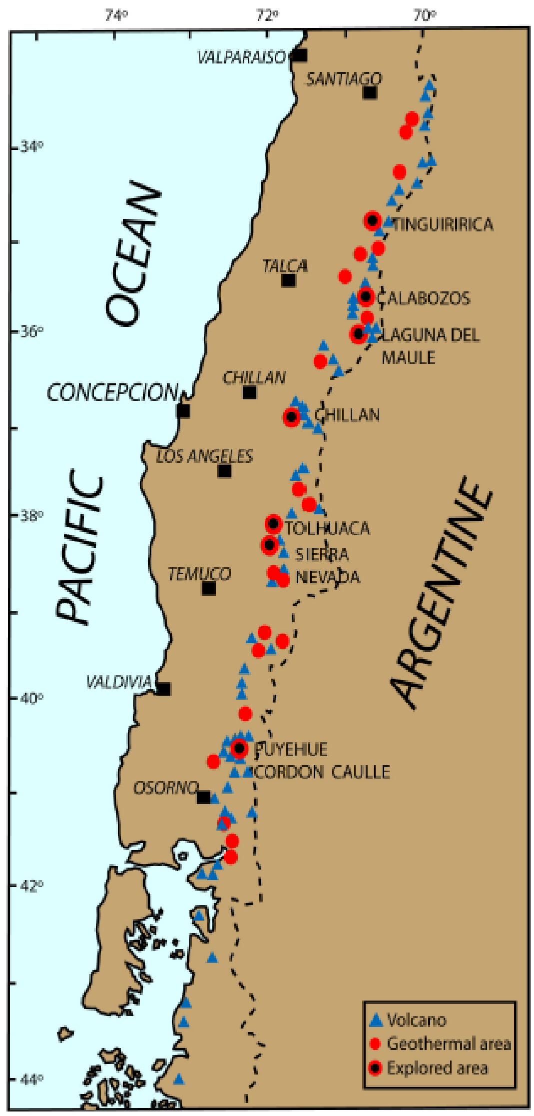

FIGURE 8: Geothermal areas of Central-Southern Chile (Lahsen et al., 2010)

4.5 Concessions and developers

As of 2011, 54 exploration permits and 6 exploitation permits had been issued by the Ministry of Mines and the Ministry of Energy (CER, 2011). At the time, 68 additional exploration permits were pending approval and 20 new designation areas were being prepared for designation later in the year. As of January 2013, one 50 MW geothermal power plant project had been approved by the Environmental Assessment Service (Servicio de Evaluación Ambiental) and was pending construction and another 70 MW project was undergoing environmental impact assessment (CORFO, 2013).

5. COLOMBIA

5.1 Geographical setting/Geological setting

The geography of Colombia can be divided into 5 main regions on the South American continental landmass, in addition to islands off the coast (Figure 9):

- The Andean region, covering the three ridges of the Andes mountains found in Colombia;
- The Caribbean region, comprised of the area next to the Caribbean Sea;
- The Pacific region, adjacent to the Pacific Ocean;
- The Orinoquía region (Llanos Orientales) along the border with Venezuela, mainly in the Orinoco river basin;
- The Amazon region; and
- The Insular region comprised of islands in the Caribbean Sea and Pacific Ocean.

The 3 branches of the Colombian Andes are (Figures 10; Figure 11):

- Cordillera Occidental adjacent to the Pacific coast;
- Cordillera Central running up the center of the country between the Cauca and Magdalena river valleys; and
- Cordillera Oriental extending north-east toward the Guajira Peninsula.

Colombia has 15 active volcanoes that lie at the triple junction of the Nazca, Caribbean and South American plates (Figure 1). The major ones are Nevado del Ruiz, Tolima, Huila, Purace, Doña Juana, and Galeras (Figure 12) and high temperature geothermal resources are associated with some of them.

5.2 Geothermal resources (Alfaro et al., 2000; Alfaro et al., 2005; Alfaro et al., 2010)

The first geothermal reconnaissance study in Colombia was a geological exploration effort of the Ruiz volcanic complex in 1968. Since then, numerous studies have been done on both high and low temperature areas. These studies indicate that high temperature systems are to be found by the Nevado del Ruiz, Chiles-Cerro Negro, Azufral, and Paipa volcanoes (Figure 12). Most of the studies have been confined to the surface, though a well was drilled on the west flank of Nevada del Ruiz in 1997. Studies on the geology of the borehole suggested a high temperature system, but the well did not reach the reservoir.

Colombia has about 300 hot springs. The highest density is found in the Cerro Bravo – Machín volcanic complex in the Cordillera Central. At least 42 thermal springs can be found in the Cundinamarca Department in the Cordillera Oriental.

5.3 Direct utilization (Alfaro et al., 2005)

Geothermal utilization in Colombia is restricted to bathing and swimming for recreational purposes at present. Medical balneology is also an object of interest as indicated by the establishment of the Colombian Hydrothermal Techniques Association in 1998. Local communities with hot spring areas recognize their healing properties, and the localities of Paipa and Santa Rosa de Cabal have implemented programs for relaxation and health tourism to utilize their hot springs.

5.4 Recent developments

In early 2012, the governments of Colombia and Ecuador announced their joint study on the feasibility of developing geothermal power projects in a remote border region between the two countries with three active volcanoes: Chiles, Tufiño, and Cerro Negro (ThinkGeoEnergy, 2012). The involved institutions are CELEC from Ecuador and ISAGEN from Colombia, and the goal is to update existing studies to prepare a preliminary model for the selection of drilling targets (Alfaro, 2012). Both governments contribute equally to the 4 million USD study, with the final target being the development of a geothermal power plant generating up to 150 MW_e (ThinkGeoEnergy, 2012).

FIGURE 9: The regions of Colombia (Wikipedia, 2010)

FIGURE 10: The Colombian Andes

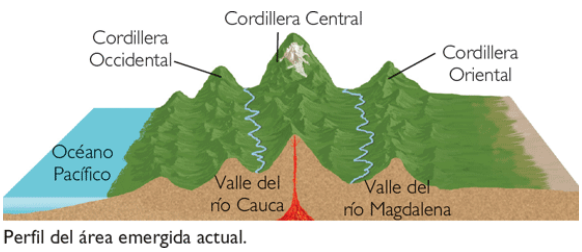

FIGURE 11: Cross section of the Colombian Andes

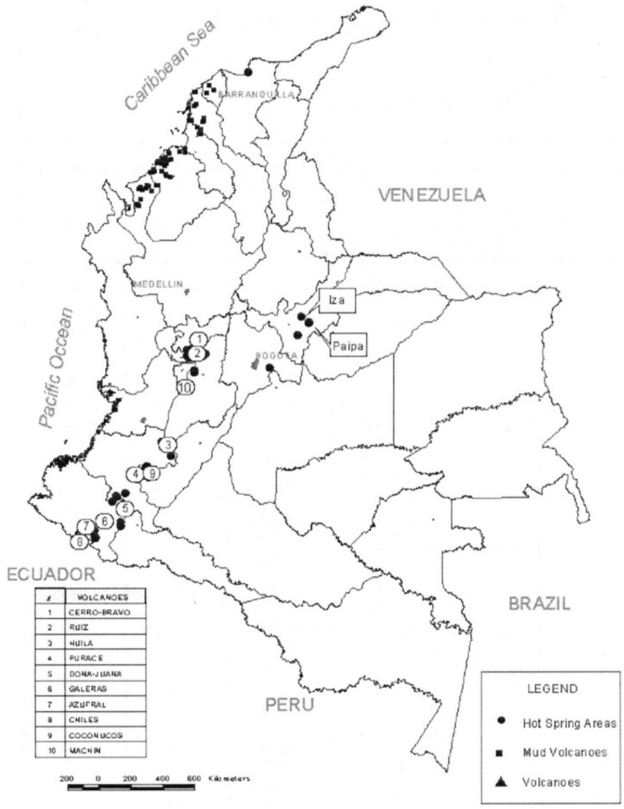

FIGURE 12: Volcanoes and geothermal areas in Colombia (Alfaro et al., 2000)

The development area of the prospect lies across the Ecuador-Colombia border, in Nariño department on the Colombian side, and in Carchi province on the Ecuadorian side. Gas thermometers indicate temperatures as high as 230°C and resistivity data confirm a reservoir under the Volcán Chiles massif, with likely drilling elevation being between 3,800 and 4,200 m a.s.l. (Beate and Salgado, 2010).

Efforts are underway to develop two sites in the Nevado del Ruiz area and exploration studies also continue in the Azufral and Paipa – Iza areas (Alfaro, 2012).

6. ECUADOR

6.1 Geographical/Geological setting

Geographically and geomorphologically, mainland Ecuador consists of three regions (Figure 13):

- Costa (the coastal range);
- Sierra (the Andes mountain chain); and
- Oriente (the Amazon basin).

The Galapagos islands are the fourth region about 1,000 km west of the mainland. They are thought to be the product of a hot spot and consist of about 15 basaltic shield volcanoes, increasing in age towards the east.

The Ecuadorian Andes consist of two parallel NNE striking mountain chains:

- Cordillera Occidental to the west; and
- Cordillera Real to the east.

Both cordilleras have been uplifted and are capped by late Tertiary volcanics. Volcanic activity is extinct in the southern part, but a well developed Quaternary volcanic arc that extends into Colombia covers both in their northern half. It consists of more than 50 volcanoes, out of which 30 are still active. The Inter-Andean Valley divides the cordilleras.

FIGURE 13: Geographical visualization of Ecuador

6.2 Geothermal exploration and resources

A reconnaissance study carried out in 1979-1980 divided hydrothermal systems in areas of recent volcanism into two main groups based on temperature (Beate and Salgado, 2010; Figure 14):

- Group A: Tufiño, Chachimbiro and Chalupas high temperature areas; and
- Group B: Ilaló, Chimborazo and Cuenca low-temperature areas.

Beate and Salgado (2010) report that further studies by the government's Instituto Ecuatoriano de Electrificación (INECEL) indicated an electricity generation potential of 534 MW for the three high-temperature areas. Following the shut-down of INECEL in 1993, a period of exploratory stagnation lasted until 2008. In that year, the Ministry of Electricity and Renewable Energy (MEER) restarted exploration with the aim of developing one or more of the former INECEL geothermal prospects. Exploration drilling was undertaken at the Tufiños-Chiles prospect, where the first geothermal exploration well in Ecuador was completed in May 2009. The Chachimbiro prospect received 1 MUSD of funding for geophysical exploration and siting of deep exploration wells. The National Council for Electricity (CONELEC) commissioned a desk-top study on a 50 MW_e plant at the Chalupas prospect and an overall assessment of Ecuador's geothermal prospects (Beate and Salgado, 2010).

Feasibility studies have been completed for the Chacana and Chachimbiro prospects in the northeast, culminating in conceptual models for the two areas and the targeting of exploratory wells (Montalvo, 2012). Recommendations have been made for the drilling of slim-hole wells, but funding has not been secured. Feasibility studies, including mapping, geological, geophysical, geochemical, and seismic studies have been made for the Chalpatán area in the north of the country and are currently under evaluation, with results due in February 2013, leading to a conceptual model of the field (Montalvo, 2012).

6.3 The Tufiño-Chiles prospect

See section 5.4.

6.4 Current utilization and electricity generation

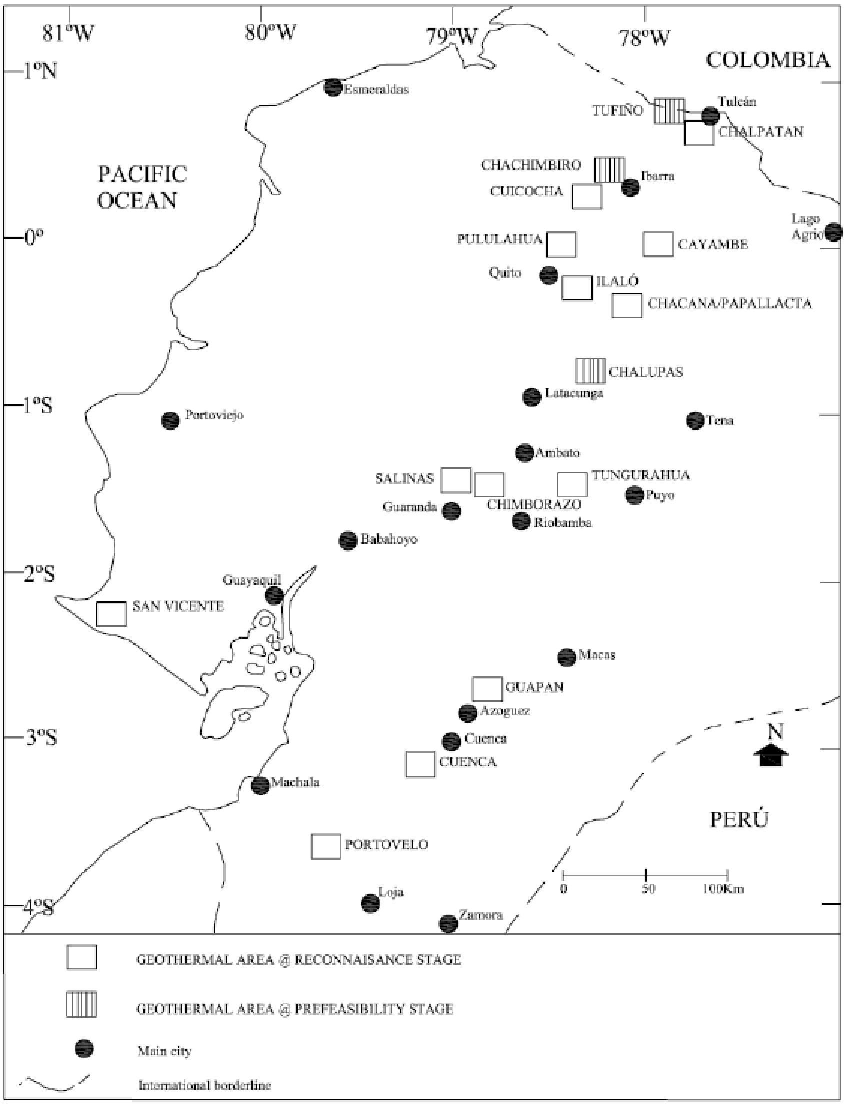

FIGURE 14: Geothermal areas in mainland Ecuador (Beate and Salgado, 2010)

Current utilization of geothermal resources in Ecuador is restricted to direct use for bathing, balneology and swimming pools. Several aquaculture projects (fish hatcheries) await funding (Beate and Salgado, 2010).

The installed electricity generation capacity of Ecuador was 5,243 MW in 2010 with a total net generation of 17,088 GWh, of which 50% came from hydropower and 47% from conventional thermal power plants (EIA, 2013). These numbers indicate a capacity factor of 0.37. In 1999, GEA estimated Ecuador's geothermal electricity generation potential at 420-850 MW, which is 8-16% of the installed capacity in 2010.

6.5 Outlook

The government has decided to fund, explore and develop clean, indigenous, renewable energy resources. Hydro-electric generation capacity is expected to increase significantly in the coming years and to cover over 90% of electricity demand by 2021, but the construction of geothermal power plants is also envisioned (Valencia, 2012). The first geothermal power plant is expected to be on line within 10 years. The government also intends to further explore and develop direct use of geothermal resources for the tourist industry, agriculture and fish hatching.

FIGURE 15: The three geographic regions of Peru

FIGURE 16: Geographical map of Peru

7. PERU

7.1 Geographical/Geological setting

Geographically, Peru is divided into three regions (Figures 15 and 16):

- The Coast;
- The Andean mountain chain; and
- The Amazon basin, which accounts for approximately 60% of the land area.

7.2 Geothermal resources

Vargas and Cruz (2010) note that Peru has a vast geothermal potential that is evident in numerous surface manifestations such as hot springs, geysers and fumaroles. In northern and central Peru, high temperature manifestations are the result of the geothermal gradient and infiltrated meteoric water flowing in deep faults, while in the southern part the manifestations are related to active volcanism, and hot spring water is of both meteoric and volcanic origin (Vargas and Cruz, 2010).

In the Geothermal Map of Peru, recently updated by Vargas and Cruz, the country is divided into six geothermal regions with different temperatures of surface manifestations (Figure 17):

- Cajamarca – La Libertad (28-74°C);
- Callejón de Huaylas (24-60°C);
- Churín (20-73°C);
- Central (20-55°C);
- Eje Volcánico Sur (20-90°C); and
- Cuzco – Puno (24-88°C).

In this context it is worth noting that the boiling point of water at 3,000 m is approximately 90°C. Most of the studies to date have been focused on Eje Volcánico Sur, which has more than 300 volcanic centersm and more than 300 surface manifestations from hot springs to fumaroles. It is subdivided into three zones based on the quality of resources recognized from preliminary studies (Vargas and Cruz, 2010):

- Zone A (high importance): Tutupaca, Calacoa, Maure, Laguna Salinas, Chachani and Chivay;
- Zone B (medium importance): Puquiao, Parinacochas and Orcopampa; and
- Zone C (low importance): Catahuasi, Coropuna, Caylloma and Mazo Cruz.

In 2011, the Ministry of Energy and Mines reported a potential of exploitable geothermal energy capacity of 3,000 MW in Peru (ThinkGeoEnergy, 2011). This is considerably higher than the estimate of Gawell et al. (1999), which was in the range 600-1,410 MWe.

7.3 Past and current utilization

The use of geothermal manifestations for entertainment and balneology in Peru goes back to pre-Inca and Inca periods (Cernik et al., 2010). The pre-Incan Caxamarca culture built an important city by the hot springs that later became known as Baños del Inca (Inca baths). The place at that time consisted of some buildings that were one of the principal residences of the Caxamarca chiefs, who used the hot springs for healing and the worship of water (Figueroa Alburuqueque). As the Incas gained influence in the region, the baths by Cajamarca became one of the principal residences of Inca chiefs prior to the arrival of the Spanish conquistadors. This is where Inca emperor Atahualpa first heard of the Spanish invasion and some sources say that he was aroused from the baths to receive the news.

Kepinska (2003) notes that a great number of Inca palaces and temples were built near natural geothermal ponds and hot springs that were equipped with bathing facilities supplied with hot and cold water through a system of pipelines. Both aristocracy and common people had opportunities to bathe in warm springs.

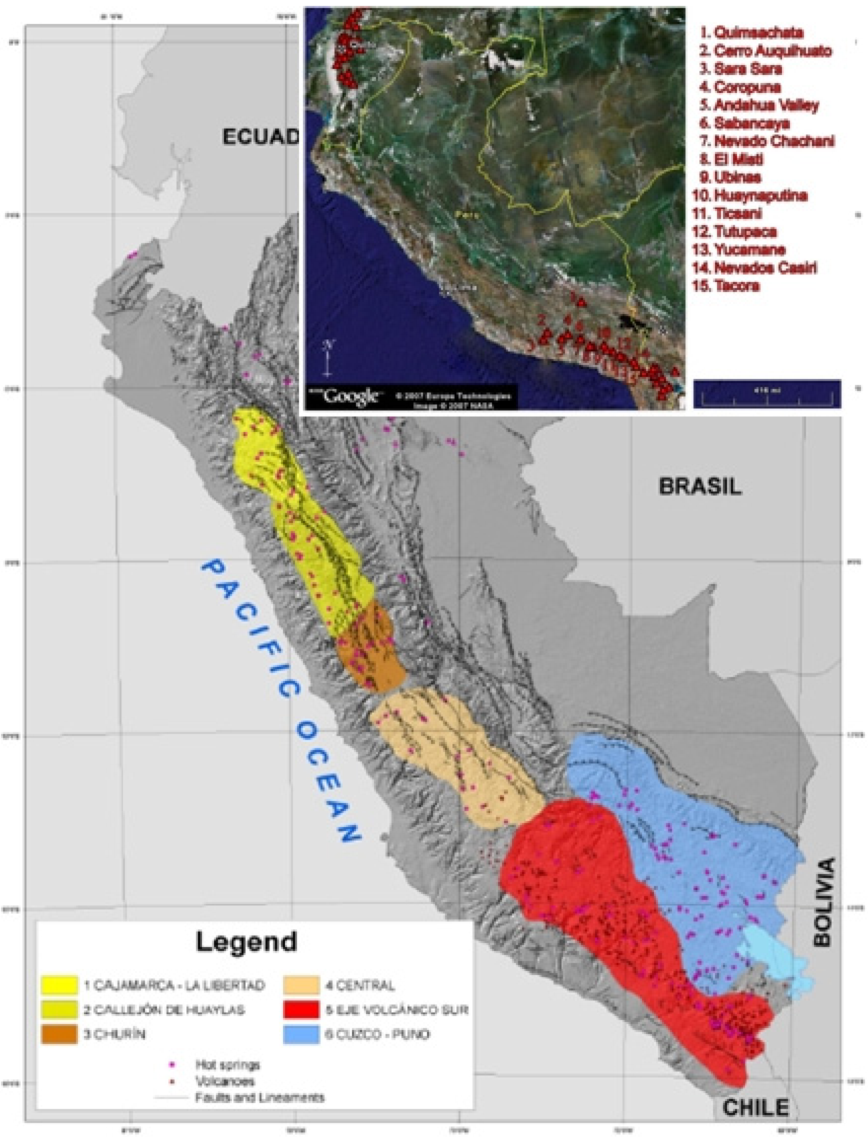

FIGURE 17: Updated geothermal map of Peru (Vargas and Cruz, 2010) and the volcanoes of Eje Volcánico Sur (Europa Technologies; NASA)

The utilization of geothermal resources in Peru is still mostly limited to entertainment and balneology at places such as Baños del Inca, Callejón de Huaylas, Churín hot spring, and Aguas Calientes, which are located at the closest access point to Machu Picchu. As such, they play an important role for the tourist industry.

7.4 Electricity generation

Conventional thermal power plants accounted for 60% of the electricity generation capacity of 8,613 MW in Peru in 2010, while hydro power plants accounted for 40% - although the fractions were reversed when it came to the actual net generation, which totaled 33,328 GWh (EIA, 2013). This reveals a capacity factor of 0.44. In 1999, GEA estimated Peru's geothermal electricity generation potential at 600-1,410 MW, which is 7-16% of the installed capacity in 2010.

7.5 Recent developments

According to Vargas and Cruz (2010), the Peruvian Geological Survey (INGEMMET) conducted the first geothermal studies in the 1970s. Due to world market trends, a renewed emphasis has been placed on geothermal development and to that end all existing information has been collected in the Geothermal Map, which is intended to help with management decisions to be taken on possible investment in exploration and exploitation.

On March 25th 2010, the Peruvian Ministry of Energy and Mines presented a draft regulation on Law No. 26,848 for public commenting (MINEM, 2010). The regulation is considered necessary to reorganize and develop the various aspects regulating the rational development of geothermal resources to ensure energy supply necessary for economic growth, the welfare of the population and the efficient diversification of the country's energy sources, cautious development of those activities, access and issues related to competition (ThinkGeoEnergy, 2010). The regulation addresses planning, the acquisition of land, the application of concessions, exploration, exploitation, rights, permits, performance guarantees, taxation, general procedures, and obligations. It is indicative of the intent of the Peruvian government to develop the country's geothermal resources beyond the traditional direct use of natural hot-springs.

In 2011, seven concessions had been granted to Mustang Geothermal Corporation at Baños del Inca, Paclla, Ninobamba, Atecata, Coline, Condoroma South, and Condoroma (PR Newswire, 2011). However, the company has been unsuccessful in obtaining financing for the development of the concessions and has determined that the prospects for financing are not likely to improve in the foreseeable future (GlobeNewswire, 2012). As a result, the company has changed its focus to other projects. The Ministry of Energy and Mines has also authorized the exploration of geothermal resources in the regions of Arequipa and Cuzco by Hot Rock Peru SA (ThinkGeoEnergy, 2011). At present, the Energy Development Corporation of the Philippines and Hot Rock are jointly working on the exploration and development of the Chocopata and Quellaapacheta concessions (Remo, 2012).

8. FINAL REMARKS

Based on the World Energy Council 2007 Survey of Energy Resources, Fridleifsson and Haraldsson (2011) report a 0.73 capacity factor for geothermal power plants, which is far higher than that of any other renewable power plants. Assuming this average factor in the five countries reviewed in this paper and a geothermal generation potential that is midway between the GEA low and high estimates from 1999, except for Chile where the generation capacity is assumed to be that reported by Lahsen et al. (2010) and Peru where the assessment of the Ministry of Energy and Mines is used, leads to the numbers presented in Table 1. US Energy Information Administration data are used for capacity and generation in 2010 and those numbers may vary slightly from other sources. It is clear that geothermal can in all cases contribute significantly to the energy mix of the countries.

In 1999, the Geothermal Resources Council estimated average carbon dioxide emissions from geothermal power plants to be 0.08 kg/kWh, while the emissions from fossil fuel plants were: coal 0.97, petroleum 0.71, and natural gas 0.47 kg/kWh of carbon dioxide respectively (Bloomfield and Moore, 1999). This compares with 0.12 kg/kWh for geothermal power plants reported by Bertani and Thain (2002). From these numbers it is clear that using geothermal resources to generate electricity in place of fossil fuel based thermal power plants can avoid substantial CO_2 emissions.

TABLE 1: Comparison of installed capacity and generation in 2010 to estimated geothermal potential

	Cap. factor		**Gen. capacity**		**Generation**		**Geoth. vs. 2010**	
	Total 2010 -	**Geoth -**	**Installed 2010 MWe**	**Geoth potential MWe**	**Total 2010 GWh**	**Geoth potential GWh**	**Generation capacity %**	**Generation %**
Bolivia	0.45	0.73	1,655	885	6,589	5,659	53	86
Chile	0.44	0.73	16,206	16,000	62,863	102,317	99	163
Colombia	0.47	0.73	13,545	1,035	55,275	6,618	8	12
Ecuador	0.37	0.73	5,243	635	17,088	4,061	12	24
Peru	0.44	0.73	8,613	3,000	33,328	19,184	35	58

The United Nations University Geothermal Training Programme (UNU-GTP) can support the countries of South America in strengthening the skills of experts who are tasked with the responsibility of carrying out geoscientific exploration, utilizing and managing geothermal resources. Since its inception in Iceland in 1979, the programme has graduated 515 Fellows from 53 developing countries. The Fellows have obtained both a broad overview of the major geothermal disciplines as well as committing to in-depth studies in one or more of the 9 available lines of specialization: geological exploration, borehole geology, geophysical exploration, borehole geophysics, reservoir engineering, environmental studies, chemistry of thermal fluids, geothermal utilization, and drilling technology. Many of the Fellows bring with them data from home to analyze during the nearly 3 month long project work, which entails the writing of a report that is included in the annual publication *Geothermal Training in Iceland*. The individual reports are available on the UNU-GTP website (www.unugtp.is). In this way, strong groups of geothermal experts have been established in many developing countries over the years. A selected number of Fellows who have shown outstanding performance in their 6 month studies, have been offered the opportunity to further their geothermal studies at the University of Iceland towards an MSc degree, and a few have been enrolled in PhD programmes.

Since 2006, the UNU-GTP has offered semi-annual Millennium Short Courses in cooperation with LaGeo S.A. de C.V. in El Salvador for the Latin America region. The courses are the contribution of the government of Iceland towards the United Nations Millennium Development Goals and are intended to strengthen the skills of participants in specific geothermal disciplines, as well as providing a venue for experts in the region to meet and compare books. These Short Courses are often the first step for candidates to take towards further studies at the UN University Geothermal Training Programme.

In 2010 and 2012, the University of El Salvador offered a geothermal diploma course in cooperation with LaGeo S.A. de C.V. and the Italian Cooperation of the Italian Ministry of Foreign Affairs, which funded the courses. It is foreseeable that this regional geothermal training programme will be continued in modified form with the support of the Inter-American Development Bank and the Nordic Development Fund, and will thus provide opportunities to Spanish speakers to study the geothermal disciplines in their native language.

Geothermal energy has been an under-developed energy source in South America, but it has the potential of providing reliable base load electricity, reducing greenhouse gas emissions, lessening reliance on imported energy, bringing electricity to the rural poor and possibly lowering electricity prices. The exploitation of geothermal resources can thus help raise the standard of living in the countries along the Andean mountain range, while also contributing to the UN Millennium Development Goals and a better worldwide environment.

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UNITED NATIONS UNIVERSITY
GEOTHERMAL TRAINING PROGRAMME

LaGeo S.A. de C.V.

GEOTHERMAL STATUS, PROGRESS AND CHALLENGES IN THE EASTERN CARIBBEAN ISLANDS

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ABSTRACT

These 11 volcanic islands of the Eastern Caribbean lying on the inner arc have an estimated power potential of 16,310 MWe collectively, according to USDOE studies (Huttrer, 2000). Guadeloupe nonetheless still remains the only country in the region to have a geothermal plant. This 4.5MWe double flash power plant was installed in 1984 and was later upgraded to 15.7MWe in 2004. The Commonwealth of Dominica during the period of 2011 - 2012 was able to successfully complete a series of 3 exploratory wells and is slated to start the production wells with the Iceland Drilling Company in 2013. The British territory - Montserrat has also forged ahead in the development of their geothermal resource securing funding to start the drilling of 2 full size production wells on the 20th of February 2013. On the down side, works in Nevis have stopped for some time initially because of financing and most recently due to litigations between the developer WIPH and the Nevis Island Administration (NIA). The geothermal status for the region continues to evolve but at a much slower pace that previously envisioned. Its challenges such as financing and human resource building persist yet the islands are slowly finding ways to combat these issues so that more of the estimated potential of the region can be harnessed and used for the advancement of the counties.

1. INTRODUCTION

The Eastern Caribbean has been defined in terms of politics, culture, language, geographical location etc. but for the purpose of this paper, it will be considered to be largely the islands sitting on the Caribbean Plate. The Caribbean Plate is bordered by the North American Plate, Cocos Plate and the South American Plate (Figure 1). This group of islands form two archipelagos starting with Saba in the North and joining at Martinique then trending southward into the Paria Peninsula of Venezuela (Maynard-Date and Farrell, 2011) as can be seen in Figure 2. The outer of the two arcs host the older extinct volcanoes whereas those in the inner arc have numerous surface manifestations of geothermal activities. The Caribbean Plate is mostly an oceanic tectonic plate covering approximately 3.2 million square kilometres in area and is thought to

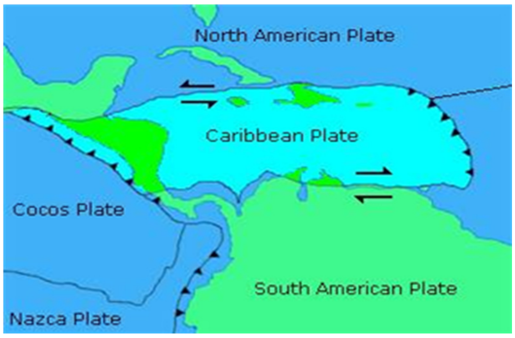

FIGURE 1: Caribbean Plate (Olelog, 2012)

be a large igneous province that formed in the Pacific Ocean tens of millions of years ago. The subduction of the western edge of the Atlantic Ocean floor under the thicker layer of the Caribbean Plate gave rise to the chain of islands in this archipelago (Olego, 2012).

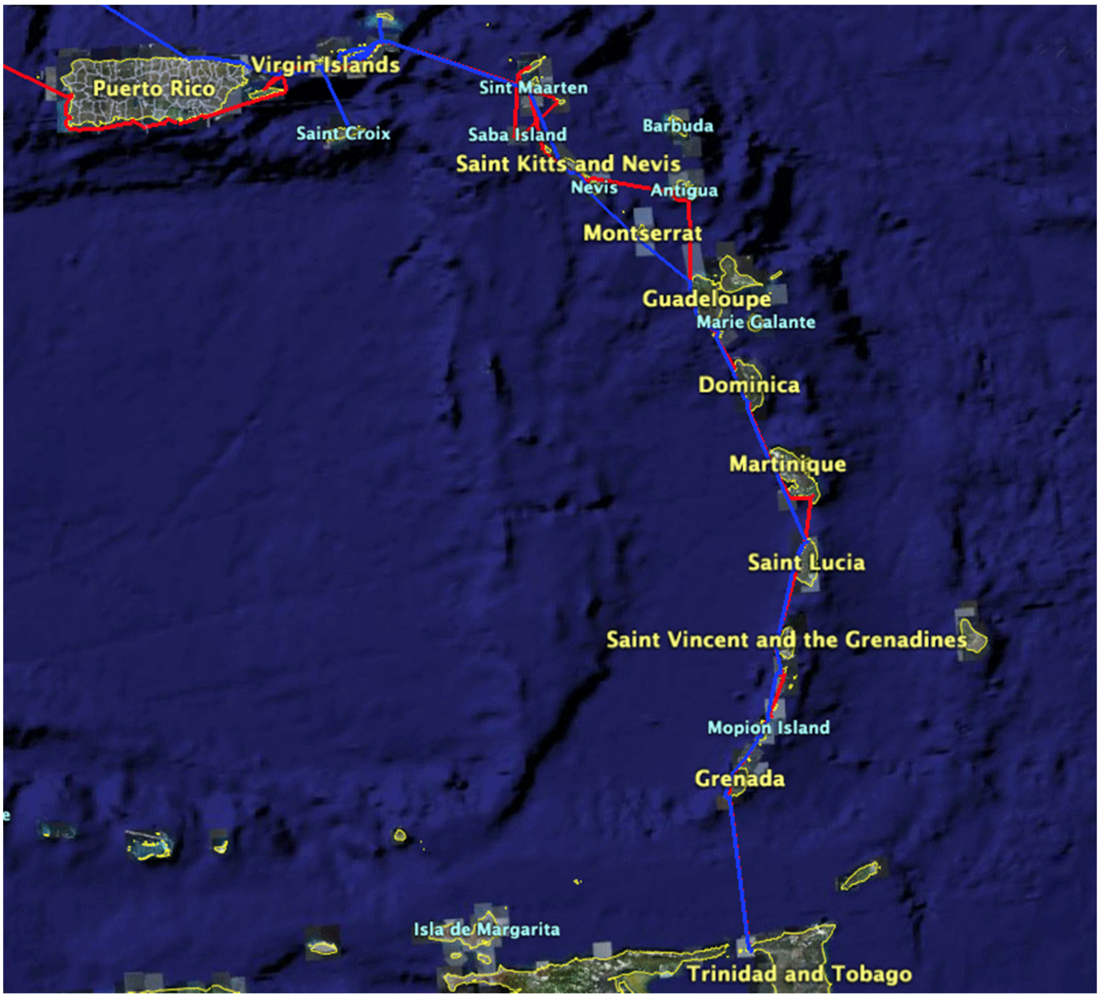

FIGURE 2: Map of the Eastern Caribbean (Svaurora, 2008)

2. HISTORY OF GEOTHERMAL ACTIVITIES IN THE EASTERN CARIBBEAN

Historically, documentation of geothermal activities has been recorded as early as the 1950's by P.H.A. Martin-Kaye in the Caribbean (Maynard-Date and Farrell, 2011). In 1969 to 1970, the French territory of Guadeloupe drilled a series of 4 wells at Bouillante reaching maximum temperature and depth of 242^{0}C and 1,200m respectively. Guadeloupe went on further in 1984 to build the first geothermal plant in the Eastern Caribbean which supplies electricity to the leeward coast of Basse-Terre. The initial plant was a 4.5 double flash plant which was later expanded in 2004 to 15.7 MWe (Maynard-Date and Farrell, 2011).

Guadeloupe is not the only island in this archipelago that saw investigative work done in terms of geothermal advancement. In 1998, prefeasibility studies were done on 11 islands on the inner arc by the United States Department of Energy (USDOE) (Huttrer, 1998a). The findings revealed an estimated 16,310MWe (Huttrer, 1998 (a&b)) of untapped geothermal energy throughout these islands collectively.

This work prompted further development for the Eastern Caribbean islands with the signing of Memorandum of Understanding (MOU) with government to do geological and related drilling works on St. Vincent with an American Company called Growth Capital Holdings (GCH). Another MOU was signed with the government of St. Lucia and UNEC Corporation of United States, a subsidiary for Qualibou Energy Inc., to build a 120MWe by 2015 (Kay 2010).

In 2007 to 2008, the government of Saba, Nevis and Dominica signed agreements with West Indies Power Holdings (WIPH) to conduct exploratory work for geothermal resources. Not much work was done in Saba or at the Soufrière site in Dominica where license was granted to WIPH.

In 2008, 3 slim-hole wells were drilled by WIPH in Nevis reaching maximum temperature and depth of 260^0C and 1,065m respectively (Table 1).

TABLE 1: Slim hole wells information (WIPH, 2008a and b)

Well	Year	Depth (m)	Pressure [Bott. hole] (bar)	Pressure [Well head] (bar)	Temp (ºC)
Nevis 1	Jun. 2008	1065	82	-	250
Nevis 2	Jul. 2008	732	-	-	260
Nevis 3	Oct. 2008	899	-	16	201

In the case of the Commonwealth of Dominica (Dominica), from a joint venture between government and the French Bureau de Recherches Géologiques et Minières (BRGM) geothermal exploration started as early as 1977 in Dominica and 3 areas namely, Wotten Waven, Boiling Lake and Soufrière were successfully identified as potential geothermal sites for commercial development (Maynard-Date and Farrell, 2011).

3. PROGRESS IN GEOTERMAL ACTIVITIES IN THE EASTERN CARIBBEAN

3.1 The Dominican story

The exploratory drilling phase of geothermal project in Dominica which is jointly funded by The European Union (EU) who contributed 1.45M Euro and the French Development Agency (AFD) 4.0M euro. This donation was used for the drilling of the exploratory well, well testing, drilling and well testing supervision and advisory and technical assistance support to the GPMU. The European Investment Bank (EIB) has pledged 1.1M Euro which will go towards the feasibility and engineering studies for a submarine electrical interconnection of Dominica with Martinique and Guadeloupe and to define the optimal power rating of the new electrical link. ADEME funded the drilling Environmental Impact Assessment (EIA). The study was undertaken by Caraïbes Environment from Guadeloupe.

TABLE 2: Slim hole wells information for Dominica

Well	Year	Depth (m)	Bottom hole pressure (bar)	Temp (ºC)
Rain Forest Aerial Tram- Laudat	Jan. 2012	1469	82	241
Domlec's Balancing Tank - Laudat	Mar. 2012	1613	98	245
Wotten Waven	Apr. 2012	1200	108	180

From prior work done on Dominica, the three drilling sites are located in Wotten Waven (Well site WW-1) and Laudat (Well sites WW-2 and WW-3) respectively (Figure 3). Work started in December 2011 and by April, all 3 exploratory wells were successfully drilled (Table 2 and 3).

Having successfully completed the drilling and testing of three exploratory wells (see test results in Table 3) and proven the existence of a viable geothermal resource, the GoCD is now seeking to develop a 10 – 15 megawatt Geothermal Power Plant within the Wotten Waven Geothermal field. It is envisaged however that this development will occur in incremental phases, which will be determined in the production planning stage, and based to a large extent on the productive capacity of the wells, and to the dictates of local demand.

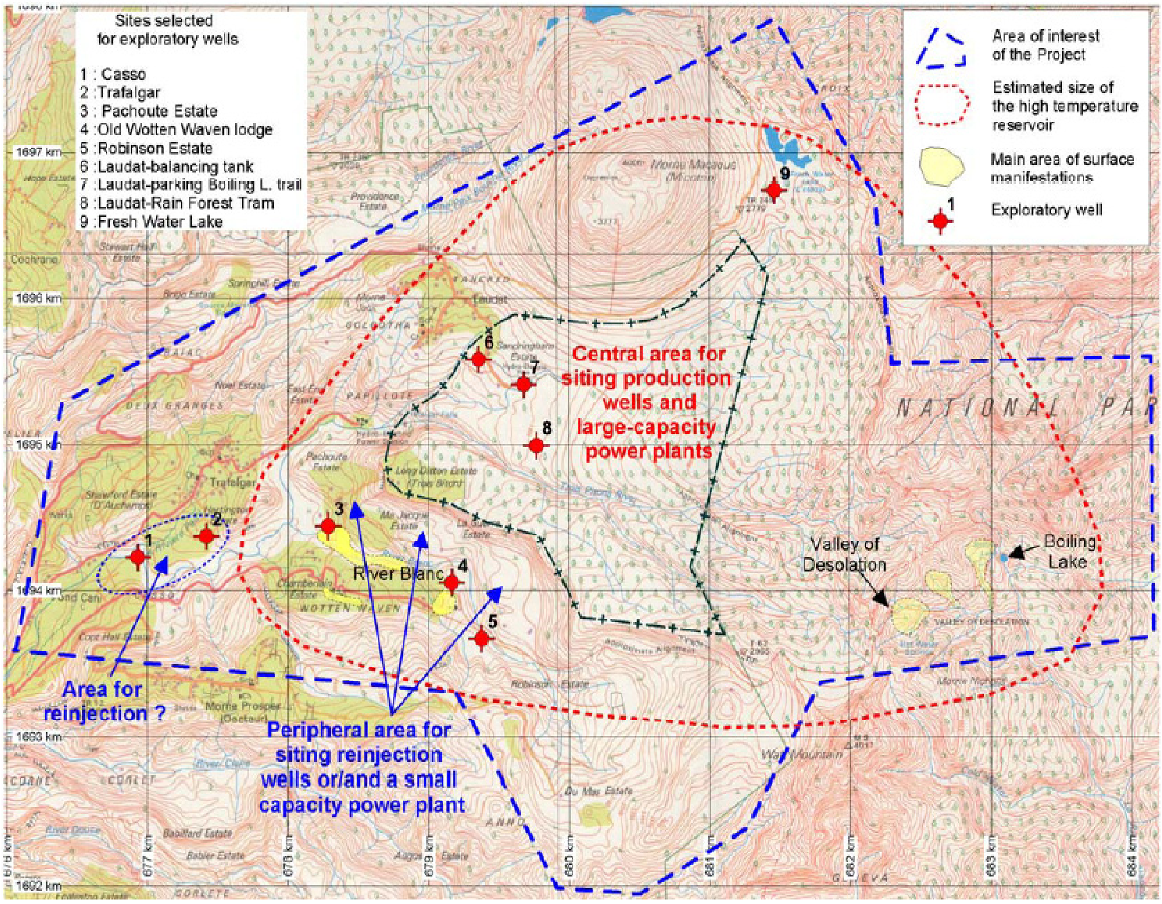

FIGURE 3: Dominica's drilling plan

The development of the small geothermal power plant (SGPP) is intended to reduce the cost of electricity to consumers, and will also serve as a pilot and demonstration plant which would allow for further assessment of the resource and to observe the reaction of the reservoir to commercial exploitation, thereby guiding the planning and management of the further exploitation and development of the resource to provide electricity for Martinique and Guadeloupe. The GoCD is currently engaged in negotiations with prospective investor Electricité de France (EDF) for the development of the small plant as well as the larger plant for export.

TABLE 3: Well summary flow results for Dominica

Well	Enthalpy (kJ/Kg)	Output (MWe)	Total estimated flow (kg/s)
Rain Forest Aerial Tram- Laudat	940-980	0.5	6.4-6.6
Domlec's Balancing Tank - Laudat	-	2.9	22
Wotten Waven	1010-1051	3.9	27.5

As a result the GoCD is also carrying out a feasibility study regarding a submarine electrical interconnection of Dominica with Martinique and Guadeloupe and to define the optimal power rating of the new electrical link, through funding from the European Investment Bank (EIB) in the sum of €500,000.00.

On Monday December 10, 2012 a drilling contract was signed between the GoCD and Iceland Drilling Company (IDC) to drill two full size wells, one production (1500-1800 m in depth) and one reinjection well (1300-1400 m in depth). Contract sum €4,735,171.00 (exclusive of VAT) Estimated commencement date – May/June 2013.

3.2 Montserrat progress in geothermal development

The government of Montserrat issued in February 2012, an invitation for expression of interest to private companies for the confirmation and exploitation of the expected superheated geothermal resource on the north side of the island (Jamaica Observer, 2012). The Iceland Drilling Company won the bid to do the drilling and drilling is expected to start on February 20, 2013. This has move the geothermal development from a pre-exploration stage to an exploration phase.
All works have been completed on the site for drilling to commence and well lining materials have all been delivered to site along with the drilling rig. During the exploration phase where geological, geophysical and geochemical analyses were done along with a financial risk analysis, the results yielded a focused zone of high probability between Garibaldi Hill and Weekes Village (Figure 4). Based on these findings, it was believed that there will not be much gained from drilling slim hole wells and hence, 2 production size wells are slated to be drilled between Weekes and Garibaldi Hill. The expected depth lies around 1,400-1,600m, however the rig has the capability to go up to 2,000 m. One of the wells will be used for reinjection so they will be positioned 550 m apart to prevent circulation.

FIGURE 4: Montserrat's drilling site (Google earth map)

It is the hope of the developers to meet the 2 MWe demand of the island and for such reason will be installing a 2.5MW plant upon successful completion of the wells.

4. CHALLENGES WITH GEOTHERMAL DEVELOPMENT IN THE EASTERN CARIBBEAN

In the Eastern Caribbean the fundamental problem in the development of geothermal energy is the availability of funds. The countries in the Eastern Caribbean find it quite difficult to self fund these projects. Moreover, securing financial assistance from independent companies or lending institutions pose similar challenges since the rate of return on investment is very slow due to the small power consumption of these discrete islands. Serious consideration need to be given to the creation of a regional grid or even a 2-3 islands grid to make the project more viable to both developer and the country in question. At present, the region's lack of experience in geothermal development have left some countries with an undesirable taste to the development of geothermal energy. The region has seen developers starting projects and setting unrealistic timelines and reaping nothing at the end of it all. Also due to the lack of education on geothermal in the region, the schools are not equipping the youth with geothermal friendly subjects and as such the country has little to no technical personnel to deploy into this area. Additionally, the lack of education lends itself to secondary problems such as exploitation by developers and self servicing groups who may wish to sabotage the progress for personal gain. In the case of the development of geothermal on Nevis, the project was stopped due to litigations brought again WIPH by the Nevis Island Administration (NIA), the case was won by NIA (Da Vibes Inc., 2013) giving them the right to develop the resource themselves or invite an independent developer, however an appeal has been made to the Courts on the ruling.

The list of challenges is not exhausted by any means, nonetheless, the region continues to address them and overcome them for the betterment of the country.

5. DISCUSSION AND CONCLUSION

The Eastern Caribbean islands are beautifully placed on the Caribbean plate in an archipelago stemming from Saba in the North and extending to Grenada in the South. Of these islands, only 4 of the 11 islands that have some form of commercial source of renewable energy being supply to their grid. The countries were renewable energy exist include Dominica and St. Vincent and the Grenadines with hydro-electric plants, Guadeloupe with the only geothermal plant and Guadeloupe and Nevis with wind farms. The hydroelectric and geothermal plants are considered to be base load plants but none of the installed plants contribute 50 or above percentage to the overall power consumption. This means that a significant amount of the power generated in these discrete islands are as a result of diesel usage whose price is subjected to the international market.

To become more energy independent, there is a dire need for more base load type of energy such as geothermal. The benefits to be gained from geothermal development are far reaching and for a third world country it is extra-phenomenal. The forward movement of Dominica and Montserrat in geothermal energy advancement is encouraging and their experience is creating a plateau from which the other countries can move off in the development of their own resource. The region has great potential and must be seized in order for the area to develop. Serious consideration needs to be given to a regional grid since islands such as Antigua & Barbuda and Barbados can benefit from these resources. This too will assist in making the project more viable for the investors since collectively, economies of scale will be achieved.

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GEOTHERMAL SYSTEMS IN GLOBAL PERSPECTIVE

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ABSTRACT

Geothermal resources are distributed throughout the world. They are classified in various ways on the basis of heat source, heat transfer, reservoir temperature, physical state, utilization and geological settings. Common classification of geothermal systems is: (a) volcanic systems with the heat source being hot intrusions or magma chambers in the crust, (b) convective systems with deep water circulation in tectonically active areas of high geothermal gradient, (c) conductive sedimentary systems with permeable layers at great depth (2-5 km), (d) geo-pressured systems often in conjunction with oil resources, (e) hot dry rock or EGS systems where abnormally hot masses of low permeability rocks are found at drillable depths, (f) shallow resources in normal geothermal gradient areas utilized with ground-source heat pump applications. In most of these classes the energy transport medium is the water within the geothermal system and such systems are therefore called hydrothermal systems, exceptions being the EGS systems and the shallow, ground-source heat pump resources. The geothermal systems are suitable for various applications depending on the reservoir temperature and fluid type. The hot volcanic systems are utilized primarily for electric power generation and the lower temperature systems for space heating and other direct uses.

Some 50 years ago a classification was proposed in which geothermal fields in Iceland were divided into high- and low-temperature hydrothermal fields or areas. This division was based on (arbitrarily) inferred temperature at 1 km depth, high temperature fields where a temperature of 200°C is reached at 1 km depth and low temperature fields where temperature is below 150°C in the uppermost km. The HT-fields are all related to volcanism whereas the LT-fields draw heat from the general heat content of the crust and the heat flow through the crust. Other temperature subdivisions have been proposed by adding intermediate or medium temperature systems in-between the two main categories. There are several types of systems in each of the two main groups.

1. INTRODUCTION

The words *geothermal energy* refer to the thermal energy contained within the earth. Nowadays we use the word, however, for that part of the earth's heat that we can recover from the ground primarily through boreholes and exploit for various purposes. Geothermal resources are found throughout the world but exploitable geothermal systems are mainly found in regions of normal or abnormally high geothermal gradients. Even though the greatest concentration of geothermal energy is associated with the Earth´s plate boundaries, geothermal energy may be found in most countries and exploitation of geothermal systems in normal and low geothermal gradient areas has been gaining momentum during the last decade. The geothermal potential is though highly concentrated in volcanic regions, but may also be found as warm ground water in sedimentary formations world-wide and the flux of heat to the surface is, in most regions of the world, sufficiently high to be utilized for house heating using shallow boreholes and ground source heat pumps. In many cases geothermal energy is found in populated, or easily accessible, areas. But geothermal activity is also found at great depth on the ocean floor, in mountainous regions and under glaciers and ice caps. Numerous geothermal systems probably still remain to be discovered, since many systems have no surface activity. Some of these are, however, slowly being discovered. The following definitions are used here:

- *Geothermal Field* is a geographical definition, usually indicating an area of geothermal activity at the earth's surface. In cases without surface activity this term may be used to indicate the area at the surface corresponding to the geothermal reservoir below.
- *Geothermal System* refers to all parts of the hydrological system involved, including the recharge zone, all subsurface parts and the outflow of the system.
- *Geothermal Reservoir* indicates the hot and permeable part of a geothermal system that may be directly exploited. For spontaneous discharge to be possible geothermal reservoirs must also be pressurized, either artesian or through boiling.

Geothermal systems and reservoirs are classified on the basis of different aspects, such as reservoir temperature, enthalpy, physical state or their nature and geological setting. Table 1 summarizes classifications based on the first three aspects.

TABLE 1: Classifications of geothermal systems on the basis of temperature, enthalpy and physical state (Bodvarsson, 1964; Axelsson and Gunnlaugsson, 2000)

<table>
<tr><td>Low-temperature (LT) systems with reservoir temperature at 1 km depth below 150°C. Often characterized by hot or boiling springs.</td><td rowspan="2">Low-enthalpy geothermal systems with reservoir fluid enthalpies less than 800 kJ/kg, corresponding to temperatures less than about 190ºC.</td><td rowspan="2">Liquid-dominated geothermal reservoirs with the water temperature at, or below, the boiling point at the prevailing pressure and the water phase controls the pressure in the reservoir. Some steam may be present.</td></tr>
<tr><td>Medium-temperature (MT) systems with reservoir temperature at 1 km depth between 150- 200°C.</td></tr>
<tr><td rowspan="2">High-temperature (HT) systems with reservoir temperature at 1 km depth above 200°C. Characterized by fumaroles, steam vents, mud pools and highly altered ground.</td><td rowspan="2">High-enthalpy geothermal systems with reservoir fluid enthalpies greater than 800 kJ/kg.</td><td>Two-phase geothermal reservoirs where steam and water co-exist and the temperature and pressure follow the boiling point curve.</td></tr>
<tr><td>Vapour-dominated reservoirs where temperature is at, or above, boiling at the prevailing pressure and the steam phase controls the pressure in the reservoir. Some liquid water may be present.</td></tr>
</table>

Geothermal systems may also be classified based on their nature and geological settings as:

A. *Volcanic geothermal systems* are in one way or another associated with volcanic activity. The heat sources for such systems are hot intrusions or magma. They are most often situated inside, or close to, volcanic complexes such as calderas, most of them at plate boundaries but some in hot spot areas. Permeable fractures and fault zones mostly control the flow of water in volcanic systems.

B. In *convective facture controlled systems* the heat source is the hot crust at depth in tectonically active areas, with above average heat-flow. Here the geothermal water has circulated to considerable depth (> 1 km), through mostly vertical fractures, to mine the heat from the rocks.
C. *Sedimentary geothermal systems* are found in many of the major sedimentary basins of the world. These systems owe their existence to the occurrence of permeable sedimentary layers at great depths (> 1 km) and above average geothermal gradients (> 30ºC/km). These systems are conductive in nature rather than convective, even though fractures and faults play a role in some cases. Some convective systems (B) may, however, be embedded in sedimentary rocks.
D. *Geo-pressured systems* are analogous to geo-pressured oil and gas reservoirs where fluid caught in stratigraphic traps may have pressures close to lithostatic values. Such systems are generally fairly deep; hence, they are categorized as geothermal.
E. *Hot dry rock (HDR) or enhanced (engineered) geothermal systems (EGS)* consist of volumes of rock that have been heated to useful temperatures by volcanism or abnormally high heat flow, but have low permeability or are virtually impermeable. Therefore, they cannot be exploited in a conventional way. However, experiments have been conducted in a number of locations to use hydro-fracturing to try to create artificial reservoirs in such systems, or to enhance already existent fracture networks. Such systems will mostly be used through production/reinjection doublets.
F. *Shallow resources* refer to the normal heat flux through near surface formations and the thermal energy stored in the rocks and warm groundwater systems near the surface of the Earth's crust. Recent developments in the application of ground source heat pumps have opened up a new dimension in utilizing these resources.

The classification of geothermal systems into low temperature (LT) and high temperature (HT) is commonly used in Iceland and dates back some 50 years. It should be pointed out that hardly any geothermal systems in Iceland fall in-between 150 and 200ºC reservoir temperature, i.e. in the MT range. The few ones are declining volcanic geothermal systems, on their flanks or in the outflow zone. Different parts of geothermal systems may be in different physical states and geothermal reservoirs may also evolve from one state to another. As an example a liquid-dominated reservoir may evolve into a two-phase reservoir when pressure declines in the system as a result of production. Steam caps may also evolve in geothermal systems as a result of lowered pressure. Low-temperature systems are always liquid-dominated, but high-temperature systems can either be liquid-dominated, two-phase or vapour-dominated.

In the following chapters we will look in more details at the various types of low and high temperature geothermal fields in the word. We will start by dividing them in low and high temperature fields and then into sub types based on the geological settings.

2. LOW-TEMPERATURE GEOTHERMAL SYSTEMS

Low temperature geothermal activity is spread over most of the Earth, and low temperature fields are found in various geological settings. They are divided into several types as described below but primarily they depend primarily on the regional geothermal gradient, permeability (primary or secondary) of the rock and depth of circulation if such exists.

2.1 Shallow systems

Shallow resources refer to the normal heat flux through near surface rock formation and the thermal energy stored in these and warm ground water systems near surface of the Earth. The heat flux varies from place to place over the surface of the Earth. The average value is about 60 mW/m^2, which corresponds to an average geothermal gradient of ~30°C/km. Geothermal resources could earlier only be utilized economically in regions of abnormally high heat flow. This has changed and recent developments in application of ground source heat pumps have opened up new frontiers in utilizing shallow geothermal resources in areas of normal or even subnormal geothermal gradient using boreholes in the depth range of few tens of meters to few hundreds of meters and downhole heat exchangers. The feasibility of this utilization has also changed due to governmental actions i.e. subsidy programmes and green tariffs and there are examples where ground source heat pumps are utilizing up 2 km deep wells in a normal gradient areas, where the bottom hole temperature is therefore only 60°C.

2.2 Sedimentary systems

Sedimentary geothermal systems are found in many of the major sedimentary basins of the world. Sedimentary basins are layered sequences of permeable (limestone, sandstone) and impermeable strata (shale or mudstone) which alternate. Water is interstitial water, commonly brine, formerly thought to be of connate origin. Temperature is variable, depending on depth of permeable rocks in basin. These systems owe their existence to the permeable sedimentary layers at great depth (>1 km), often above average geothermal gradients (>30°C/km) due to radiogenic heat sources in the shallow crust or tectonic uplifting (folding) in the region or for other reasons. These systems are conductive in nature rather than convective, even though fractures and faults play a role in some cases (Figure 1). Some convective systems may, however, be embedded in sedimentary rocks. Examples of geothermal systems in sedimentary basins are the Molasse basin north of the Alps, the Paris basin, the Pannonian basin, the Great Artesian Basin in Australia, the sediment filled Rhine graben and several basins in China to mention only few. These systems are of different origin and the heat flow differs widely. The depth to useful temperatures may vary from 1 up to 5 km. The fluid salinity is also different from relatively fresh water to high salinity brine (250,000 ppm). Natural recharge of the geothermal fluid is minimal and reinjection is needed to maintain reservoir pressure and is often a mandatory way to dispose of the geothermal water after passing through heat exchangers. Doublets (production-injection) boreholes are commonly used.

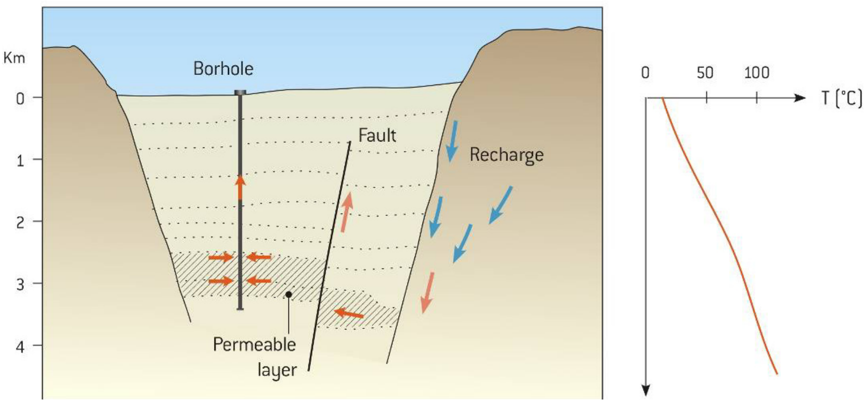

FIGURE 1: Schematic figure of a sedimentary basin with a geothermal reservoir at 2- 4 km depth. The temperature profile to the left shows a typical sedimentary geothermal gradient profile

Some sedimentary basins contain sedimentary rocks with pore pressure exceeding the normal hydrostatic pressure gradient. These systems are classified as geo-pressured geothermal systems. They are confined and analogous to geo-pressured oil and gas reservoirs where fluid caught in stratigraphic traps may have pressures close to lithostatic values. Such systems are fairly deep; hence they are categorized as geo-pressured geothermal systems. The known geo-pressure systems are found in conjunction with oil exploration. The most intensively explored geo-pressured geothermal sedimentary basin is in the northern part of the Gulf of Mexico and in Europe in Hungary. Geo-pressured geothermal fields have not yet been exploited.

2.3 Fracture or fault controlled convection systems

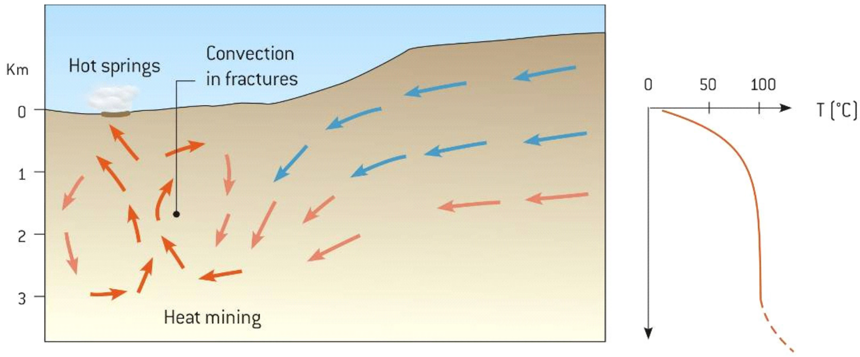

FIGURE 2: A conceptual model of fractured low temperature convective system. The temperature profile to the right represents the temperature in the central part of the convective reservoir

In fracture or fault controlled convection systems circulation may be deep or shallow. The recharge water is rain from mountainous areas some distance from the geothermal field that flows as ground water stream towards a permeable fracture area where fluid convection mines heat from the deeper parts of the geothermal field (Figure 2). The convecting water picks up heat at depth (cools the formations) and transports the heat from base area of the system to upper parts of the reservoir (Figure 2 and 3). The reservoir water is generally low in TDS but may be high in sediment filled rift zones or in coastal areas. Temperature is anywhere from little above ambient to 160°C depending on depth of circulation. Highly fractured ground hosts relatively cold systems. High discharge (such as over 100 l/s) of >100°C water from a single fault would suggest transient character. Temperature inversion commonly occurs in open, fracture controlled geothermal systems as hot water flows or spreads laterally in the near-surface part of the fractures. These low temperature systems are common in Iceland as in other tectonically active countries.

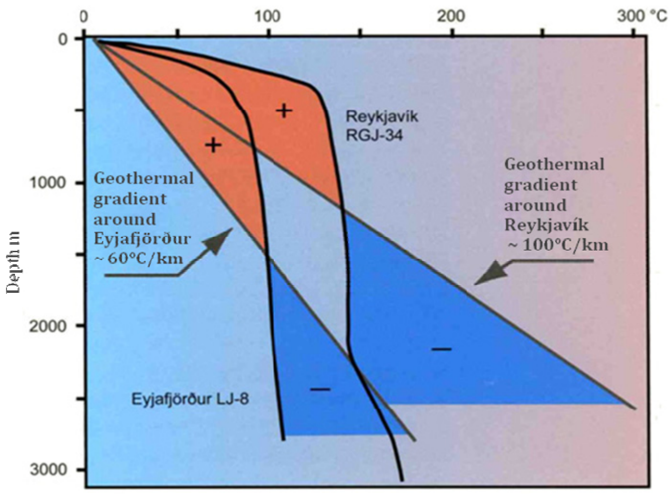

FIGURE 3: Reykjavík and Akureyri, Iceland. Bold lines show actual reservoir temperature, 130-140°C for Reykjavík, 90-95°C for Akureyri. Water transports heat from deep levels, thus cooling the rock (heat mining). Shallower levels consequently are heated up

Fracture permeability is dependent on the type of rock. Fracture-friendly rocks are hard and „non-yielding“, such as igneous rock (basalt, andesite and intrusive rock) and also granite, gneiss, quartzite, also limestone and indurate sandstone. Fracture-unfriendly are claystone, shale and the like which react to rock stress by plastic deformation. Only a part of the fractures contribute to an effective fracture volume. Release joints and tension fractures have a relatively high effective fracture volume contrary to compressional fractures. Water contained in matrix pores and micro-fractures is inaccessible in case of low-temperature geothermal exploitation. Pressure decrease due to drawdown in high-temperature reservoirs may cause pore and micro-fracture water to boil and hence contribute to the available part of the resource.

2.4 Off-flow from volcanic (high-temperature) geothermal systems

Systems with off-flow from volcanic (high-temperature) geothermal areas include groundwater heated by contact with hot ground and/or mixing of deep reservoir water with local ground water. Commonly inversion of temperature is found and in some cases deposits of travertine occur, especially where the geothermal system is on the decline. Aquifers may be either stratabound or fracture related. Temperature decreases with distance from the source region. Depending on the temperature in the uppermost kilometre, the outflow systems are classified as low temperature systems but close to the volcanic areas the temperature may exceed 150°C at 1 km thus lifting it to medium temperature system (MT).

2.5 Distal part of fissure swarms via their laterally injected dyke swarms

Fissure swarms of volcanic origin pass downwards into dyke swarms. These may extend into the marginal blocks of the rift zones and create secondary permeability within them and thus pathways for deep circulation (Figure 4). The proximal parts of fissure swarms are located within the rift zones (actually defining them), usually in areas of thick young volcanics of high permeability and sediments. Surface manifestations may be scarce under such conditions, but at deep levels (below 1-1.5 km) conditions for a geothermal system may exist.

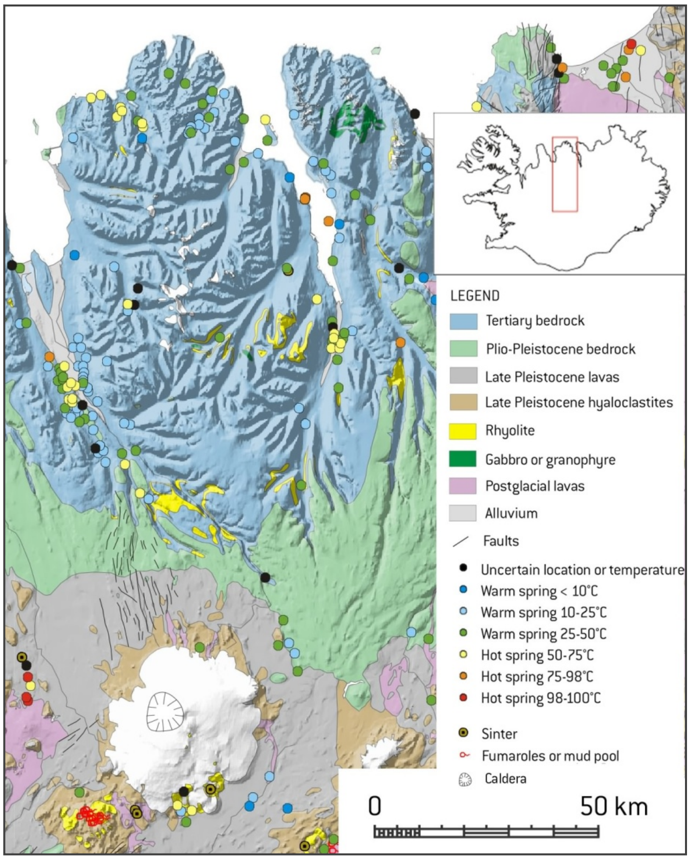

FIGURE 4: Hofsjökull volcano in central Iceland. A fissure swarm extends about 90 km to the NNW from it. Fissure eruptions occur along the first 30 km (proximal part). Faults and fissures extend another 60 km beyond with numerous hot springs in valleys eroded into 7-8Ma basalts (distal part)

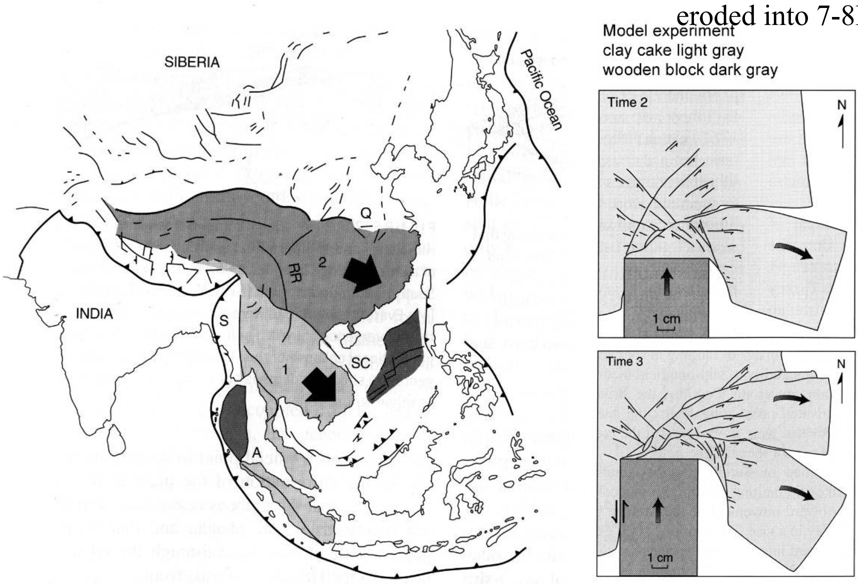

FIGURE 5: Tectonics of SE-Asia showing eastward escape of large crustal blocks along major strike-slip faults as suggested by Tapponier et al. (1982). Model for comparison (from Pluijm and Marshak 2004)

2.6 Active fracture zones on land

Active fracture zones on land host some of the richest low-temperature geothermal resources (China, South Iceland). In China enormous deformation zones have developed due to collision of India with Asia. The collision gives rise to lateral escape of China to the east along left lateral transcurrent fault systems (Figure 5). In Iceland the South Iceland Seismic Zone (left lateral) connects between offset spreading centres. It hosts about 30% of Iceland´s low-temperature geothermal resources.

3. HIGH-TEMPERATURE GEOTHERMAL SYSTEMS

These are volcanic/intrusive in origin as regards occurrence and heat source. Most magma does not reach the surface but heats large regions of underground rock. Most active fields are of Pliocene to Recent age. Young batholiths at relatively shallow depth may still be hot. Rapid removal of uppermost overburden helps to get near to them. Aquifers are strata-bound and or fracture controlled. The high-temperature geothermal fields occur in different types of geological settings, most of them at plate boundaries, but also in continental rifts and in hot spot environments.

High temperature geothermal systems are water dominated, but often vapour dominated to a varying depth if the reservoir is boiling. Induced steam zone may develop as production proceeds. This is a corollary of drawdown in a boiling reservoir as characterize most of the high-temperature geothermal fields. A shallow steam zone may thus thicken by hundreds of metres if recharge is limited. The volume increase from water to steam under conditions such as prevail at shallow depth may be on the order of 50 fold with a corresponding pressure increase. This is manifested by increased steam flow from hot ground and fumaroles and locally also by new steam emanations from fissures.

3.1 Rift zone regimes

3.1.1 Mid ocean ridges

The mid oceanic ridges comprise over 50,000 km long continuous volcanic zone on the ocean floor. Hot springs at great depths on the mid-oceanic ridges are known as “black smokers” (Figure 6). They are the surface activity on the ocean bottom of geothermal systems under the ocean floor. The knowledge on these systems is limited but the Asal system in Djibouti may be the closest supramarine analogue. At slow spreading ridges as in Djibouti, high viscosity asthenosphere causes rift valley to form with uplifted, outwardly dipping flanks. Salton Sea California is also on a ridge crest, which is all buried in sediment except latest Pleistocene volcanics (Salton Buttes).

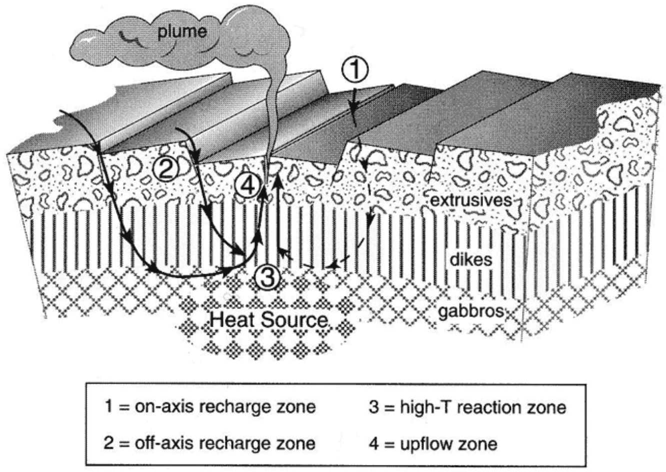

FIGURE 6: Schematic illustration of a black smoker geothermal system. Depth of circulation is about 3-4 km (Encyclopedia of Volcanoes, 2000)

3.1.2 Supramarine oceanic rifts: Iceland

Geothermal systems develop at high volcanic foci of elongated volcanic systems (Figure 7). In Iceland the flanks of the rift dip inwardly, i.e. towards the rift zone, as at fast spreading oceanic ridges (such as the East Pacific Rise). This is because the asthenosphere is hot and of lower viscosity due to an exceptionally powerful mantle plume. The reservoir fluid is of meteoric or seawater origin depending on the relative distance to the ocean shores and the heat source is magmatic intrusions at depth and sometimes a magma chamber exists in the roots of the volcanic system (Figure 8).

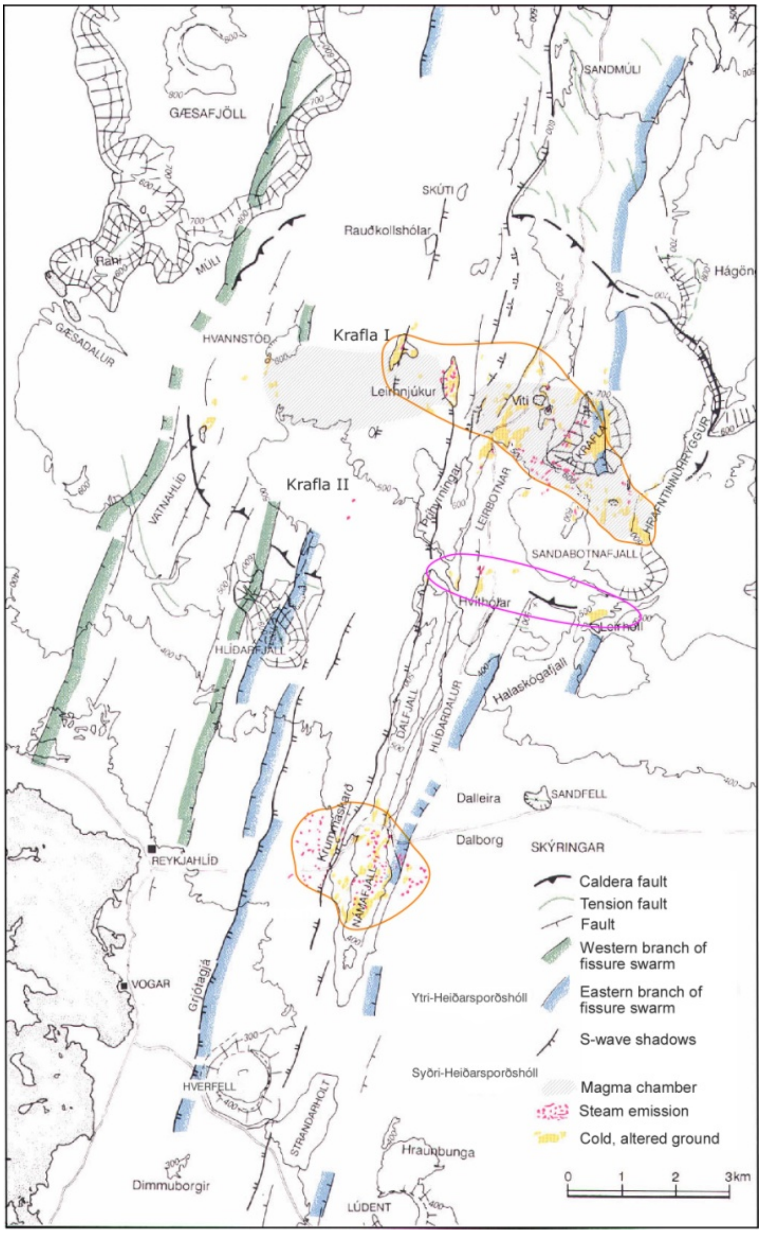

FIGURE 7: Central part of Krafla volcanic system showing caldera and fissure swarms which transect it. The Krafla caldera hosts a geothermal system. It has a magma chamber (S-wave shadow) at 3-7 km depth. A second geothermal area at Námafjall on the fissure swarm 7 km south of Krafla is located where basaltic fissure eruptions concentrate

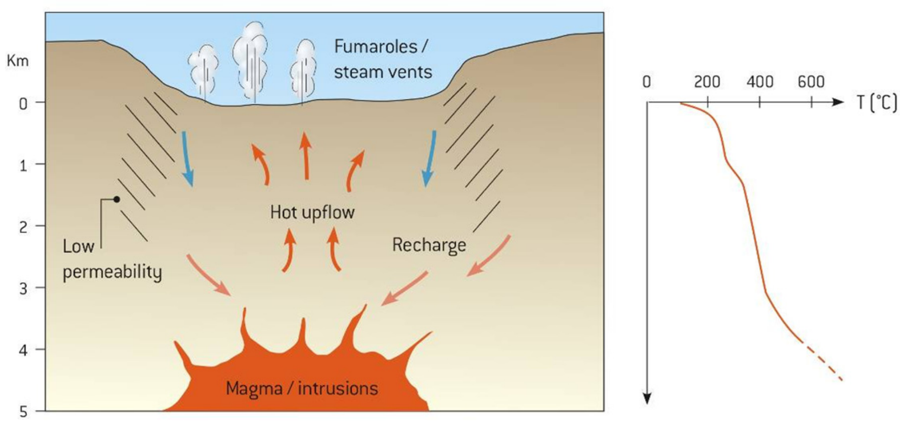

FIGURE 8: Conceptual model of a high temperature field within a rifting volcanic system. The temperature profile to the right represents the central part of the model

3.1.3 Continental rifts: East Africa

The East African rift valleys, exclusive of the Western Rift, are at the apex of two domal uplifts. They developed from stray stratovolcanoes (Mt Elgon, Mt. Kenya, both at the southern dome) to a later stage rift valley with elongated volcanic systems on their floor. Again the geothermal systems formed in areas of high volcanic production, i.e. in the core areas of the volcanoes (Figure 9).

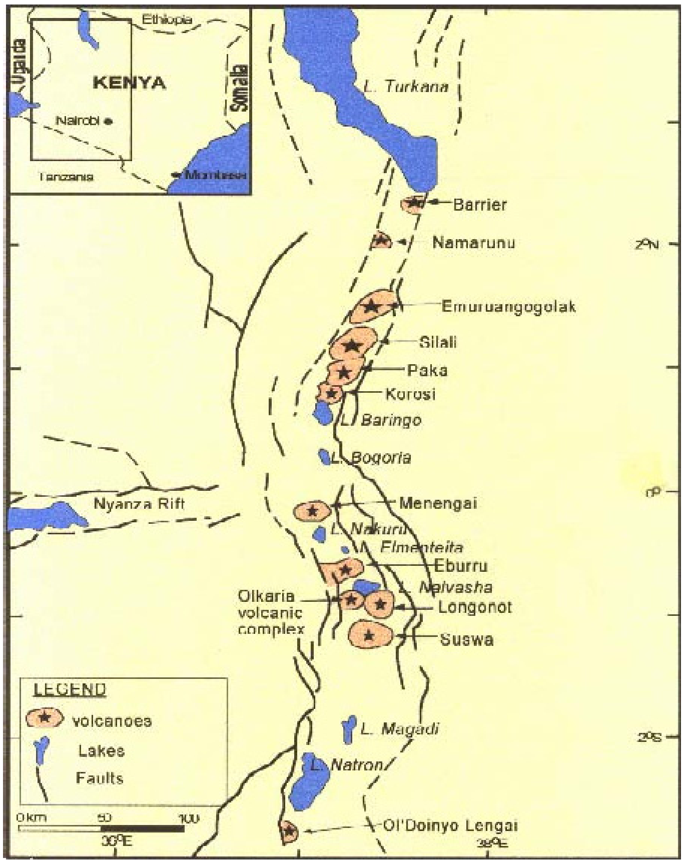

FIGURE 9: Apex of Kenya Rift domal uplift with two volcanically active rift branches and a third E-W branch dying. Stratovolcanoes are shown. Fissure swarms have not been identified as integral parts of volcanic systems (Mwawongo 2004)

3.2 Hotspot volcanism

Hotspot volcanism is off, sometimes far off, from spreading centres. Two examples will be mentioned one located on oceanic crust the other on continental crust. Both have a hot spot track associated with them.

3.2.1 Hawaii and Yellowstone

At Hawaii basaltic shield volcanoes begin on top of a mantel plume, and are carried off from plume centre as the plate passes over it. Geothermal systems may develop at apex of the volcanoes and also on their associated fissure swarms in areas of local concentrations of dykes.

Yellowstone is the world's largest rhyolite volcano. A huge, composite caldera has formed in it following major ignimbrite eruptions. Rhyolite volcanoes generally contain little other than rhyolite the low density rock type possibly forming a volcanic shadow zone, impenetrable for heavier less silicic melts. Near-surface intrusions (magma chambers) of rhyolite magma at depth below these long-lived centres promote very active geothermal systems.

3.2.2 Flank zone volcanism

Flank zone volcanism occurs far off from oceanic ridge crests. It is characterized by alkalic rocks of deeper mantle origin than tholeiites. The Azores are an example of this (Figure 10). There the flank zone volcanism occurs where fracture zones intersect hot spots. In Iceland the Snæfellsnes Peninsula is an example. Shear stresses prevail in these regions.

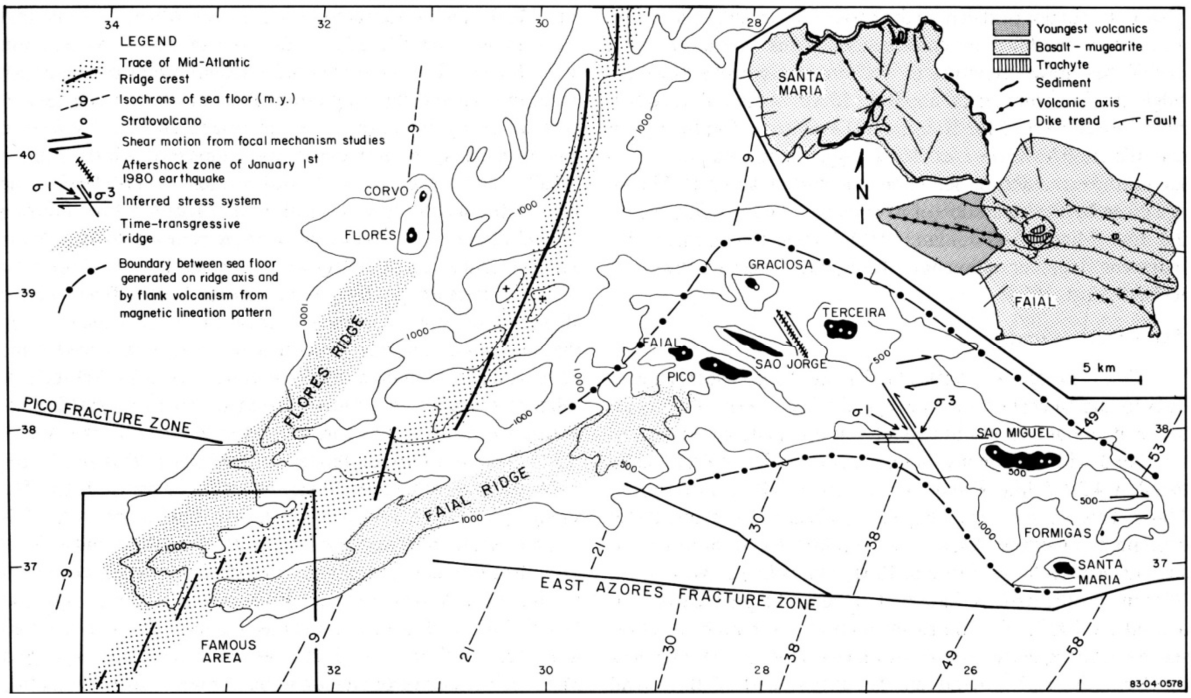

FIGURE 10: High-temperature geothermal fields on the Azores Islands are related to flank zone volcanism north of the Azores Fracture Zones. They developed in caldera regions of stratovolcanoes. Prominent fissure swarms formed in the direction of maximum stress

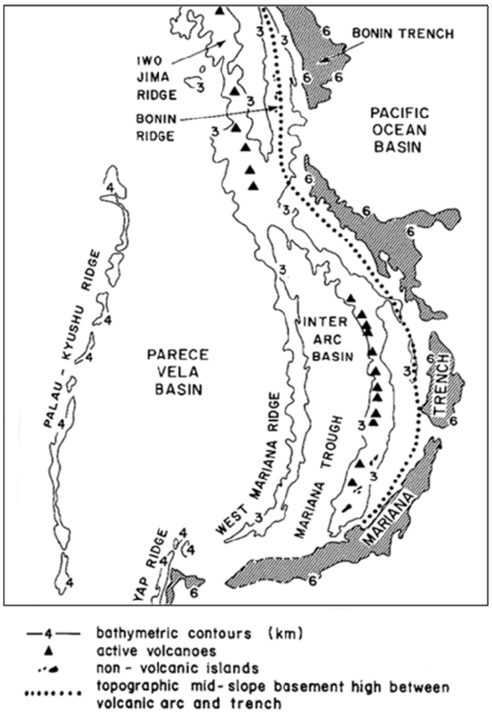

FIGURE 11: Example of a young island arc with inter arc basin and remnant arc. Evolved arcs develop from repeated splitting, crustal thickening and re-melting. At the same time the volcanic products evolve from basaltic to acid (Cas and Wright 1995)

3.3 Compressional regimes

Compressional regimes are the most common type of high temperature geothermal fields, globally. The tectonic environment is, however, variable (Circum Pacific Ring of Fire) (paragraphs 3.3.1-3.3.3; are from Cas and Wright (1995).

3.3.1 Young island arc volcanoes and inter arc basins

Young island arc volcanoes and inter arc basins are such as occur in the Marianas, Tonga-Kermadec, the Philippines, the West Indies (Figure 11). Successive splitting and ocean-ward migration of the frontal half of the arc block creates new inter-arc basins. Rock types mainly comprise basalt and basaltic andesite (island arc tholeiite).

3.3.2 Micro-continental arc volcanoes

Micro-continental arc-volcanoes are found in Japan, in New Zealand and in Indonesia. Arc-block is wider and is thicker than in young island arcs. Magmatic products are much more silicic. Calc-alkaline rocks are prominent. Taupo Volcanic Zone in New Zealand has erupted mainly rhyolite during the last 1 m. y. There are 15 harnessable geothermal fields with reservoir temperatures >220°C. Average size is 12 km², at 15 km intervals. The entire volcanic field is comparable in size to Yellowstone also as regards geothermal output. To maintain it the corresponding magma "intrusion" rates are 1.9 m^3/s (Yellowstone) and 1.7 m^3/s (Taupo) (Taupo and Yellowstone comparison from Wilson et al. 1984).

3.3.3 Continental margin arc volcanism

Continental margin arc volcanism, such as in the Andes and the Cascades. Magmatism takes place upon a wholly sialic, continental type crust, up to 60 km thick. The proportion of silicic volcanics is high, including huge ignimbrites (Ilopango, El Salvador: 40 km^3 erupted in 260 A.D.) and contemporaneous granitoids (batholiths).

3.3.4 Batholith driven geothermal systems

Batholith (pluton) driven geothermal systems, such as in Larderello in Italy and Geysers in California, are both vapour dominated. The geothermal resource is primarily found in the enveloping sedimentary strata.

4. HOT DRY ROCK OR ENHANCHED GEOTHERMAL RESOURCES

Hot dry rock (HDR) or enhanced (engineered) geothermal systems (EGS) consist of volumes of rock that have been heated to useful temperatures or abnormally high heat flow, but have low permeability or are virtually impermeable. They may be regarded as a downward extension of the batholith driven systems, the thermal resource being the cooling pluton itself. Permeability of the rock is very low but fracture permeability is induced by injecting cold water under high pressure into the hot part of it. Natural fractures and fissures are supposed to widen and new flow paths be created. Shortcuts tend to occur between injection and production boreholes. The heat source is vast and several experiments have been conducted in a number of locations to use hydro-fracturing to create or enhance permeability and hence create what we could call an artificial geothermal reservoir. Such systems will mostly be used through production/reinjections doubles. The best known of these experiments are the Fenton Hill project in the Jemez Mountains, New Mexico and the Soultz project in the Rhine graben near the border of France to Germany. These projects demonstrated that it is possible to create such artificial reservoirs. In the Fenton Hill project a small geothermal power unit was actually operated on steam from the reservoir for a short period of time in the 1970ties and in Soultz, a 1.9 MW ORC power plant has been in operation since June, 2008. The production cost of energy HDR/EGS systems are, however, still much higher than electricity from conventional geothermal resources but there are hopes that the production cost can be lowered and ambitious EGS projects are now underway in Australia.

5. SUMMARY AND DISCUSSION

In this paper we have discussed various types of geothermal systems. True to the Icelandic traditions we have focused the discussion on the two categories that we divide our geothermal systems into, i.e. *low temperature fields*, where temperature at 1 km depth is below 150°C and *high temperature fields*, where the reservoir temperature at 2 km exceeds 200°C. Very few Icelandic geothermal fields have reservoir temperatures in the obvious temperature gap in this definition but those few are sometimes called medium temperature fields. Each of these two types can be divided into several subgroups based on the regional geological setting of the geothermal field.

The sub classification used in this paper is to divide the low temperature system into:

- *Shallow resources* refer to the normal heat flux through near surface formations and the thermal energy stored in the rocks and warm groundwater systems near the surface of the Earth's crust.

- *Sedimentary low temperature systems* are found in many of the major sedimentary basins of the world.
- *Geo-pressured systems* are also sedimentary systems but are often categorized as a special class due to their similarities to geo-pressured oil and gas reservoirs where fluid caught in stratigraphic traps may have pressures close to lithostatic values.
- In *convective low temperature systems* the heat source is the hot crust at depth in tectonically active areas, with above average heat-flow. Here the geothermal water has circulated to considerable depth (> 1 km), through mostly vertical fractures, to mine the heat from the rocks.

The high temperature fields are without exception found in the volcanically active areas of the Earth. They are therefore also categorized as: *Volcanic geothermal systems,* and the sub classification applied here is to look at the tectonics and volcanism in the regions of the geothermal activity. These are:

- *Rift zone regime geothermal systems* are located in volcanic systems on the mid ocean ridges, on the supra-marine rifts or in continental rifts, most on plate boundaries where the tectonic plates are moving apart. The geothermal systems are in one way or another associated with the volcanic activity. The host rock is usually igneous and the permeability fracture dominated.
- *Hotspot volcanism* is accompanied by geothermal activity and the heat source is magmatic intrusions, derived from the mantel plume underneath.
- *Compression regions,* where oceanic plates collide with continental plates forming subduction zones. The collision creates various volcanic arcs on the continental side; narrow islands arcs; micro-continental arcs and continental margin arcs.

The low temperature activity is spread over most of the Earth. The exploitation has, however, been mostly in areas of normal to abnormally high geothermal gradient areas where geothermal systems of category (B) and (D) are found. Sedimentary systems (B) are for example found in France, Eastern Europe and throughout China. Low temperature systems of the convection type (B) are found in Iceland, USA and in China. Improved ground source heat pump technology has increased drastically the exploitation of shallow resources (A). Typical examples of geo-pressured systems (C) are found in the Northern Gulf of Mexico Basin in the U.S.A., both offshore and onshore. Their exploitation is, however, very limited.

Numerous volcanic geothermal systems are found in the rift zones (E) and the compressive regions (C) of the world, for example in The Pacific Ring of Fire, in countries like New Zealand, The Philippines, Indonesia, Japan, USA and Central and South America and in East Africa, Iceland and Italy. Geothermal systems related to hot spot volcanism (F) are found on Hawaii and the Azores and in Yellowstone and in Iceland.

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UNITED NATIONS UNIVERSITY
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LaGeo S.A. de C.V.

CONCEPTUAL MODELS OF GEOTHERMAL SYSTEMS – INTRODUCTION

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ABSTRACT

The key to the successful exploration, development (incl. drilling) and utilization of any type of geothermal system is a clear definition and understanding of the nature and characteristics of the system in question. This is best achieved through the development of a conceptual model of the system, which is a descriptive or qualitative model incorporating, and unifying, the essential physical features of the system. Conceptual models are mainly based on analysis of geological and geophysical information, temperature and pressure data, information on reservoir properties as well as information on the chemical content of reservoir fluids. Monitoring data reflecting reservoir changes during long-term exploitation, furthermore, aid in revising conceptual models once they become available. Conceptual models should explain the heat source for the reservoir in question and the location of recharge zones, the location of the main flow channels, the general flow patterns within the reservoir as well as reservoir temperature and pressure conditions. A comprehensive conceptual model should, furthermore, provide an estimate of the size of the reservoir involved. Cooperation of the different disciplines involved in geothermal research and development is of particular importance. Conceptual models are an important basis of field development plans, i.e. in selecting locations and targets of wells to be drilled and ultimately the foundation for all geothermal resource assessments, particularly volumetric assessments and geothermal reservoir modelling, used to assess the energy production capacity of a geothermal system. Initially a conceptual model depends mostly on surface exploration data, but once the first wells have been drilled into a system subsurface data come into play, increasing the knowledge on a geothermal system. Most important are feed-zone, temperature-logging and well-test data. Conceptual models should be revised, and improved, continuously throughout the exploration, development and utilization history of a geothermal system, as more data and information become available.

1. INTRODUCTION

Geothermal resources are distributed throughout the Earth's crust with the greatest energy concentration associated with hydrothermal systems in volcanic regions at crustal plate boundaries. Yet exploitable geothermal resources may be found in most countries, either as warm ground-water in sedimentary formations or in deep circulation systems in crystalline rocks. Shallow thermal energy suitable for ground-source heat-pump utilization is available world-wide and attempts are underway at developing enhanced geothermal systems (EGS) in places where limited permeability precludes natural hydrothermal activity. Geothermal systems and reservoirs are classified on the basis of different aspects, such as reservoir temperature or enthalpy, physical state, their nature and geological setting. Steingrímson et al. (2013) and Axelsson (2008a) review these classifications and the distribution of geothermal resources worldwide.

Geothermal springs have been used for bathing, washing and cooking for thousands of years in a number of countries world-wide, e.g. China, Japan and the remnants of the Roman Empire (Cataldi et al., 1999). Yet commercial utilisation of geothermal resources for energy production only started in the early 1900's. Electricity production was initiated in Larderello, Italy, in 1904 and operation of the largest geothermal district heating system in the world in Reykjavik, Iceland, started in 1930. Extensive geothermal heating of greenhouses also started in Hungary in the 1930's. Since this time, utilisation of geothermal resources has increased steadily.

The understanding of the nature of hydrothermal systems didn't really start advancing until their large-scale utilization started during the 20th century. Some studies and development of ideas had of course been on-going during the preceding centuries, but various misconceptions were prevailing (Cataldi et al., 1999). In Iceland, where highly variable geothermal resources are abundant and easily accessible, a breakthrough in the understanding of the nature of geothermal activity occurred during the middle of the 19th century, a breakthrough which was, however, beyond the scientific community at the time (Björnsson, 2005). Increased utilization and greatly improved understanding went hand in hand with geothermal wells becoming the main instrument for geothermal development. This is because geothermal wells enable a drastic increase in the production from any given geothermal system, compared to its natural out-flow, as well as providing access deep into the systems, not otherwise possible, which enables a multitude of direct measurements of conditions at depth.

The key to the successful exploration, development (incl. drilling) and utilization of any type of geothermal system is a clear definition and understanding of the nature and characteristics of the system in question, based on all available information and data. This is best achieved through the development of a ***conceptual model*** of a geothermal system, which is actually the focus of this short course. Conceptual models are descriptive or qualitative models incorporating, and unifying, the essential physical features of the systems in question (Grant and Bixley, 2011). The cooperation of the different disciplines involved in geothermal research and development is of particular importance here, rather than each discipline developing their own models or ideas independently. Conceptual models are an important basis of field development plans, i.e. in selecting locations and targets of wells to be drilled (Axelsson and Franzson, 2012) and ultimately the foundation for all geothermal resource assessments, particularly volumetric assessments and geothermal reservoir modelling (Axelsson, 2013a).

This paper presents an introduction to the development and utilization of conceptual models of geothermal systems, the subject of this short course. Other presentations go into comprehensive detail regarding the data that provide the basis for conceptual models, how they are developed and finally how they are used for siting the different types of wells and as the basis of resource assessments, including the development of models of geothermal systems.

2. WHAT ARE CONCEPTUAL MODELS?

The diverse information and data available on geothermal systems is increasingly being unified through the development of conceptual models of the respective systems. They play a key role in all phases of geothermal exploration and development, e.g. by providing a unified picture of the structure and nature of the system in question. Conceptual models are descriptive or qualitative models, not used for calculations. They are mainly based on geological information, both from surface mapping and analysis of subsurface data, remote sensing data, results of geophysical surveying, information on chemical and isotopic content of fluid in surface manifestations and reservoir fluid samples collected from wells, information on temperature- and pressure conditions based on analysis of available well-logging data as well as other reservoir engineering information. Comprehensive conceptual models of geothermal systems should incorporate the following as far as available information allows:

(1) Provide an estimate of the size of a system, more specifically information on areal extent, thickness and depth range as well as external boundaries (vertical)
(2) Explain the nature of the heat source(s) for a system
(3) Include information on the location and strength of the hot up-flow/recharge zones, including the likely origin of the fluid
(4) Describe the location and strength of colder recharge zones
(5) Define the general flow pattern in a system, both in the natural state and changes in the pattern induced by production
(6) Define the temperature and pressure conditions in a system (i.e. initial thermodynamic conditions through formation temperature and pressure models)
(7) Indicate locations of two-phase zones, as well as steam-dominated zones
(8) Describe locations of main permeable flow structures (faults, fractures, horizontal layers, etc.)
(9) Indicate the location of internal boundaries (vertical and/or horizontal) such as flow barriers
(10) Delineate the cap-rock of the system (horizontal boundaries)
(11) Describe division of system into subsystems, or separate reservoirs, if they exist

Not all geothermal conceptual models incorporate all of the items above, in fact only a few do so. How advanced a conceptual model is depends on the state of development of the system in question. In the early stages knowledge is limited and only information on a few of the items above will naturally be available. When development continues knowledge on the items above increases; first when substantial deep drilling has been conducted and later when large-scale utilization has been on-going for quite some time, with associated monitoring. Fairly comprehensive knowledge on all the items listed has only then become available.

Three examples of visualizations of geothermal conceptual models are presented in Figures 1 – 3. Other examples are available in the geothermal literature, such as a number of examples presented by Grant and Bixley (2011), the conceptual model for the Olkaria geothermal system in Kenya (Axelsson et al., 2013) and the conceptual model for the Hengill geothermal system presented by Franzson et al. (2010). It may also be mentioned that general conceptual models have also been proposed for different types of geothermal systems, capturing their main characteristics, without being as detailed as conceptual models for individual systems (Steingrímsson et al., 2013).

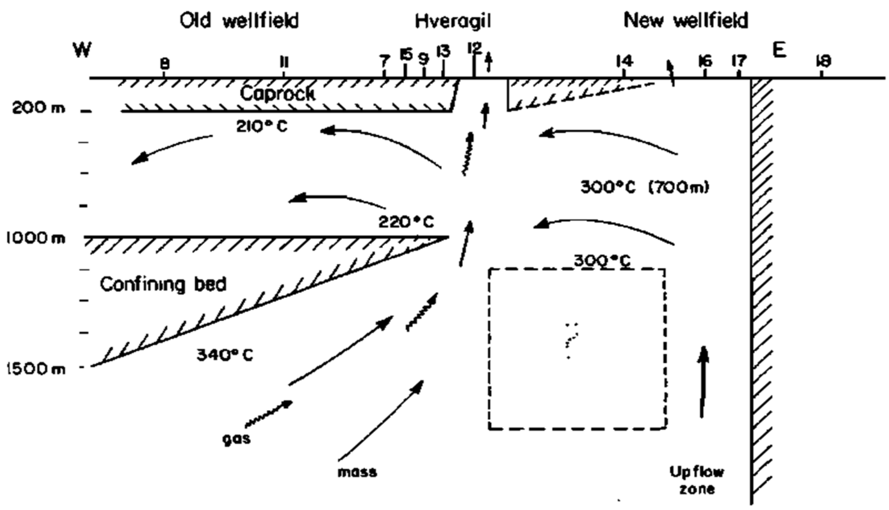

FIGURE 1: A simplified sketch of one of the first conceptual models of the Krafla volcanic geothermal system in N-Iceland (Bödvarsson et al., 1984)

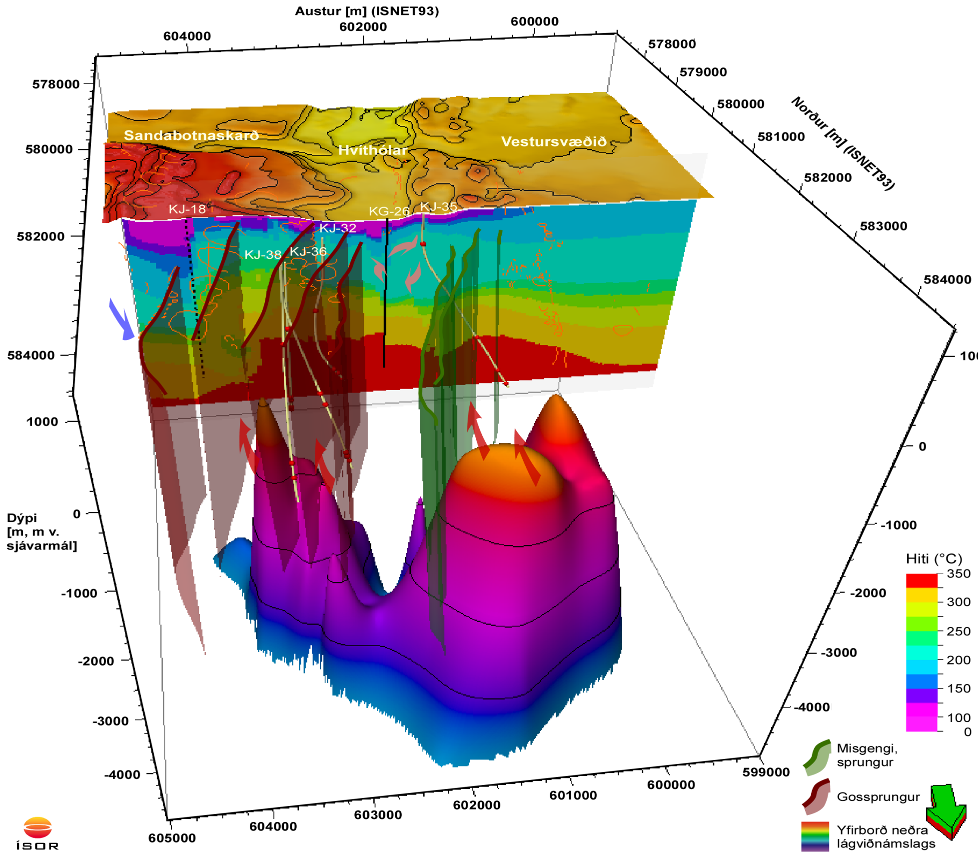

FIGURE 2: A 3-dimensional view of the current (25 years younger than the one in Figure 1) conceptual model of the Krafla geothermal system in N-Iceland (Mortensen et al., 2009) showing a deep-seated low-resistivity anomaly reflecting a magma chamber, faults and eruption fissures as well as temperature conditions and inferred flow directions

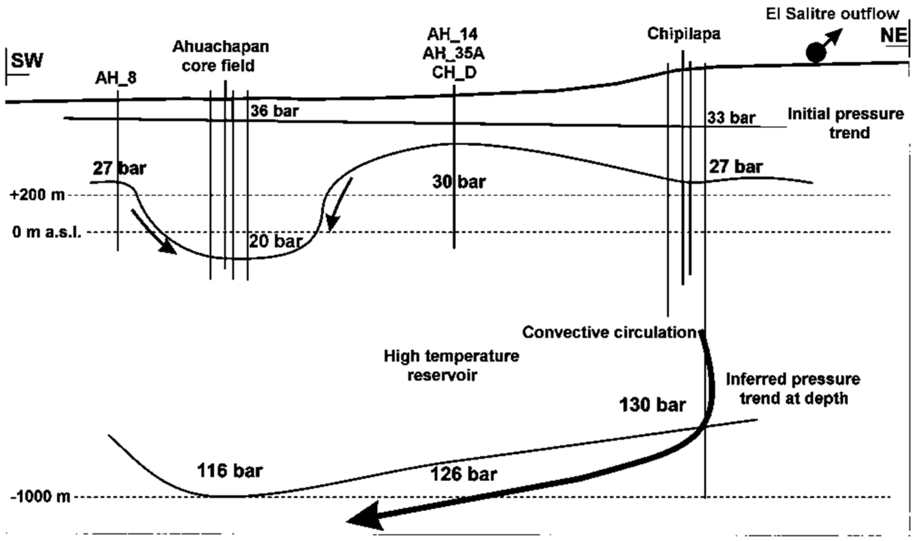

FIGURE 3: A simplified sketch of the Ahuachapan geothermal system in El Salvador (Monterrosa and Montalvo, 2010)

3. DEVELOPING CONCEPTUAL MODELS

Geothermal exploration and exploitation is a multidisciplinary science, starting with surface exploration followed by collection of drill-hole data and finally reservoir engineering modelling studies and utilization monitoring. Each discipline looks at the geothermal system from a certain viewpoint, having a tendency to define the geothermal system from that perspective. That is why developing a conceptual model is quite beneficial, as it unifies the different viewpoints. In order to create the most comprehensive geothermal conceptual model all the disciplines have to be incorporated, but essentially the focus is on geological structures, permeability, temperature and pressure conditions as well as fluid chemistry.

When developing conceptual models the focus should be placed on the following data / information:

- Surface geological and structural maps and other related information. Particular emphasis should be placed on information on fractures, faults and the general tectonic setting (including crustal stress conditions at the location in question). Aerial photos and other remote sensing data should also be considered, if available.
- Borehole information including location and design.
- Borehole geological data including geological cross sections and information on zones of circulation losses.
- Information on porosity of different formations, as far as available.
- Data on borehole alteration mineralogy.
- Surface geophysical data including gravity data, magnetic data and resistivity data. Emphasis should be placed on available interpretations of such data.
- Seismic data, including information on regional seismicity, micro-earthquake data and seismic survey data (seldom available), as well as relevant interpretations.
- Information on temperature and pressure conditions in the geothermal system from well-logging data. Also initial temperature- and pressure-models, if available.
- Information on feed-zone locations based on circulation losses, temperature and pressure logs, as well as spinner logs, if available.
- Pressure transient data, both from short-term well-tests and longer-term interference tests, along with available interpretation results.
- Available information on the chemical composition and gas content of reservoir fluid, including isotope data, e.g. based on samples from surface manifestations.
- Detailed well-by-well information on mass production history.
- Detailed well-by-well information on reinjection history.
- Monitoring data including information on reservoir pressure changes (preferably from monitoring wells) and reservoir temperature changes as well as changes in well-head pressure, well enthalpy, chemical content and gas content.
- Reinjection test data, tracer test data and reinjection monitoring data.
- Surface monitoring data such as geodetic measurements (e.g. surface subsidence data) and results of repeated micro-gravity surveying.
- Hydrogeological information on the whole geothermal region, including available hydrogeological models incorporating ideas on regional flow, recharge and boundaries.
- All relevant previous studies, in particular studies presenting conceptual models, resource assessments, modelling work and chemical studies.

The relevant data and corresponding interpretation results, for the different disciplines involved in geothermal research and development, are described in various presentations at the present short course as well as how these data and results are combined in a unified conceptual model (Mortensen and Axelsson (2013). Cumming (2009) discusses the development of conceptual models on basis of surface exploration data in particular. Specific examples of interpretation results incorporated into the relevant conceptual models are presented in Figures 4 – 6 below.

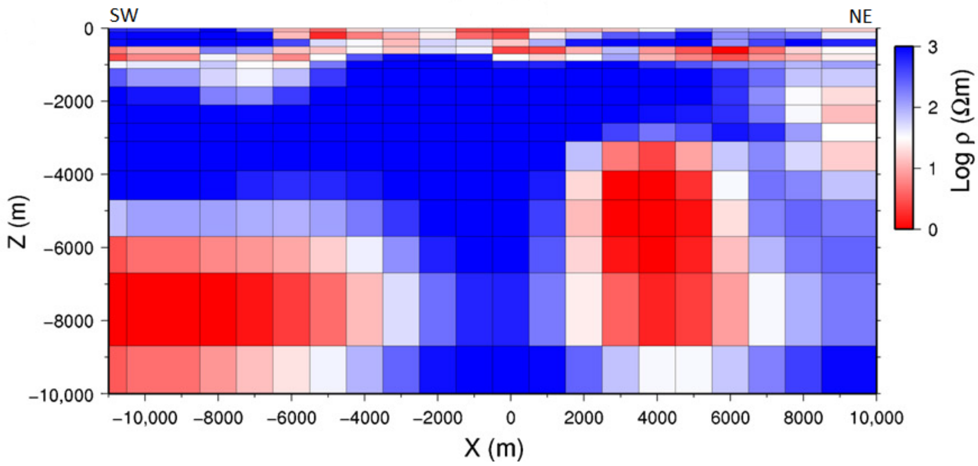

FIGURE 4: Resistivity distribution in a NE-SW cross-section through a 3-D resistivity model of the Hengill geothermal region in SW-Iceland, extending down to 10 km depth (from Árnason et al., 2010)

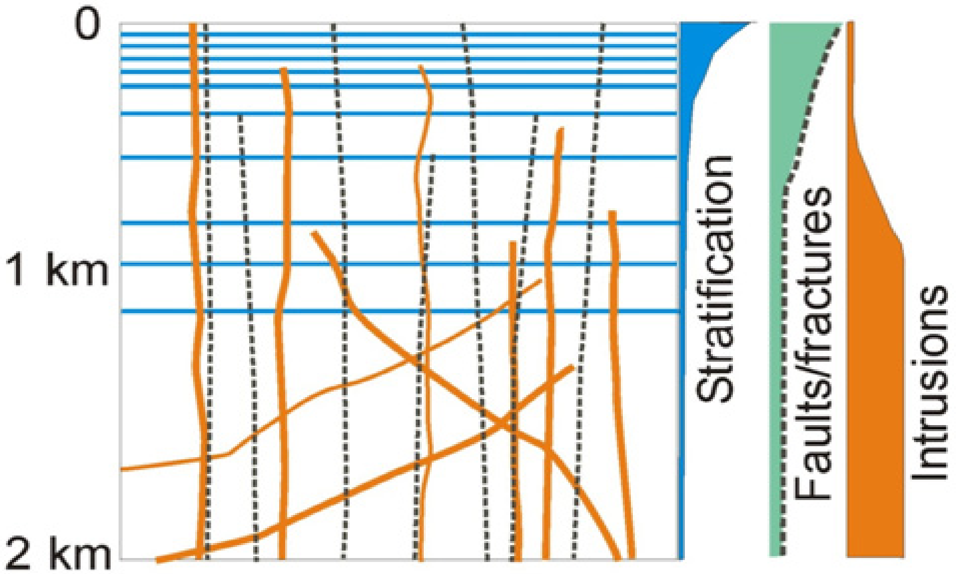

FIGURE 5: A schematic figure showing how the importance of permeability associated with different geological structures varies typically with depth in volcanic geothermal systems in Iceland (from Axelsson and Franzson, 2012). The best permeability is often found at the intersection of two such structures

It may be mentioned that three-dimensional visualization software is increasingly being used to visualize, merge and jointly interpret various types of geothermal research data, as great advances have been made recently in computer software intended for this purpose. The PETREL software package, developed by Schlumberger Ltd. (initially for the petroleum industry), is e.g. used to some extent by the geothermal business.

Initially conceptual models depend mostly on surface exploration data, with geological (e.g. faults /fractures) and geophysical (e.g. resistivity) data being most important. Formation temperature is e.g. unknown at such an early stage. The only indications of reservoir temperature at that stage come from chemical investigations. Once the first wells have been drilled, however, subsurface data come into play, increasing drastically the knowledge on, and understanding of, a geothermal system. Most important are lithological and feed-zone data, temperature-logging data and well-test data. Some of the logging and reservoir engineering data collection in geothermal wells is described in other presentations at this short course (see also Axelsson and Steingrímsson, 2012). Thus a conceptual model of a geothermal system relies more and more on subsurface data as development progresses.

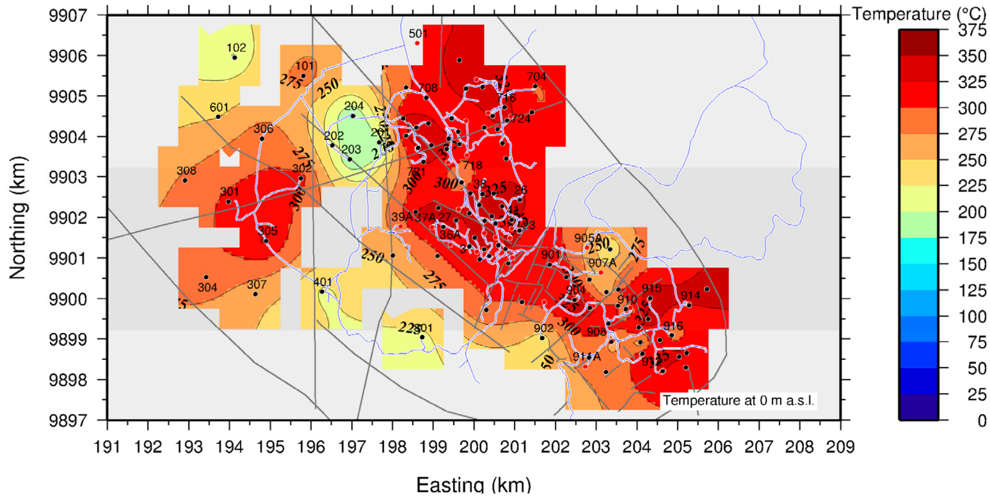

FIGURE 6: Horizontal view of the temperature distribution at 0 m a.s.l. (~2000 m depth) in a temperature model of the Olkaria geothermal system in Kenya (Axelsson et al., 2013)

Once the drilling of a geothermal well has been completed the results, or data collected from the well, should be compared with the interpretation of surface exploration data, i.e. with what was expected. Based on this comparison the conceptual model of the geothermal system should be updated, e.g. to ensure that the next well siting will be based on the most up-to-date information and understanding.

4. EMPLOYING CONCEPTUAL MODELS

Conceptual models of geothermal systems play two main roles in geothermal development and utilization management, as already stated; firstly as the basis of field development plans, in particular in terms of well siting, and secondly as the basis of resource assessments and modelling studies. These two roles will be reviewed briefly below. The importance of revising geothermal conceptual models on a regular basis is also discussed.

4.1 Field development / well siting

Geothermal field development plans are plans describing how a geothermal field should be developed for utilization; including the generation capacity to aim for, well drilling plans (drilling targets, well number and well locations) and reinjection strategies. These are based on conceptual models in two ways:

(1) Indirectly through energy production capacity estimates based on the results of the models used for capacity assessment, which are in turn based on available conceptual models. This also involves the number of wells as well as the appropriate distance between wells, both production and reinjection wells.

(2) Directly by using a conceptual model to delineate both general and specific well drilling targets. This applies to all type of geothermal wells, exploration, production, step-out, make-up, reinjection and monitoring wells. Conceptual models also provide the basis for reinjection strategies during long-term utilization and management.

Axelsson and Franzson (2012) discuss well siting in more detail, as well as reviewing the different types of geothermal wells.

The principal geothermal drilling targets (for production wells) are in fact structures, or volumes, of adequate permeability and sufficiently high temperature to yield adequately productive wells. The nature of the permeability depends on the type of geothermal system concerned, being controlled by the geology involved (formations, faults/fractures, etc.) and in-situ stress conditions reflected by the nature of local seismic activity. Temperature conditions may be indirectly inferred from resistivity surveying and concentration of chemical components or measured directly through wells. The permeability structure of a geothermal system is usually quite complex and usually not well defined until a certain number of wells has been drilled into a geothermal system. Once this structure becomes well known and clearly defined drilling success usually peaks. Figure 5 above shows e.g. a schematic figure of the geological structures most often controlling permeability in Icelandic geothermal systems as well as how their relative importance changes with depth. It should be pointed out that experience has shown that the best permeability is often found at the intersection of two or more such geological structures.

Targets for reinjection wells are not fully comparable to the targets of production wells. This applies in particular to temperature conditions as reinjection is not always applied directly in the hottest parts of a geothermal reservoir or system (Axelsson, 2012). In fact reinjection sectors selected are quite variable from one area to another with the reinjection targets therefore being quite different. Sufficient permeability is, of course, also a necessary requirement for successful reinjection wells. A research method particular to reinjection studies is tracer testing, which is used to study connections between reinjection and production wells and to estimate the danger of production well cooling because of reinjection (Axelsson, 2012 and 2013b).

4.2 Geothermal resource assessments / modelling

Conceptual models of geothermal systems also provide an essential basis for the development of all reliable models of geothermal systems (Axelsson, 2013a). This applies to a varying degree to the different kinds of models, ranging from static volumetric models to dynamic models such as simple analytical models, lumped parameter models and detailed numerical reservoir models. This was emphasised as early as by Bödvarsson et al. (1986) in their treatise on numerical modelling of geothermal systems. Axelsson (2013) and Sarmiento et al. (2013) review the different geothermal modelling, or assessment, methods in later presentations at this short course.

The volumetric assessment method involves estimating the total energy content (both that of the solid rock and energy content of water stored in pores and fractures) in a geothermal system and consequently estimating how much of that can be extracted (i.e. recovery factor) and used over a specific time-period. The principal input parameters for this are the size (i.e. surface area and thickness) of the system in question and temperature conditions in the system. These are clearly derived from a corresponding conceptual model. Other parameters, such as rock porosity, physical and thermal properties of the reservoir rocks and water at reservoir conditions, are only of secondary importance, however, regarding the outcome of a volumetric assessment. In addition the recovery factor depends on the nature of the system; permeability, porosity, significance of fractures and recharge, all of which hinges on the corresponding conceptual model. The recovery factor also depends on the mode of production, i.e. whether reinjection is applied as well as being to some extent dependent on time. Figure 7 shows an example of the outcome of a volumetric resource assessment for the Hengill geothermal region in SW-Iceland, in which the Monte Carlo method was used by assigning probability distributions to the different parameters involved and consequently estimate the system potential with probability, enabling incorporation of overall uncertainty in the results (see Sarmiento et al., 2013).

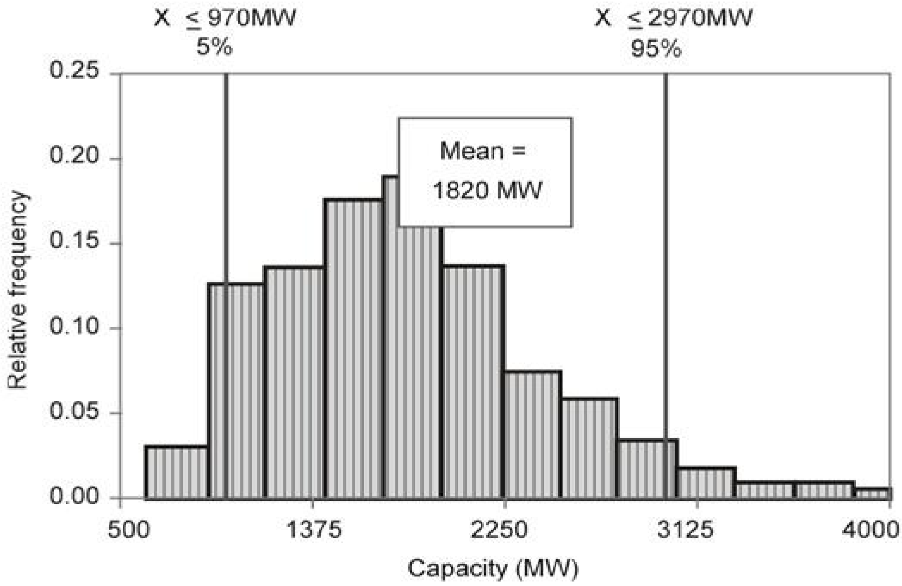

FIGURE 7: An example of the results of a volumetric resource assessment for the greater Hengill geothermal region in SW-Iceland. The Monte Carlo method was applied in the assessment (Sarmiento and Björnsson, 2007)

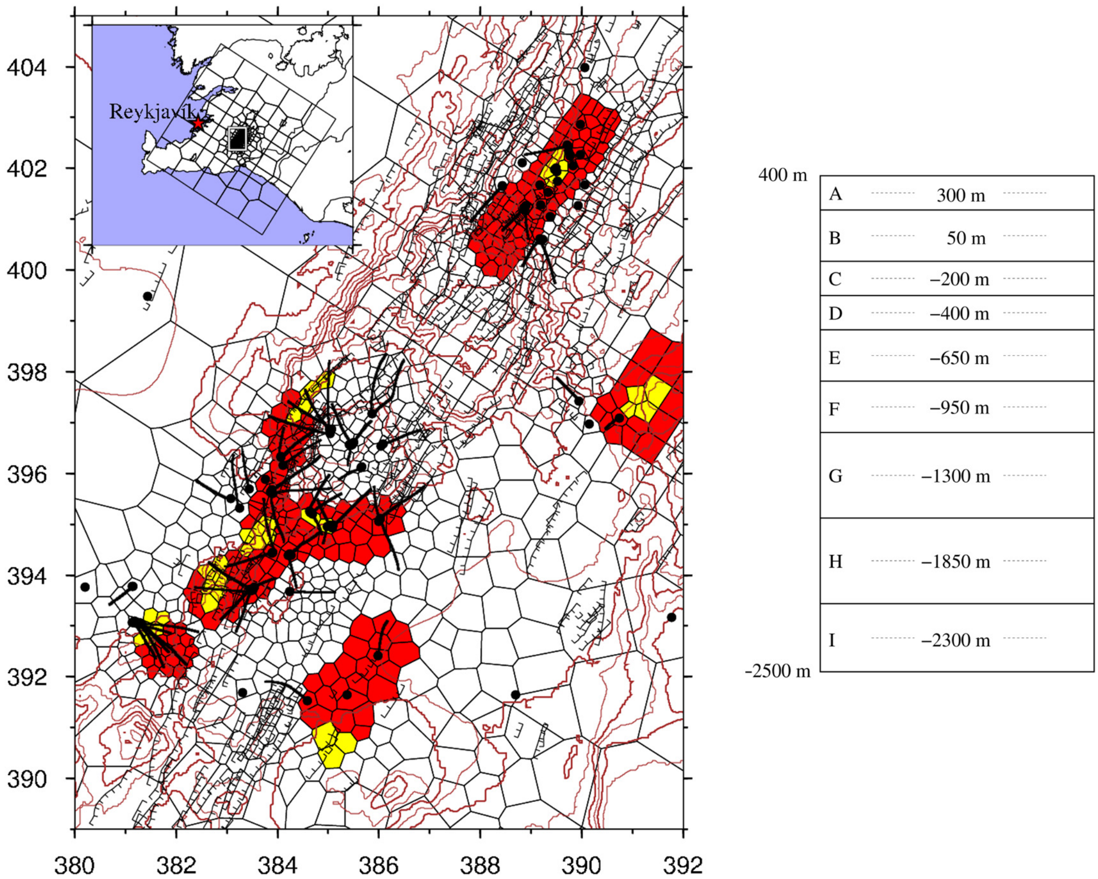

FIGURE 8: The numerical grid of detailed numerical model of the Hengill geothermal region in SW-Iceland (see insert top left), horizontal grid on the left and vertical stratification on the right in m a.s.l. (Gunnarsson et al., 2010). The coloured areas show the elements where heat is introduced into the bottom of the model, with the yellow ones indicating hot fluid recharge

Detailed numerical modelling of geothermal systems is the most comprehensive and accurate geothermal modelling method, provided comprehensive and correct data are available to calibrate the models. Such models rely heavily on corresponding conceptual models, principally in designing the numerical grid of a model, setting up the relative distribution of permeability, defining boundary conditions and setting up heat sources, all of which is incorporated before actual calibration of a numerical model is performed. The corresponding temperature and pressure model are also kept in mind when a numerical model is set up, while these data are also the principal data used to calibrate the numerical model (the natural state) along with well-test and physical monitoring data (production state). Figure 8 shows an example of the grid of a numerical model of the Hengill geothermal system in SW-Iceland, along with the distribution of heat sources.

Finally it should be mentioned that the conceptual models of geothermal systems should be kept in mind when selecting a simple analytical model of a geothermal system (Axelsson, 2013), even though such a model constitutes a drastically simplified version of the real system. The converse applies to lumped parameter models, which in fact ignore the geometry of a geothermal system. The results of lumped parameter modelling can be used, however, as supporting information for conceptual model development.

4.3 Revising conceptual models

Once a conceptual model of a geothermal system has been developed it isn't a stationary entity, as it should be revised and updated continuously as new, relevant information becomes available. This is essential so as to keep them up-to-date and to incorporate data which may lead to significant changes in the model. This applies e.g. to when new surface exploration data, new well data (even from a single well) or monitoring data become available. An example of such revisions over a long period (~3 decades) is presented by Axelsson et al. (2013) at the present workshop. The most important aspects / steps of conceptual model revision are:

a) Incorporation of new surface exploration data (geological, geophysical and / or chemical), not available for previous model developments. Such data and their interpretation are discussed in several presentations at this short course.
b) Incorporation of well data from newly drilled wells, e.g. on lithology, alteration and feed-zone locations; also discussed in other presentations.
c) Upgrading of temperature and pressure models on basis of formation temperature and pressure profiles estimated for new wells (see later presentations).
d) Incorporation of results of production response monitoring (Monterrosa and Axelsson, 2013); e.g. well-output data (mass-flow and enthalpy changes), reservoir pressure and temperature change data and data on changes in chemical content. These results, which usually don't become available until long-term utilization has started, may comprise essential information on boundary conditions, recharge characteristics, permeability structure, etc.
e) Indirect monitoring, such as repeated micro-gravity and surface deformation surveying as well as monitoring of micro-seismic activity, may also provide invaluable information on the nature of geothermal systems and their recharge.

The results of geothermal system modelling (see above) may, moreover, provide input into the development, or revision, of conceptual models of geothermal systems, or lead to changes therein, e.g. if the modelling indicates discrepancies between what appears to be physically acceptable and the conceptual model.

5. CONCLUSIONS AND RECOMMENDATIONS

This paper presents an introduction to the development and utilization of conceptual models of geothermal systems, the subject of this short course. A good conceptual model provides a clear understanding of the nature and characteristics of the system in question, and unifies the essential physical features of the system, which is the key to its successful exploration, development (incl. drilling) and utilization. The paper has reviewed the variable data and information conceptual models are based on, but it should be emphasised that monitoring data, reflecting reservoir changes during long-term exploitation, can be extremely useful in revising conceptual models once they become available (often overlooked). Cooperation of the different disciplines involved in geothermal research and development is of particular importance when conceptual models are developed, as well as being one of the benefits of their development.

Conceptual models are an important basis of field development plans, i.e. in selecting locations and targets of wells to be drilled and ultimately the foundation for all geothermal resource assessments, particularly volumetric assessments and geothermal reservoir modelling, used to assess the energy production capacity of a geothermal system. Initially a conceptual model depends mostly on surface exploration data, but once the first wells have been drilled into a system subsurface data come into play, increasing the knowledge on a geothermal system. Most important are feed-zone, temperature-logging and well-test data. Conceptual models should be revised, and improved, continuously throughout the exploration, development and utilization history of a geothermal system, as more data and information become available.

Conceptual models are qualitative and, hence, not used for calculations. But the results of geothermal system modelling may provide input into the development, or revision, of conceptual models of geothermal systems, or lead to changes therein, e.g. if the modelling indicates discrepancies between what appears to be physically acceptable during calibration of a numerical model and the conceptual model itself.

ACKNOWLEDGEMENTS

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CASE HISTORY OF LOS AZUFRES – CONCEPTUAL MODELLING IN A MEXICAN GEOTHERMAL FIELD

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ABSTRACT

The conceptual model provides a descriptive representation of a geothermal system, based on geological, geophysical and geochemical information and the analysis of data and measurements made in the drilled wells in order to define the main reservoir characteristics such as shape, limits, dimensions, probable recharge and discharge areas and temperature and pressure distribution.

In this paper, the conceptual model of Los Azufres geothermal wells is presented. This geothermal field is a complex formed by extruding a series of lavas with an extension of 20 km^2, of basaltic and acidic quaternary age composition on a basement of tertiary andesitic composition. The unit Mil Cumbres andesite is the one that contains the reservoir while the unit Agua Fria rhyolite operates locally as a cap rock. The hydrothermal alteration is typical of a high-temperature geothermal system. Faulting has occurred along three principal trends NW-SE, NE-SW and the youngest E-W. The chemical composition of the fluid is sodium chloride type. The fluid seem to flow vertical with limited lateral movement, a high resistivity rock body existing at the central of the field, separates the geothermal reservoir as the north and the south sectors. The production zones of the wells in most of the cases are located to intercept a zone associated with a permeable structure. The thermodynamic state is conceptualized as a reservoir with three different areas, the deepest one composed of compress liquid, the middle one of two phases layer of liquid dominated reservoir and the shallow one of two phases steam dominated reservoir.

1. INTRODUCTION

Conceptual models are based on the integration of data from different disciplines to explain in our case a geothermal reservoir, in other words is a descriptive representation of a geothermal system based on the geological, geophysical and geochemical surface and data analysis and measurements made in boreholes.

The considerable amount of investigation that has been conducted in the Los Azufres field, combined with the extensive information available from the large number of wells drilled, has allowed a reliable model of the geothermal reservoir to be developed in order to create a numerical model. This conceptual model is described and discussed in the sections that follow.

1.1 The Los Azufres geothermal field

Los Azufres geothermal system is located in the State of Michoacán to 80 km east of the city of Morelia and 16 km northwest of Ciudad Hidalgo, this geothermal field was explored in the mid 70 and since 1982 it has been in development, in the natural state was classified as conventional liquid-dominated high temperature system but during the long term of exploitation several thermodynamic studies have shown that the reservoir has three zones: dominant vapour in the upper reservoir, liquid saturation in the middle and liquid compressed in the bottom part of the reservoir. This field is located at an altitude above sea level ranging from 2500 to 3000 m, surrounded by valleys.

At the present time Los Azufres geothermal field have 43 production wells, 6 injections wells producing 14.7 million tonnes of vapour and generating 185 MW from 1 condensing unit of 50 MW, 4 condensing units of 25 MW each, 7 back-pressure units of 5 Mw each. In the present time there is under construction one 50 MW condensing unit in the northern part of the field that will replace 4 unit of 5 MW for a total electric generation of 215 MW.

1.2 Previous work

Several geological, geochemical and geophysical studies have been conducted since 1975, being in 1984 when the first geothermal conceptual model of the field was prepared, revealing the volume, reserves and reservoir boundaries, based on the above studies and complementary data produced from wells drilled to date (De la Cruz, 1984). In February 1987, new exploration data was available and an update of the conceptual model was done (Lira, H., 1987), in this work, configurations of isotherms were performed every 50 °C from the 150 °C to 300 °C, for elevations of 500 masl to 2500 masl, from the interpolation and extrapolation of the stabilized temperatures of 52 wells. Also, the configuration of the top of the epidote was conducted in the same levels as the isotherms, taking into account the 10% lower limit of the presence of epidote. And finally, the boundaries of the reservoir were defined taking into account the isotherm of 225 °C, the minimum resistive of geothermal interest, epidote settings and production wells.

Another redefinition of the conceptual mode was made in 1996 but only in the northern-east part of the field (Flores, et, al., 1996), while the conceptual model of the south part was made in 1997 and it mentioned that the reservoir is made up of three lithological units (andesite, dacite and rhyolite), rhyolite is functioning as a caprock, also mention that the production zone in most cases appears to intersect one permeable zone associated to the E-W structure or a influence zone between the interval from the top of the epidote and amphibole. It should be clear that the overall thickness was calculated by averaging the calculation from the correlation of the obtained permeable zones and the difference between the top of the amphibole and epidote. In addition it is mentioned that the fluid is spread vertically through faults and the direction of the preferential fluid flow is NW-SE according to plan distribution of total gas, ratio of CO_2/H_2S, isotopy, pressure and temperature.

In 2003 CFE hired the services of GeothermEx, Inc. to update the conceptual and numerical model of the geothermal field of Los Azufres and in 2007 West Japan Engineering Consultants, Inc. (West JEC) and Japan Bank for International Cooperation (JBIC) reinterpret the conceptual model in the feasibility study of the Los Azufres III geothermal energy expansion project which is the most recently reinterpretation of the model with no big changes from the last one.

2. SURFACE MANIFESTATIONS

The Los Azufres field extends over a considerable area (in excess of 20 km2) in the highland area east of Morelia in the state of Michoacán, within the Mexican Volcanic Belt. Manifestations of geothermal activity are distributed widely within and around the highlands (Figure 1); however, the principal manifestations are clustered within the field itself, and particularly within the areas that deep drilling has revealed to be the northern and southern sectors of the productive geothermal field.

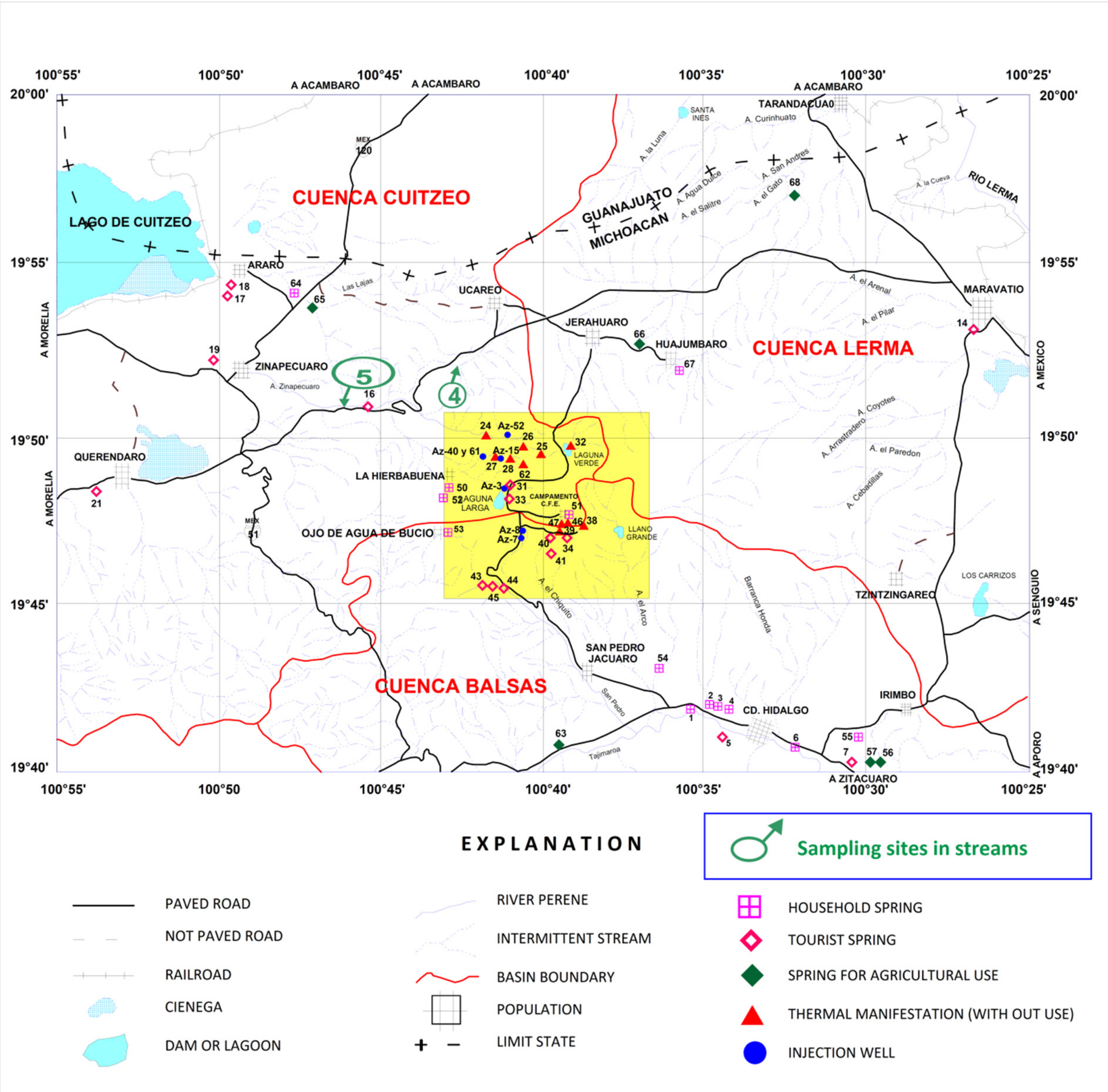


FIGURE 1: Location of the Los Azufres geothermal field and the surface manifestation

The majority of the thermal manifestations are described as hot springs of acid-sulfate composition, with pH lower than 4.0, and often with temperatures near boiling (Tello and Suárez, 2000). The composition of the waters indicates an origin for these springs from steam boiled from the geothermal reservoir, which has then mixed with oxidizing groundwater to form the acidic discharge. This is a common phenomenon in high-temperature, volcanic-hosted geothermal systems located in mountainous terrain.

Some springs located around the periphery of the field are of sodium chloride type, indicating a more direct discharge of liquid water from the reservoir to the surface. Still other springs are of sodium bicarbonate type, with low geothermometer temperatures, indicating a significant degree of mixing with cooler waters or other interaction with the shallow environment. Again, these types of manifestations are typical of volcanic-hosted geothermal systems in which the reservoir fluid is fundamentally neutral sodium-chloride water.

Many, though not all, of the superficial manifestations are located along the mapped traces of major faults that transect the field. Leakage of steam and water from the geothermal reservoir toward the surface may occur principally along faults, but the surface locations could be controlled by a combination of structure and lithostratigraphy (permeable volcanic formations), with the interaction of the two creating a complex arrangement of thermal discharges. The manifestations provide a certain amount of evidence regarding patterns of flow within and from the geothermal reservoir; this is discussed further in subsequent sections (GeothermEx, 2003).

3. GEOLOGY

The geology of the Los Azufres field has been studied in exhaustive detail, both by means of geologic mapping and other studies conducted at the surface, and by analysis of drill cuttings, cores and other data from the numerous deep wells in the field. This section summarizes the geologic characteristics of the field that are pertinent to the development of a reliable numerical model.

3.1 Stratigraphy

Los Azufres geothermal field is one of several Pleistocene silicic volcanic zones with geothermal systems in the Trans Mexican Volcanic Belt (TMVB). The volcanic rocks in Los Azufres geothermal field are mainly divided into four principal units.

Mil Cumbres Andesitic Unit – This unit occurs throughout the field, and is the thickest unit of an average of 2700 m, accounting for all of the reservoir rocks and extending below sea level. This volcanic sequence comprising andesitic rocks with some paleo-soil layers, basaltic rocks and volcanic agglomerates of 18 to 1.0 My age forms local basement in the field.

Agua Fría Rhyolite Unit – This unit is a silicic sequence up to 1,000 m thick and overlies the Mil Cumbres Unit, and consists mainly of a spherulitic rhyolite lava with ages between 1 and 0.15 My. It is present at shallow levels, often outcropping, and is found mainly in the southern and central part of the field.

Dacita Tejamaniles – These young lavas occur locally in the southern sector of the field, and overlie the Agua Fría Ryolite.

Tuff (pumice flow deposits) – This unit is considered to include a variety of young, superficial pyroclastics deposits, which have originated from relatively young volcanic activity in the vicinity of the field.

3.2 Structure

Faulting in the Los Azufres field has occurred along three principal trends. From youngest to oldest, these trends are NW (or NNW)-SSE, NE-SW, and E-W. All three trends are represented by major faults that have been mapped within or near the field. The E-W trend appears to be the most significant, exerting a strong influence on the geomorphological characteristics of the area, as well as on certain characteristics of the geothermal system. Most of the fault systems consist mainly of normal faults with steeply dipping.

The fault system in the south sector with E-W trending are San Alejo, Agua Fría, Puentecillas, Tejamaniles, Los Azufres y El Chinapo faults and in the north sector are Laguna Larga, El Chino, Espinazo del Diablo, Coyotes, Maritato y La Cumbre faults. This last two faults have left-lateral strike-slip, which accompanies en echelon segments. The NE-SW trending faults in the south are El Vampiro, El Viejon and Agua Ceniza faults and the ones that occur in the north are Nopalito and

Dorado faults. And The NNW-SSE trending faults (La Presa, Laguna Verde and Río Agrio) are located in the north zone (Figure 2).

Concealed NNW-SSE trending fault is supposed to exist in the field, which probably extends to the basement rocks, based on topographical analysis and geophysical data analysis. Topographic features of NNW-SSE trending fractures are highly dissected and are cut by E-W trending faults system. The NNW-SSE trending fractures, therefore, are supposed to be older systems compared with those of E-W trending faults systems (West JEC, 2007).

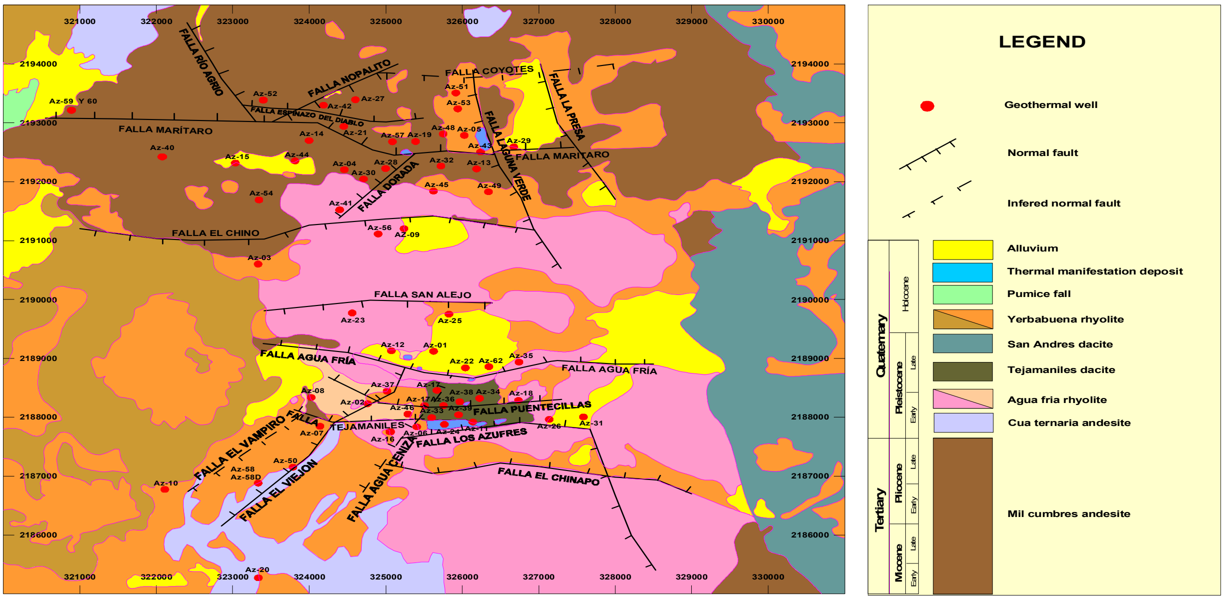


FIGURE 2: Surface geology and fault location of Los Azufres geothermal field

3.3 Hydrothermal alteration

Hydrothermal alteration in the Los Azufres field is fairly typical for a high-temperature, volcanic-hosted geothermal system (Figure 3). Secondary minerals observed in drill cuttings include clay minerals, calcite, chlorite, pyrite, quartz, epidote, hematite and other oxides, and hydrothermal amphibole. Several zones of different hydrothermal mineral assemblages have been identified; these are distinguished principally on the basis of the first appearance (as a function of depth in the well) of epidote and hydrothermal amphibole. The appearance of epidote has been found to correlate with formation temperatures of about 250°C, whereas the first appearance of amphibole tends to coincide with temperatures near 300°C. The surface of first appearance of epidote has also been correlated with the top of the productive reservoir zone, while the first appearance of amphibole has been inferred to correspond with the base of the productive reservoir.

3.4 Impermeable zone and cap rock

One of the important elements of the geothermal reservoir is the cap rock which prevents cold groundwater from invading into the high temperature reservoir. In the depths shallower than 500 – 700 m, clay alterated minerals such as smectite, zeolite and chlorite are identified in geological analysis of production wells. Arigillic alteration zone consists of kaolinite, alunite, sulfer and quartz are also identified. In general, clay mineral such as smectite and zeolite are formed under the circumstances below the temperatures ranging approximately 70 to 200 °C. Therefore, it is considered that the formation at the depths shallower than 500 – 700 m acts as a cap rock of the geothermal system due to clay alterations that are generally impermeable.

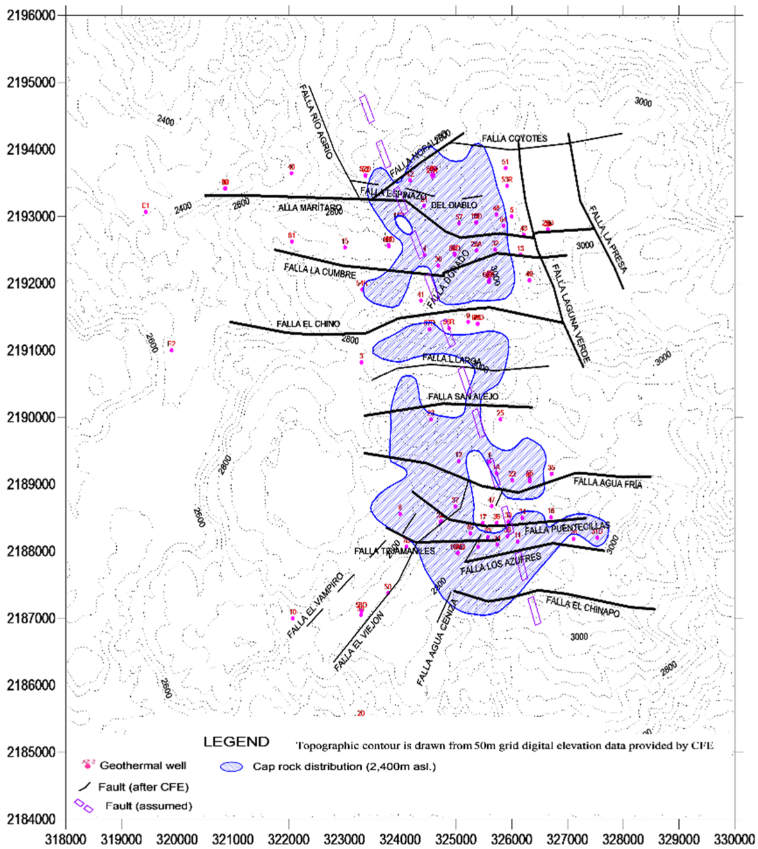


FIGURE 3: Cap rock distribution map (2,450 masl)

The upper limit of the cap rock in the north sector is probably shallower than that of the south sector. At depths of 2,400 – 2,600 masl the cap rock is widely developed in the main productive zone in both the north and the south sectors. Around the wells Az-41 to Az-9 in the north sector, the depth of the lower limit of cap rock is relatively shallow as well as the depth of the upper limit of epidote. This facts indicate that higher temperature zone may exist at shallower depths and an up-flow zone of geothermal fluids may also be formed around there. In the south sector, the depth of lower limit of cap rock deepens toward the west. This indicates that the subsurface temperature decreases toward the west.

In the south sector, the distribution of the cap rock disappears around El Chinapo at the south. In the north sector, the distribution of the cap rock disappears around the Laguna Verde fault at the east, and around both the Coyotes and the Nopalito faults at the north. In the Central zone the cap rock is relatively weak as well as the subsurface manifestations. This limitations seem to represent the distribution of the geothermal system in the field.

4. GEOCHEMESTRY

The geochemistry of the Los Azufres system has been interpreted from analyses of numerous samples of fluids (water and steam) from the various deep wells in the field, as well as analyses of discharges from surface manifestations.

4.1 Fluid characteristics

The water and steam from all the wells in The Los Azufres are of neutral sodium-chloride composition typical of geothermal fluids in the world. So far, it hasn´t been reported acidic waters in the reservoir. Chloride is dominant among major anions and although these vary considerably from one well to another, the water concentrations separated at atmospheric pressure is around 2,500 – 4,000 ppm at the initial stage of exploitation. This reflect in part the variable distribution of phases within the reservoir, particularly in the southern sector.

In the case of the non-condensable gas (NCG) the concentration in reservoir liquid may be as low as 1% by weight or less, while NCG concentrations in the steam phase range between 2% and 8% by weight (Suarez, et al., 2000). Carbon dioxide (CO_2) is the main component of NCG and its content is over 90 mole% in NCG at most wells. Other NCG that are measured but in lower concentrations are H_2S (0.5 – 18 mole%), N_2, NH_3, H_2, CH_4, Ar and He. Gas concentrations in the southern sector have always been larger than in the north sector. It should be mentioned that the chemical geothermometry of waters produced from the reservoir zone is generally consistent with temperatures interpreted from measured downhole temperature profiles, with maximum geothermometer temperatures well in excess of 300°C.

4.2 Origin of the fluid

At the beginning of the project (1980 – 1987) measurements of isotopic composition of the fluid from the wells indicate a combination of process water – rock interaction and admixing of magmatic water (including the andesitic water) with meteoric water. The meteoric water that is main constituent of reservoir fluid is believed to be fossil meteoric water infiltrated into subsurface during pre-historic time.

One of the important characteristics of the well fluids in Los Azufres is that show high concentrations of boron in comparison to other geothermal fields, this could be interpreted by the interaction of deep fluid with sedimentary rock with a high content of boron. And although none of the wells intercepted sedimentary rock (including the well Az-44 which is the deepest with 3,500 m), the regional basement at Los Azufres is built up by metamorphosed sediments. Relatively high NH_3 content up to 3.5 mole% in NCG of the well steams also indicates the contribution of sedimentary rocks to the reservoir fluids.

4.3 Fluid flow pattern

The parental fluid is found at a great depth within or over the metamorphic and sedimentary basement rocks and even though no one knows for sure what geologic structure controls the flow of fluid, but there are tectonic history that suggest that high permeable zones associated with faults control fluid flow. The NNW-SSE trending faults assumed by geological and geophysical data is one possibility for controlling the northwestward regional fluid flow of parental fluid at deeper depth.

The parental fluid ascends through the high permeable zones developed along the faults and stored in andesitic rocks. The high resistivity rock body existing at the central part of the field, separates the geothermal reservoir as the north and south sectors (Figure 4). The main direction of movement of the flow in both areas at intermediate depths appears to be vertical with very limited lateral movement. The ascending hot fluid yield convective circulation systems beneath the cap rock in both sectors. The fluids reaching shallower part of the reservoir boil and provide two–phases or vapor dominated reservoir. This is more significant in the south sector than in the north. Partial steam condensation at the shallowest part of the reservoir in the south sector yields gas rich zones.

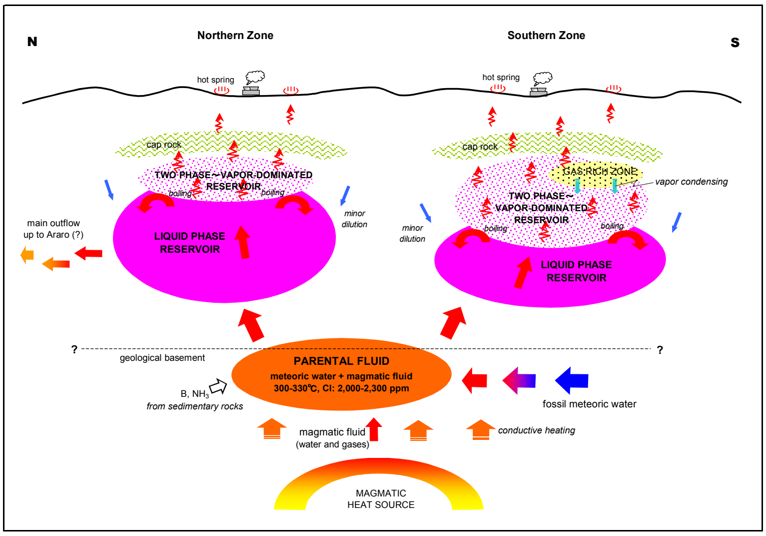


FIGURE 4: Fluid flow model of Los Azufres reservoir

Outflows are limited compared with many geothermal systems, however we can consider the Araro hydrothermal system is a part of outflow from Los Azufres system even though is 20 km NW away. Also another important outflow can be located in the SW in the north sector of the field; nevertheless, it could be present other unidentified flows.

5. GEOPHYSICS

In Los Azufres there have been various geophysical studies such as gravimetry, magnetometry, passive seismic and geoelectrical prospecting, including vertical electric soundings (VES) and a magnetotelluric survey of part of the field. Of these methods, the geoelectrical survey have been of the most direct use for delineating the productive geothermal field.

Maps of apparent resistivity for progressive electrode spacing show that, in the shallow part of the field, zones of low resistivity are concentrated within the central part of the northern and southern sectors of the field and a high resistivity in the central part of the field (Figure 5). With increasing depth, these zone expand outward, forming a more generalized conductive layer joining both sectors of the field. This is a very common pattern, which most often reflects the distribution of conductive hydrothermal minerals near and above the top of the reservoir zone. In general there is a good correlation between the position of the low resistivity zone and the position of the geothermal reservoir, confirmed by drilling.

The distribution of the low resistivity zone has been used as a means of delineating the extent of the geothermal reservoir, however, the use of low resistivity cutoff to delineate the reservoir at deeper levels therefore runs a risk of overestimating the area of the reservoir. Once a field has been drilled as extensively as Los Azufres, the distribution of observed temperature and well productivity is likely to be a more reliable guide to the extent of the productive geothermal reservoir.

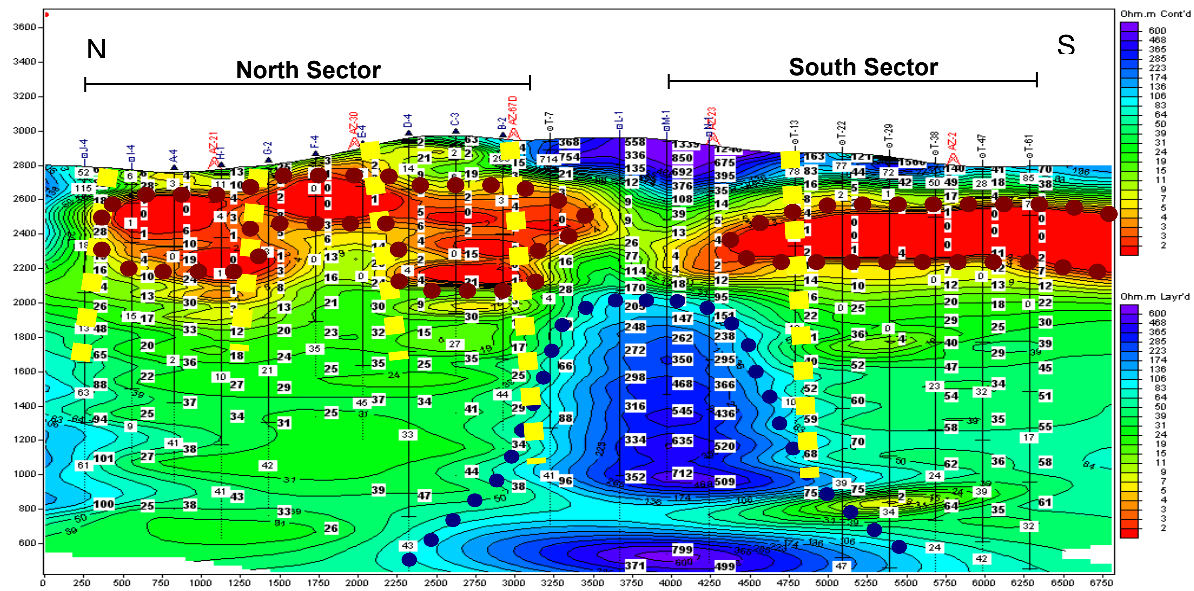


FIGURE 5: Resistivity section along N-S direction in Los Azufres geothermal field

In addition, Local Bouguer high anomaly and high total magnetic values in the field suggest the possibility of existence of the magnetic intrusion under the field.

6. RESERVOIR ENGINEERING

Reservoir temperature and pressure as well as the permeability distribution are fundamental elements of any physical model of a geothermal system. The distribution of subsurface temperature is a critical parameter used to establish (by matching) the initial-state model of the field. A good interpretation of pressure distribution can be important for understanding the thermodynamic characteristics of the reservoir (particularly the distribution of fluid phases), as well as the hydrodynamic aspects of the system in order to establish the production and injection strategies in the field to maximize sustainable power generation.

6.1 Lost circulation and permeable zones

Reservoir permeability in volcanic-hosted geothermal systems is, in nearly all cases, a product of fractured competent rocks, rather than a result of rock porosity. Fracturing can result from a variety of mechanisms, including original rock emplacement (e.g. fracturing of a lava flow), rupture along or adjacent to major faults, more generalized tectonic stress (not necessarily associated with major fault zones), and hydraulic forces.

Zones of higher permeability in the Los Azufres reservoir has been interpreted to be localized, at least in large part, along major faults, particularly of the E-W-trending set, or their zones of influence. Also temperature pattern correlation indicates a fairly rapid drop in permeability with distance to the south and to the west of the zone of highest temperature in the southern sector. Because the reservoir appears to terminate rather than extending along the trends of the major mapped faults, the possibility could be considered that several of the major faults act as permeability barriers that serve to localize the reservoir.

Lost circulation zones observed during well drilling are mainly within the andesitic rocks. The most of lost circulation are correlated with the fault locations (Figure 6) which are inferred from geological consideration and other information such as result of PTS loggings.

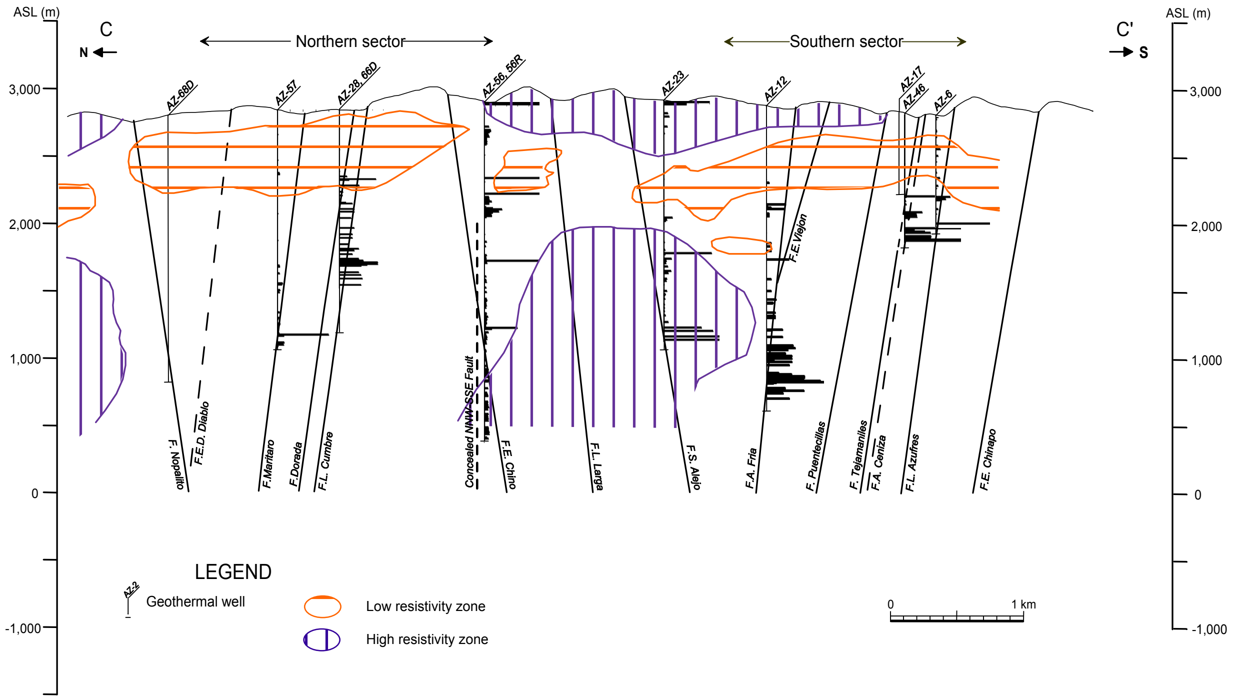


FIGURE 6: Lost circulations

6.2 Subsurface temperature and pressure

In Los Azufres many wells have been drilled which allows us to understand with certainty subsurface temperatures, some important aspect that reveal the temperature distribution are:

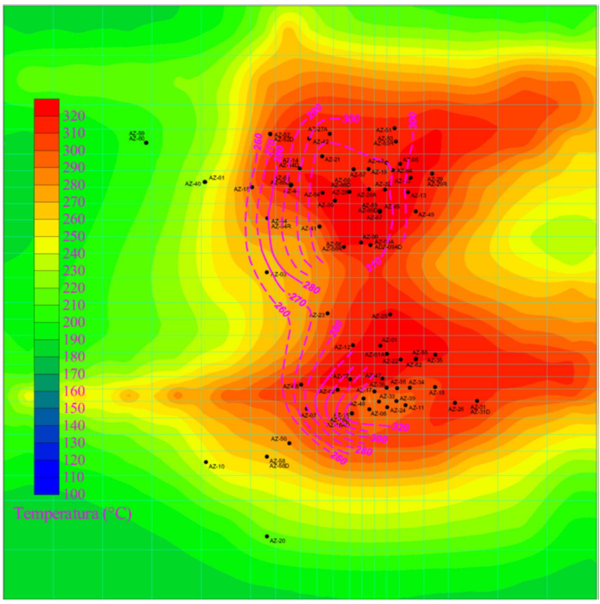
- Two distinct zones of high temperatures are evident: one corresponding to the north sector of the field, and the other to the south sector. In both zones, temperatures increase steadily with depth, reaching more than 320°C at an elevation of 700 masl in the hottest part of both sectors (Figure 7). The maximum measurement temperature is 347 °C at 250 masl of well Az-9.

- The horizontal position of the zone of highest temperatures in each sector changes only slightly with changes in depth. The northern hot zone is elongated slightly along a northeastward trend. The southern hot zone has an eastward to ENE elongation; its eastern limit has not been defined by drilling. The temperature distribution does not indicate the presence of extensive zone of outflow.

- The two high-temperature zones are distinct at most levels, though the distinction becomes smaller with increasing depth, so that, at the deepest levels for which data are available, there is uncertainty as to whether the two sectors of the field constitute separate hot zones. It must also be noted that the distinction of the two hot zones is based mainly on temperatures observed in 3 wells (AZ-12, AZ-23 and AZ-25), which lie in between the northern and southern sectors. In both sectors measured temperature reaches 200 °C at 2,200 masl on the other hand, the central part between them, the temperature is around 150 °C at the same elevation.

- In the north sector, characterized by liquid dominated reservoir, the average reservoir temperature is reported as 300 ºC at the elevation between 200 and 2,200 masl. In the south sector, the two-phase steam-dominated reservoir at the elevation between 1,800 and 2,600 masl indicates an average temperature of 270 ºC. The temperature of two-phase liquid-dominated reservoir at elevations between 400 and 1,800 masl has been reported to be 300 °C. An average temperature of the deep liquid reservoir at the elevation between –50 and 400 masl is reported 350 ºC.

- The iso-therm counters at 1800 masl shows in the north sector an area hotter than 250 °C is identified in between La Cumbre and Chino faults, and it is limited by Dorada fault at the west and by the Laguna Verde at the east. In the south sector an area hotter than 250 °C is identified in between Agua Fria and Los Azufres fault, and it is limited by El Viejon fault at the west.



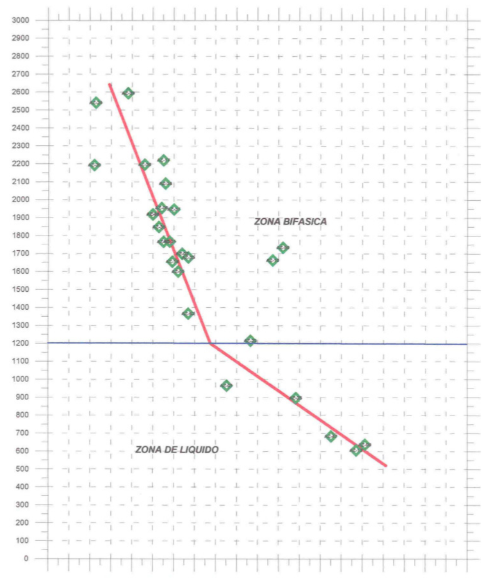


FIGURE 7: Distribution temperature (700 masl) and pressure profile

Liquid geothermometry using the NaKCa and silica (quartz) temperatures indicate the reservoir fluid temperature from 250 to 330 °C for initial stage. Gas chemical temperatures of TCO_2/Ar and TH_2/Ar for the well gases are relatively scattered within a range from 200 to 350 °C. The parental fluid assumed at deeper depth is estimated as 300-330 °C.

Initial static bottomhole pressures in wells of varying depth provide a useful indication of the distribution of initial static pressures in the geothermal system. In the southern sector, there is a clear transition from a single-phase-liquid pressure gradient below an elevation of about 1,200 masl, to a lesser pressure gradient above this level (Figure 7); this indicates the presence of two-phase conditions in the upper zone, which (based on the overall evidence) transitions to a steam-dominated zone in the shallowest part of the reservoir. In the northern sector, no such distinct transition of pressure gradient is observed, indicating that the reservoir in the northern sector was initially single-phase throughout, except perhaps in its shallowest part.

6.3 Production and reinjection

At present, more than 43 production wells are producing steam and connected to the power plants. The fluid enthalpy is relatively high for most of the production wells, while some of the production wells are producing only steam but without water, so that the fluid enthalpy is very high in these wells. Among the wells that show medium enthalpy, the increasing trend of the enthalpy value can be observed in wells AZ-4, AZ-5, AZ-13, AZ-18, AZ-26, AZ-28, AZ-43 etc.

The reinjection capacity at present is around 2000 t/h, there are 6 wells accepting separated water and condensed water. The total reinjection amount is around 700-800 t/h. The capacity of existing reinjection well is much larger than actual reinjection amount, which means additional drilling of reinjection well is not necessary at the moment (West JEC, et al,. 2007).

7. CONCLUSIONS (GEOTHERMAL RESERVOIR CONCEPTUAL MODEL)

The Los Azufres geothermal reservoir includes a broad zone, at least 20 km2 in extent, in which the geothermal fluids are stored in high permeable zones, associated to faults in andesitic rocks accompanied with rhyolites that act as cap rock and are formed at depths between 500 – 700 m from subsurface, and mainly due to clay alteration zone. This cap rock prevents cold groundwater from infiltrated into the high temperature reservoir.

The heat source of the system is presumably related to young volcanic activity of the area. Heat may be supplied to the system by a cooling magma chamber or intrusive body of rock; however, the precise characteristics of such a source cannot be determined from available data even though a local Bouguer high anomaly and high total magnetic values in the field suggest the possibility of existence of the magnetic intrusion under the field. Similarly, the nature of the source of upwelling fluids feeding the system cannot be determined with complete precision. Based on the temperature distribution conclude that the high temperature fluid (>320°C) is caused mainly by the meteoric water circulation at deep levels that enter to the system and mix with magmatic water. The concealed NNW-SSE trending faults probably extend to the basement rocks and are supposed to control the deep geothermal fluid flow supply and discharge of fluids towards Araro; however, other unidentified outflows may be present.

The geothermal reservoir is divided in two productive zones, the north and the south sectors, this two sector are separated by a low permeability zone which shows high resistivity characteristics. The production zones are located where the wells intersects to the E-W trend faults, and within a depth interval defined approximately between the first appearance of epidote and the top of the amphibole (Perez, 2001). In the south sector, the geothermal fluids at depth are considered to be up-flowing around the conjunction trending faults (Puentecillas, Tejamaniles, Los Azufres) and NE-SW trending fault (Agua Ceniza) and in the north sector, the geothermal fluids seem to be up-flowing around El

Chino, La Cumbre and Dorada faults and spreading along high permeable zones defined by E-W trending faults. Around wells Az-41 and Az-9 the geothermal fluids seem to be ascending to shallower levels. Presence of fracture zone (en echelon fractures) caused by strike slip of La Cumbre and Maritaro faults is assumed to exist and probably this fracture zone controls the ascension and spread of geothermal fluid (West JEC, et al., 2007).

In consideration of the faulting geometry, cap rock development, subsurface temperature etc., the productive area of the reservoir extent in the north sector is delineated by Laguna Verde fault at the east, and by Coyotes and Nopalito faults at the north. In the south sector, the reservoir extent is bounded by El Chinapo at the south and El Viejon at the west. In the central zone, between San Alejo and Agua Fria faults where the permeability and subsurface temperatures in volcanic rocks are estimated to be lower compared with those of the north and the south sectors.

Figure 8 shows a geothermal conceptual model in a plane view and Figure 9 shows a cross section of the conceptual model. Having a conceptual model in such a detail has allowed a proper management of the production and injection strategy, to maximize power output in a sustainable way. It is also important to be able to locate well makeup wells and also as an input for numerical modeling, in order to be able to check changes in the strategies, well location and effects in the reservoir if an expansion plan is advisable or not.

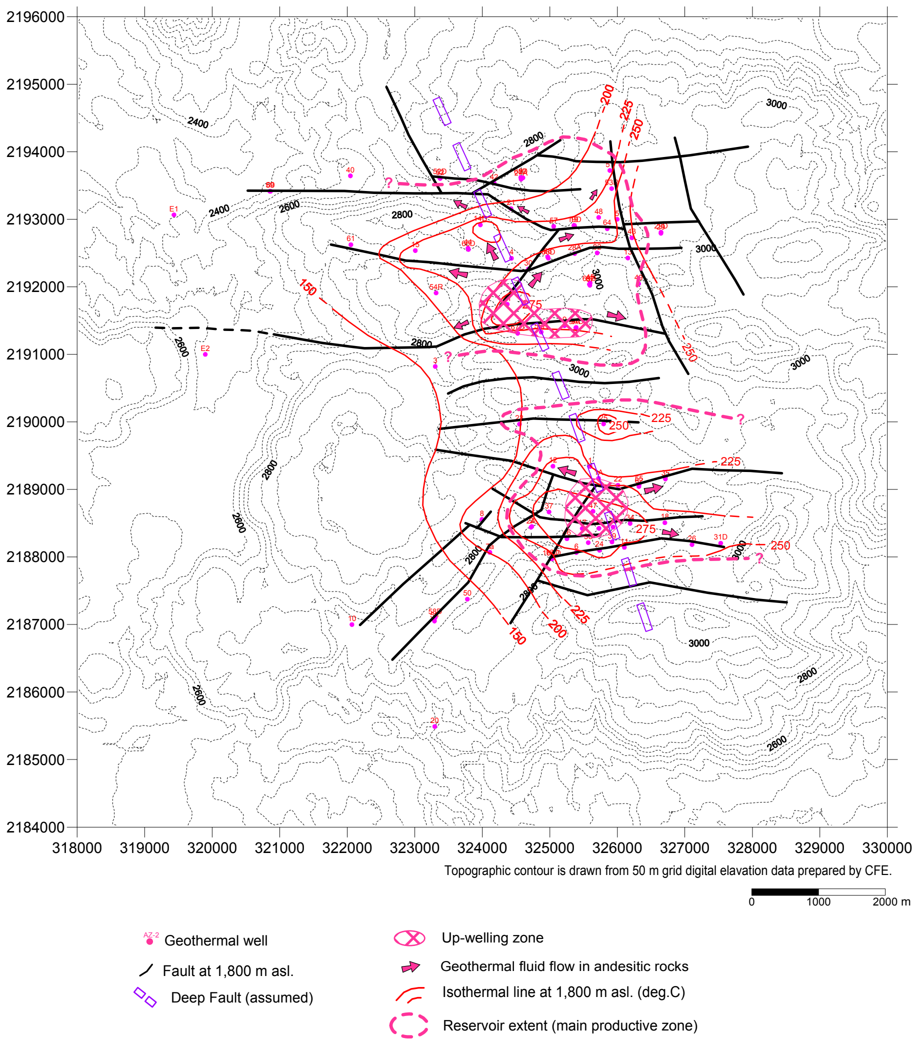


FIGURE 8: Geothermal conceptual model (plane view)

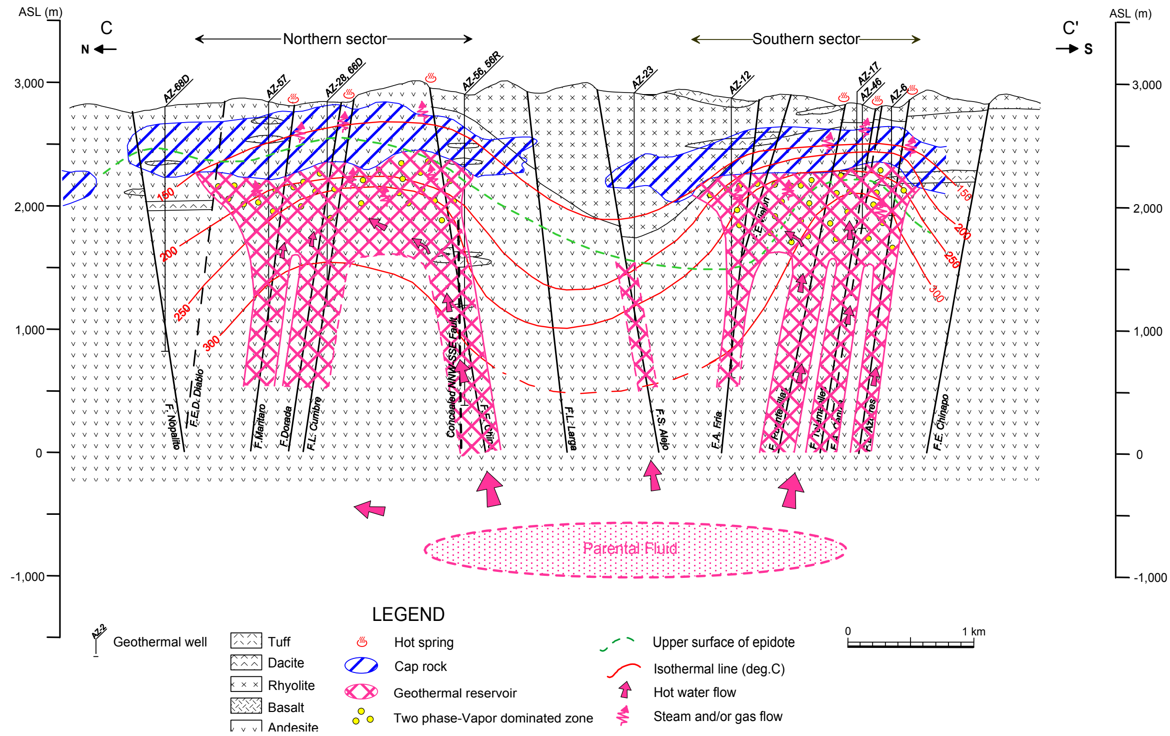


FIGURE 9: Geothermal conceptual model (cross section)

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GEOTHERMAL TRAINING PROGRAMME

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GEOLOGICAL MAPPING IN VOLCANIC REGIONS: ICELAND AS AN EXAMPLE

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ABSTRACT

This paper reviews the approach to geological mapping of low and high temperature geothermal areas in Iceland. Geological mapping is a key part of the surface exploration of geothermal areas before the subsurface is explored through drilling. The objectives of geological mapping are manifold but focus on outlining the geological setting and structure of the area; identifying fractures and fissures, which are controlling fluid flow in the system; outlining the potential size of the system and characterising the size, age and productivity of the heat source etc. The outcome of geological mapping is presented on maps. Geothermal maps show the distribution of the different types of geothermal manifestations in comparison with volcanic and tectonic structures, while the geological map presents the type of volcanic deposits and their extent, age relationship and possible origin. Along with geochemical and geophysical surface exploration, this constitutes the basis for siting the first wells and proceeding to the subsurface exploration phase, providing the outcome of surface exploration is promising.

Iceland is located in an extensional geological setting straddling the North Atlantic mid-ocean ridge. The neo-volcanic zone extends from the southwest to the northeast of the country, which constitutes parallel aligned volcanic systems within which the high temperature geothermal areas are located. This paper presents some of the volcanic and tectonic features characteristic of geothermal systems in Iceland.

1. INTRODUCTION

The process of developing geothermal fields for utilisation can be divided into three stages; surface exploration, exploration drilling and development drilling. The surface exploration stage is usually implemented in three phases starting from (1) a due diligence work which is carried out by thoroughly reviewing available information related to previous investigations of hot springs, fumaroles, silica mounds, solfataras and alteration zones as well as air-photo analyses and remote sensing studies, (2) field reconnaissance surveys including the acquisition of geology and geochemistry data and a review of the environmental aspects of the area and 3) detailed exploration survey, which includes geological mapping, geophysical surveying and geochemical sampling and analysis.

The objective of the surface exploration is to obtain information about factors such as; 1) the geological setting, 2) structural and hydrological setting within the system, 3) the size of the system, 4) subsurface temperatures and 5) heat source and natural recharge. The results of the different surface investigations are combined into a preliminary conceptual model of the system and are used to outline suitable sites for exploration drilling (Richter et al., 2010; Pálmason, 2005; Steingrímsson & Guðmundsson, 2010). Thus geological mapping features most prominently in the early stages of exploration and development of a geothermal system, but the geological and structural framework that is delineated during this stage, forms the basis of the subsequent drilling stage.

2. GEOLOGICAL MAPPING

Geological or geothermal mapping is applied both on a regional scale, e.g. in country-wide reconnaissance for areas with geothermal potential, as well as on a local scale when exploring specific geothermal areas.

2.1 Regional reconnaissance

Regional or country-wide geothermal reconnaissance aims to identify areas with geothermal potential, thus the geologist is required to cover large areas in a relatively short time. In such regional surveying the geologist is seeking to locate and map areas with geothermal manifestations such as warm springs, hot springs, fumaroles, hot and altered ground, but temperature, flow rate, pH and conductivity of the spring is recorded and samples collected for geochemical analysis. In order to find hidden or partly hidden geothermal areas the geologists commonly use a number of different approaches depending on availability; review of regional geological maps, aerial photos, remote sensing such as thermal imaging, while place names can often point to locations with warm or hot springs, e.g. in older literature. When the geologist is eventually in the field it is often valuable talking to local farmers, as they are most likely to know about less conspicuous geothermal manifestations, springs and fumaroles.

The preliminary geothermal reconnaissance is used to rank the geothermal areas according to their estimated potential, that is to say preliminary information about potential size and estimated reservoir temperature. This preliminary work forms the foundation for governments to either pursue the exploration of the geothermal fields under governmental administration, or to lease the exploration rights of the geothermal field to private companies through open tendering.

2.2 Geological mapping of geothermal areas

Geological mapping is more detailed during exploration of a specific geothermal area; however, the detail required in the mapping depends on the type of geothermal area and the costs of carrying it out. In Iceland geothermal energy is abundant with numerous low and high temperature geothermal fields. Many low temperature fields have been successfully developed for domestic heating while the high temperature fields have both been developed to sustain both power generation as well as serving for direct use purposes, e.g. domestic heating.

Approximately 25-40 high temperature fields straddle the neo-volcanic zone, which extends from the south-western corner of the Reykjanes peninsula, across the central highland and to the north-eastern shores of Iceland (Figure 1), but the neo-volcanic zone forms the landward extension of the North Atlantic mid-ocean ridge. The low temperature areas are found all across the country both inside and outside the neo-volcanic zone, although they are more predominant in the western part of Iceland. The low temperature geothermal fields are used for domestic heating, green house heating and fish farming etc.

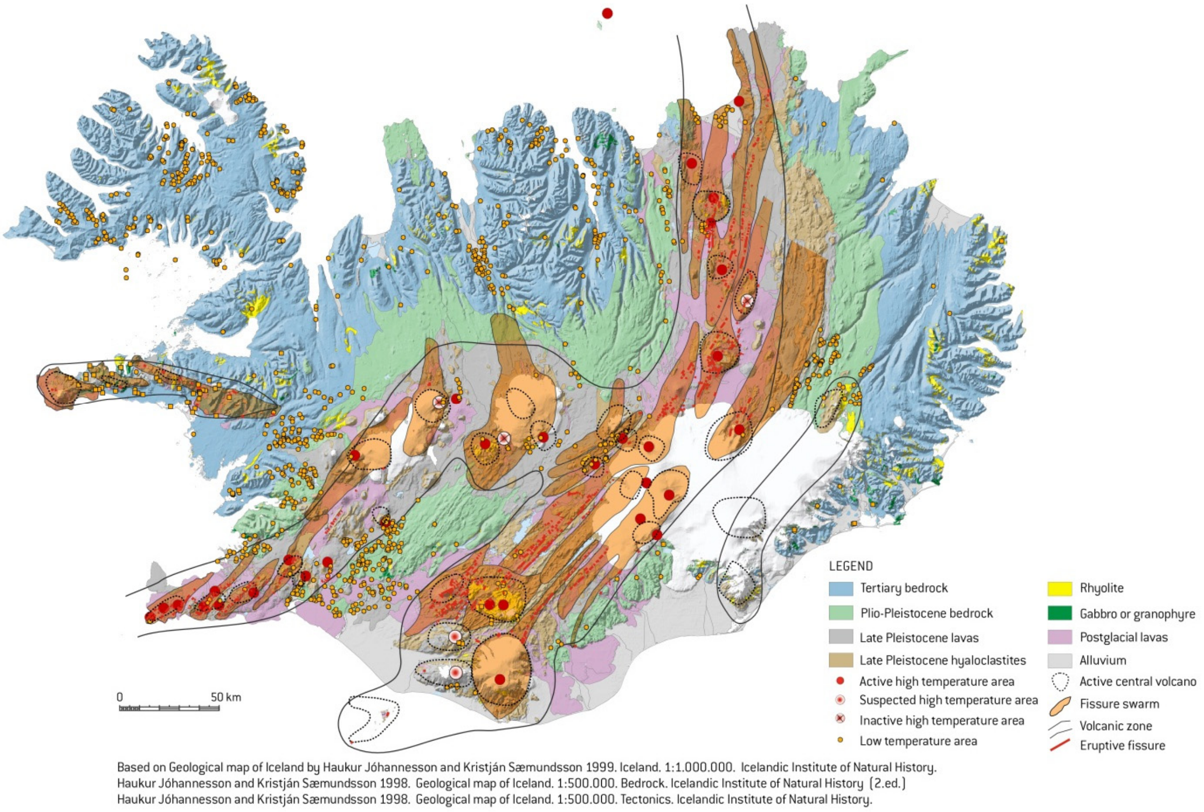

FIGURE 1: Geological map of Iceland highlighting the volcanic systems and central volcanoes within the neo-volcanic zone (Jóhannesson and Sæmundsson, 1998)

2.3 Geological mapping in low temperature areas

Exploration of low temperature geothermal areas has to be cost efficient to ensure that the energy source is competitive with other conventional energy sources. Geological mapping is therefore more limited and the primary objective is to identify the main permeable fractures and the centre of warm water upflow. In Iceland low temperature fields located outside the neo-volcanic zones are situated in the Tertiary volcanic pile (Figure 1), which formed more than 3 million years ago, but in these formations the porosity is limited, thus aquifers are mostly linked to dykes or active faults, which remain open and allow up-flow of warm water to the surface (Figure 2).

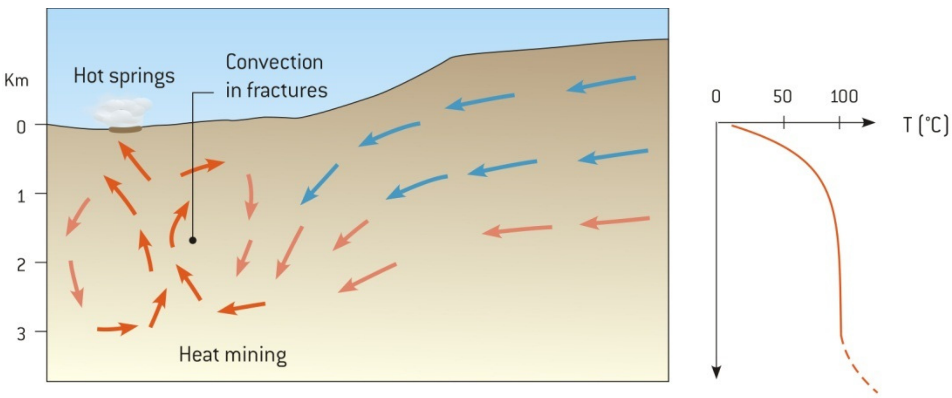

FIGURE 2: Conceptual model of low temperature geothermal systems in Iceland. Deep circulation along dykes and active faults allows the groundwater to heat and rise to the surface in the upflow zone of the convection cells (Axelsson, 2008). The diagram to the right shows a typical geothermal gradient in a low temperature geothermal reservoir characterised by fracture bound convection

The aim of geological mapping in low temperature fields is to find where the centre of warm water upflow is located by identifying, for example, faults and dykes and to determine the strike and dip of the permeable structures in order to outline an appropriate well site, which will intersect the structures at depth.

Geological mapping in low temperature areas typically includes:

1) Detailed mapping of warm and cold water springs, measurement of their temperature, flow rate, pH and conductivity.
2) Temperature measurements in soils, where they cover the basement rock.
3) Detailed mapping of all visible fractures, faults and dykes in the vicinity of the expected drilling area, including determining strike and dip of the structures.
4) Temperature measurements in shallow holes to determine the temperature gradient near the surface. In Iceland this method has been successfully applied to identify thermal anomalies
5) In some cases geological mapping is complemented by geophysical surveys in areas with limited surface exposure, however magnetic surveys are used to discern dykes, and in rare cases, faults. Resistivity profiling is a rather expensive method and thus is used sparingly, although it is applied to delineate fluid conductive fractures.

Providing that the geological investigations point towards the presence of a low temperature field, they can form the foundation for siting a well in preparation for the next stage of the exploration of the field.

2.4 Geological mapping in high temperature areas

Geological mapping in high temperature areas is much more extensive. Mapping during the surface exploration phase generally involves the following:

- Detailed geological map of the geothermal field and its surroundings
  - Rock type
  - Frequency, volume and type of volcanic eruptions
- Detailed mapping of tectonic features such as faults, fissures and fractures
- Mapping of thermal manifestations, including recording the temperature, flow rate, pH, conductivity etc.
- Detailed mapping of surface alteration and alteration minerals
- Thermal manifestations of tectonic features and volcanism – heat sources, hydrology and flow paths in the reservoir
- Mapping of groundwater, cold springs, lake levels and groundwater levels
- Risk assessment
- Environmental aspects

The basic concept of geological mapping is to present the stratigraphy, rock types and structural features of the exploration area. Geological mapping in geothermal exploration focuses in particular on establishing the volcanic history of the area; the type of volcanic eruptions and their tectonic setting, the volume of the eruptions, their frequency and changes in volcanic and tectonic activity through time. Volcanic activity and type of rocks erupted can shed a first light on the geological conditions within the geothermal reservoir and the size and configuration of its heat source.

Structural mapping is an integral part of studying volcanic systems, but through this work, structural features are outlined, and both large and small scale structures such as faults and fractures are mapped. At first they can be outlined with the aid of satellite images and aerial photos, followed by field work, but mapping includes determining the movement and amount of displacement along the faults (normal/reverse/strike-slip/oblique), so that the stress regime and orientation can be determined. The aim is to make preliminary projections about the orientation of fluid conductive faults and fractures with depth, being both volcanically and tectonically controlled.

Through mapping it is also attempted to date larger tectonic events and the frequency of their occurrence through geological correlation, tephrachronology and/or C^{14} dating. Current tectonic activity and crustal movement can be monitored through an array of geophysical techniques such as GPS-networks and InSAR satellite techniques and seismic surveys.

Geological mapping shows not only a first inference about the geology and structural setting within the geothermal reservoir but also gathers evidence about the location, size and frequency of volcanic and tectonic events and possible slope failures. When developing geothermal fields, these data are used to evaluate the probability of such hazards, to minimize the risk of damage to surface constructions, in particular to the power plants.

2.5 Geological and structural mapping in geothermal areas in Iceland

Iceland is located on the Mid-Atlantic Ridge, which is an active spreading centre, where the American and Eurasian plates are moving apart at a rate of 2 cm/yr. In Iceland the region of extension and volcanism is centred within the neovolcanic zone, which extends across the country from the south-western corner to the northeast (Figure 1). A mantle plume is located under the south eastern part of Iceland, resulting in increased magmatic production rate and the sub-aerial exposure of Iceland.

The volcanic activity is centred within the neovolcanic zone of Iceland, but the volcanic activity is constrained by volcanic systems arranged in an en echelon pattern (Figure 1). The volcanic systems comprise a fissure swarm, a central volcano and a high temperature geothermal area, but the high temperature geothermal areas are all located within the Icelandic neovolcanic zone.

The rocks in Iceland are fairly uniform in composition with more than 90% of the rocks being of basaltic composition. The onset of glaciations 3 million years ago in the Plio-Pleistocene was the result of general cooling of the Northern Hemisphere. This transformed the Icelandic landscape as it became covered with glaciers and sub-glacial volcanic eruptions created hyaloclastite ridges and table mountains. As a result of this climatic change, in many of the high temperature areas hyaloclastites commonly form the cap rock of the geothermal reservoirs, while basaltic lavas and pillow basalts are the principal reservoir rocks.

The maximum volcanic production rate is in the central volcanoes of the volcanic systems, which therefore constitute the topographic highs along the fissure swarms. The distribution and volume of volcanic products erupted on the surface provide clues about the dynamic interaction between volcanism and tectonics. Just as importantly this provides information about the configuration of the magma plumbing system and the rate of magmatic input into the shallower part of the crust. The cooling and solidifying magma in the form of plutons, dyke swarms and sills form the heat source of the geothermal systems. As only a percentage of the magmatic input into the shallow crust is erupted onto the surface, estimating the volume and distribution and production rate of volcanic deposits through time provide essential information about the potential depth, shape, size and age of the heat source for the geothermal system.

To determine the age of volcanic deposits a combination of cross correlation of deposits and structures is applied along with dating of selected samples, this being K-Ar, Ar-Ar dating or C^{14} dating depending on the age of the deposit. Deposits from the Holocene have been successfully dated in Iceland using tephrachronology, but the record of larger volcanic eruptions is preserved as ash layers in soils across the country.

2.6 Krafla volcanic system

Development of central volcanoes in Iceland can be divided into several stages, but they form at the centre of highest volcanic production rate within the volcanic systems. As an example, the Krafla central volcano in north-eastern Iceland is briefly described here based on some of the following references: Sæmundsson (1991, 2008a,b), Ármannsson et al. (1986); Mortensen et al. (2009).

The oldest rocks related to Krafla central volcano are at least 300.000 years old, but over this time a large basaltic shield has developed, which constitutes the Krafla central volcano. The shield is about 20 km in diameter with a 300-400 m high relief. In the centre of the volcano is an 8x10 km large caldera (Figure 3). The caldera formed as a result of a large paroxysmal eruption approximately 110.000 years ago, which created an extensive ignimbrite deposit that is most prominent east of the caldera. Today the caldera has an elliptical shape as a result of the continued extension along the rift zone. The caldera has almost been filled with hyaloclastites and basaltic lavas during succeeding eruptions. Within the caldera is a large east-west trending area with geothermal manifestations (Figure 4), but the geothermal manifestations are most active and prominent east of the centre of the caldera, while they have cooled and/or are extinct towards the edges of the caldera. The caldera is intersected by a 90 km long, almost N-S striking fissure swarm (N5-10°E). The fissure swarm is 7-8 km wide at the central volcano and divides into two southwards from the caldera.

In the Holocene volcanic activity have been shifting back and forth between the two sections of the fissure swarm, but fissure eruptions have been originating from the eastern section of the swarm in the past 3000 years at intervals between 300-1000 years. The volcanic eruptions have occurred along both linear and curved fissures. Eruptions along curved fissures are conspicuous in the north-eastern part of the caldera as well as outside the caldera, but these curved fissures form the surface manifestations of cone sheets, which are believed to originate from a shallow magma chamber beneath the caldera. The linear fissure eruptions extend towards the north and south along the fissure swarm, but they also originate from the centre of the caldera were maximum extension has taken place, as exemplified with the latest volcanic episode, the 1975-1984 Krafla Fires. In addition to the geological features at surface, monitoring of crustal deformation and seismicity during the Krafla Fires supported the notion of magma accumulation in a shallow magma between 3-7 km depth below the Krafla caldera (Einarsson, 1991) and subsequent extrusion of lava onto the surface along the N-S fissure swarm, when the critical pressure in the magma chamber was exceeded.

It is not only basaltic lava, which is extruded from the Krafla Central Volcano. Both rhyolitic and mixed extrusives (rhyolite/basalt mixture) form prominent ridges outside the caldera and along N-S fissures in the eastern part of the caldera (Figure 3), but the geochemistry of rhyolites suggest that they have formed by partial melting of hydrothermally altered basalt in the vicinity of the magma chamber. In the eastern part of the caldera are other distinct volcanic features in the form of explosion craters (Figure 4). No significant magma extrusion has been connected to these craters, which are 300-400 m in diameter, but it is suspected that steam explosions from the underlying high temperature geothermal system have played a significant role during their creation.

The geological studies of Krafla geothermal area have thus shown that it formed in an active volcanic setting, where frequent volcanic eruptions ensure a high magmatic input into shallow crustal levels with a magma chamber at 3-7 km. In the eastern part of the caldera there is a correlation between the presence of the hottest, most active and pervasive part of the geothermal surface manifestations and recent volcanism in the caldera. This includes fissure eruptions and explosion craters as well as the most recent extrusion of rhyolite merging towards the current centre of the magmatic heat source, which supports the heat for a high temperature geothermal reservoir.

FIGURE 3: Geological map of Krafla. Holocene lavas (purple and pink colours) and hyaloclastite ridges (brown colours) have filled the caldera centre. Yellow colours represent rhyolitic and mixed rhyolite/basalt deposits, which are conspicuous outside the caldera, while the most recent deposit is in the eastern part of the caldera (Sæmundsson, 2008a). Map scale is 1:25000. The width of the map is equivalent to ~12 km

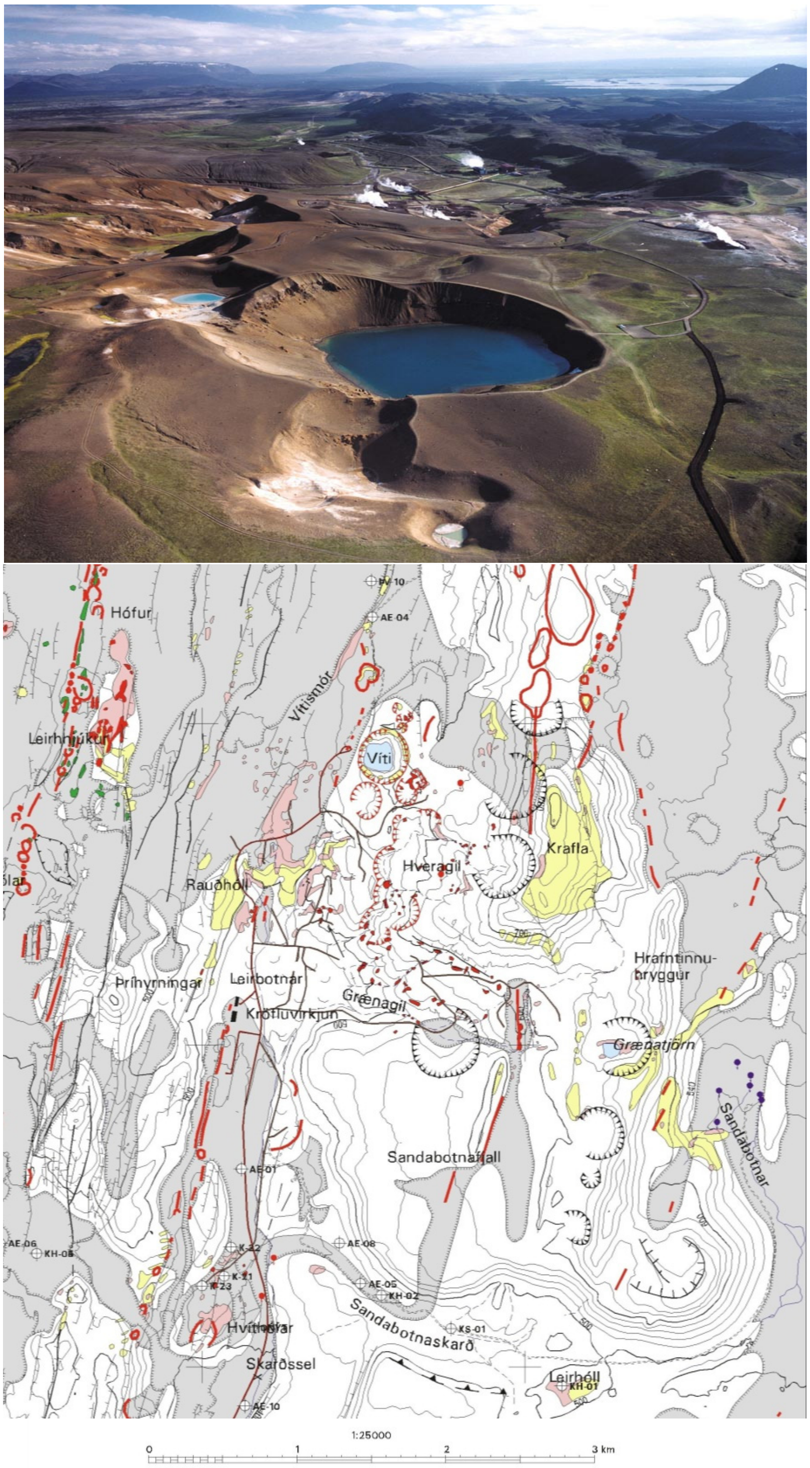

FIGURE 4: Above: Photo looking towards the south from Krafla with explosion craters in the foreground (Picture: Á. Guðmundsson) Below: Geothermal map from part of Krafla geothermal area, outlining the location of explosion craters (circular features), fumaroles (red dots), hot ground (pink) and slightly altered ground (yellow). Serrated lines indicate normal faults while lines with triangles symbolize the caldera margin (bottom) (Sæmundsson, 2008b)

3. GEOTHERMAL MAPPING

Mapping geothermal manifestations in high temperature areas in Iceland is relatively easy due to sparse vegetation (Figure 5). Aerial photos or satellite images can be used to initially outline the aerial distribution of the geothermal manifestations, but this has to be complemented by field work for detailed mapping. In the field the aerial distribution and directional trends of the geothermal manifestations are mapped along with their intensity, coherence, type of geothermal manifestations (e.g. fumaroles, solfatara, hot and boiling springs, mud pools, steaming ground, hot ground) and identification of what type of precipitates have formed there (e.g. sulphur, silica, aragonite, hematite and clay types). At times XRD-analyses are used to identify the type of precipitates. Both active and extinct geothermal manifestations are mapped, but through correlation with surrounding lavas and soils, it is attempted to establish when the geothermal manifestations became extinct. The outcome of the field work is a geothermal map showing the extent and type of geothermal manifestations in correlation with the structural features (Figure 5). In Iceland it is common that geothermal manifestations appear along faults and fissures as is exemplified in the geothermal map from Þeistareykir geothermal area in NE-Iceland (Sæmundsson, 2007), which reflects that fluid flow in the geothermal system is to a large degree controlled by tectonics.

When mapping active geothermal manifestations, temperature, flow rate, pH and conductivity is measured and fluid and gas samples collected for geochemical analyses. In areas covered with thick soils a complimentary temperature survey may be carried out, but the density of measurements is dependent on the survey area. Figure 6 shows an example of a temperature survey conducted at the Reykjanes geothermal area in SW Iceland. This reveals a rather complex set of lineaments, but from the map N-S, NW-SE and NE-SW lineaments in the temperature distribution happen to correlate with the orientation of open fissures, faults and eruptive fissures within the Reykjanes field. Based on the temperature distribution map the thermal output from the geothermal field can be estimated. Therefore s maps of this kind can give a first idea of the potential of such a field.

The ground usually becomes covered with snow during the winter in Iceland. In the geothermal areas melting of snow is also used as a tool to map the aerial extent of the active geothermal manifestations, and repetition of these measurements over several years can outline changes in the geothermal surface activity. Such monitoring can reveal natural changes through time, which can be linked to deeper seated changes in the geothermal reservoir e.g. cooling or volcanic episode, or may reflect changes as a response to production from the geothermal field.

Mapping diffuse CO_2 degassing through soil is another useful method to delineate areas with fractures controlling flow in the geothermal systems. This type of mapping has been successful in revealing anomalies in the CO_2 flux that align along already known faults and fractures, but it is has also revealed active fractures that are not visible at surface. Wells have been directed through these anomalies in Iceland, and the outcome have been highly productive wells, reinforcing the correlation between high CO_2 soil fluxes and active flow controlling fractures in the reservoir (Ármannsson *et al.*, 2007). Maps of CO_2 soil flux and snow melt are thus far not part of the initial surface exploration stage in Iceland, but are rather included in the later stages of field development, e.g. as part of environmental monitoring of changes in the geothermal areas.

The geothermal map helps to develop the first conceptual model of the geothermal field. The aerial distribution of the geothermal manifestations gives the first indication of the potential size and capacity the geothermal reservoir. Variation in the type of geothermal manifestations that occur across the area can outline zones of upflow and/or out flow and likely temperature regime in the reservoir.
Geothermal manifestations such as fumaroles, boiling springs, hot spring and mud pools and deposits of native sulphur and siliceous sinter deposits are typically found above upflow zones from high temperature geothermal reservoirs. If leached rocks and acid springs are present this could even point towards a vapour dominated reservoir, but gasses from these reservoirs condense near surface to form acids. Areas with CO_2 springs and travertine deposits (aragonite/calcite) form either in vicinity of relative low temperature reservoirs which are only suitable for direct use purposes, or alternatively mark the outflow zones from hot geothermal reservoirs where travertine deposits form through cooling and groundwater dilution of the fluids (Goff and Shevenell, 1987).

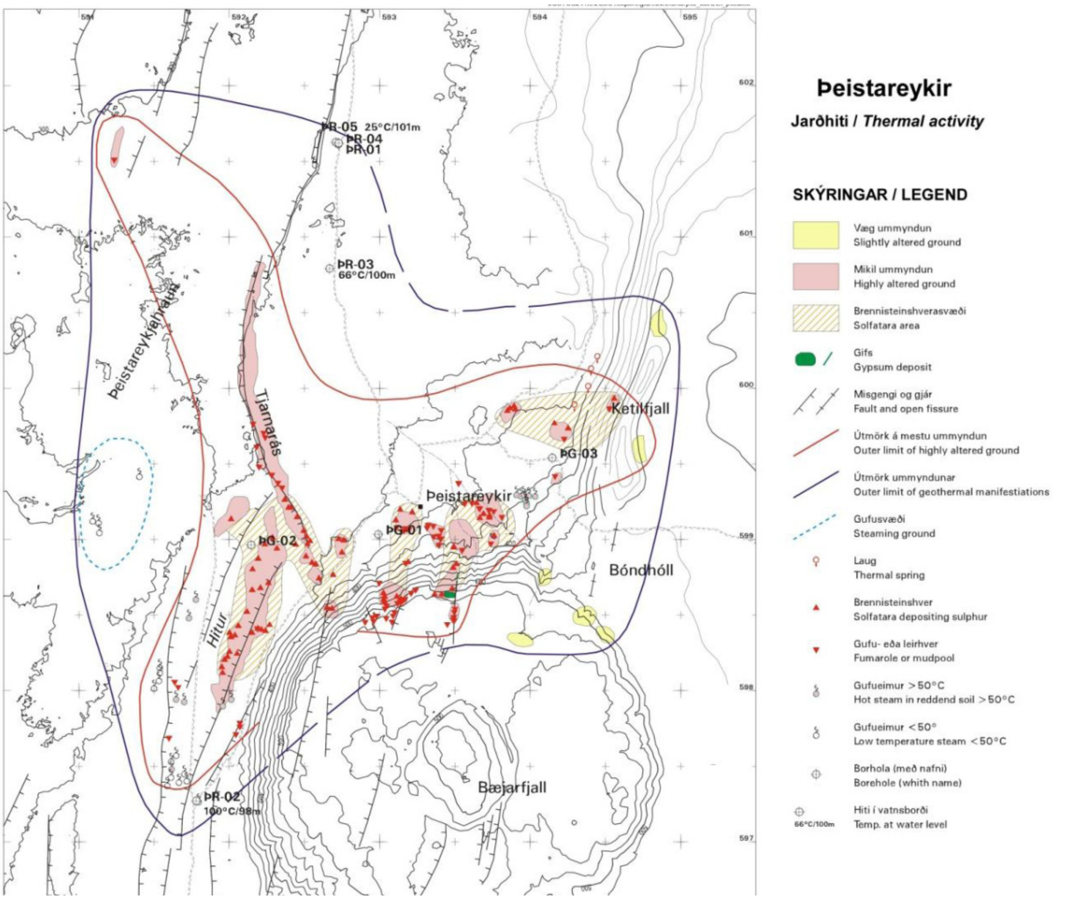

FIGURE 5. Geothermal map of Þeistareykir Geothermal field NE-Iceland. Faults and fissures are shown, and the geothermal manifestations appear along the faults and fissures (Sæmundsson, 2007)

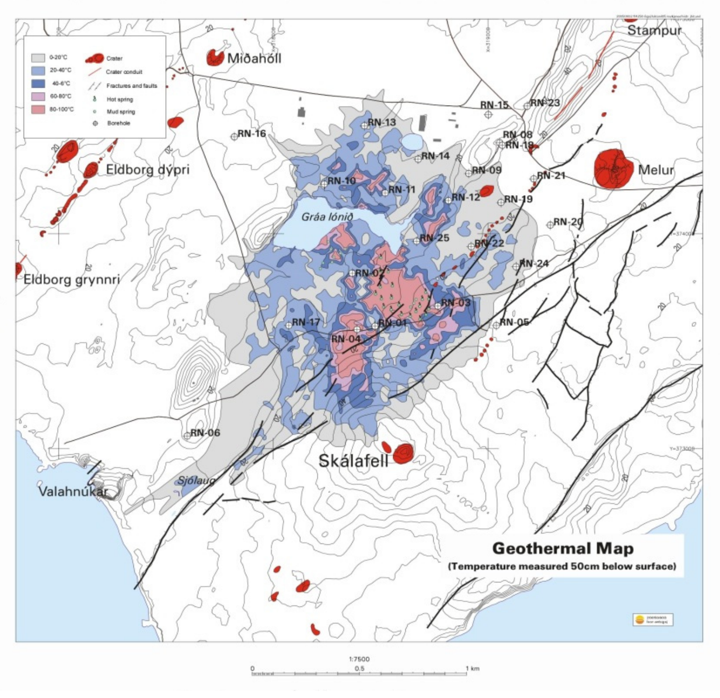

FIGURE 6. Temperature distribution map from 1968 of the Reykjanes geothermal area SW-Iceland. Temperature was measured at 50 cm depth in soil (Jónasson 1968)

4. SIMPLE CONCEPTUAL MODEL

After surface exploration of geothermal areas, the outcome of geological mapping, geochemical and geophysical surveying are combined to form the basis for developing the first conceptual model of the geothermal system. This paper has focussed on the information gathered through geological mapping, while other papers will present the principles and interpretation of geochemical and geophysical surveys.

The objective of the conceptual model is to outline the potential target areas for the first exploration well/s, where the upflow zone is located and the highest temperatures are expected to be found. The model should highlight potential structures, which control the fluid flow in the reservoir and their orientation with depth in order to outline drilling targets.

In Figure 7 is an example of a simplified conceptual model, which is representative of high temperature systems in Iceland, but arrows are used to represent the fluid cycle within such systems. Through surface exploration the detail of such a model increases and it is possible to start highlighting the potential size of the geothermal area, outline potential upflow and recharge centres, fluid conducting structures, likely reservoir formations and heat source characteristics.

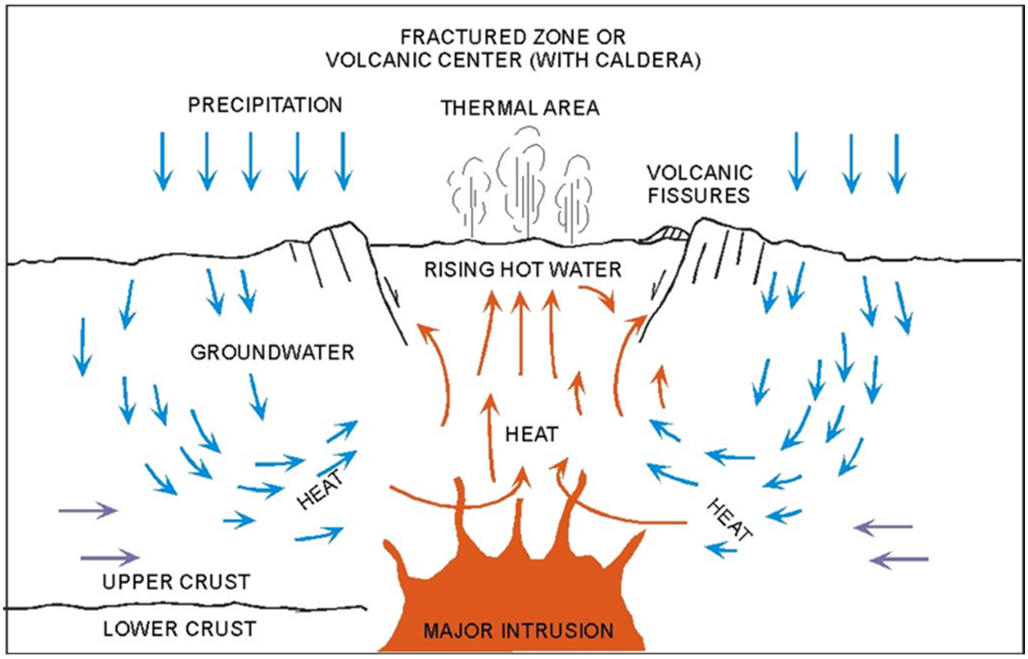

FIGURE 7. Simplified conceptual model of a magmatic heated high temperature geothermal system in a region of rather low relief, e.g. region of extension as in Iceland (Axelsson, 2008)

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GEOLOGICAL SURVEYS FOR GEOTHERMAL EXPLORATION IN COSTA RICA

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ABSTRACT

The knowledge of the geological characteristics of a region is of particular importance during the evaluation of a geothermal prospect. Field mapping is essential in the reconstruction of the geological framework of an area, which in complement with geochemical surveys represent the basics for the incoming studies. Geological surveys will give clues regarding the relationship between field characteristics and the probable existence of a geothermal resource. A brief guide concerning a methodology in geological surveys applied to geothermal investigations is presented. As an example the results of a geothermal reconnaissance study carried out in the central north sector of Costa Rica is exposed.

1. INTRODUCTION

The knowledge of the geological characteristics of a region is of particular importance during the evaluation of a geothermal prospect. Compilation and collection of field information is essential for the elaboration of the geological framework that will represent the basic for future investigations. In this sense is important to have a methodology applied to the exploration, and particularly to the geological mapping. The short guide presented here is based on the Latin American Energy Organization approach to geothermal energy exploration (OLADE, 1994) and Wohletz and Heiken (1992).

2. DEVELOPMENT OF A GEOTHERMAL PROJECT

According to OLADE (1994) in general terms the execution of a geothermal field involves two phases: one of high risk (incertitude) associated to the exploration aimed to identify the probable reservoir; and the other of less risk is related to the development and exploitation. At the first stage, during the reconnaissance, the low detail studies take place in a large area and as investigations advance the area is reduced and studies are of greater detail (prefeasibility and feasibility) but in smaller area. First part involves high economical risk levels, to be faced with progressively crescent inversions but that are of relatively low cost. Second part, involves minor risks but requires major investments (Figure 1).

In the different stages of the geothermal exploration, from reconnaissance to feasibility studies (Figure 2), geological surveys plays a very important role because is an inexpensive tool useful for identifying the different elements of the geothermal system.

Geological field surveys in conjunction with geochemical sampling of hydrothermal waters and gases are extremely cost-effective and represents the first step before the incoming more expensive geophysical studies and exploration drilling campaigns (Wohletz and Heiken, 1992).

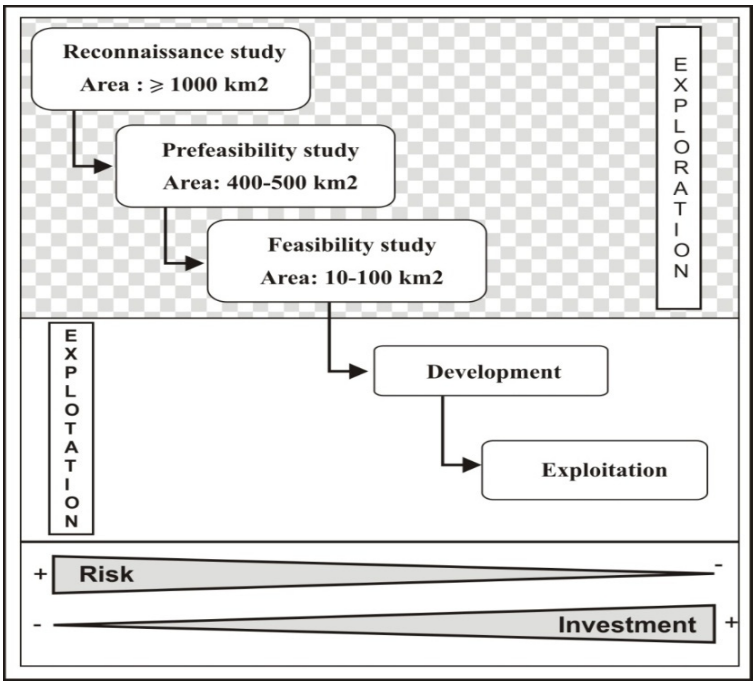

FIGURE 1: Flow chart showing the stages in the execution of a geothermal project and the risk and investment associated, according to the OLADE (1994) methodology

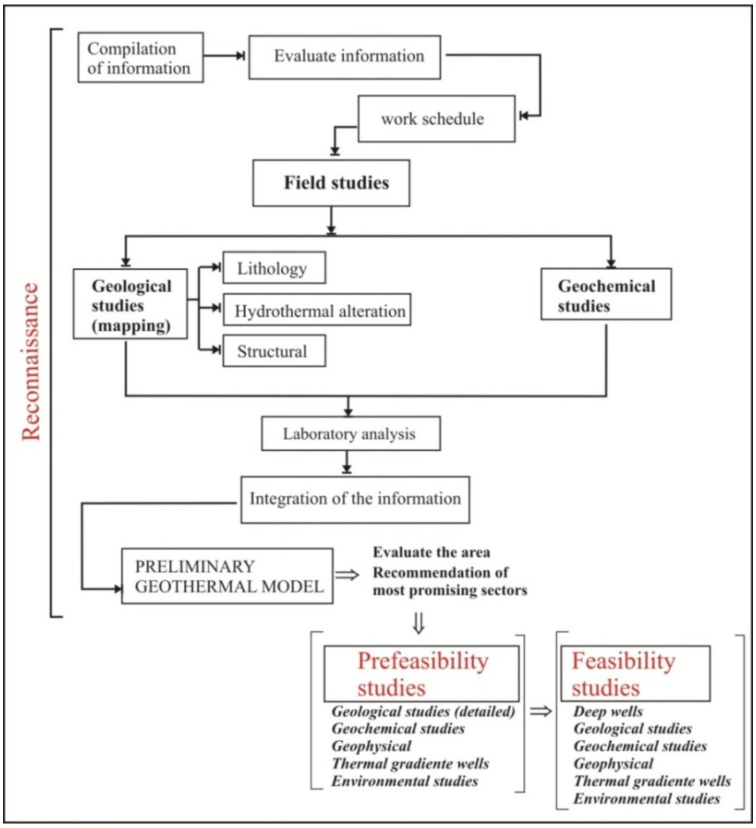

FIGURE 2: General flow diagram of the different investigation steps during the exploration of geothermal resources. Based on the OLADE (1994) methodology

3. GEOLOGICAL SURVEYS

The scope of geological surveys during the exploration of geothermal resources in a general manner could be summarized in the next points (OLADE, 1994):

- Elaborate the regional mapping and define the preliminary volcanic scheme.
- Define the relationship of the regional geodynamic tectonics and volcanism in the area.
- Determine the thermal anomalies at shallow crustal levels.
- Define the regional stratigraphic sequence and lithology types.
- Elaborate the geovolcanological mapping of the identified geothermal areas.
- Describe in a preliminary way the geovolcanological setting of the identified thermal anomalies or geothermal areas.
- Identify the elements that could integrate the geothermal system (heat source, reservoir and cap rock) and formulate preliminary schemes.
- Define, classify and select the geothermal areas of interest.

Geological surveys involve three main phases: 1. compilation and evaluation of the available information, 2. Geological studies (office, field and laboratory investigations) and 3. interpretation and elaboration of the conceptual model.

Phase 1
Compilation and evaluation of the available information.
According to OLADE 1994 and Wohletz and Heiken, 1992 this process includes the compilation of:

- All published and unpublished including stratigraphy, volcanology, structural geology, tectonics, geochemistry and geophysical data. Is important to have the available information on ages of volcanic and intrusive rocks (dating information).
- Topographic and geological maps at any scale, preferable 1: 100.000 and 1:1000000.
- Satellite and radar imagery, aerial photography and digital terrain models (DTM). It is convenient to count with digitized information for post processing.
- Specific information regarding the presence and characteristics of hot springs, fumaroles, and hydrothermal alteration.
- Subsurface information on drillholes or coreholes from any source, including water well drilling, petroleum drilling, and coring by mining companies.

The use of geographic information systems (GIS) is recommended due to the facilities in displaying, combining and updating of the information (OLADE, 1994).

Phase 2
Office, field and laboratory investigations.

Based on the information compiled in phase 1 is necessary to carry out the following activities (OLADE, 1994):

- Evaluation and synthesis of the information.
- Morphological and structural studies by remote sensing (identification of faults and volcanic structures).
- Elaboration of a preliminary geologic-structural map.

The information has to be evaluated in order to identify the known geothermal areas and prospects and define the areas where the field geological studies will take place.
In accordance with OLADE (1994) and Wohletz and Heiken (1992) in volcanic regions, it is important to focus the geological observations on a number of points:

- Recognize areas with episodes of recent volcanism. Definition of "recent" varies according to the volume of material erupted because large magma bodies retain heat much longer than small ones.
- Evaluate the relative quantities of silicic and mafic or intermediate volcanic products (volumes estimations).
- Define the relationship between the volcanic structure and the regional tectonic setting.
- Incidence of recent episodes, mainly of phreato-magmatic origin.
- Sampling of all lithologic types for laboratory analysis, including petrographic and chemical analyses.
- Collect lithic clasts (xenoliths) from pyroclastic units for petrographic analysis.
- Determine the absolute ages of representative lithologic units (dating).
- Study in preliminary way all possible reservoir and caprock units.

Some important aspects regarding the field and laboratory investigations are mentioned by Wohletz and Heiken, 1992:

1. The study of thermal anomalies in the upper crust implies mapping and sampling young volcanic eruption sequences, especially rock types indicative of shallow magma bodies. Mapping and sampling of all areas of hydrothermal manifestations (both fossil and active) in conjunction with hydrogeochemical sampling. All volcanic structures have to be mapped, including craters, domes, phreatic craters, and related faults.

2. In areas with surface hydrothermal manifestations, potential caprocks are mapped and sampled, and their origin is determined. In volcanic zones is necessary to emphasize the search of explosion craters.

3. The extent of potential geothermal reservoirs can be estimated by:
   - A study of lithic clasts (xenoliths) in the pyroclastic units; which provide information on the nature of rocks underlying the volcano.
   - Identification and mapping of recent faults. This effort is essential because active faults frequently represent zones of fracture permeability.
   - Determination of the degree of hydrovolcanic activity responsible for pyroclastic deposits in the volcanic field. This work may identify aquifers beneath the volcano during recent eruptions. These aquifers could be current hydrothermal reservoirs.

4. In tropical countries geological mapping is considerably more difficult due to rapidly soil formation and thick vegetation coverage. In these environments, several additional approaches are necessary:
   - Landform mapping. These maps are based primarily on the interpretation of aerial photographs and satellite images, especially in young volcanic fields. The interpretations are field checked along road cuts, stream bottoms, and shorelines, as well as in quarries.
   - Radar imagery is extremely useful in mapping faults and volcanic landforms in tropical areas because their outstanding surface penetration.

Phase 3
Interpretation of the information and elaboration of the conceptual model.

The information resulting from the interpretation should lead to the development of a preliminary conceptual model of the geothermal system, which will be the basis for the development of subsequent investigations.

The conceptual model has to be oriented in answering questions about (based on OLADE, 1994):

- The existence and probable location of a heat source, indicating its nature, possible extension, depth and age (based on the volcanological conditions complemented with geochemical geothermometers and dating).

- The existence of favorable structural and stratigraphic conditions for the accumulation and movement of geothermal fluid in the ground, it means the existence of a geothermal reservoir and its relation to the heat source. The evaluation must be based on the degree of tectonic fracturing of the rocks and/or the primary permeability characteristics.

- The extension and depth of the inferred reservoir. These parameters allow tentatively estimating the volume of the reservoir, which in fundamental to approximate energetic capacity of the area and determine the magnitude of the drilling costs to reach the reservoir.

4. STUDIED CASE: ARENAL - POCOSOL GEOTHERMAL AREA

The area is located at 75 km NW of San José, Costa Rica (Figure 3), corresponding to the NE border of the Tilaran Range (which consist of a NW-SE Tertiary-Quaternay magmatic belt), adjoining to the Arenal active volcano to the North.

This area in the geothermal reconnaissance study of the Republic of Costa Rica in 1989 was classified as a priority sector for medium-high geothermal prospecting.

The Instituto Costarricense de Electricidad (ICE) in the evaluation of new prospects for future developments finalized a new geothermal reconnaissance study in 2011(Chavarría et al., 2011). The study was carried out in an area of 690 km^2 and includes the compilation of the geocientific available information combined with geologic and geochemical field and laboratory investigations.

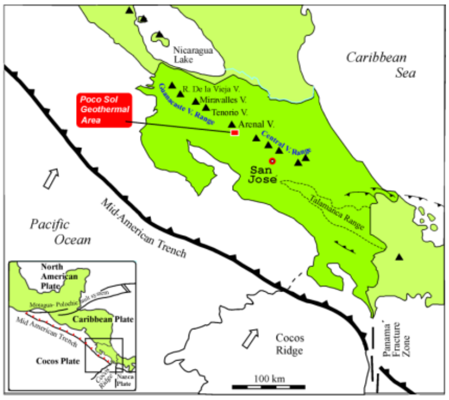

FIGURE 3: Location of the Arenal- Poco Sol geothermal area

4.1 Regional geology

Using the compiled information the regional geologic setting was defined and reflected in a general geological map including the regional geological units and main structures. In a general way, most of the area corresponds to Tertiary to Quaternary volcanic sequences composite mainly of lavas minor pyroclastic deposits. Locally to the north of the Arenal active volcano is the outcropping of marine sediments related to an old sedimentary basin of Miocene age. This suggests the existence of intense tectonic episodes with the consequent development of important structural controls.

4.2 Geomorphology

The area is dominated by eroded volcanic structures formed during the Pliocene and Pleistocene, however towards the north is located the Arenal active volcano, characterized by a young morphology.

As product of the intense erosive processes that had affected the area, the topography is irregular with evident structural alignments such as the Peñas Blancas river, which is a WSW-ENE straightly lineament of about 20 km long. At the center of the area there is a 10 km diameter morphological ring structure known as Poco Sol Caldera, which is located in a sector of high erosion rate that contrast widely with the young shape of the Arenal volcano (Figure 4). Toward the East sector is notable a flat topography related to the deposition of large alluvium deposits due to the erosion of the volcanic belt.

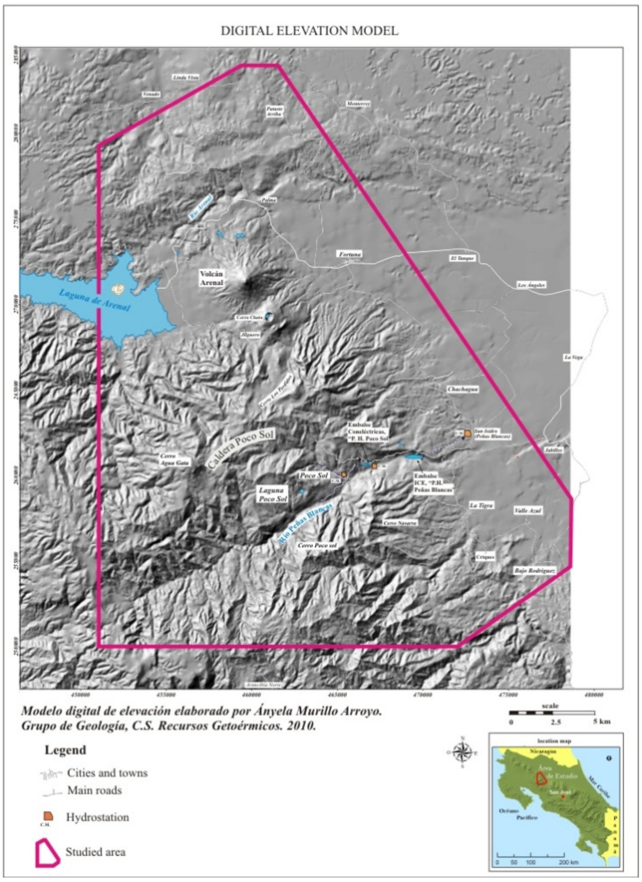

FIGURE 4: Digital elevation model showing the main structural lineaments and morphological features of the area (From Chavarría et al, 2011)

4.3 Geological mapping

After the geomorphological study, where the main volcanic and tectonics structures as well the morphological units were drawn in an integrated map, we proceeded with geological and geochemical field studies, which emphasized the verification of the generated information and collecting of new data. Most of the area corresponds to andesitic-basaltic to andesites lavas and minor pyroclastic products associated to the Monteverde Formation. This unit corresponds to an ancient volcanic plateau which at the present is greatly affected by erosion and landslides. At the centre of the area is clear the existence of semi circular structure (10 km diameter, Poco Sol caldera) whose origin is not yet clear as it could be of volcanic origin or even by erosion processes. This structure is crossed by a 20 km long NE-SW regional lineament knows as Peñas Blancas fault (Figure 5). Just north of the Poco Sol caldera structure there are some minor volcanic centers whose activity seems to have migrated from south to north, until the Arenal volcano.

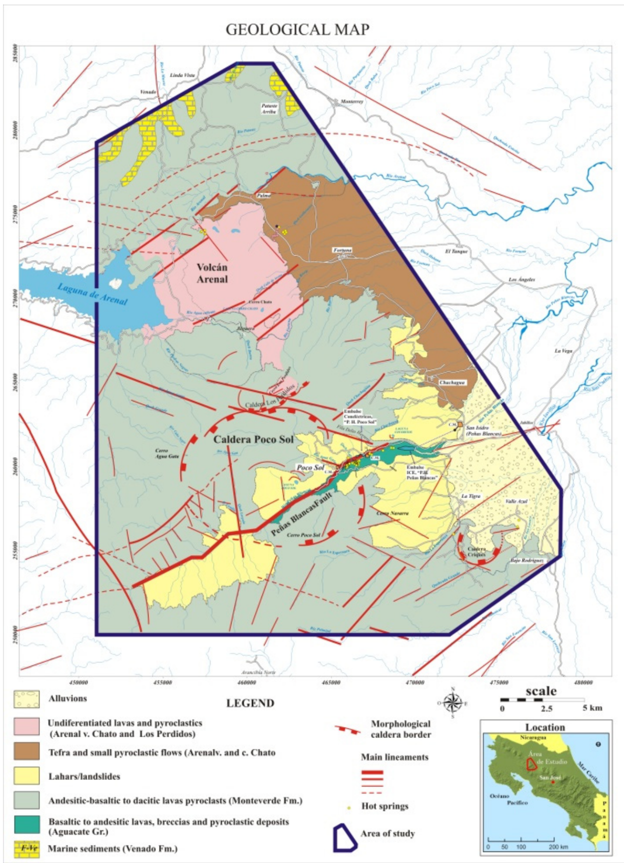

FIGURE 5: Geological map of the studied area (From Chavarría et al, 2011)

According to the available information the area seems to have been exposed to several tectonic phases, allowing the formation of representative structures including faults and caldera structures, evident in aerial photographs and satellite images. The main straight structures are normal faults trending NE-SW direction, some of them with evidence of neotectonic activity. Other important fracture systems are NW-SE and N-S trending. All these tectonic features are positive for the development of secondary permeability.

4.4 Conceptual model

The model was based on the integration of the geological and geochemical information collected during fieldwork and subsequent laboratory analysis, as well relevant data obtained from previews investigations.

The following is an interpretation of the different elements identified:

Heat source
In the north sector of the area undoubtedly there is a local primary heat source related an andesitic magma chamber feeding the Arenal volcano, likewise some recent lava flows and probably shallow intrusive represents secondary heat sources to the formation of shallow thermal hot springs. Toward the center of the area, inside the Poco Sol Caldera structure, is inferred a local heat source in cooling process, which hypothetically could be related to the caldera structure or even to a local intrusion (Figure 6).

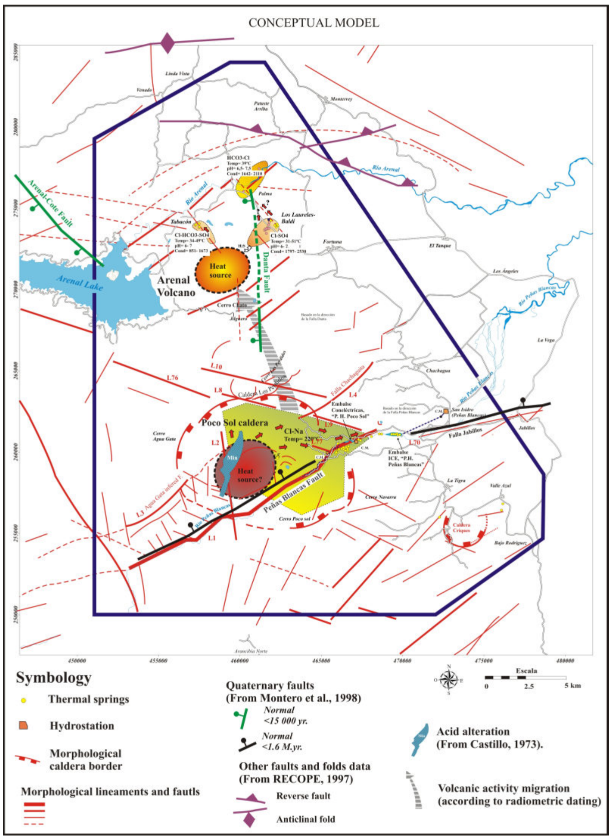

FIGURE 6: Conceptual model (From Chavarría et al, 2011)

Fluid circulation

The circulation of the thermal aquifers in the sector of the Arenal volcano seems to be influenced by N-S structures (Danta fault) and probably local NW-SE fracture systems.

In the sector of the Poco Sol caldera the fluids movement seems to be controlled by regional structures like Peñas Blancas and Jabillos faults (normal faults). Additionally NW-SE fracture systems contribute to the movement of the fluids and outcropping of hot springs along the Peñas Blancas River.

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GEOCHEMICAL SURVEYING AND CONCEPTUAL MODEL OF CHILANGUERA GEOTHERMAL SYSTEM, EL SALVADOR

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ABSTRACT

Geoscientific surveys were performed in the Chilanguera geothermal area in El Salvador between years 2004 and 2011. The main objective of this study is to present contribution of geological, geophysical and geochemical surveys for elaboration of the Chilanguera conceptual model. Different criteria were defined in order to identify the main characteristics of the geothermal reservoir. Chilanguera geothermal area is defined as a volcanic geothermal system in the Jucuarán mountain range of 0.63 M.y. age. The heat source has been identified as a sub-volcanic body at 8 km depth. Reservoir is formed by lava rocks belonging to Chalatenango formation, with fluid temperature up to 200°C according to gas geothermometers, thickness of 400 m and located between -800 and 1200 m.a.s.l. Upflow zone is located approximately 500 m south of Laguna Agua Caliente through fracture W-O delineated by structural geology and fluid circulation pattern is towards north through NW-SE and NNE-SSE structures, this alignments were also confirmed by MT strikes and by gravimetric structural alignments. The recharge zone is located in the Jucuarán mountain range and isotopic composition of water indicates that recharge zone is at 600 m a.s.l. Discharge zone is located in the hydrothermal alteration zone in the surroundings of Laguna Agua Caliente.

1. INTRODUCTION

Chilanguera Geothermal Area is located to the southeast of Chaparastique volcano in San Miguel at the eastern part of El Salvador, with an extension of 100 km^2. The Chilanguera Geothermal Area is associated to Jucuarán mountain range (Figure 1).

The first geothermal studies for identification of hydrothermal zones in El Salvador were carried out in 1953. In year 2004 LaGeo S.A. de C.V. conducted exploration surveys in the most eastern part of the country in an area of 640 km^2 included Chilanguera. After these surveys, two main areas were identified: Conchagua in La Unión and Chilanguera in San Miguel. Later in year 2011 LaGeo conducted detailed surveys in both areas and present study focuses on an area of 100 km^2 in size.

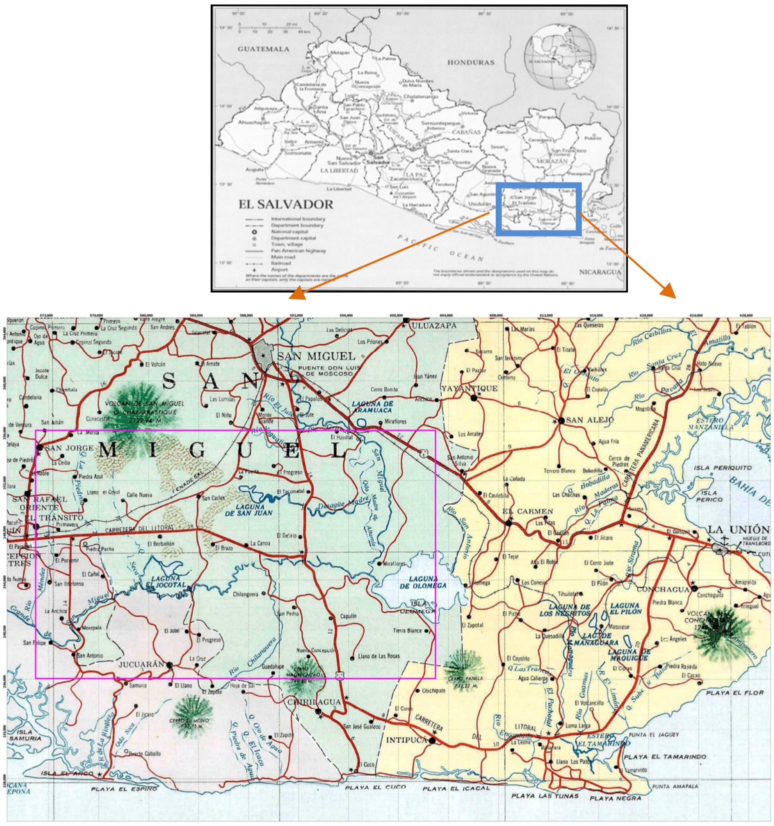


FIGURE 1: Studied area - aerial extension of 100 km^2

2. GEOLOGICAL REVIEW

2.1 Structural geology

The studied area is located in the Chortis Block, there are important features related to tectonic environment that influences the geological evolution of the region, firstly North American Plate moving toward West meanwhile in the south the Caribbean Plate is moving in opposite direction with the formation of Polochic-Motagua Fault; and the last, is the subduction of the Cocos Plate that sinks under the Caribbean Plate, generating an extension E-W of Chortis Block (Figure 2).

These plates interaction produce a fault system which strikes NW-SE as well as extensional zones with the creation of a second fault system which strikes N-S.

2.2 Local geology

The studied area is composed by basic, intermediate and acidic volcanic rocks of Miocene-Recent (Holocene) age. The stratigraphic sequence of the mountain range can be described as follows:

- *Epiclastic deposits*. This unit is located to the west of studied area, this epiclastic deposits are the oldest unit attributable to El Bálsamo formation with Miocene age. These deposits were formed during volcanic activity of Tertiary.
- *Effusive basaltic-intermediate, pyroclastic rocks and volcanic epiclastic subordinated*. This unit is located to the East of studied area and includes the Cerro El Panecito which has andesitic lavas partially altered and by a deposit of pyroclastic flow with subordinated lavic blocks of 15-50 cm, this flow is eroded and hydrothermal altered.

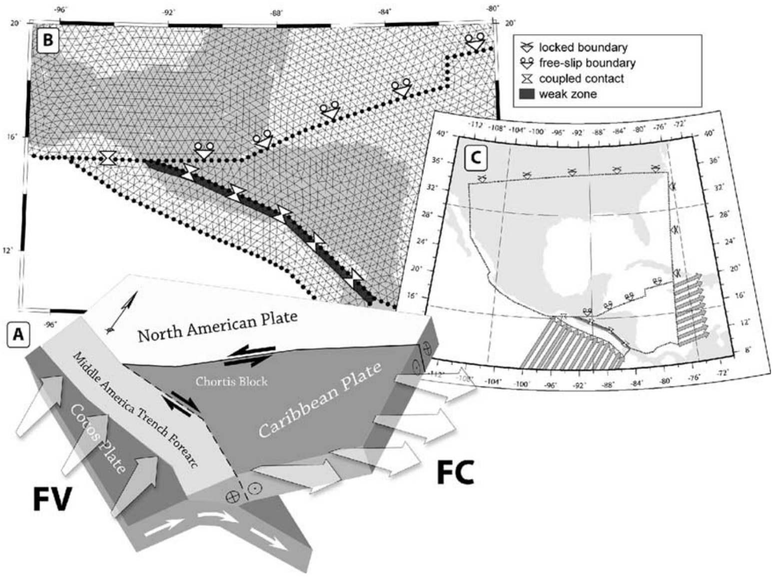


FIGURE 2. Geodynamic conceptual model of the Chortis Block, where FV is the vectorial force of the oceanic trench, FC is the Caribbean plate force (after Alvarez-Gómez, et al. 2008)

In La Joyona and Zúngano creeks fossil geothermal alteration was observed; in the zone of the Cerro el Panecito silicic rocks were observed showing a neutral alteration with chlorite clays, silica and iron oxides; on the other hand, in the Zúngano, alteration is more acid, since pyrite and deposits of sulphur are present.

Deposits of pyroclastic flows of intermediate composition were observed at Jucuarán, there is evidence of partial hydrothermal alteration near the El Jutal, these deposits underlie effusive basic-intermediate unit. This unit belongs to b2 member of El Bálsamo formation of Miocene-Pliocene age.

- *Basic-intermediate effusive rocks*. This unit covers most of the studied area and belongs to eroded andesitic rocks. At the south, at the highest part of Jucuarán mountain range, andesitic deposits are hydrothermally altered. Rocks forming this unit are andesite type, pyroxene andesite with porphyritic texture; on the other hand, to the North there is no evidence of hydrothermal alteration.

  According to Misión Geológica Alemana, 1978, this unit belongs to b3 member of Bálsamo formation of Pliocene age. These deposits overlie effusive basic-intermediate unit, pyroclastic rocks and volcanic epiclastic subordinated.

- *Basic-intermediate lavas and pyroclastic flows from Chaparrastique volcano*. The most important constituents of this unit are andesite-basaltic rocks with porphyritic-vesicular texture, they are present in the northern side of the studied area, and they belong to s2 members of San Salvador formation and come from Chaparrastique volcano.

- *Accumulation cone of Chaparrastique volcano*. This unit belongs to pyroclastic deposits of basic composition erupted by parasitic cones of Chaparrastique volcano. These cones are located in the northern part of the studied area and are composed by two main centres: scoria deposits of Loma de Merlos with 60 m high and diameter of 200 m and Cerro El Borbollón which is composed by thin layers of pyroclastic deposits and ash. This hill is 110 m high y 900 m diameter.

- *Quaternary flood deposits.* They are the most recent deposits eroded from highest places, transported and deposited in the lower parts by floods of water. These deposits are thin and cover the Laguna el Jocotal and Laguna Agua Caliente which is 50% of studied area.

2.3 Petrographic analysis

The studied area is comprised of many volcanic edifices that make up the Jucuarán mountain range, so have obtained a variety of rock composition of basic, intermediate and acidic. Petrographic analysis provides information about different types of rocks present in the studied area.

- *Basalts.* This group of rocks was found mainly at the southeast of Jucuarán city and belongs to a dike of basaltic composition.

- *Andesite-basaltic*. Lava flows of andesite-basaltic composition have been classified by its low content of Olivine 2-3%, pyroxenes 7-10%, plagioclase 20-25% and opaque minerals 1-3%. Most of these flows belong to basic-intermediate effusive unit from Chaparrastique volcano.

- *Andesite.* Lava flows of andesite composition are the most predominant in the studied area; they are divided into two groups: andesite and andesite-pyroxene. Secondary minerals as calcite 1-3%, chlorite clays 1-5%, quartz 1-2% and iron oxide 1-5% are present.

2.4 X-ray diffraction analysis

Ten samples were collected in different zones of fossil alteration in the Jucuarán mountain range for X-Ray diffraction analysis at LaGeo Geological Laboratory. The main found minerals belong to Argillic facie of a hydrothermal system where the most abundant minerals are montmorillonite which is clay of the low temperature smectite group.

There is another mineralogical assembly which is characteristic of Argillic zones, calcite, quartz, montmorillonite, halloysite, and cristobalite minerals are present suggesting temperature in the range of 100°-120°C.

Laguna Agua Caliente reveals the presence of gypsum also suggesting low temperatures and represents evaporite deposits.

2.5 Geochemistry of rocks

Geochemical analysis of rocks was performed in order to determine the origin and different types of rocks existing in the studied area. Seven samples were analysed by X-ray fluorescence at Geochemistry Laboratory of Universidad Nacional Autónoma de México.

Results of analysis suggest that two main groups of rocks are present in the studied area; the first one is andesite rocks of intermediate composition which is representative of lava flows in the area, the second is the pyroclastic flow which is divided into two events: the ones of dacitic composition and the ones of rhyolitic composition. See TAS diagram after Le Bas et al., 1986 Figure 3.

Geochemical analysis of andesite rocks shows that SiO_2 and oxides of major elements content are high, suggesting that the magmatic chamber feeding the volcanoes of Jucuarán mountain range are not deep enough because parent magmas of lava flows present in the area are evolved magmas.

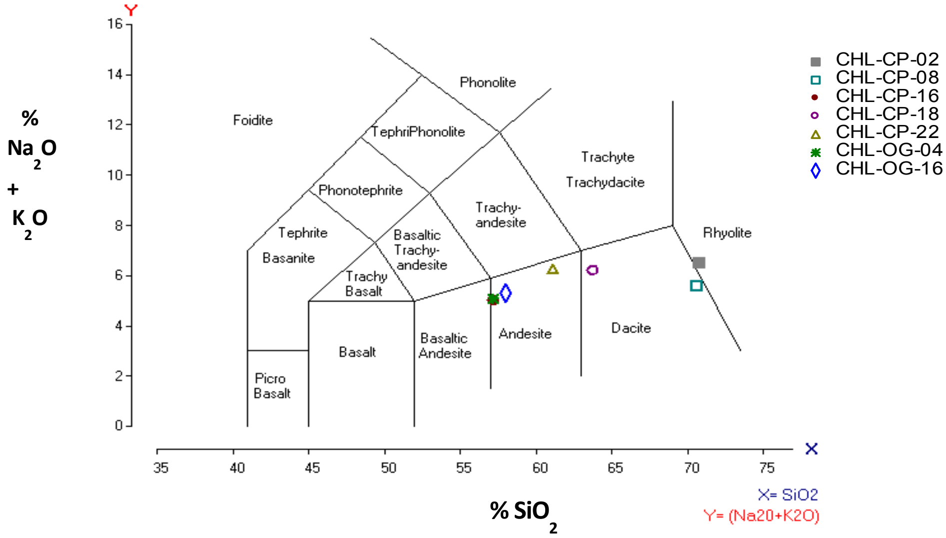


FIGURE 3: TAS diagram shows volcanic rocks of Chilanguera geothermal area (after Le Bas et al., 1986)

2.6 Hydrothermal manifestations

Hydrothermal manifestations in the studied area are located in the surroundings of Laguna Agua Caliente mainly consisting in hot springs and fumaroles at the southeast margin of the lagoon. Some hot springs are extended to the East and some others to the North where temperature decreases.

Hot springs and fumaroles are located in a small portion of the studied area temperatures ranged between 31 and 102°C; highest temperatures were measured in domestic wells at the south and East of Laguna Agua Caliente.

There is evidence of hot springs alignment at the end of Jucuarán mountain range slopes suggesting structural control. The presence of a main structure at the south of hot springs with E-W orientation dipping to the North, can be correlated to the southern margin of central depression, confirm this structural control.

3. GEOPHYSICAL DATA

3.1 Gravimetric surveys

Different gravimetric surveys have been carried out in the Chilanguera geothermal area. Surveys were conducted in the years 2004, 2008-2009, and 2011. 770 surveys were conducted up to year 2011 with an average spacing between measurements of 1000 m and represent a regional coverage of approximately 1500 km^2 including San Miguel volcano, Conchagua and Chilanguera geothermal areas. This density of points gives a very good resolution of observed gravimetric anomalies in both local and regional perspective.

In the last two surveys a Scintrex CG-5 model was used and each gravimetric point was positioned with double frequency GPS in cinematic mode with minimum time data logging of three minutes. Data was filtered, assessed and processed using Gravmaster software (Geotools) and exported to WingLink (Geosystem) for calculation of Bouguer grid anomalies, residual anomaly and application of some filters as first horizontal derivative, first and second vertical derivative, interpretation an correlation with resistivity studies. GPS data were processed using Trimble Geomatic Office (Trimble) and Surfer software was used for map visualization.

Figure 4 shows Bouguer anomaly with density of 2.3 g/cm^3, the white line differentiates between maximum and minimum gravimetric values and represent an isocontour of 30. Zones with values lower than 30 are considered as gravimetric minimum values.

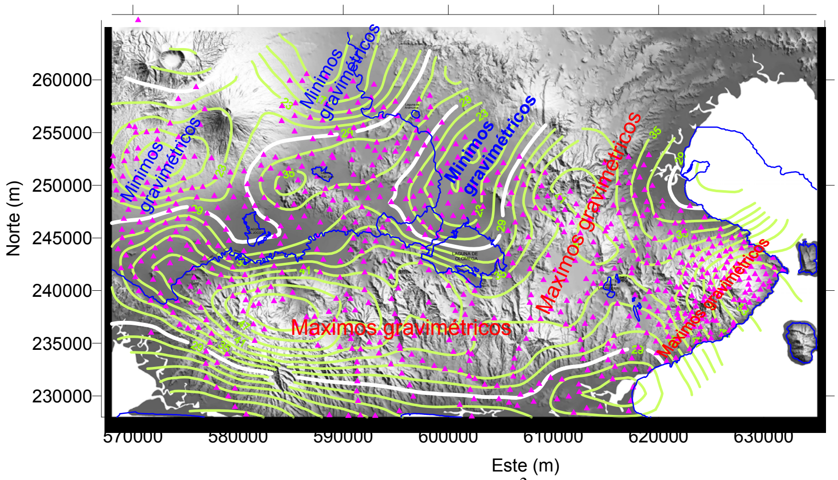


FIGURE 4: Bouguer anomaly map for a 2.3 g/cm^3, contour intervals every 3 mGal

Maximun values of the Bouguer anomaly appear concentrated on the Jucuarán mountain range W-E oriented, then this maximum values drift toward North in the eastern part of Laguna de Olomega. A regional alignment is observed with W-E direction parallel to the coast at the south of Jucuarán mountain range and could be defining big regional structures probably associated to southern edge of the central graven or to the subduction zone.

Figure 5 shows the residual anomaly map at density of 2.3 g/cm^3. Typically a residual anomaly shows local structural characteristics of the studied area differentiated by positive and negative gravimetric anomalies i.e. high and low rock density. Positive anomalies are associated with very well-consolidated rocks due to mineralization, compaction and type of rock. Positive anomalies are related to Jucuarán Mountain range and some areas towards North. In zones with hydrothermal alteration, to the North of Jucuarán mountain range, are represented by positive anomalies. A very good correlation exits between positive and negative gravimetric anomalies and the structural geology.

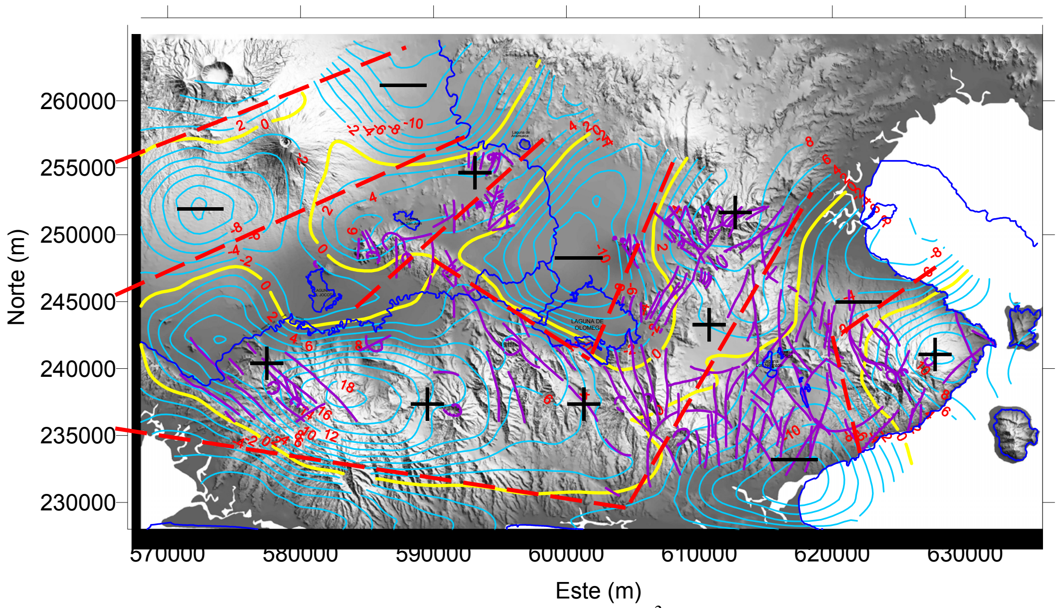


FIGURE 5: Residual anomaly map with density of 2.3 g/cm^3. The yellow line represents cero value of residual anomaly map. Purple lines depict structural geology alignments. Dashed red lines represent suggested structures based on cero value of residual anomaly

In general, there are structural contour lines defining a WNW-ESE direction, consistent with Jucuarán mountain range and other systems with NE-SW orientation. Some local structural systems contour lines are aligned with the residual anomaly.

According to gravity survey, there are indicators that a possible major geothermal area is associated with a heat source of the Jucuarán mountain range that the San Miguel volcano since this is located on a negative anomaly zone.

The grid of Bouguer anomaly as well as the residual anomaly were used in depth analysis to calculate the power spectrum through the Fast Fourier Transform, it was estimated that the bodies that produce anomalies are at 0.4, 2.1, 4.3 and 8.8 km.

3.2 MT and TDEM surveys

Electrical resistivity DC surveys were carried out in Chilanguera in year 2004 and they included 60 electrical pits and 45 vertical electrical soundings (VES). This survey was used for delimitation of 100 km^2 study area where main physical anomalies were present.

In year 2008 a complementary electrical resistivity survey was conducted and 23 MT soundings were included. Penetration capacity of VES is affected by the presence of shallow aquifers, for this reason in year 2010 MT and TDEM soundings were conducted with the main objective of getting information related to deeper electrical stratigraphy in the studied area.

Data collected from soundings were processed and modelled using 1D technique and one 2D profile was also analysed with the main objective of characterization of the main productive reservoir and the seal layer for well targeting proposes.

3.2.1 Strike analysis

In Chilanguera, the strike map for a frequency of 0.5 Hz (0 to 1500 m) shows preferential directions where fluids circulate in NW-SE, NE-SW and W-E orientation (figure 6) which are well correlated to local fault system in the studied area and playing an important role in the circulation of geothermal fluids.

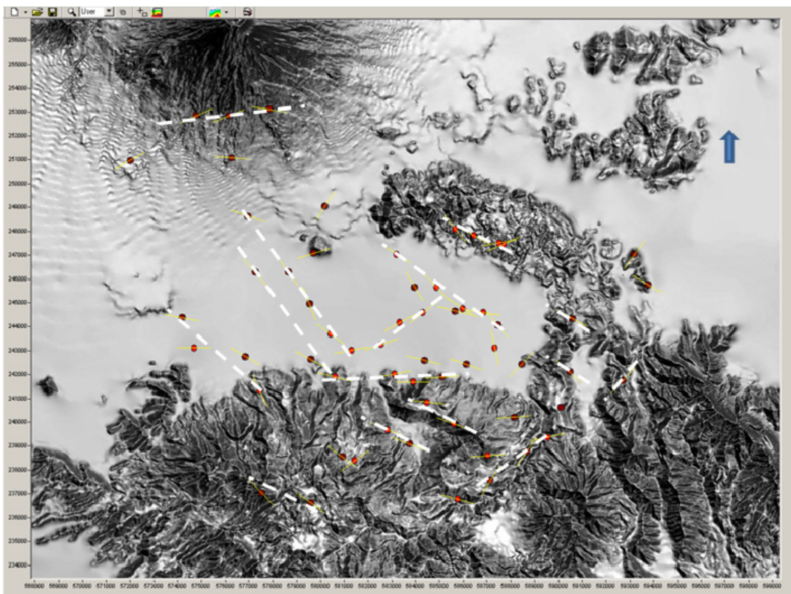


FIGURE 6: Structural alignment suggested by a strike map at 0.5 Hz (0-1500 m depth)

3.2.2 1D and 2D models.

1D model was performed using WinGLink software with Occam algorithm and shows the presence of deep resistive layer with resistivities higher than 30 ohm-m underliying a conductive layer of variable thickness at 400-600 m depth and resistivity values lower than 10 ohm-m.

Figure 7 shows correlation between 1D profiles NE-SW oriented. Resistive layers are shown in blue with values higher than 20 ohm-m and conductivie layer is depicted by resistivity values lower than 10 ohm-m in red. Plain stratigraphy and thickness of conductive layer suggest that this profiles are located in the margin of the main hydrothermal zone and are representative of low temperature minerals associated with discharge zone of geohtermal system.

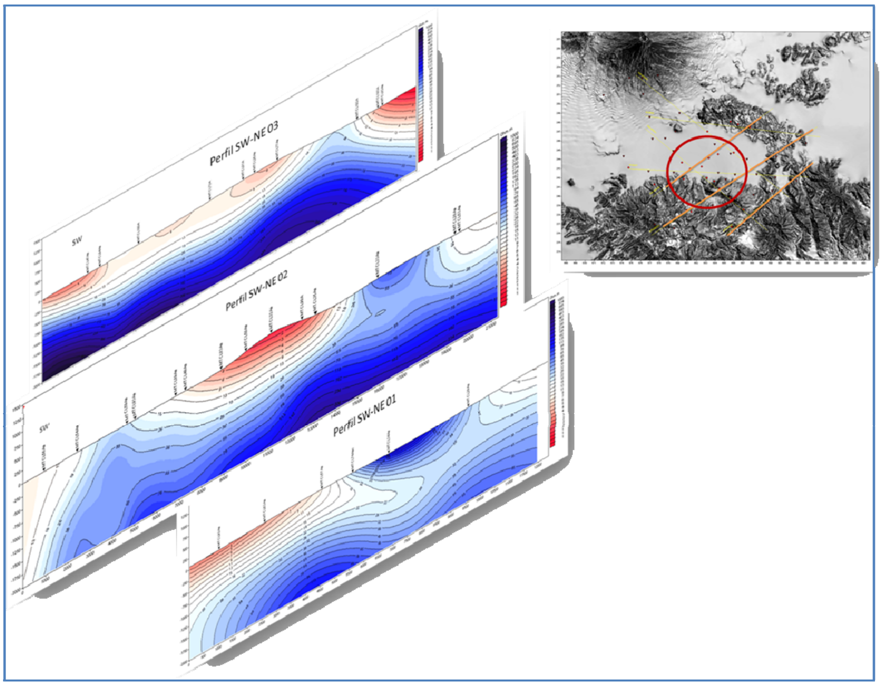


FIGURE 7: 1D correlation profiles with NE-SW orientation

There is an agreement between different 1D profiles suggesting that the zone of interest for geothermal exploration is the one showed in the red circle of Figure 7, in addition suggest that the upflow zone is located below the area where profile shows resistivity values below 5 ohm-m. This suggests that the heat source is associated to an intrusive body of the Jucuarán volcanic system.

Results of 2D modelling are shown in Figure 8 and the main characteristics of this section are as follows:

There is a well-defined conductive layer with values lower than 10 ohm-m going deeper since the surface up to -600 to -800 m a.s.l. This layer is associated to impermeable clays and represents the seal cap of the geothermal reservoir (Figure 8). The section suggests the presence of resistive dome identified at 800 m depth depicted by the white dotted line. The possible reservoir is bounded by resistivity values between 20 and 90 ohm-m which is located between -800 and -1200 m a.s.l.

The main zone of interest is located in the central section of 2D profile in figure 8 and is the best option for well targeting.

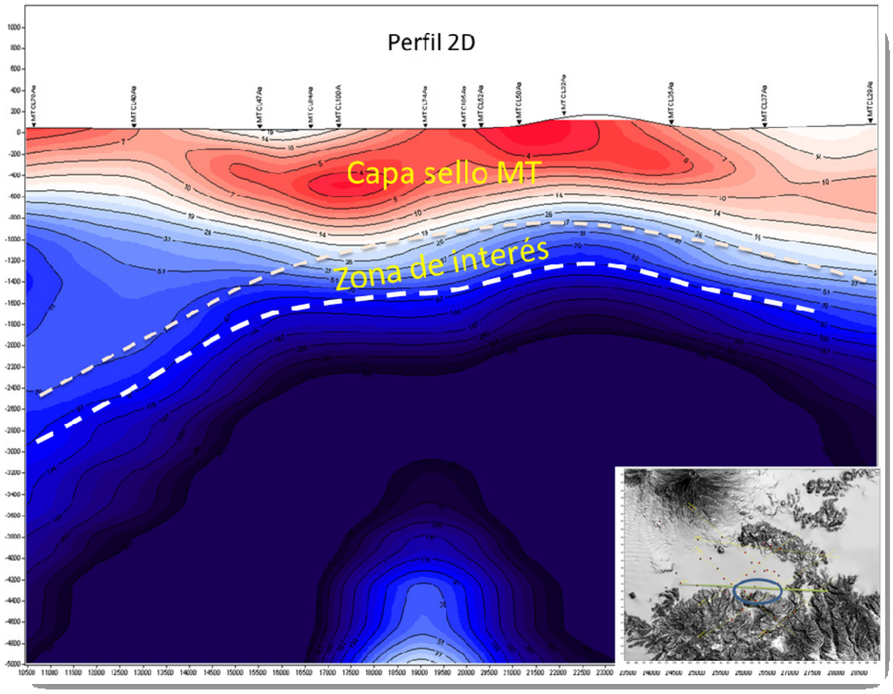


FIGURE 8: Seal cap and possible reservoir from MT/TDEM survey

4. GEOCHEMISTRY OF FLUIDS

4.1 Geochemistry of water

Geochemical exploration started in 2004 in an area of approximately 640 km^2, at that time a total of 53 water and steam samples from cold and hot springs, domestic wells, lagoons and fumaroles were collected. Twenty four new sites were sampled in addition in year 2011. Map in Figure 9 show places where samples were collected.

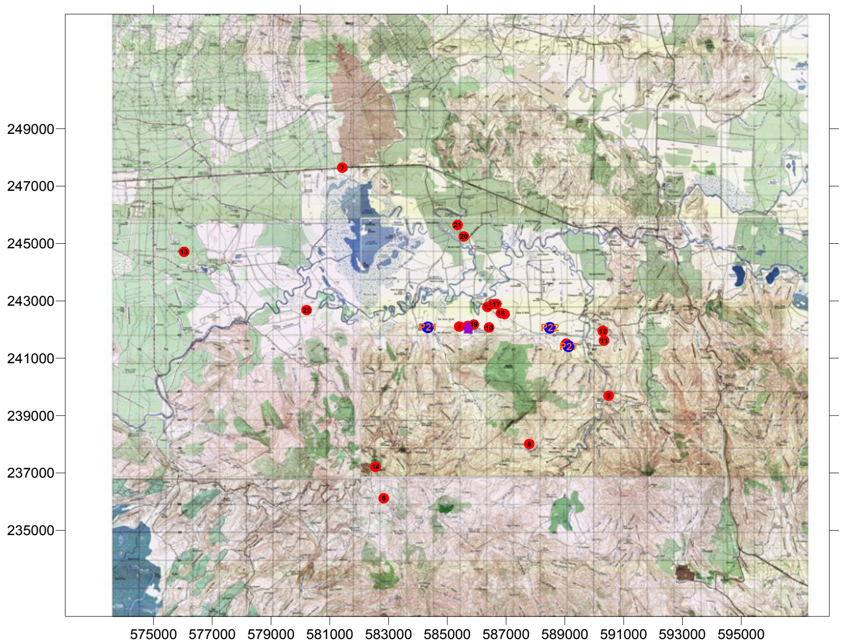
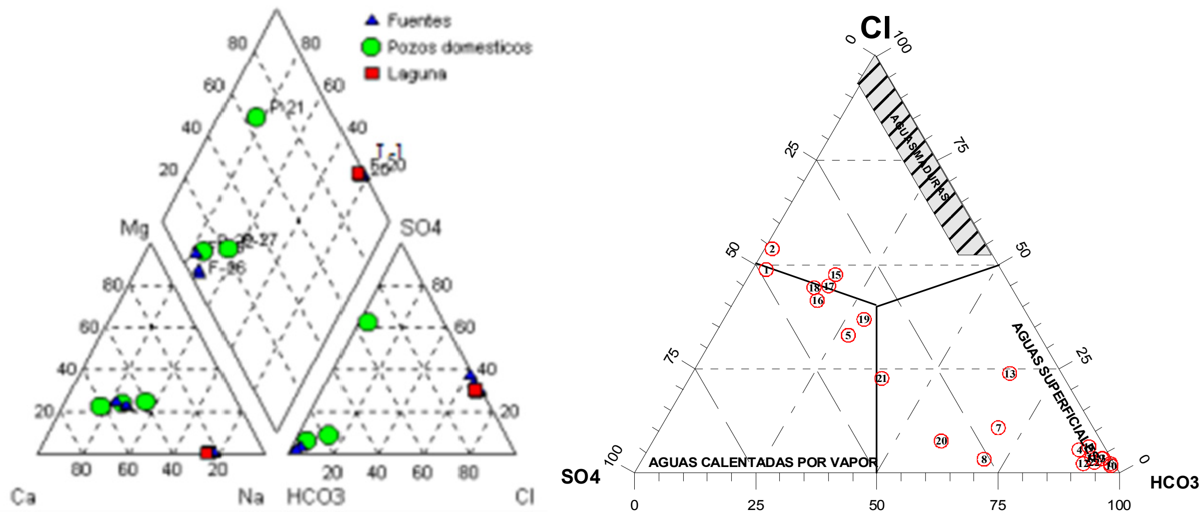


FIGURE 9: Location map for chemical sampling in the Chilanguera geothermal area

Samples localized near Laguna Agua Caliente and in the margins of the lagoon are Na-Cl-SO_4 type with evidence of geothermal composition. Sampling temperature ranged between 40-50°C. Remaining samples show bicarbonate composition and lower temperatures (figure 10).

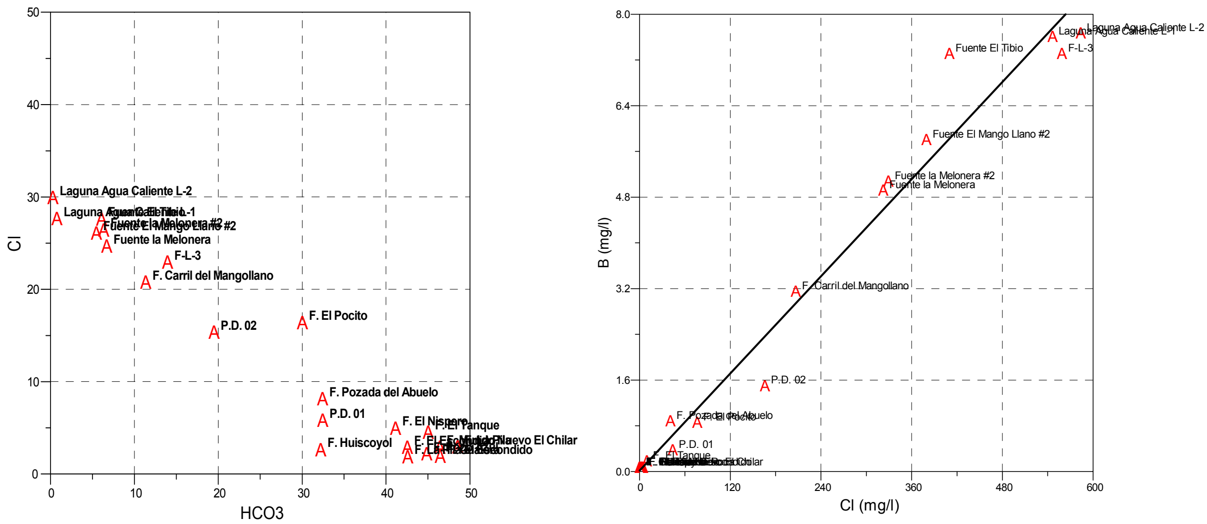


(a) (b)

FIGURE 10: a) Piper and b) Cl-SO_4-bicarbonate diagrams for waters from Chilanguera geothermal area

Figure 11 shows the Cl-HCO_3 relationship as assessment of type of waters and presence of end members (chloride and bicarbonate waters) as well as intermediate members suggesting mixing processes. The same relationship is shown in the Cl-B diagram where boiled waters show higher chloride concentration.

Na-K relationship (Figure 12) confirms this hypothesis; waters from Laguna Agua Caliente are from geothermal origin and mix with cold water coming from East and South in the studied area.



(a) (b)

FIGURE 11: a) Cl-HCO_3 and b) Cl-B relationship for waters of Chilanguera area

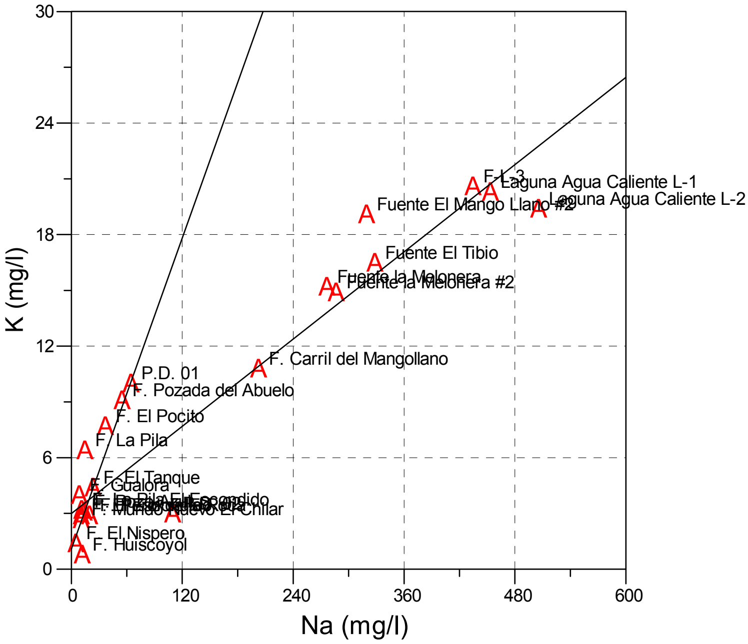


FIGURE 12: Na-K relationship (in mg/l) for waters from Chilanguera area

4.2 Isotopes

Isotopic composition of studied waters is shown in Figure 13, sample L2 from Laguna Agua Caliente shows high evaporation. Fuente el Magollano is from geothermal origin and fits in the same evaporation line than sample L1 showing low water-rock interaction suggesting low deep temperature.

Fuente Guarola shows more negative isotopic composition suggesting that the most probable recharge zone is at 600 m a.s.l.

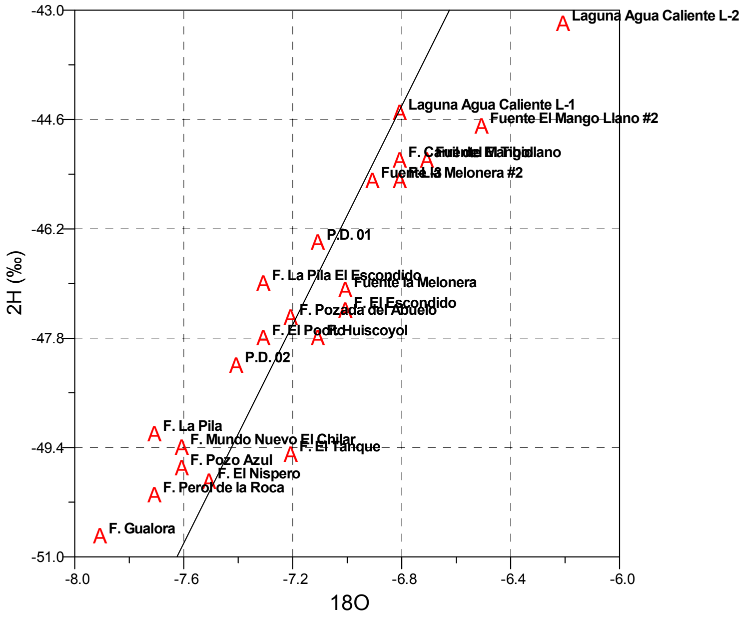


FIGURE 13: ^{18}O-^{2}H isotopic relationship (in ‰)

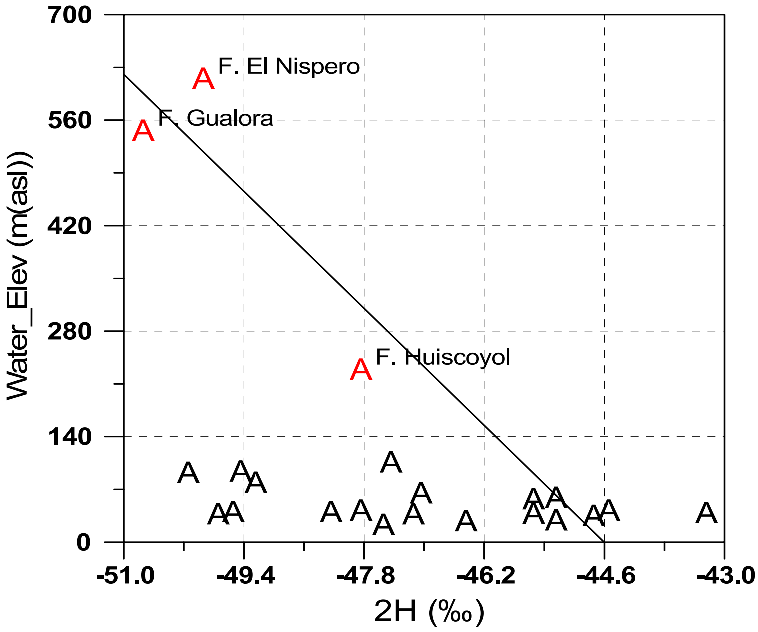


FIGURE 14: ^{18}O (in ‰) - elevation relationship

4.3 Water geothermometry

Table 2 shows results of cation geothermometers for Chilanguera area, geotemperatures range between 100-150°C.

TABLE 2. Temperature of water in Chilanguera area
:

ID	Lugar de Muestreo	Punto de Muestreo	Na	K	Ca	Mg	Cl	SO4	HCO3	SiO2	Nak F/T 73	NaK F79	NaK Arn83	NaKCa F/T73	Calcedonia Fournier 77	Calcedonia Arnorsson 83	Cuarzo F/P82	Cuarzo Arnorsson 85 (max steam loss)
1	L Agua Caliente, Cton. Chilanguera	L-1	456	20.3	123.2	1.45	548.2	543.58	30.6	124	106	156	125	142	124	122	150	145
2	L Agua Caliente, Cton. Chilanguera	L-2	508	19.4	114	0.0521	585.6	486.06	16.07	127.5	94	146	114	137	126	123	151	146
5	Cton. Chilanguera	F. Carril del Mangollano	205	10.8	49.8	7.54	208.6	248	173.51	102.3	120	168	138	144	112	110	139	135
15	Chilanguera	F El Tibio	331	16.5	96.8	2.58	412	300.42	152.56	81.2	115	164	133	144	98	97	126	124
16	Chilanguera	F la Melonera	279	15.2	60.4	2.21	324.2	325.39	132.91	106.8	123	170	140	149	115	113	141	137
17	Chilanguera	F la Melonera 2	289	14.9	59.1	3.63	331.3	276.47	129.64	107.9	118	166	136	147	115	113	142	138
18	Chilanguera	F Mango Llano 2	322	19.1	70.9	2.39	381.5	348.87	126.41	126	130	176	147	154	125	123	151	145
19	Laguna Agua Caliente	F-L-3	437	20.6	114.8	0.4116	560.9	520.36	439.16	133.1	110	160	129	144	129	126	154	148
21	Cantón El Brazo	P.D. 02	112	3	94.6	30.23	167.8	277.49	292.14	101.3	69	125	91	103	111	110	138	135

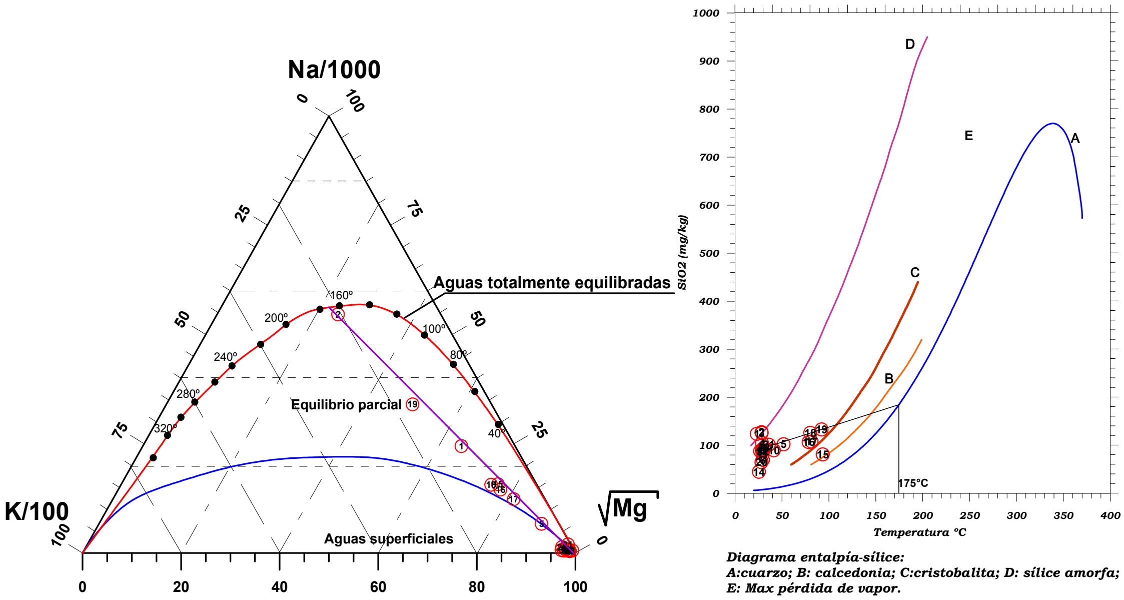
Giggenbach diagram in Figure 15 shows that estimated temperature is 170°C and temperature of mixing diagram is 175°C.

4.4 Gases

Fumaroles and boiling water was sampled in Laguna Agua Caliente. Origin of gases may be inferred using ternary diagram N_2-He-Ar (Giggenbach, 1980). Gases are from magmatic origin but meteoric influence was also observed (Figure 16). Degasification is also present as product of interaction with surrounding water. Gas geothermometers show temperatures between 150-250°C (Table 3).

TABLE 3: Gas geothermometer temperatures

ID	Lugar de Muestreo	Punto de Muestreo	$T_{DP(1)}$	$T_{H2S-CO2(2)}$	$T_{CO2(3)}$	$T_{H2S(3g)}$	$T_{H2S(3)}$	$T_{H2(3g)}$	$T_{H2(3)}$	$T_{CO2/H2(3g)}$	$T_{H2S/H2(3g)}$	$T_{CO2/N2(4)}$	$T_{CO2-H2S(5)}$	$T_{CH4/CO2}$
1	Cton. Chilanguera	Laguna Agua Caliente Gas-1	152.69	220.54	227.11	255.48	185.92	234.24	137.31	241.63	215.56	180.31	246.33	270.79
2	Cton. Chilanguera	L. Agua Caliente Hervidero Gas-3	155.96	205.96	180.20	246.66	173.45	228.60	127.47	244.42	212.53	191.[illegible]	241.11	246.97



(a) (b)

FIGURE 15: a) Giggenbach diagram (1988) b) Silica geothermometer

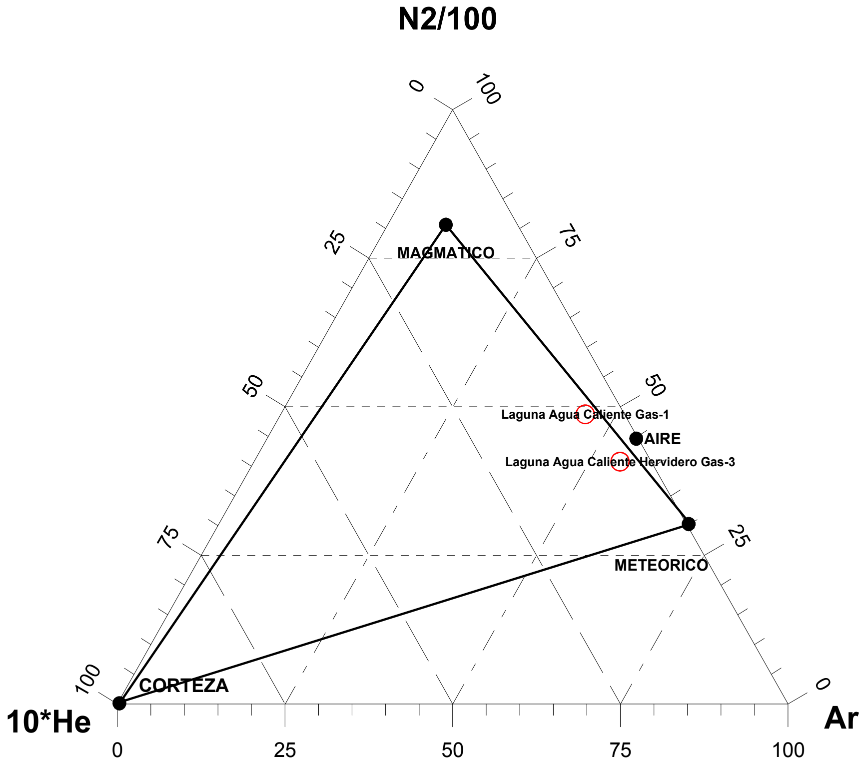


FIGURE 16: Relative content of N_2-He-Ar (Giggenbach, 1980).

4.5 Diffuse degassing

Diffuse degassing surveys were conducted in year 2004 in aproximately 640 km^2 in an area located southeast of Chaparrastique volcano in San Miguel. CO_2 flux, radon and thoron gases were measured in 217 points with separation of 1.5-2 km from each other, see Figure 17.

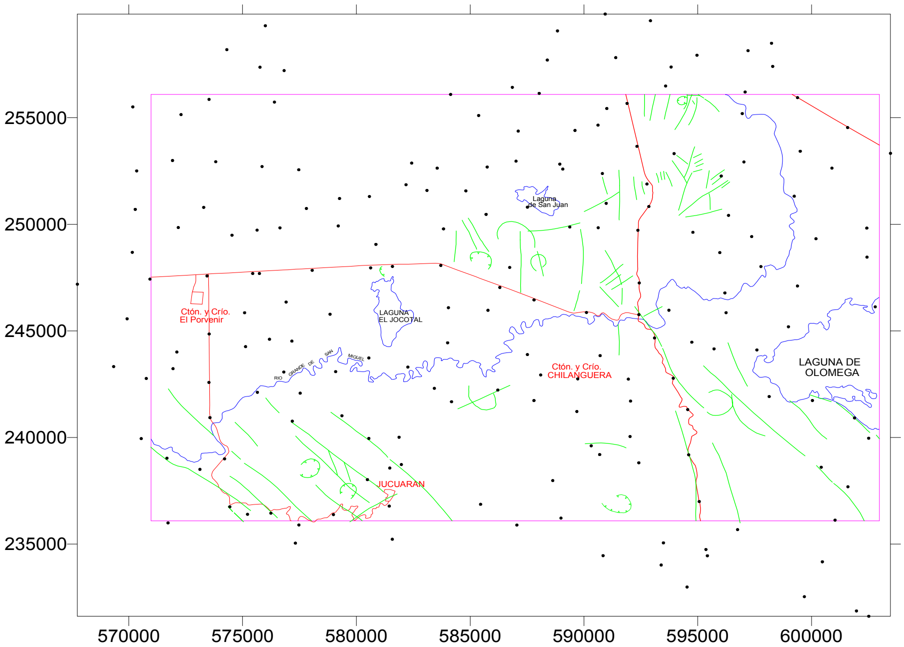


FIGURE 17: Location sites for difusse degassing monitoring in Chilanguera

4.5.1 CO_2 flux (g/m^2-day)

Measured values range between 60 and 130 g/m^2-day, background value is 25 g/m^2-day, higher values are associated to faults and structures in the estudied area.

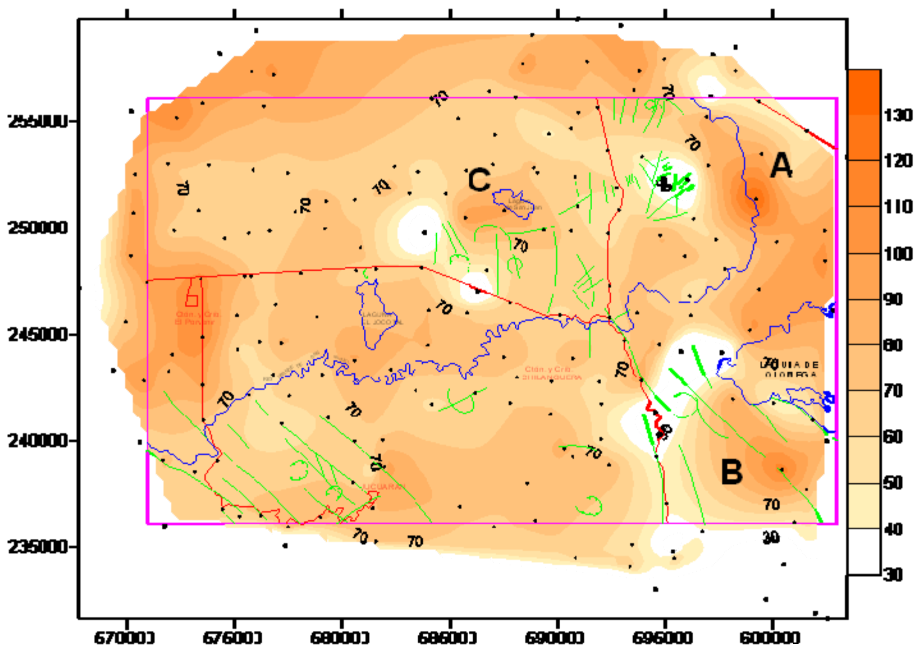


FIGURE 18: CO_2 flux distribution map

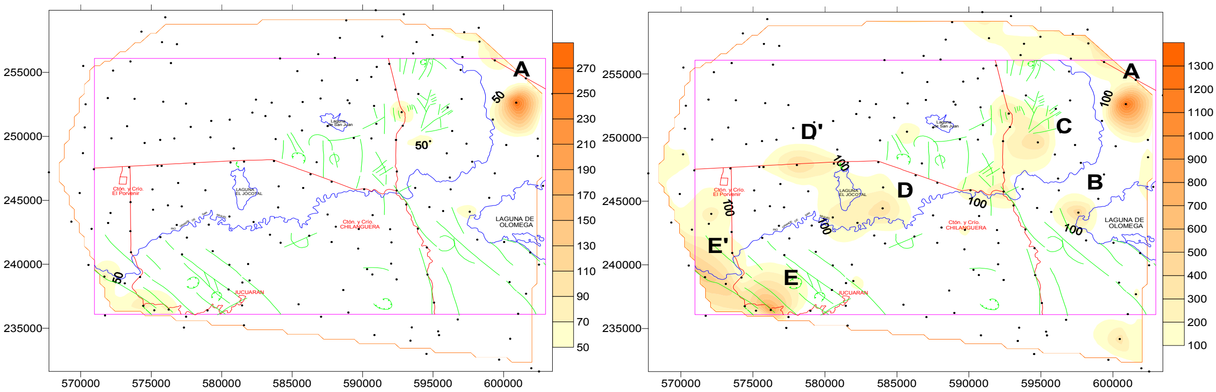
Anomalies B and C in Figure 18 are related to comfirmed structures in the studied area and both are therefore considered active faults. Anomaly A suggests the presence of another estructue which is comfirmed by presence of a radon anomaly, therefore the existence of a structure that is capable of flow transport in a convectively way is confirmed.

4.5.1 Radon and thoron

Radon and thoron anomalies can be observed in Figure 19, where anomaly A is consistant for three mentioned gases (CO_2, Radon and Thoron). In adition Thoron anomalies B, C, D-D’ and E-E’ were ploted. Anomaly D-D’ have good correlation with main structures observed in the studied area.

4.5.2 Thoron/Radon ratio

Thoron/radon ratio defined high permeability and vertical ascent of fluids. Anomaly B-B’ suggests that a high permeability circular structure is present and probably overlaying recent volcanic deposits (Figure 20).



(a) (b)

FIGURE 19: a) Radon and b) Thoron distribution maps

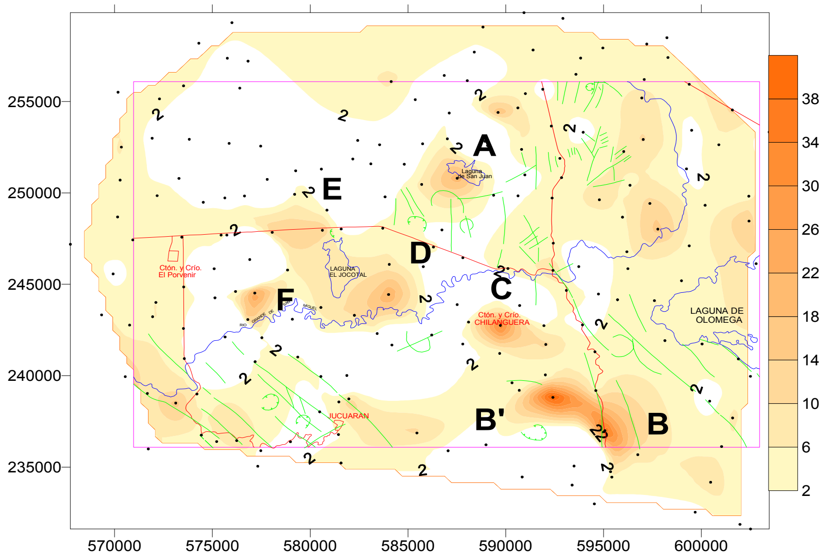


FIGURE 20. Thoron/Radon ratio distribution map

5. CONCEPTUAL MODEL

Geoscientific criteria has been defined for elaboration of the Chilanguera geothermal area conceptual model. Table 4 sumarizes main results of geoscientific surveys describes in previous chapters. The conceptual model of the geothermal area is shown in Figures 21 (cross-section with a rough sketch) and 22 (which shows a planar view).

TABLE 4: Geoscientific criteria for elaboratorion of conceptual model in Chilanguera

Reservoir characteristic	**Geoscientific criteria**		
	Geology	**Geochemistry**	**Geophysics**
Heat source	Sub-volcanic in the Jucurán mountain (dyke 0.63 M.a.)	?	Positive gravimetric anomaly supported by grvimetric spectral analysis (8 km depth)
Reservoir	Lavas from Chalatenango formation	Equilibrated aquifer 150-180°C (water geothermometer) a cerca de 200°C (gas geothermometer). Magmatic gases.	Reservoir between 40 and 90 Ohm-m, between -800 and -1200 m
Seal Cap	Pyroclastite and epiclastite from El Bálsamo formation (b1 unit)	?	Cunductive strata since surface up to -600 to -800 m
Fluid circulation pattern	Upflow zone approximately 500 m toward south of Laguna Agua Caliente though fracture E-W (Cerro Panecito) moving to the north by NW-SE and NNE-SSW structures	Mixing process geothermal and cold water	NW-SE and NNEa-SSO alignments defined by MT srikes and gravimetric structural alignments
Recharge zone	Jucuarán mountain range	Isotopes: Jucuarán mountain range at 560-600 m.a.s.l. (Guarola and El Níspero springs)	?
Discharge zone	?	Zone of hydrothermal manifestation near Laguna Agua Caliente	?

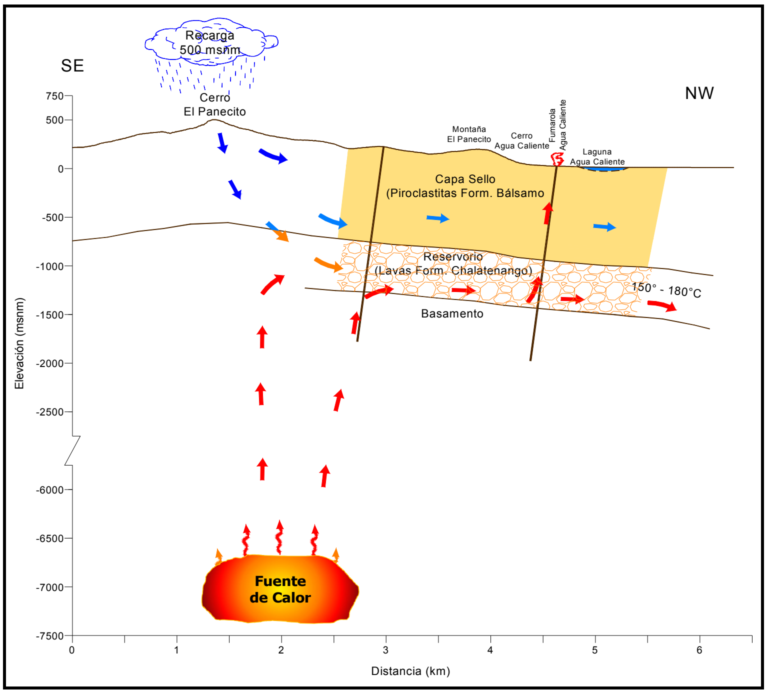


FIGURE 21: Chilanguera conceptual model sketch.

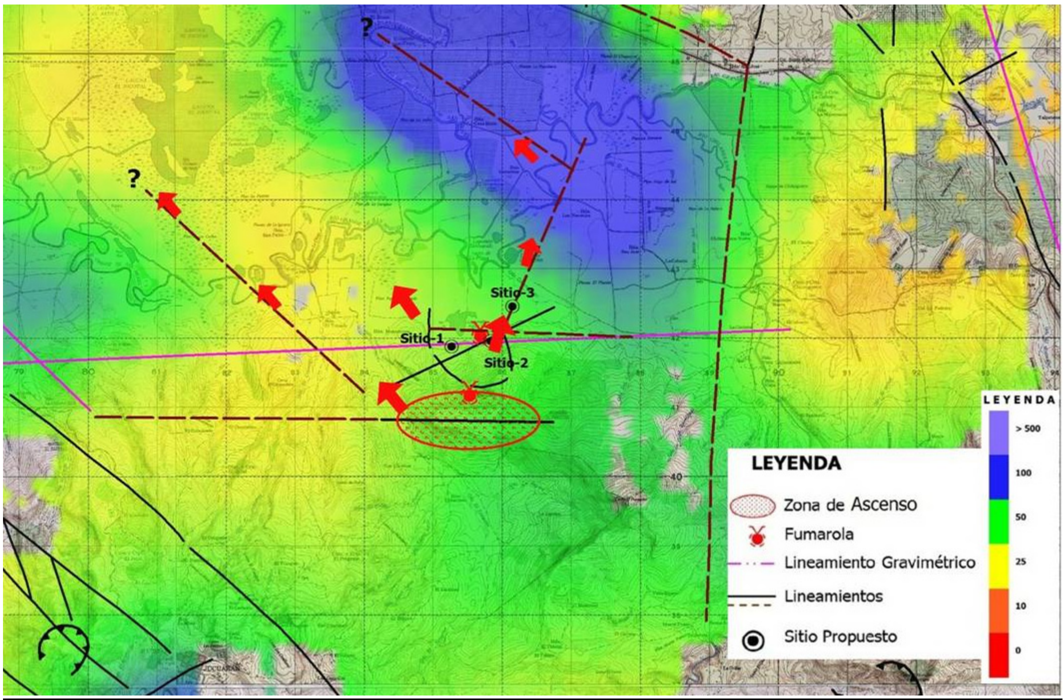


FIGURE 22: View of the Chilanguera conceptual model, resistivity values at -1000 m

6. CONCLUSIONS

Geoscientific studies have been performed in Chilanguera for elaboration of Chlilanguera conceptual model between years 2004 and 2011. A geothermal reservoir of volcanic origin with temperature between 150 and 200°C has been defined at 1200 m depth, thicknes of 400 m.

Area of interest of 0.8 km^2 for exploratory drilling has been delineated by 2D resistivity modeling with the main objective of intersection of transition zone between shallow conductive and high resistivity dome.

In order to improve resolution of Thoron/Radon ratio anomaly in the suroundings of Laguna Agua Caliente, distance between difussive degassing measurements should be reduced in the grid.

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UNITED NATIONS UNIVERSITY
GEOTHERMAL TRAINING PROGRAMME

LaGeo S.A. de C.V.

RESISTIVITY METHODS USED IN EL SALVADOR GEOTHERMAL EXPLORATION

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ABSTRACT

The resistivity methods have been used in the exploration of the geothermal fields in El Salvador since the 60's. The DC resistivity techniques such as Schlumberger, Misse a la masse, Dipolo dipole and Head on were applied for decades, despite the limited penetration capacity, they have contributed in delineating the major geothermal areas as well as defining drilling target.

The natural source method such as MT combined with artificial source technique such TDEM have demonstrated to be a powerful tool to estimate the size and the thickness of the producer reservoir. The joint analysis of these techniques allows mapping of the resistivity distribution from the very shallow level up to several kilometres depth.

While geothermal systems are usually associated with low resistivity at shallower levels, the high-temperature geothermal reservoir itself has a resistive signature, due to lower porosity and resistive alteration minerals (epidote, quartz, chlorite). The upflow zone is located where the conductive-resistive interface attains its highest elevation. Conductive anomalies within the reservoirs may represent large fractured zones to be used in defining drilling targets.

1. INTRODUCTION

A geothermal system generally causes inhomogeneity in the physical properties of the subsurface, which can be observed to varying degrees as anomalies measurable from the surface. These physical parameters include temperature (thermal survey), electrical conductivity (electrical and electromagnetic methods), elastic properties influencing the propagation velocity of elastic waves (seismic survey), density (gravity survey) and magnetic susceptibility (magnetic survey). Most of these methods can provide valuable information on the shape, size, and depth of the deep geological structures constituting a geothermal reservoir, and sometimes of the heat source. (Manzella, 1995).

The parameter of electrical resistivity gives information on temperature and alteration of the rocks with depth, which are major parameters for understanding the geothermal systems. The correlation

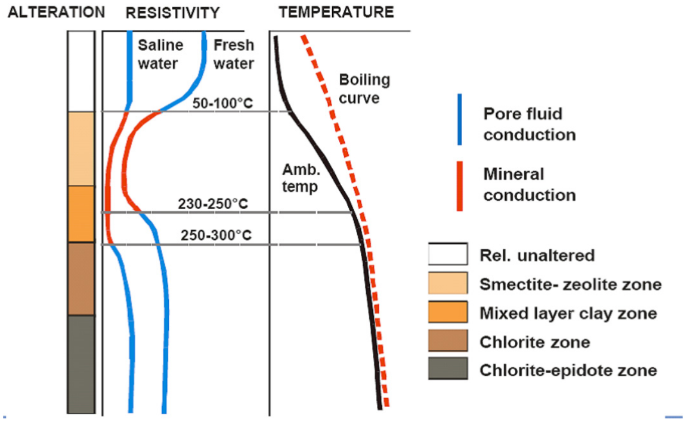

FIGURE 1: Resistivity of rocks and its association with alteration and temperature (Árnason et al., 2000)

between the resistivity parameters and alteration, lithology, temperature, porosity, water saturation etc. is shown in Figure 1.

The typical structure of a high-temperature geothermal system is presented schematically in Figure 2. The resistivity of the smectite zone is primarily determined by the type and intensity of alteration, modified by the degree of saturation and actual temperature, and is generally between 1 and 10 ohm-m. The amount of illite increases with temperature, forming the mixed-layer clay (illite-smectite) at 180°C. Above this temperature, the smectite content continues to decrease, and pure illite commonly appears at greater than 220°C with other high-temperature alteration minerals (chlorite, epidote, etc) in the propylitic alteration assemblage, with typical resistivity lying between 10 and 60 ohm m (Errol et al, 2000).

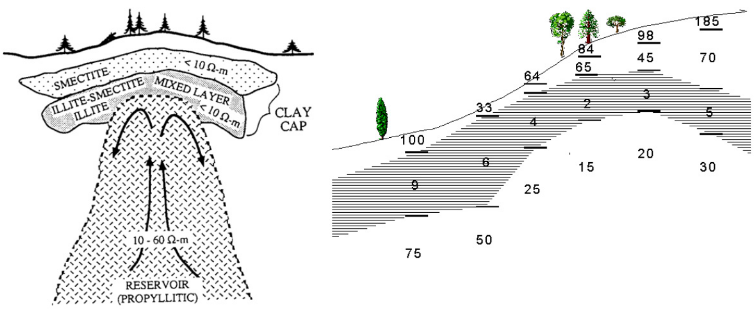

FIGURE 2: Typical structure of a high-temperature geothermal system (Errol et al, 2000)

While geothermal systems are usually associated with low resistivity at shallower levels, the high-temperature geothermal reservoir itself has a resistive signature, due to lower porosity (lithostatic load) and resistive alteration minerals (epidote, quartz, chlorite). The upflow is located where the conductive-resistive interface attains its highest elevation. Conductive anomalies within the reservoirs can represent large fractured zones to be used in defining drilling targets.

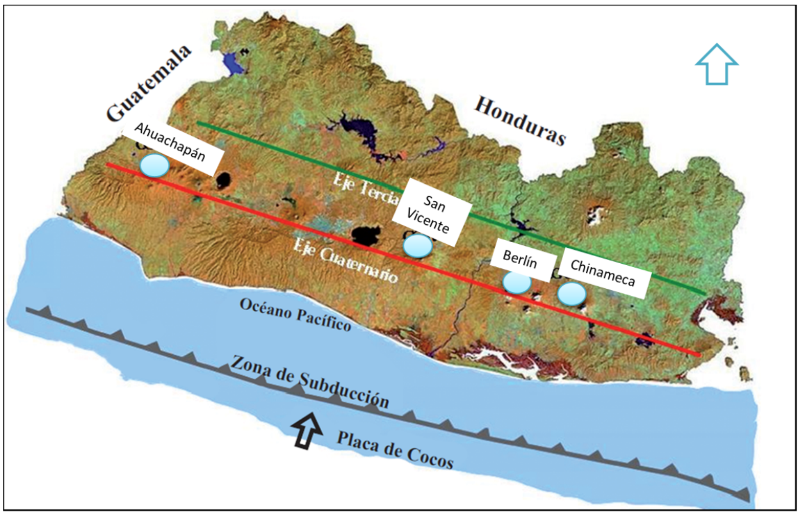

FIGURE 3: Location of the high temperature geothermal field in El Salvador

High temperatures geothermal fields in El Salvador are located at the northern flank of the active volcanic chain, from the Quaternary age as shown in Figure 3.A brief review of the geophysical methods applied in the different geothermal areas of El Salvador is shown in Table 1. Important contributions in the knowledge and characterization of the different geothermal systems in El Salvador have been provided through the implementation of these techniques.

TABLE 1: Geophysical methods applied in the different geothermal areas in El Salvador

	DC RESISTIVITY METHODS					ELECTROMAGNETIC		SEISMIC METHODS			
AREA	SEV	DIPOLO-DIPOLO	CALICATAS	MISE ALA MASSE	HEAD ON	MT/TDEM	MAGNETIC	PASSIVE SEISMIC	SEISMIC TOMOG	GRAVITY	HEAT FLOW
AHUACHAPAN	●	●	●	●	●	●	●	●		●	
CHIPILAPA	●	●	●	●	●	●	●	●		●	
CUYANAUSUL	●		●			●	●			●	
BERLIN	●	●	●	●	●	●	●	●	●	●	
COATEPEQUE	●	●								●	
SAN VICENTE	●				●	●				●	
CHINAMECA	●				●	●				●	
OBRAJUELO	●									●	●
CHILANGUERA	●		●				●			●	
CONCHAGUA	●		●		●		●			●	
PENETRATION	>1Km	>.5Km	>.3Km	>1Km	>.3Km	<5Km	>.3 Km	<5Km	<2Km	<2Km	>.1Km

2. RESISTIVITY METHODS USED FOR THE GEOTHERMAL EXPLORATION IN EL SALVADOR

Electrical methods include many different types of measurements and varying setups or configurations for the different types. The most important types used in El Salvador are:

- Direct Current (DC) Resistivity Methods such as Shlumberger, Dipole Dipole, Mise a la Masse and Head on profile.
- Artificial Source Electromagnetic methods such Time Domain Electromagnetic Method (TDEM), Control Source Audio magnetic Method (CSAMT).
- Natural source Resistivity Electromagnetic Methods such as Magnetotellúric (MT), Audio Magnetotelluric Method (AMT) and the Self Potential.

This paper will present the resistivity method applied in El Salvador, its principles and main results.

3. DIRECT CURRENT (DC) RESISTIVITY METHOD

The resistivity measurement is normally undertaken by injecting into the ground a known current (I) through the two current electrodes (A, B), and measuring the resulting voltage difference (V) at two potential electrodes (M, N). From the current and voltage values, an apparent resistivity ($\rho\alpha$) value is calculated as follows.

$\rho a = kV/I$, where k is a geometric factor which depends on the electrodes array.

Several electrode arrays are used to measure resistivity, and most of them are illustrated in Figure 5.

DC resistivity methods can be divided into various subcategories depending on

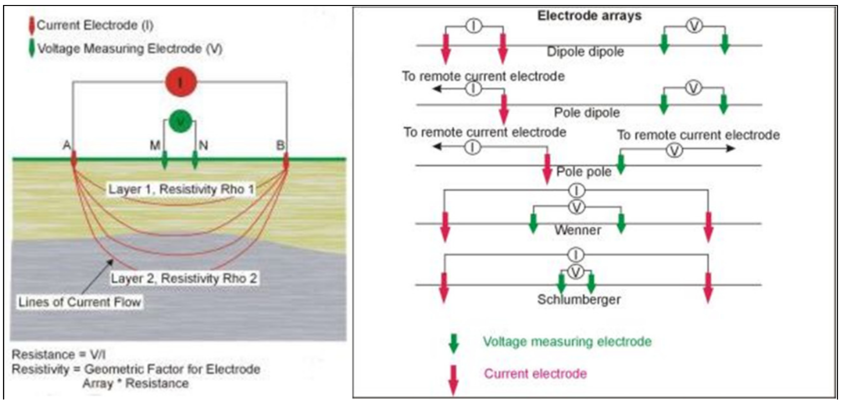

FIGURE 5: Basic principle of DC Resistivity methods and different electrodes arrays (www.cflhd.gov/resources)

the geometrical arrangement of electrodes. The most common used in El Salvador are:

1. Schlumberger
2. Head on profile resistivity sounding
3. Dipole dipole profile sounding
4. Mise a la Masse

3.1 DC Schlumberger resistivity sounding

In this method, the two potential and two current electrodes are placed along a straight line. The array is symmetrical around the midpoint O (Figure 6). As the distance between the current electrodes is increased, as a consequence, the prospecting depth is increased too. For each electrode separation, a value of apparent resistivity is calculated. This value is plotted in on a graph known as the field curve.

$$\rho_{BC} = [\Delta V_{BC}\, \pi\, (S^2 - P^2)]/[IP]$$

where S= Distance between AB electrodes
P= Distance between MN electrodes

The field data are inverted into 1D layer resistivity model by using commercial software. In this process, one initial guess model is used for running the software, after finish a defined numbers of iteration, the final model is generated and accepted if a good fitting between the measured and calculated curves is achieved (Figure 6)

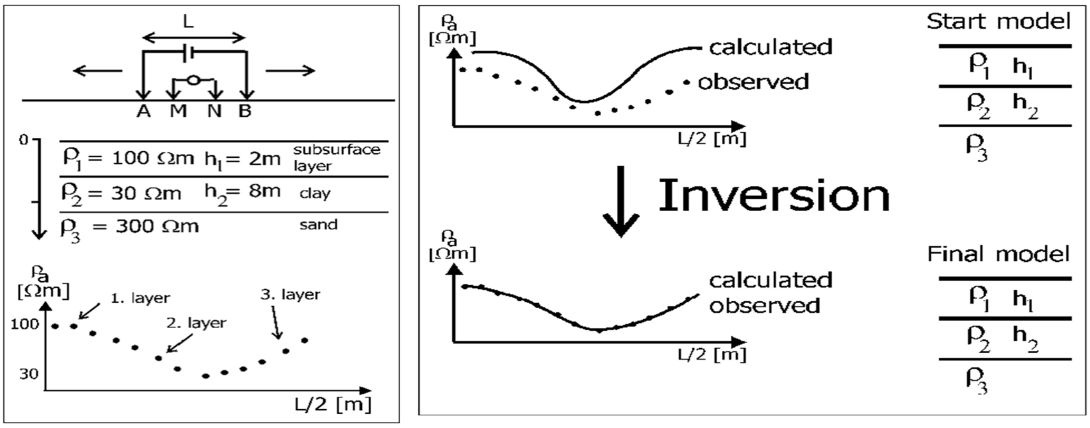

FIGURE 6: Schlumberger array and data process
(modified from www.fhwa.dot.gov/)

More than 120 SEV have been done at the Berlin Geothermal Field in El Salvador, located in the eastern part of the country. The geothermal area was delineated by a low resistivity anomaly (1D resistivity map) while the top of the producer reservoir was associated with uplifted resistive anomaly body at the southern part of the field (Figure 7).

By applying this technique, it is possible to get a picture of the subsurface resistive distribution of the most of geothermal areas of El Salvador.

3.2 Head-on profile resistivity method

Head-on profiling resistivity method designed for detecting narrow conductive zones in a resistive background, which could be associated with faults, dykes or fractures. The method uses a half-Schlumberger electrode layout, where a third current electrode C is additionally placed at an infinite distance and perpendicular to the Schlumberger array (Figure 8). The infinite distance must be at least four times the AB separation distance.

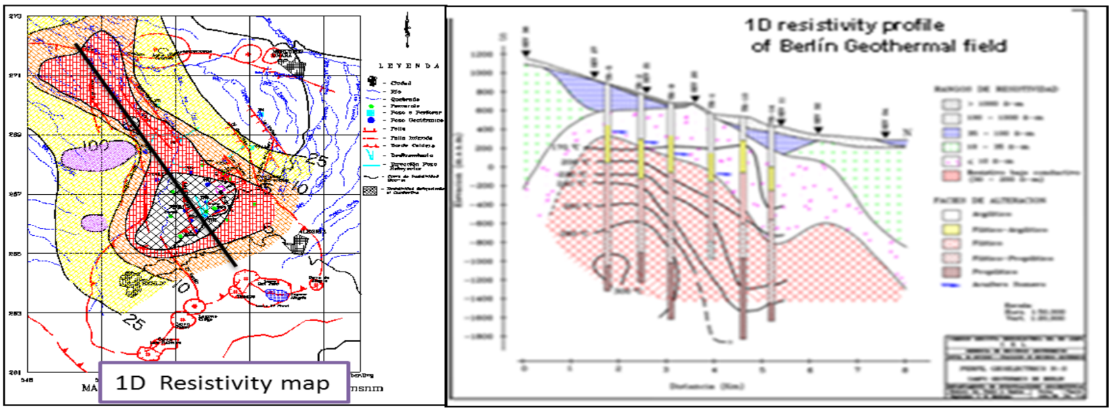

FIGURE 7: Schlumberger resistivity results in different geothermal area

The potential difference between the dipoles AB, BC y AC is measured and the corresponding resistivity values are calculated by using the next formulas:

$$\rho_{AC} = [\Delta V_{AC}\, \pi\, (S^2 - P^2)]/[IP]$$
$$\rho_{AB} = [\Delta V_{AB}\, \pi\, (S^2 - P^2)]/[2IP]$$
$$\rho_{BC} = [\Delta V_{BC}\, \pi\, (S^2 - P^2)]/[IP]$$

where S= Distance between AB electrodes
P= Distance between MN electrodes

The resistivity along the profile is plotted as a function of deploy center ("O"). In the same graph, the differences ρ_{AC}- ρ_{AB} , ρ_{BC}- ρ_{AB} and ρ_{AB} are plotted. The estimate location the fault is the point the curves ρ_{AC}- ρ_{AB} and ρ_{BC}- ρ_{AB} are intercepted (Hersir and Bjornsson, 1991).

The profile is set perpendicular to the supposed system of fault trend. The electrode C is kept fixed, while the half-Schlumberger electrode layout is moved along the profile, across the conductive structure. The evidence of the faults is suggested by a cross in the apparent resistivity curves.
The penetration depth is similar to that obtained with a full Schlumberger electrode array with the same maximum AB/2 value. This means that investigation will be restricted to the shallow resistive surface layer.

This method has been implemented with successful results in different geothermal areas in El Salvador such as San Vicente, Ahuachapán, Chinameca and Berlin.

In 2010, a resistivity survey using the head on profile was carried out at the southern part of San Vicente Geothermal field. As a result, a possible permeable area toward the south of the SV-1 well was inferred, which was confirmed by the last drilled geothermal well (Figure 8).

3.3 Dipole-dipole, 2D resistivity profile

Profiling with 2D DC-resistivity methods is conducted by making measurements along a surface profile using different offsets. The data are inverted to create a model of resistivity along a section of the subsurface that can be used to detect and define individual fracture zones.

The dipole-dipole array has better horizontal resolution but poorer depth of penetration, compared to the Schlumberger array.

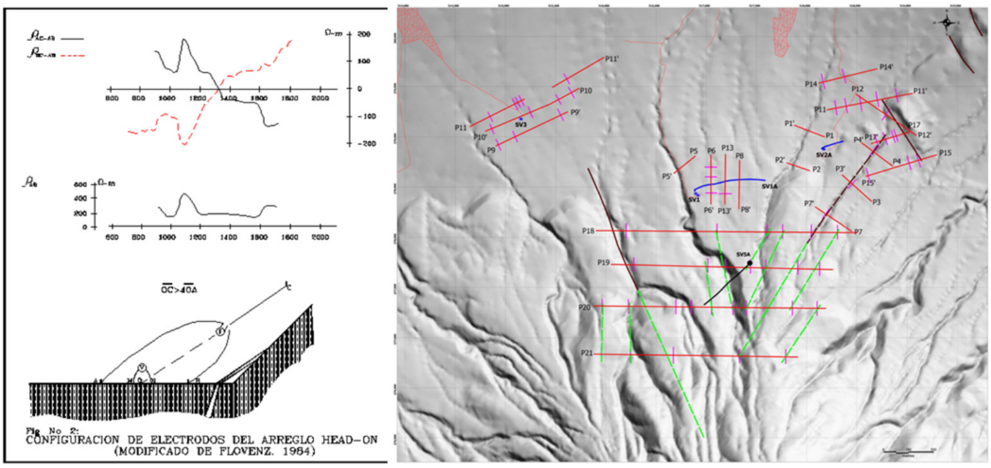

FIGURE 8: Head on profile array and head-on (Flovenz, 1984) and the obtained results in San Vicente geothermal area

The equipment used in this method is the same as that used for DC resistivity soundings, but more current injection capacity is required.

The dipole dipole survey is conducted with the electrodes arranged in a linear array. The first pole is used to inject the current while the others poles are used to measure the induced potential. The process is repeated by injecting in the second pole and so on as is shown in Figure 9. The resistivity is calculated as follows:

$\rho a = \pi n(n+1)(n+2)aV/I$

where n is the ratio of the distance between the C1-P1 electrodes to the C1-C2 dipole spacing

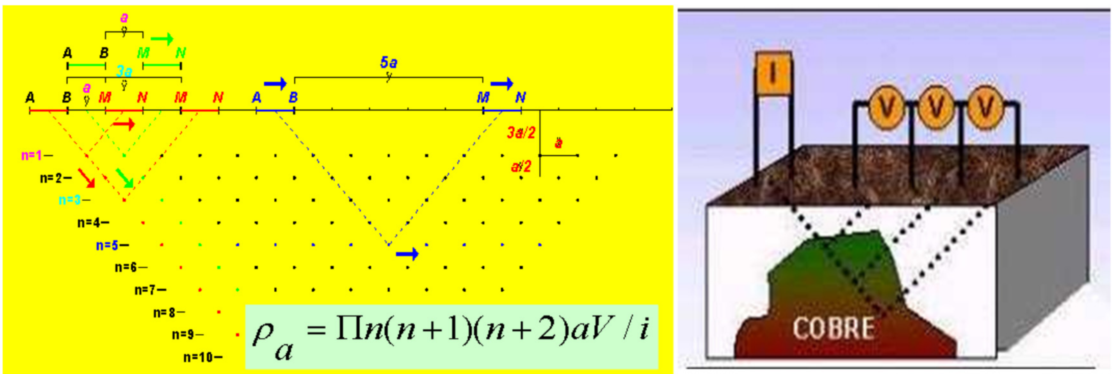

FIGURE 9: Dipole dipole array applied in the geothermal exploration (www.geofisica.cl)

This technique has been successfully applied in Ahuachapán and Berlin geothermal fields. Lateral resistive discontinuity suggested the presence of faults or fractures in Ahuachapan geothermal field, as shown in Figure 10.

3.4 Mise a la mase Method

Mise-a-la-masse or “Charged body potential” is a resistivity method where a DC current is injected into the ground using the well casing as electrode; the other current electrode is set at theoretically at “infinity’, which means at least three times the depth of the well. The potential field caused by this signal at ground surface is measured by a roving dipole, setting in radial lines, and usually separated 45 degrees from each other (Figure 11). The apparent resistivity at each point is calculated from the

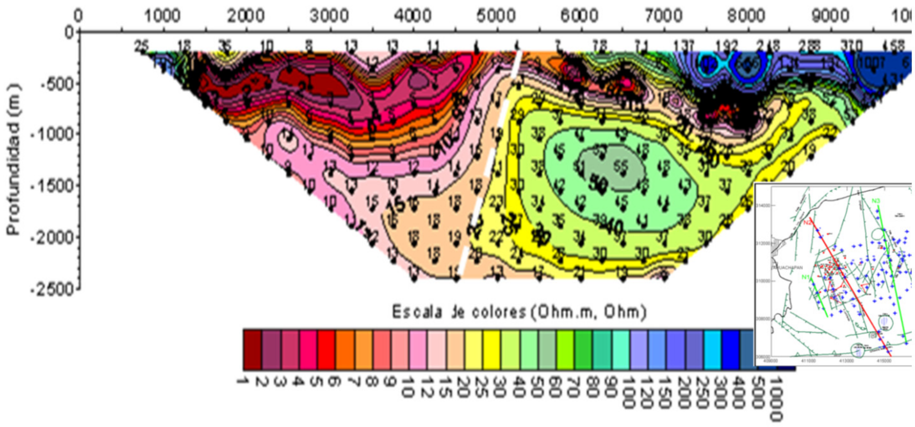

FIGURE 10: 2D modeling of dipole dipole profile in Ahuachapán geothermal field, inferred fault shown in dotted lines

measured potential difference, the current and the distance from the well. This parameter is defined by:

$$\rho a = 4\Pi X V/I,$$

where x is the distance between the current and the potential electrode.

By the use of the Misanaly software, the well casing effect is removed and the residual apparent resistivity map is elaborated.

The lateral resistivity discontinuities as well as the strong gradient curves observed in the residual resistivity anomaly map are correlated to the permeable fractures as is shown in Figure 12.

This method was implemented in 1996 and has been applied in most of the geothermal wells of Ahuachapán and Berlin geothermal fields. The results were considerable for defining geothermal target for production wells at both geothermal fields.

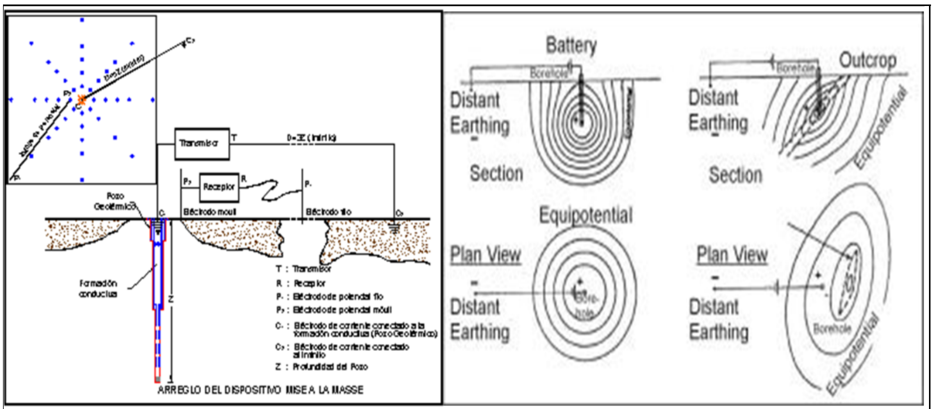

FIGURE 11: Mise a la Masse DC resistivity method array and anomaly example

4. ARTIFICIAL SOURCE ELECTROMAGNETIC METHODS

In these methods, an artificial source is used to generate the electromagnetic (EM) field and the most used in geothermal exploration are the Control Source Audio Magnetotelluric Method (CSAMT) and de Time Domain Electromagnetic Method (TDEM).

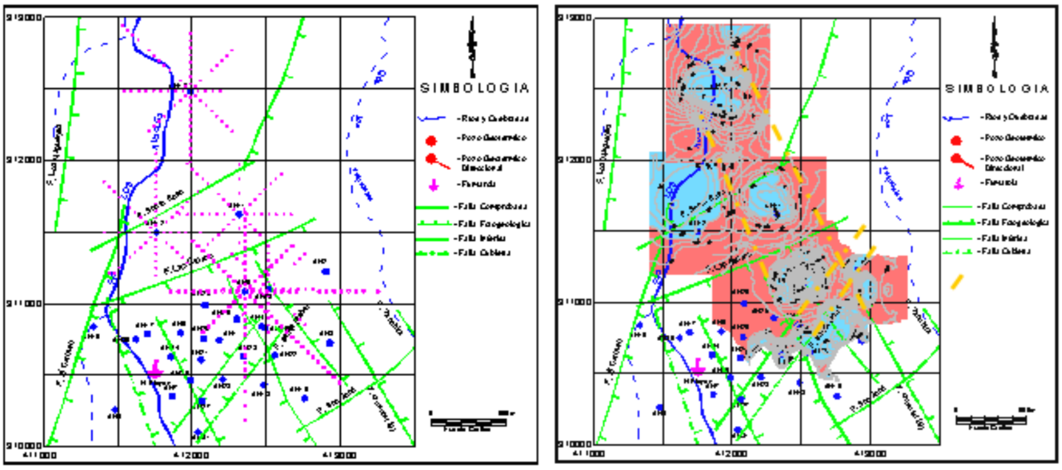

FIGURE 12: Mise a la masse results in Ahuachapán geothermal field, conductive fracture has been defined

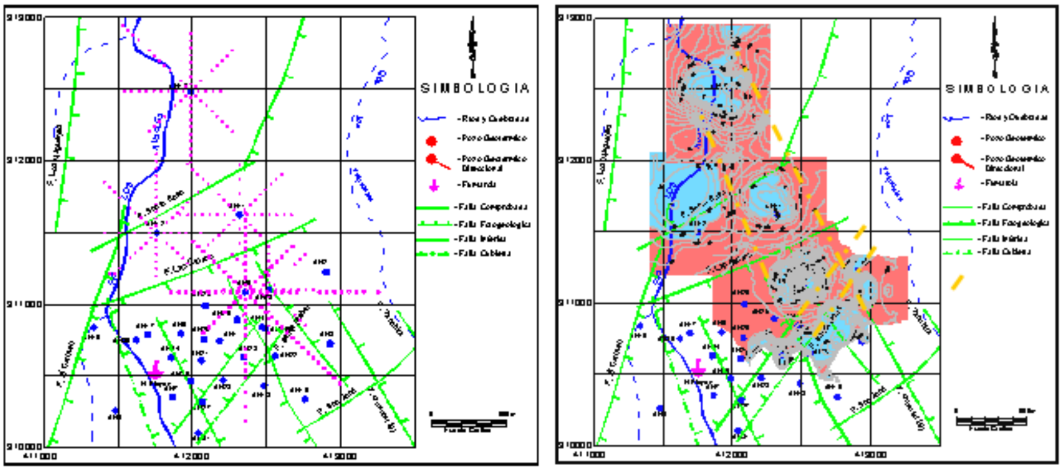

FIGURE 12: Mise a la masse results in Ahuachapán geothermal field, conductive fracture has been defined

4.1 Control source audio magnetotelluric method (CSAMT)

The CSAMT method involves transmitting a controlled signal at a series of frequencies (0.167 to 1024 Hz) into the ground from one location (transmitter site), and measuring the received electric and magnetic fields in the area of interest (receiver site). The ratio of orthogonal, horizontal electric and magnetic field magnitudes (e.g. Ex and Hy) are used to calculate the resistivity structure of the earth (Figure 13) given by the equation

$$\rho_a = \frac{0.2}{f}\left|\frac{E}{H}\right|^2$$

where, ρ_a: apparent resistivity in Ohm-m

f : Frequency in Hz

E : Electric field magnitude in mV/km

H : Magnetic field magnitude in nT

Equivalent depth of investigation, *D= 356√f (D in meters)*

Lateral resolution is mainly controlled by the station spacing. The received signal strength is proportional to the length of the station spacing, so if the station size is cut in half, the signal strength is also reduced in half. The station spacing is usually between 10 to 200 m.

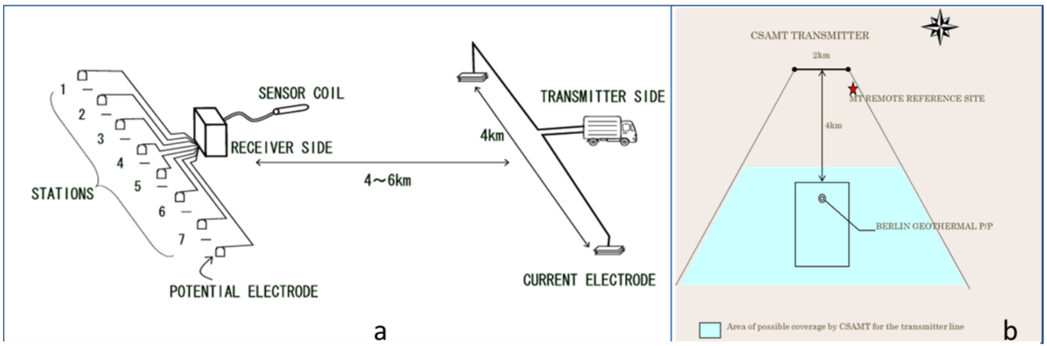

FIGURE 13: a) General layout for CSMAT and b) Survey configuration in Berlin geothermal field (West Jec, 2001)

In 2001, West Jec (Japan) carried out a CSAMT resistivity survey in Berlin Geothermal field. The data was collected by Phoenix Geophysics Company. A total of 86 station distributed every 300 m along 11 profiles covering an area of 10 km^2 were measured. As a result, several resistivity maps were created, one of them is shown in Figure 14.

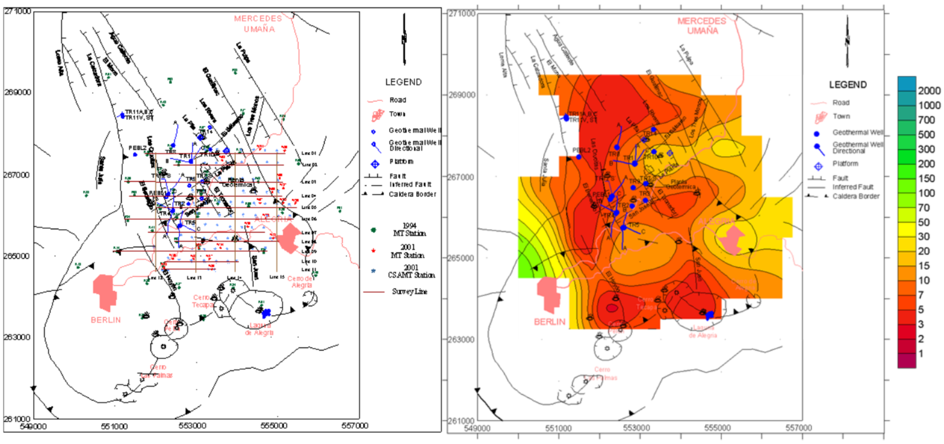

FIGURE 14: CSAMT survey at Berlin Geothermal field, measured points and resistivity map at 500 depths (West Jec, 2001)

4.2 Time domain electromagnetic method (TDEM)

In this method, a constant magnetic field is built up by transmitting current **I** through a big loop (grounded dipole). Then the current is abruptly turned off. A secondary field is thus induced, decaying with time. This decay rate is monitored by measuring the voltage induced in a receiver coil in the center of the loop on the surface. Current distribution and decay rate recorded as a function of time, depending on the resistivity structure below the measuring site. The signal can also be based on a grounded dipole to create the primary magnetic field (Figure 15).

The measured resistivity in the subsurface is similar to the Schlumberger soundings, expressed as apparent resistivity ρa, and is an expression for the "average resistivity" of the structures below the centre of the sounding. It is a function of several variables, including measured voltage; time elapsed from turn off; area of loops/coils; number of windings in loops/coils and magnetic permeability. For a homogeneous half-space, apparent resistivity, ρa, expressed in terms of induced voltage $V(t, r)$ at a later period after the source current is turned off, which is given by:

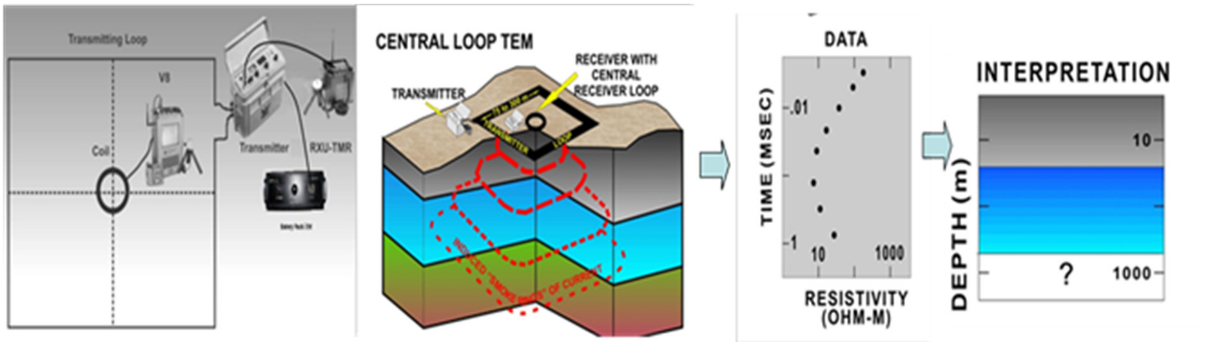

FIGURE 15: TEDM field layout, processing and interpretation process (modified from Cumming and Mackie, 2010)

$$\rho_a = \frac{\mu_0}{4\pi}\left[\frac{2\mu_0 A_r n_r A_s n_s I_0}{5t^{5/2}V(t,r)}\right]^{2/3}$$

where *Ar, As* = area of the receiver loop and the transmitter loop, respectively (m^2);
nr, ns = number of windings in the receiver loop and the transmitter loop, respectively;
Io = current sent through the transmitter loop (A);
T = time elapsed from the turn off (s);
μo = magnetic permeability (H/m).

This technique had been implemented in the geothermal exploration since 2004 in El Salvador. Figure 16 shows the results of the 120 TDEM sounding carried out in Ahuachapán Geothermal field. The resistivity map at 100 m depth as well as the resistivity profile shows the main alteration area, and a possible shallow aquifer.

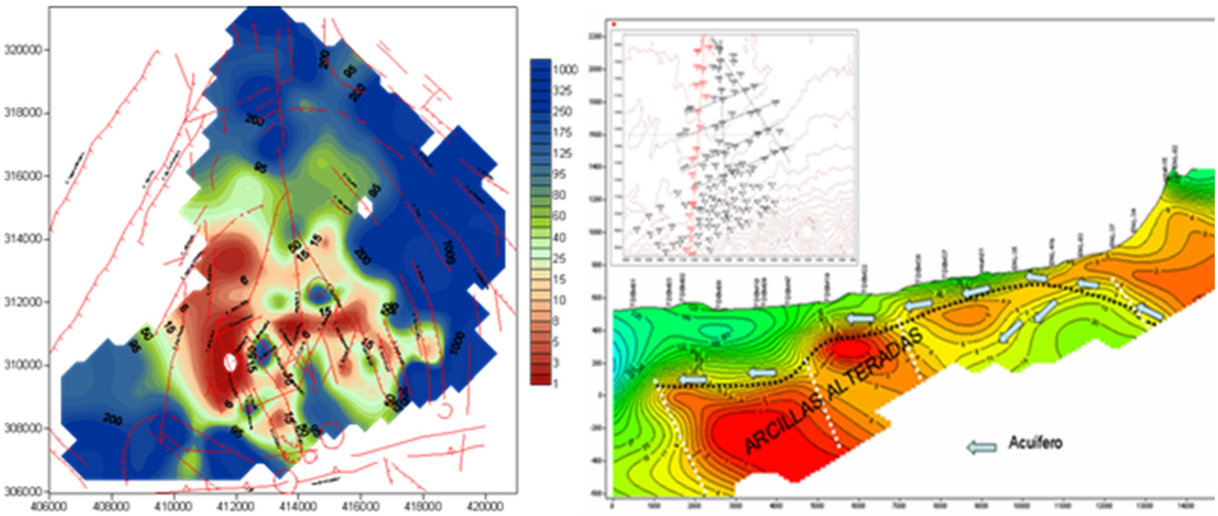

FIGURE 16: TDEM Resistivity map at 100 m depth and profile from Ahuachapán geothermal field

5. THE NATURAL SOURCE METHODS

The most common methods are the Magnetotelluric Method (MT) and self potential. In El Salvador, only the MT technique has been implemented in the exploration of the different geothermal fields.

5.1 The magnetotelluric method (MT)

The magnetotelluric (MT) method is a passive surface measurement of the earth's natural electrical (**E**) field and magnetic (**H**) field in orthogonal directions. It can be shown that the relationship between the horizontal orthogonal magnetic and electric fields depend on the subsurface resistivity structure. It is therefore used to determine the conductivity of the earth, ranging from a few tens of meters to several hundreds of kilometers. MT generally refers to recording of 10 kHz to 1000 s (0.001 Hz).

During field surveys (Figure 17), the magnetic fields are measured in the X (Hx), Y (Hy) and Z (Hz) directions and the induced electric fields are also measured in the X (Ex) and Y (Ey) directions forming 5 components. These measurements are taken over at different frequencies or time periods.

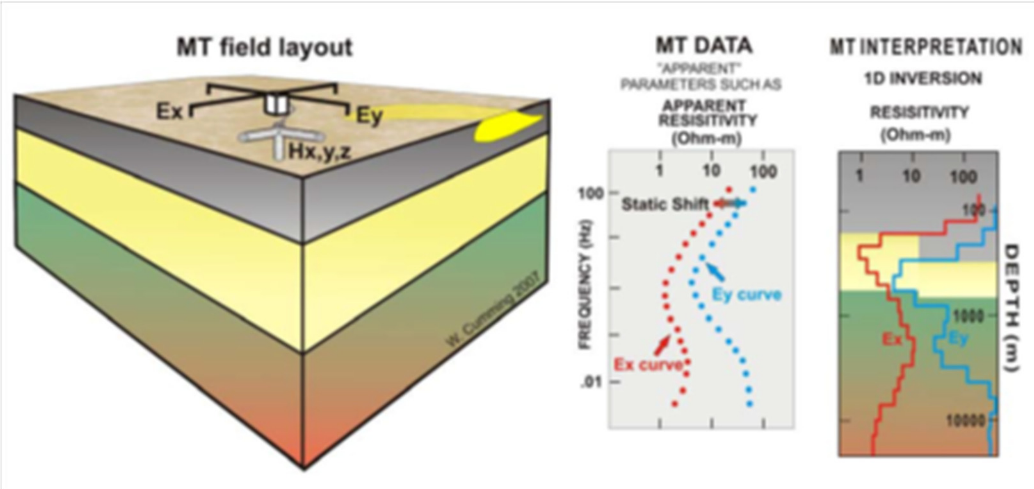

FIGURE17: MT field layout, processing and interpretation process (Cumming and Mackie,2010)

The resulting data is Fourier transformed and apparent resistivities in the two directions ρ_{xy} and ρ_{yx}, as well as the prospection depth calculated as a function of frequency (δ) and is shown in the next equation.

$$\rho_{xy} = \frac{1}{5f}\left|\frac{E_x}{H_y}\right|^2 \quad \rho_{yx} = \frac{1}{5f}\left|\frac{E_y}{H_x}\right|^2 \quad \delta = 355\sqrt{\frac{\rho}{f}}$$

In order to correct the low resolution of MT for higher frequency at the shallow levels; measurements of TDEM (Time Domain Electromagnetic Method) are done at the same MT location, because TDEM is able to resolve the shallow layers while MT would provide the deeper information. This technique was implemented in Berlin since 1994, more than 125 MT had been measured.

The 3D analysis interpretation of the MT data suggests that the geothermal propylitic reservoir is associated with an uplifted resistive body with a thin conductive cover, as is shown Figure 18.

Based on the results of geothermal wells drilled by ENEL at the southern part of the production zone, the MT model was adjusted to the well data, mainly to the temperature and mineralogy alteration. In this adjusted model, the producing reservoir corresponds to an uplifted resistive layer at depth, with resistivity values ranging form 40 to 90 ohm-m inside the resistive basement; at higher values, an inversion in the temperature curve is observed (Figure19).

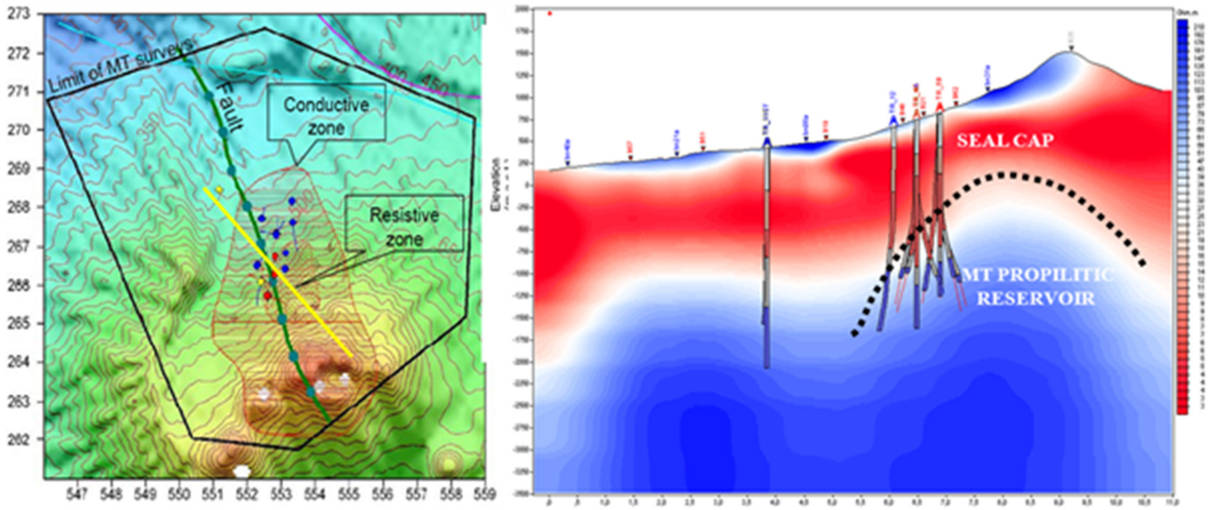

FIGURE 18: MT resistivity model of Berlin based on the 3D analysis data

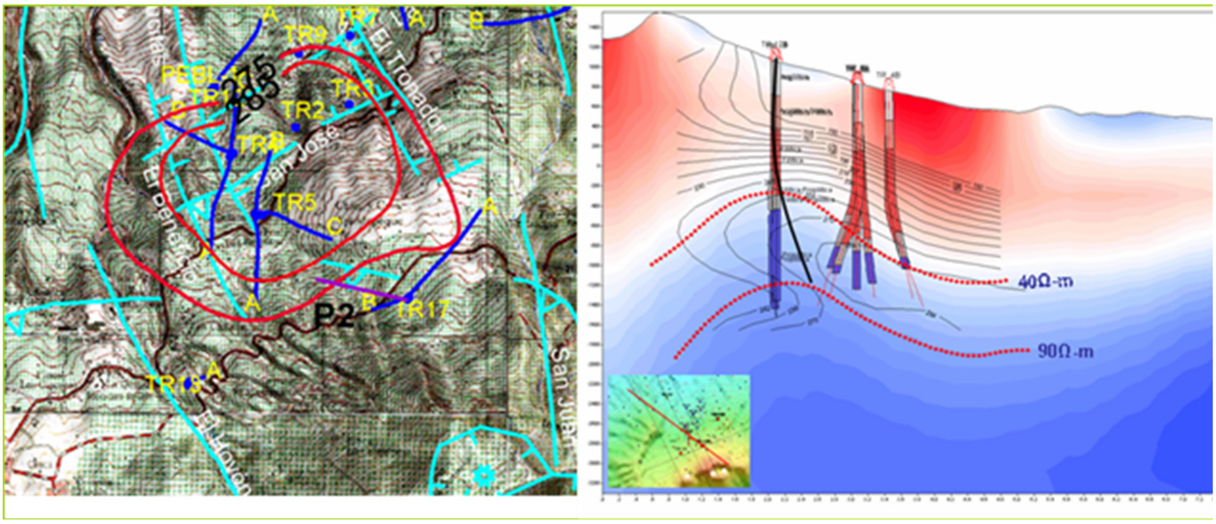

FIGURE 19: MT adjusted model based on the results of the drilled wells in the southern part of the production zone

6. CONCLUSIONS

The resistivity methods have been used in the exploration of the geothermal fields in El Salvador since the sixties; they have made an important contribution in the identification and characterization of the geothermal active system in the country.

The parameter of electrical resistivity gives information on temperature and alteration of the rocks with depth, which are major parameters for the understanding of the geothermal systems. Good correlation between the resistivity parameters and alteration, lithology, temperature, porosity, water saturation is observed.

The DC resistivity techniques such as Schlumberger, Misse a la masse, Dipole-dipole and head on were applied for decades, despite of the limited penetration capacity, they have contributed in delineating the major geothermal systems as well as defining drilling targets.

The natural source method (MT) combined with artificial source technique (TDEM) have demonstrated to be a powerful tool for estimating the size and the thickness of the producing reservoir;

the joint analysis of these techniques allows mapping the resistivity distribution from the very shallow level up to several kilometres depth.

The 3D analysis interpretation of the MT data suggests that the geothermal propylitic reservoir of Berlin is associated with an uplifted resistive body with a thin conductive cover. Based on the results of geothermal wells drilled by ENEL at the southern part of the production zone, the MT model was adjusted to the well data, mainly with the temperature and mineralogy alteration. In this adjusted model, the producing reservoir corresponds to an uplifted resistive layer at depth, with resistivity values ranging from 40 to 90 ohm-m inside the resistive basement; at higher values, an inversion in the temperature curve is observed.

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UNITED NATIONS UNIVERSITY
GEOTHERMAL TRAINING PROGRAMME

LaGeo S.A. de C.V.

SEISMIC ACTIVITY, GRAVITY AND MAGNETIC MEASUREMENTS

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ABSTRACT

Microseismic activity, gravity and magnetic exploration methods are used to provide geoscientists an indirect way to witness beneath the Earth's surface the physical properties of rocks (fractures, density and magnetization, respectively). Microseismic activity can help define the reservoir extension, how active it is and the main trend of faults, which hosts a reservoir. Gravity and magnetic exploration can help locate minerals, faults, geothermal or petroleum resources, and ground-water reservoirs. Potential field surveys are relatively inexpensive and can quickly cover large areas of the ground. The primary goal of studying potential field surveys is to provide a better understanding of the subsurface geology. The methods are relatively cheap, non-invasive and non-destructive, environmentally speaking. They are also passive – that is, no energy needs to be put into the ground in order to acquire data. The small portable instruments (gravimeter and magnetometer) also permit walking traverses.

1. INTRODUCTION

For a detailed conceptual model of a geothermal prospect, besides geological and geochemical studies, a variety of geophysical techniques may be used including seismic activity, gravity and magnetic data analysis. This leads to the interpretation of the integrated studies, which provides the next step to create a deep exploration drilling programme.

Seismicity analysis gives information about fractured zones, active faults and some indications of the heat source of the system. The spatial distribution of the seismicity could also indicate the extension of the geothermal reservoir.

Gravity measurements give structural information and can also give indications on massive intrusions, which may act as heat sources. A Bouguer map should be produced to study density anomalies, and selected profiles might be measured with dense station spacing for more detailed structural studies such as buried faults.

Aero-magnetic and/or ground magnetic surveys should also be performed. Aero-magnetic survey can map demagnetized rocks due to thermal alteration, while magnetic surveys give complementary structural information which helps in the interpretation of other data.

2. SEISMIC ACTIVITY

2.1 Introduction

If a prospect geothermal area is considered to be tectonically and/or volcanically active, a temporary deployment of a few seismic stations might be considered. A preliminary seismic survey needs a seismologist and at least four to six portable seismic stations. Specialized software is needed for locating the hypocentres of the earthquakes. A passive seismic survey should also be performed. Active faults can be located by recording and locating earthquakes. The cooling of heat sources can also produce micro-seismicity (Árnason, et al, 2009).

Figure 1 shows most hydrothermal manifestations in El Salvador, which are found within the Quaternary volcanic chain located in the southern margin of the Central American graben (Rivas, 2000). The Ahuachapán geothermal field (AGF) for example is located at the northern flank of the Ataco – Apaneca volcanic chain, at the western part of the country, and Berlín geothermal field (BGF) located on the northern flank of the Berlín - Tecapa volcanic complex.

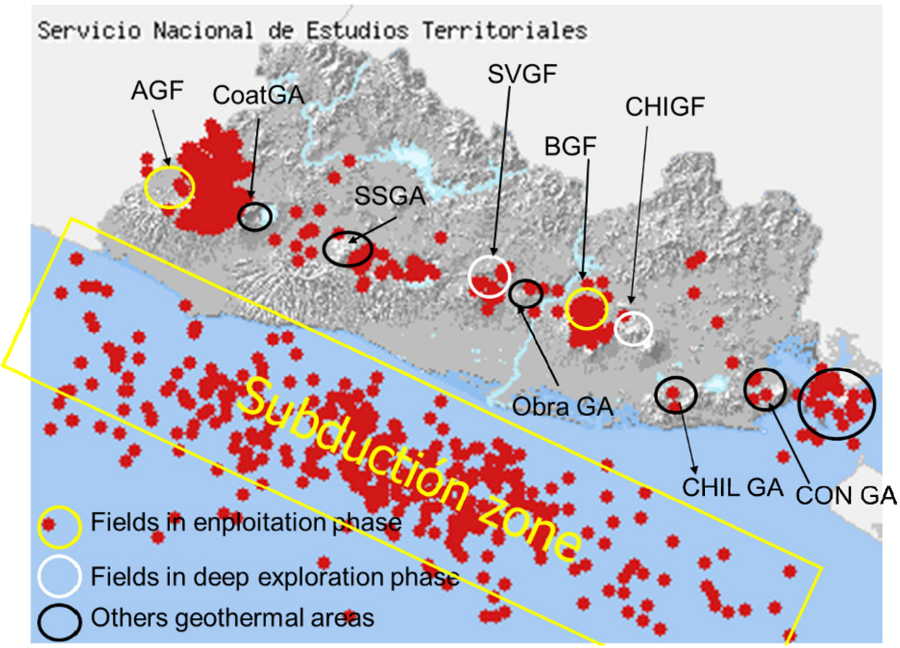

FIGURE 1: Seismicity felt by population during 2002-2010 in El Salvador. Red dots are epicentres. From left to right: AGF: Ahuachapán Geothermal Field; CoatGA: Coatepeque geothermal Area; SSGA: San Salvador Geothermal Area; SVGF: San Vicente Geothermal Field; Obra GA: Obrajuelo Geothermal Area; BGF: Berlin geothermal Field; CHIGF: Chinameca Geothermal Field; CHIL GA: Chilanguera Geothermal Area; CON GA: Conchagua Geothermal Area. (Modified from www.snet.gob.sv)

Results from volcano-seismic studies of many geothermal fields show that they are possible resource-mapping tools for geothermal exploration and reservoir monitoring. They have been able to map the size and depth of possible shallow geothermal heat sources by analysing data for seismic gaps, S-wave attenuation, reflected arrivals and converted waves. Analysis of shear wave split data for fracture density shows high permeability areas that are potential targets for drilling high-producer wells. Variation of Vp/Vs ratios is related to reservoir fluid phases where low values are related to a decrease in P-wave velocity in the area with low pore pressure, high heat flow, fracturing and steam/gas saturation in the reservoir. High velocity ratios were found in the relatively liquid-saturated high-pressure fields that these ratios are useful tools for monitoring reservoirs under exploitation. The volcano-seismic approach can be useful as a stand-alone tool for analysing geothermal resource both at the exploration and exploitation stage that is cost effective in the long term (Simiyu, 2009).

A number of changes in the recent past have modified the capacity to use micro earthquakes for geothermal studies. Recent studies have focused on the use of natural earthquake activity as a tool for geothermal evaluation of the heat source, fluid flow channels-permeability and reservoir properties. These are normally carried out following the objectives below (Simiyu, S.M. 2009):

a) Map the location of heat sources by using spatial seismic intensity, hypocentre distribution, shear wave attenuation and P wave reflection.

b) Map high crack density zones as an aide to siting high producer wells by inverting for three dimensional crack direction and crack density in the target volume using the polarization angle.

c) Determine the fluid phase, reservoir size and characteristics by determining the variation in seismic velocity within the fields.

2.2 The case of Berlin geothermal field

The spatial distribution of seismicity recorded in the period 1996 - 2005 at the Berlin Geothermal Field covering an area of 80 km^2 is shown on the left in Figure 2. The recorded seismicity reflected the geothermal anomaly and described the limits of the reservoir. The higher concentration of seismic events is where fumaroles, hydrothermal manifestations and hot soils are found. Therefore, the wells (producers and injectors) and power station are located in this area. The high epicentres concentration reveals the main area, the most fractured zone and faults and the limits of the system.

Figure 2 (right) shows a N-S cross section along the central part of the geothermal area. It shows how deep the hypocentres are located, and also a very close spatial correlation with depth and location of the wells and with reservoir. The hypocentre elevation range is between 0 and 3000 m b.s.l at the well zone (where the reservoir has been located) and from 5000 to 6000 m b.s.l., under the volcanic chain. It is believed that the heat source of the system is underlying this seismic zone. The hypocentres below the volcanic chain are deeper, and describes the upflow zone and the influence of the heat source of the system (right side of Figure 2 with blue line). Since the operation of the network, besides the big earthquakes occurred early 2001, at least 30 local events had recorded magnitude Mc of about 3. Because the very shallow depth, lower than 5 km, these events were felt by local communities. Outside the main area, to the south, there is a seismicity related with the upflow zone and influence of the heat source, possible a magmatic chamber underlying the Tecapa volcanic complex, as shown in Figure 2.

Deeper events are located below the Berlín-Tecapa volcanic complex, which is thought to be responsible of the heat source of the geothermal system. Some events suggest a continuation of other faults, at the northern part, which have been buried by alluvium at the lowest topography.

With the database collected during the period 1996-2005, a 3D seismic tomography study was performed. The results showed the velocity fields of P and S waves and the Vp/Vs ratio. These parameters were determined in order to identify zones of low pore pressure, high heat flow, fracturing and steam/gas saturation in the reservoir. Higher values of Vp/Vs ratios (> 1.68) were found in the surrounding areas of the production zone and lower values (< 1.68) where the area is hot, permeable and fractured, that is, where the producing wells are located. Figure 3 shows a map of Vp/Vs (contour lines) superimposed onto P-velocity distribution. The red contour encloses the production zone.

The P-velocity distribution was compared to Vp/Vs ratio in the area of the programmed directional well TR-14A (Figure 4) in 2005. The distribution of the two parameters were generally consistent and cross-correlated (Geosystem, 2005). In particular, well TR-14A seemed to be positioned on the northern flank of an uprising high velocity/high density feature that could be interpreted as a vertical intrusion of denser material (e.g. a dyke structure, which was found later with the drilled TR-19B well). P-velocity, density and Vp/Vs ratio were all suggesting a zone of rapid variations of the

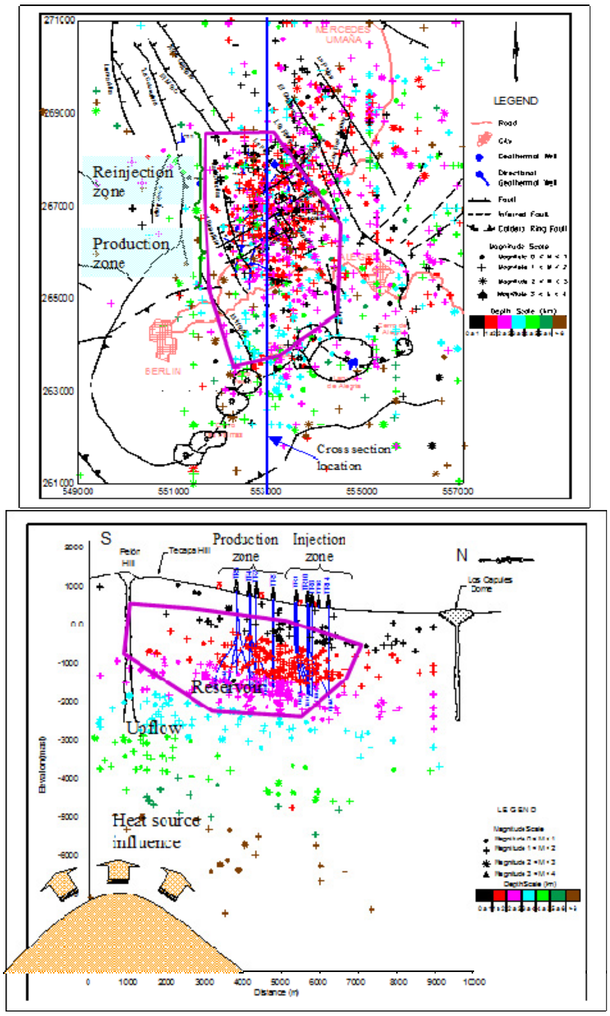

FIGURE 2: Left: Spatial distribution of seismicity at the Berlin geothermal field and surrounding areas defined by pink contour. Period 1996 – 2003: Black lines represents faults. Right: South-North Cross section showing the hypocentres. (See location of cross section, blue line, on left map). Hypocentres located one km far from the profile have been projected (Rivas, 2005)

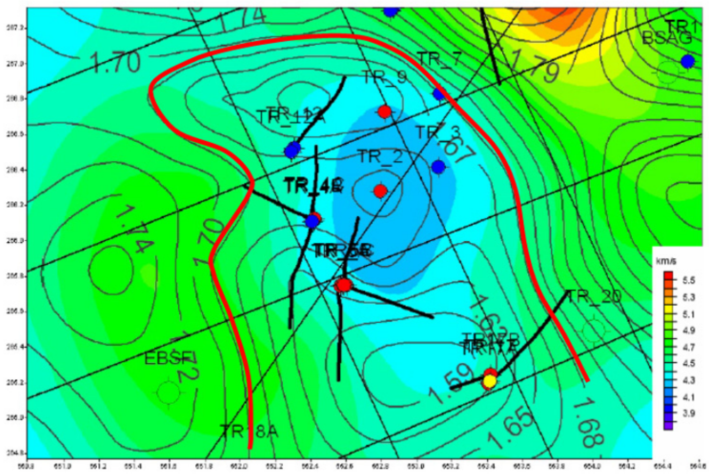

FIGURE 3: Vp/Vs ratio (countour lines) superimposed onto the P-velocity distribution at an elevation of 1500 m.b.s.l. Red and yellow circles are producing wells, blue circles are injector wells. Red contour encloses the production zone (Modified from Geosystem, 2005)

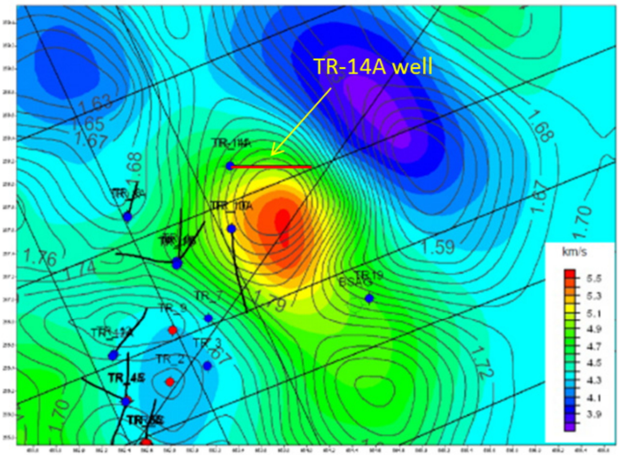

FIGURE 4: Vp/Vs ratio (contour lines) superimposed onto the P-velocity distribution at an elevation of 1500 m b.s.l. in the area around the planned directional well TR-14A (modified from Geosystem, 2005)

parameters from large to smaller values going E-W. This seemed to be especially true at the eastern termination of the well. The TR-14A was the best injector well with almost 150 kg/s absorption capacity.

Based on the cross-section shown in Figure 5 (profile WSW-ENE, left), a relative low Vp/Vs ratio (1.59, blue zone) and (profile NNW-SSE, right) low density (2.3 g/cc) were found (blue zone); where the wells are producing. In addition, an uprising high velocity/high density feature is seen in Figure 5, left, (red colour) that could be interpreted as a vertical intrusion of denser material (e.g. a dyke structure). This intrusive body was intercepted when the well TR-19B was drilled.

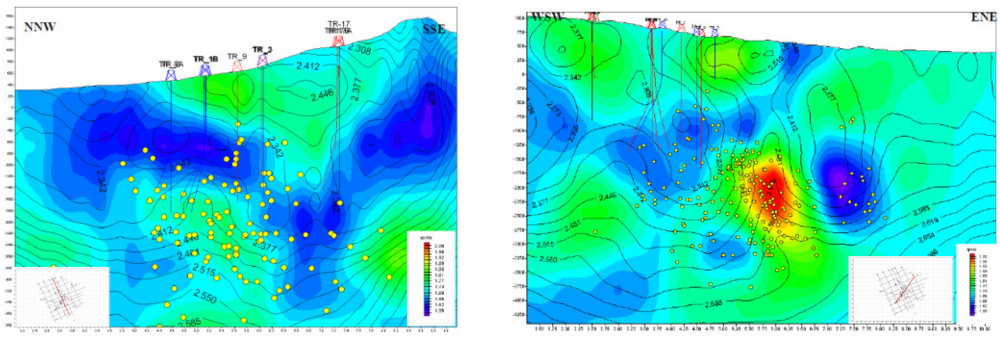

FIGURE 5: Vp/Vs-ratio (colour) cross-section. Left: Along profile SSW-NNE from seismic dataset inversion with superimposed the contour lines of the density model obtained after the inversion. Right: The same but in different direction, profile NNW-SSE (Modified from Geosystem, 2005)

3. GRAVITY METHOD

3.1 Introduction

Gravity survey measures variations in the Earth's gravitational field caused by differences in the density of sub-surface rocks. Gravity methods have been used most extensively in the search for oil and gas, particularly in the twentieth century. While such methods are still employed very widely in hydrocarbon exploration, many other applications have been found, some examples of which are (Reynolds, 1997):

- Hydrocarbon exploration
- Regional geological studies
- Isostatic compensation determination
- Exploration for, and mass estimation of, mineral deposits
- Detection of sub-surface cavities (microgravity)
- Location of buried rock-valleys
- Determination of glacier thickness
- Tidal oscillations
- Archeogeophysics (micro-gravity); e.g. location of tombs
- Shape of the earths (geodesy)
- Military (especially for missile trajectories)
- Monitoring volcanoes

Perhaps the most dramatic change in gravity exploration in the 1980's has been the development of instrumentation which now permits airborne gravity surveys to be undertaken routinely and with a high degree of accuracy. This has allowed aircraft-borne gravimeters to be used over otherwise inaccessible terrain and has led to the discovery of several small but significant areas with economic hydrocarbon potentials.

In geothermal application, the primary goal of studying detailed gravity data is to provide a better understanding of the subsurface geology. The gravity method is a relatively cheap, non-invasive, non-destructive remote sensing method that has already been tested on the lunar surface. It is also passive – that is, no energy needs to be put into the ground in order to acquire data; thus, the method is well suited to a populated setting. The small portable instrument also permits walking traverses, especially in view of the congested tourist traffic in some places.

Measurements of gravity provide information about densities of rocks underground. There is a wide range in density among rock types, and therefore geologists can make inferences about the distribution of strata.

In the geothermal fields in El Salvador, mapping of subsurface faults is usually done. Because faults commonly intercept rocks of different densities, the gravity method is an excellent exploration choice. The equipment used for measuring the variation of the earth gravimetric field is the "gravity meter" or gravimeter.

3.2 Basic theory

The basis on which the gravity method depends is based on two laws derived by Newton, namely the universal law of gravitation, and the second law of motion. The first of these two laws states that the force of attraction between two bodies of known mass is directly proportional to the product of the two masses and inversely proportional to the square of the distance between their centres of mass Equation 1). Consequently, the greater the distance separating the centre of the mass, the smaller the force of attraction between them.

Force = gravitational constant × mass of the earth (M) × mass (m) / (distance between masses (R))^2
Or

$$F=G \times M \times m/ R^2 \qquad (1)$$

where the gravitational constant, G = 6.67 x 10-11 Nm^2kg^{-2}

Newton's law of motion states that a force (F) is equal to mass (m) x acceleration (Equation 2). If the acceleration is in a vertical direction, then it is mainly due to gravity (g). In theoretical form, Newton's second law of motion states that:

$$\text{Force (F)} = \text{mass (m)} \times \text{acceleration (g)}$$

or
$$F = m \times g \qquad (2)$$

Equations 1 and 2 can be combined to obtain another simple relationship:

$$F = G \times M \times m / R^2 = m \times g$$

thus

$$g = G \times M / R^2 \tag{3}$$

This shows that the magnitude of acceleration due to gravity on earth (g) is directly proportional to the mass (M) of the Earth and inversely proportional to the square of the Earth's radius (R). Theoretically, acceleration due to gravity should be constant over the earth. In reality, gravity varies from place to place because the earth has the shape of a flattened sphere, rotates, and has an irregular surface topography and variable mass distribution.

3.3 Gravity units

The normal value of g at the Earth's surface is 980 cm/s^2. In honour of Galileo, the C.G.S. unit of acceleration due to gravity (1 cm/s^2) is Gal. Modern gravity meters (gravimeters) can measure extremely small variations in acceleration due to gravity, typically one part in 109. The sensitivity of modern instruments is about ten parts per million. Such small numbers have resulted in sub-units being used such as the:

milliGal (1 mGal = 10^{-3} Gal);
microGal (1 μGal = 10^{-6} Gal); and
1 gravity unit = 1 g.u. =0.1 mGal [10 gu =1 mGal]

3.4 Measurements of gravity

There are two kinds of gravity meters. An absolute gravimeter measures the actual value of **g** by measuring the speed of a falling mass using a laser beam. Although this meter achieves precisions of 0.01to 0.001 mGal (milliGals, or 1/1000 Gal), they are expensive, heavy, and bulky. A second type of gravity meter measures relative changes in **g** between two locations, see Figure 6. The Figure 6 shows a local base station and a site measurement using the gravity meter model CG-5 from Scintrex. This instrument uses a mass on the end of a spring that stretches, where **g** is stronger. This kind of meter can measure **g** with a precision of 0.01 mGal in about 5 minutes.

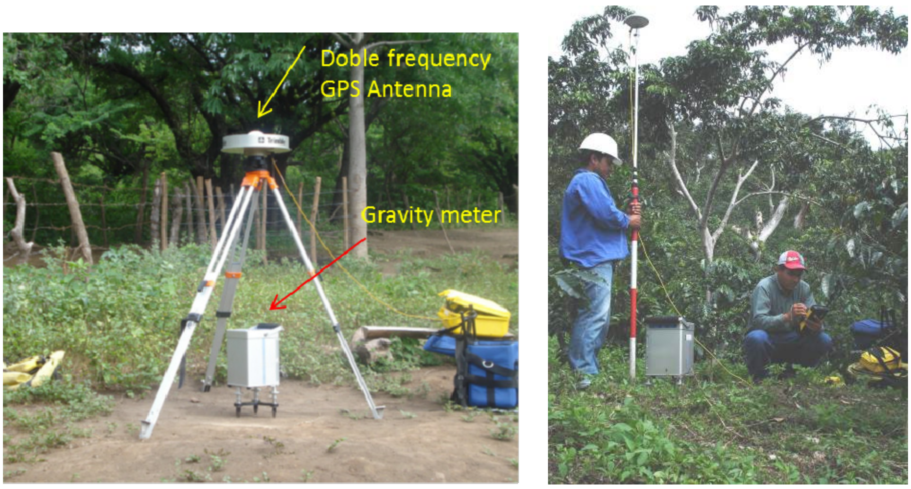

FIGURE 6: Left: Gravity meter at a base station opening loop, together with a remote reference GPS. Right: A site measurement, gravity and position using double frequency GPS

A relative gravity measurement is also made at the nearest absolute gravity station, one of a network of worldwide gravity base stations. The relative gravity measurements are thereby tied to the absolute gravity network (www.usgs.gov) (see Figure 7), which shows the absolute gravity station network of Central America.

Lateral density changes in the subsurface cause a change in the force of gravity at the surface. The intensity of the force of gravity due to a buried mass difference (concentration or void) is superimposed on the larger force of gravity due to the total mass of the earth.

FIGURE 7: Central American absolute gravity station cities; taken from NOAA, 2001.

Schematic diagrams in Figure 8 show the result of measurements, indicating the relative surface variation of gravitational acceleration over geologic structures. When the spatial craft passes over a denser body or crosses to another denser block of rocks, the gravitational attraction is increased. At the top of the diagram is a curve, which describes the gravity behaviour

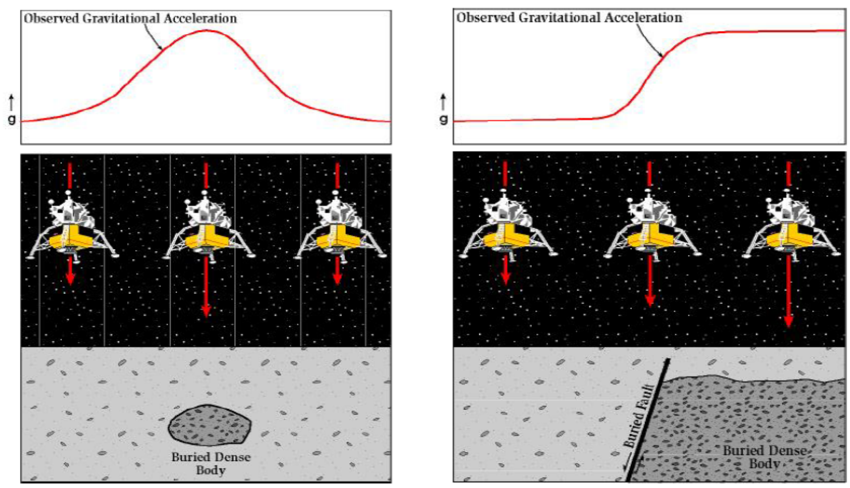

FIGURE 8: Cartoon illustrations showing the relative surface variation of gravitational acceleration over geologic structures
(taken from: geoinfo.nmt.edu/geoscience/projects/astronauts/gravity method.html)

3.5 Variation of gravity with latitude

The value of acceleration due to gravity varies over the surface of the earth for a number or reasons, one of which is the earth's shape. As the polar radius (6,357 km) is 21 km shorter than the equatorial radius (6,378 km), the points at the poles are closer to the earth's centre of mass; and therefore, the value of gravity at the poles is greater than that at the equator. Another aspect is that as the earth rotates once per sidereal day around its north-south axis, there is a centrifugal acceleration acting on it, which is greatest where the rotational velocity is largest, mainly at the equator (1,674 km/h; 1,047 miles/h); and decreases to zero at the poles. Gravity surveying is sensitive to variations in rock density, so an appreciation of the factors that affect density will aid the interpretation of gravity data.

3.6 Reduction of data

Gravimeters do not give direct measurements of gravity; rather, a meter reading is taken which is then multiplied by an instrumental calibration factor to produce a value of observed gravity (known as gobs). The correction process is known as **gravity data reduction or reduction to the geoid**. The various corrections that can be applied are the following.

Instrument drift: Gravimeter readings change (drift) with time as a result of elastic creep in the springs, producing an apparent change in gravity at a given stations. The instrumental drift can be determined simply by repeating measurements at the same stations at different times of the day, typically every 1 – 2 hours.

Earth's tides: Just as the water in the oceans responds to gravitational pull of the Moon, and to a lesser extent of the Sun, so too does the solid earth, which gives rise to a change in gravity of up to three g.u. with a minimum period of about 12 hours. Repeated measurements at the same stations permit estimation of the necessary correction for tidal effects over short intervals, in addition to the determination of the instrumental drift for a gravimeter.

Observed gravity (gobs) - Gravity readings observed at each gravity station after corrections have been applied for instrument drift and earth tides.

Latitude correction (gn) - Correction subtracted from gobs that accounts for earth's elliptical shape and rotation. The gravity value that would be observed if the earth were a perfect (no geologic or topographic complexities) rotating ellipsoid is referred to as the normal gravity.

$$g_n = 978031.85 * (1.0 + 0.005278895 \sin 2 (lat) + 0.000023462 \sin 4(lat)) \text{ (mGal)} \tag{4}$$

where lat is latitude

Free-air corrected gravity (gfa) - The free-air correction accounts for gravity variations caused by elevation differences in the observation locations. The form of the free-air gravity anomaly, gfa, is given by:

$$g_{fa} = gobs - gn + 0.3086h \text{ (mGal)} \tag{5}$$

where h is the elevation (in m) at which the gravity station is above the datum (typically sea level).

Bouguer slab corrected gravity (gb) - The Bouguer correction is a first-order correction to account for the excess mass underlying observation points located at elevations higher than the elevation datum (sea level or the geoid). Conversely, it accounts for a mass deficiency at observation points located below the elevation datum. The form of the Bouguer gravity anomaly, gb, is given by:

$$g_b = gobs - gn + 0.3086h - 0.04193r\, h \text{ (mGal)} \tag{6}$$

where r is the average density of the rocks underlying the survey area.

Terrain corrected bouguer gravity (gt) - The terrain correction accounts for variations in the observed gravitational acceleration caused by variations in topography near each observation point. Because of the assumptions made during the Bouguer Slab correction, the terrain correction is positive regardless of whether the local topography consists of a mountain or a valley. The form of the Terrain corrected, Bouguer gravity anomaly, gt , is given by:

$$gt = gobs - gn + 0.3086h - 0.04193r\,h + TC \text{ (mGal)} \qquad (7)$$

where TC is the value of the computed terrain correction.

Assuming these corrections have accurately accounted for the variations in gravitational acceleration, they were intended to account for any remaining variations in the gravitational acceleration associated with the terrain; corrected Bouguer gravity can be assumed to be caused by a geologic structure.

Once the basic latitude, free-air, Bouguer and terrain corrections are made, an important step in the analysis remains. This step, called regional-residual separation, is one of the most critical steps. In most surveys and in particular those engineering applications in which very small anomalies are of greatest interest, there are gravity anomaly trends of many sizes. The larger size anomalies will tend to behave as regional variations, and the desired smaller magnitude local anomalies will be superimposed on them.

3.7 Bouguer anomaly

The main end-product of gravity data reduction is the Bouguer anomaly, which should correlate only with lateral variations in density of the upper crust and which is of most interest to applied geophysicist and geologists. The Bouguer anomaly is the difference between the observed gravity value (gobs), adjusted by the algebraic sum of all the necessary corrections, and that of a base station (gbase). The variation of the Bouguer anomaly should reflect the lateral variation in density such that a high-density feature in a lower- density medium should give rise to a positive Bouguer anomaly. Conversely, a low-density feature in a higher-density medium should result in a negative Bouguer anomaly. See example in Figure 9 of Bouguer and residual anomaly maps.

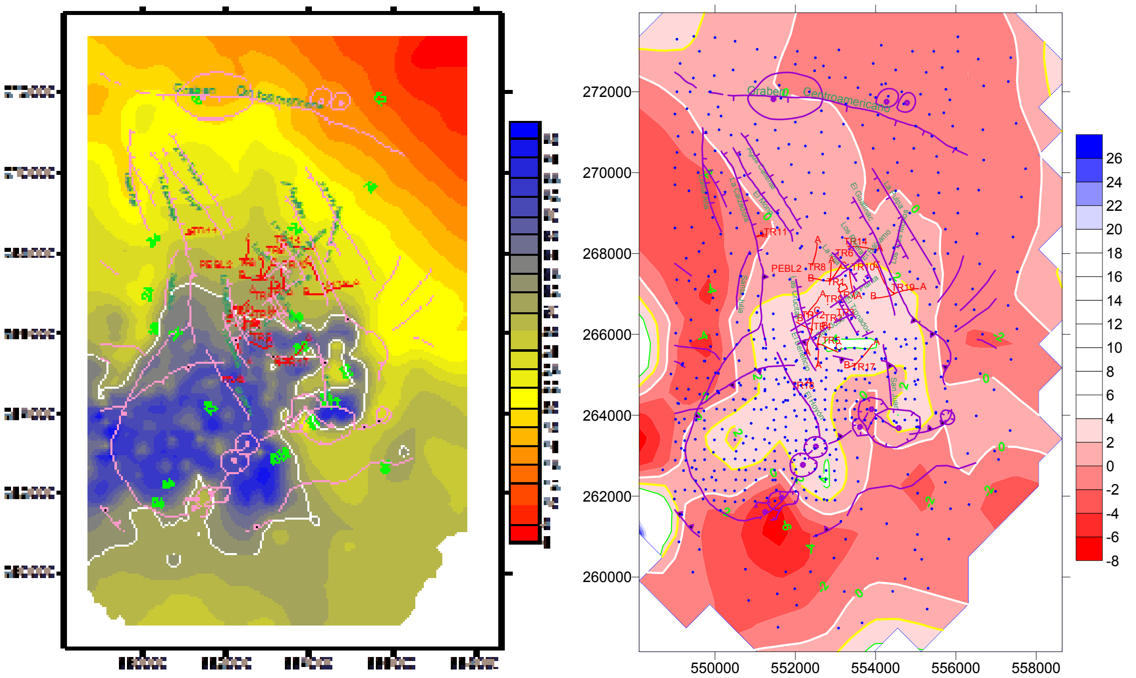

FIGURE 9: Bouguer anomaly map (left) and residual anomaly map (right) of the Berlin geothermal field

4. MAGNETIC METHOD

4.1 Introduction

The magnetic method is a very popular and inexpensive approach for near-surface metal detection. Engineering and environmental site characterization projects often begin with a magnetometer survey as a means of rapidly providing a layer of information on where utilities and other buried concerns are located (www.aoageophysics.com).

The principal operation is quite simple. When a ferrous material is placed within the earth's magnetic field, it develops an induced magnetic field. The induced field is superimposed on the earth's field at that location creating a magnetic anomaly. Detection depends on the amount of magnetic material present and its distance from the sensor. The anomalies are typically presented on colored contour maps. Common uses of magnetometers include:

- Locating buried tanks and drums
- Fault studies
- Mineral exploration
- Geothermal exploration
- Mapping buried utilities, pipelines
- Buried foundations, fire pits for archaeological studies

In geothermal application, the main objective of the magnetic study is to contribute with information about the relationship among the geothermal activity, the tectonic and stratigraphy of the area by means of the anomaly interpretation of the underground rocks' magnetic properties (Escobar, 2005).

Most of the rocks are not magnetic; however, certain types of rocks contain enough minerals to originate significant magnetic anomalies. The data interpretation that reflects differences in local abundance of magnetization is especially useful to locate faults and geologic contacts (Blakely, 1995).

The magnetic anomalies can be originated from a series of changes in lithology, variations in the magnetized bodies thickness, faulting, pleats and topographical relief. A significant quantity of information can leave a qualitative revision of the residual magnetic anomaly map of the total magnetic field. In this sense, the value of the survey does not end with the first interpretation, but rather it enriches as more geology is known.

It is more important, at the beginning, to detect the presence of a fault or intrusive body, than to determine their form or depth. Although, in some magnetic risings, such determination cannot be made in a unique manner, the magnetic data has been useful because the intrusive is more magnetic than the underlying lava flows. Faulting creates open spaces so that the hot fluids can be transported, therefore altering the host rocks. The temperature of the hydrothermal system and the oxygen volatility will determine the quantity of the present load in the fault zone and therefore, giving their magnetic response.

4.2 Basic theory

If two magnetic poles of strength *m1* and *m2* are separated by a distance *r*, a force, *F*, exists between them. If the poles are of the same polarity, the force will push the poles apart; and if they are of opposite polarity, the force is attractive and will draw the poles together. The equation for **F** is the following:

$$F = m_1 m_2 / 4\pi\mu^2 r^2 \tag{8}$$

where μ is the magnetic permeability of the medium separating the poles;
m1 and *m2* are pole strengths; and
r the distance between them.

4.3 Magnetic units

The magnetic flux lines between two poles per unit area is the flux density **B** (measured in weber/m^2 = Tesla). **B**, also called the ***magnetic induction***, is a vector quantity. The unit of Tesla is too large to be practical in geophysics work, so a sub-unit called a nanotesla (1 nT = 10^{-9} T) is used instead, where *1 nT* is numerically equivalent to *1 gamma* in C.G.S. units (1 nT = 10^{-5} gauss).

4.4 The Earth's magnetic field

The geomagnetic field at or near the surface of the earth originates largely from within and around the earth's core. It can be described in terms of the declination (D), inclination (I), and the total force vector F (Figure 10). The vertical component of the magnetic intensity of the earth's magnetic field varies with latitude, from a minimum of around 30,000 nT at the magnetic equator to 60,000 nT at the magnetic poles.

4.5 Magnetics instruments

The equipment used for magnetic measurements are called **magnetometer**, which is used specifically in geophysical exploration. There are two main types of resonance magnetometer: the proton free-precession magnetometer, which is the best known, and the alkali vapour magnetometer. Both types monitor the precession of atomic particles in an ambient magnetic field to provide an absolute measure of the total magnetic field, F.

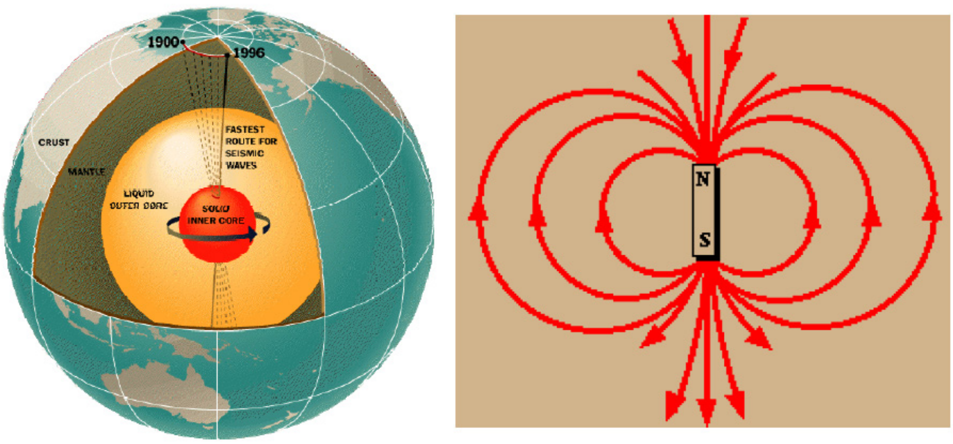

FIGURE 10: Left: Origin of the Earth's magnetic field. Right: Displacement of the force lines of the Earth's magnetic field, equivalent to the ones of the magnet

The proton magnetometer has a sensor which consists of a bottle containing a proton-rich liquid, usually water or kerosene, around which a coil is wrapped, connected to the measuring apparatus. Each proton has a magnetic moment (M) and, as it is always in motion, it also possesses an angular momentum (G), like a spinning top. Figure 11 shows examples of field measurements with a magnetometer model GEM-19T from GEM System, owned by LaGeo in a survey around the San Vicente volcano area.

4.6 Magnetic surveying

Local variations or anomalies in the earth's magnetic field are the result of disturbances caused mostly by variations in concentrations of ferromagnetic material in the vicinity of the magnetometer's sensor. Magnetic data can be acquired in two configurations:

1) A rectangular grid pattern
2) Along a traverse

Grid data consists of readings taken at the nodes of a rectangular grid; and traverse data is acquired at fixed intervals along a line. Each configuration has its advantages and disadvantages, which are dependent upon variables such as the site conditions, size and orientation of the target, and financial resources. An example of a grid along lines is shown in Figure 12. This took place in the San Vicente geothermal area in El Salvador.

FIGURE 11: Examples of a field measurement with a magnetometer model GEM-19T from GEM System, owned by LaGeo; a magnetic survey in the San Vicente volcano area

In both traverse and grid configurations, the station spacing or distance between magnetic readings is important. Single point or erroneous anomalies are more easily recognized on surveys that utilize small station spacing.

Ground magnetic measurements are usually made with portable instruments at regular intervals along more or less straight and parallel lines that cover the survey area. Often the interval between measurement locations (stations) along the lines is less than the spacing between lines. It is important to establish a local base station in an area away from suspected magnetic targets or magnetic noise, and where the local field gradient is relatively flat. Ideally, the base station is placed at least 100 m from any large metal objects or travelled roads and at least 500 m from any power lines when feasible.

The base station location must be very well described in the field book, as others may have to locate it later, based on the written description.

There are certain limitations in the magnetic method. One limitation is the problem of "cultural noise" in certain areas. Man-made structures that are constructed using ferrous material, such as steel, have a detrimental effect on the quality of the data. Other features to be avoided include steel structures, power lines, metal fences, steel reinforced concrete, surface metal, pipelines and underground utilities. When these features cannot be avoided, their locations should be noted in a field notebook and on the site map.

To make accurate anomaly maps, temporal changes in the earth's field during the period of the survey must be considered. Normal changes during a day, sometimes called *diurnal drift*, are a few tens of nT, but changes of hundreds or thousands of nT may occur over a few hours during magnetic storms. During severe magnetic storms magnetic surveys should not be made. The correction for diurnal drift can be made by repeating measurements of a base station at frequent intervals. The measurements at field stations are then corrected for temporal variations by assuming a linear change of the field between repeated base station readings.

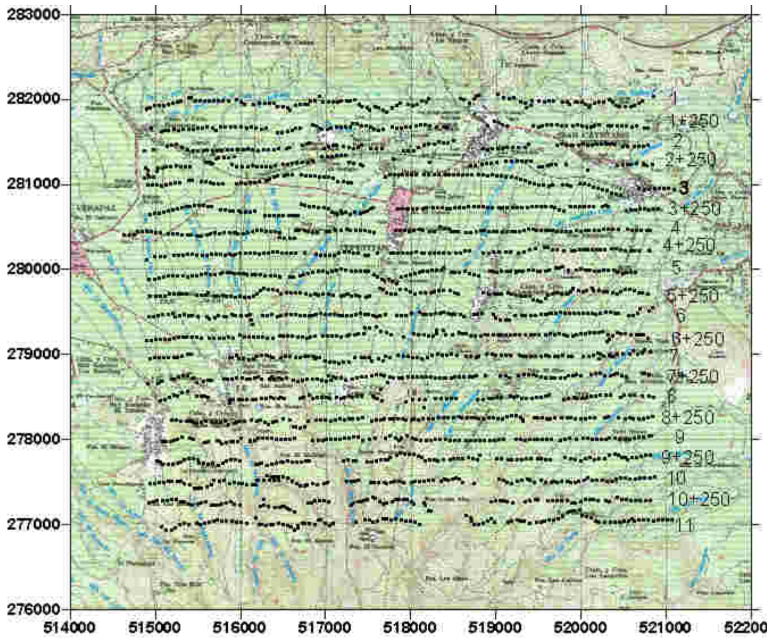

FIGURE 12: Land magnetic survey at San Vicente geothermal area; lines are six km long and measure sites every 100 m. Spacing lines are 250 m

The magnetometer is operated by a single person. However, grid layout, surveying, or the buddy system may require the use of another technician. If two magnetometers are available, data acquisition is usually doubled as the ordinary operation of the instrument itself is straightforward.

4.7 Distortion

Steel and other ferrous metals in the vicinity of a magnetometer can distort the data. Large belt buckles, etc., must be removed when operating the unit. A compass should be more than 3 m away from the magnetometer when measuring the field. A final test is to immobilize the magnetometer and take readings while the operator moves around the sensor. If the readings do not change by more than 1 or 2 nT, the operator is "magnetically clean". Zippers, watches, eyeglass frames, boot grommets, room keys, and mechanical pencils can all contain steel or iron. On very precise surveys, the operator effect must be held at under 1 nT.

Data recording methods will vary with the purpose of the survey and the amount of noise present. Methods include taking three readings and averaging the results, taking three readings within a meter of the station and either recording each or recording the average. Some magnetometers can apply either of these methods and even do the averaging internally. An experienced field geophysicist will specify which technique is required for a given survey. In any case, the time of the reading is also recorded unless the magnetometer stores the readings and periods internally.

Sheet-metal barns, power lines, and other potentially magnetic objects will occasionally be encountered during a magnetic survey. When taking a magnetic reading in the vicinity of such items, it should describe the interfering object and note the distance from it to the magnetic station in the field book. Items to be recorded in the field book for magnetic include:

a) Station location, including locations of lines with respect to permanent landmarks or surveyed points;

b) Magnetic field and/or gradient reading;
c) Time:
d) Nearby sources of potential interference.

The experienced magnetic operator will be alert for the possible occurrence of the following:

1. Excessive gradients may be beyond the magnetometer's ability to make a stable measurement. Modern magnetometers give a quality factor for the reading. Multiple measurements at a station, minor adjustments of the station location and other adjustments of technique may be necessary to produce repeatable, representative data.

2. Nearby metal objects may cause interference. Some items, such as automobiles, are obvious, but some subtle interference will be recognized only by the imaginative and observant magnetic operator. Old buried curbs and foundations, buried cans and bottles, power lines, fences, and other hidden factors can greatly affect magnetic readings.

4.8 Data reduction and interpretation

The data should be corrected for diurnal variations, if necessary. If the diurnal data does not vary more than approximately 15 to 20 gammas over a one-hour period, correction may not be necessary. However, this variation must be approximately linear over time and should not show any extreme fluctuations. The global magnetic field is calculated through a previous established model (IGRF- International Geomagnetic Reference) in Figure 9, and obtained analytically with the help of field observations. Due to the fact that the global magnetic field is variable, these maps are generated every 5 years. There are filters used for highlighting the contrast of anomalies, which are:

- Derivatives of different order or gradients
- Upward or downward continuation regarding the anomaly
- Band pass or high pass filters
- Pole reduction

After all corrections have been made, magnetic survey data are usually displayed as individual profiles or as contour maps. Identification of anomalies caused by cultural features, such as railroads, pipelines, and bridges is commonly made using field observations and maps showing such features.

4.9 Presentation of results

The final results are presented in profile and contour map form (see Figure 13). Profiles are usually presented in a north-south orientation, although this is not mandatory. The orientation of the traverses must be indicated on the plots. A listing of the magnetic data, including the diurnal monitor or looping data should be included in the report. The report must also contain information pertinent to the instrumentation, field operations, and data reduction and interpretation techniques used in the investigation.

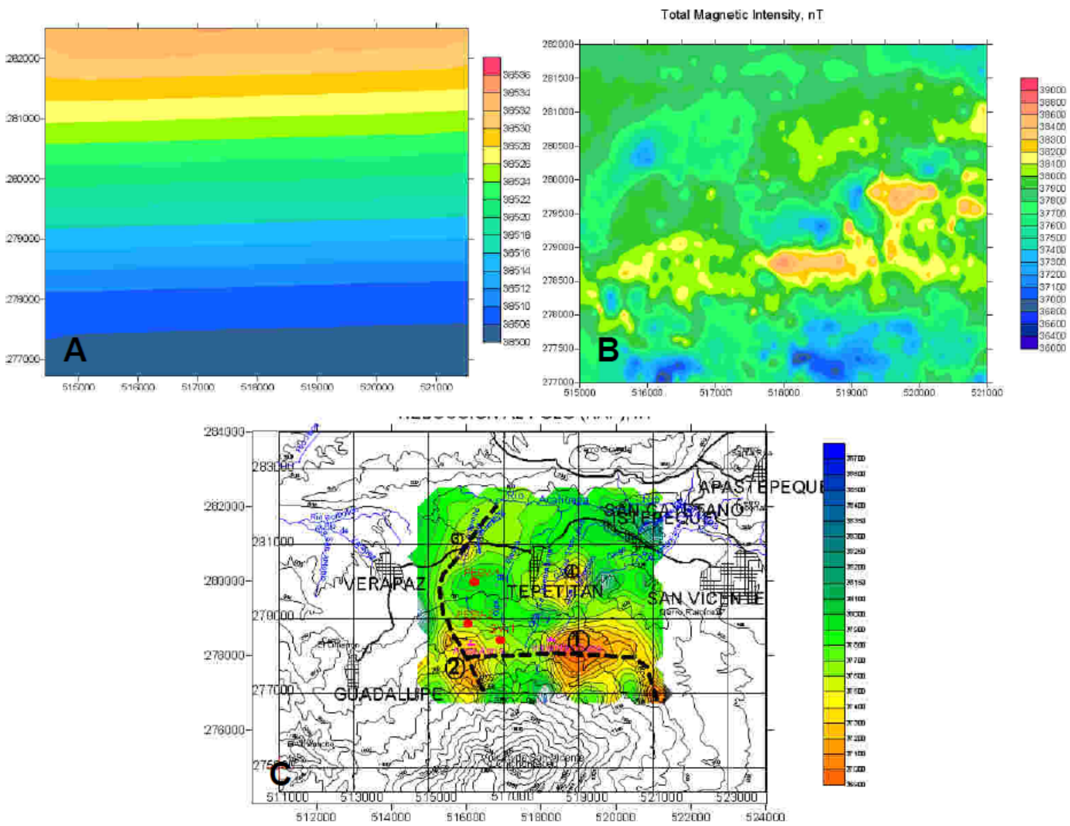

FIGURE 13: Examples of magnetic maps. A) Regional magnetic field in the San Vicente geothermal area (IGRF); B) Total magnetic field intensity, C) Pole reduction in the San Vicente magnetic survey

5. CONCLUSION

Microseismic analysis, gravity and magnetic methods have been performed in El Salvador to contribute to the surface exploration programme, and construction or updating the conceptual models of different geothermal areas such as Berlin Geothermal Field (seismic and gravity), Ahuachapán Geothermal Field (gravity), Chinameca Geothermal Area under deep exploration activities (gravity and magnetic) and San Vicente Geothermal Area under deep exploration (seismic, gravity and magnetic).

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GEOTHERMAL DRILLING

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ABSTRACT

Geothermal drilling is considered as the phase which verifies the existence of an underground thermal resource which may be utilized for energy exploitation. The earlier phases of research relate largely to the study of hot springs, fumaroles and even the presence of volcanoes themselves, but after having carried out all these studies, it is the drilling of exploration boreholes, and, above all, deep exploration, which evidences the success or failure of the research.

1. INTRODUCTION

1.1 Drilling of a geothermal well

This will be a short description of the different activities involving the drilling of a well, the different steps that must be performed to provide the final product; a completely finished well. The three components of geothermal drilling are: The rig, the personnel, and the work performed or the drilled well.

1.2 The drilling rig

The drilling rig (Figure 1) can be considered as a plant consisting of several components that are used to create the ultimate goal; a completely finished geothermal well. It must always be taken into account that each component can be transported by land via trucks, hauling trailers, or low-bed trailers, whenever the rig is transported to the site where the well will be drilled.

Generally, rigs are owned by private equity entities, which may have a sole proprietor or be owned by a partnership formed by several owners.

The rig comprises hoisting, circulation, and rotation components, as well as a steel structure with a mast, and a power source.

FIGURE 1: Massarenti 6000 rig

1.2.1 The tower or mast

It is a steel structure which must possess the capacity to house sufficient drill pipe, which can weigh up to several tons.

It is erected on a steel base called the substructure, which holds the work-floor known as the rotary table. The work-floor is where the drilling crew is deployed.

This substructure must also possess enough height so as to accommodate the arrangement of the blowout preventer valves.

1.2.2 Hoisting components

The hoisting system is comprised by the main winch, the block and tackle pulley, the crown block and the drilling cable (Figure 2).

FIGURE 2: Travelling block and hook (left) and crown block (right)

1.2.3 Rotation components

This system is comprised by the rotary head, the hexagonal Kelly, and the rotary table. This also includes the drill string and drill bits. The drill bits (Figure 3) are the tools that cut the rock formation. There are several types of drill bits, such as:

1.3 Drilling personnel

The personnel working in drilling consists of the drilling crew, where the driller is the leader and the person who operates the rig. The driller works with the derrickman, who is the person working in the mast and who is also in charge of monitoring and controlling the drilling fluid or mud tanks.

There is also an assistant driller that provides support to the operations and management of the rig. Furthermore, there is a group of three people called roughnecks, who work on the floor to conduct tightening maneuvers on the drilling tools.

The toolpusher is the person in charge of the drilling platform and the person who gives orders therein. This person is available at the drill site 24 hours a day, over a period of three to four weeks, until he is relieved from his duties.

There is also maintenance personnel on site, such as the equipment mechanic, the electrician, and the welders. Each person has their respective assistant to aid them in operations that can sometimes last for long periods of time.

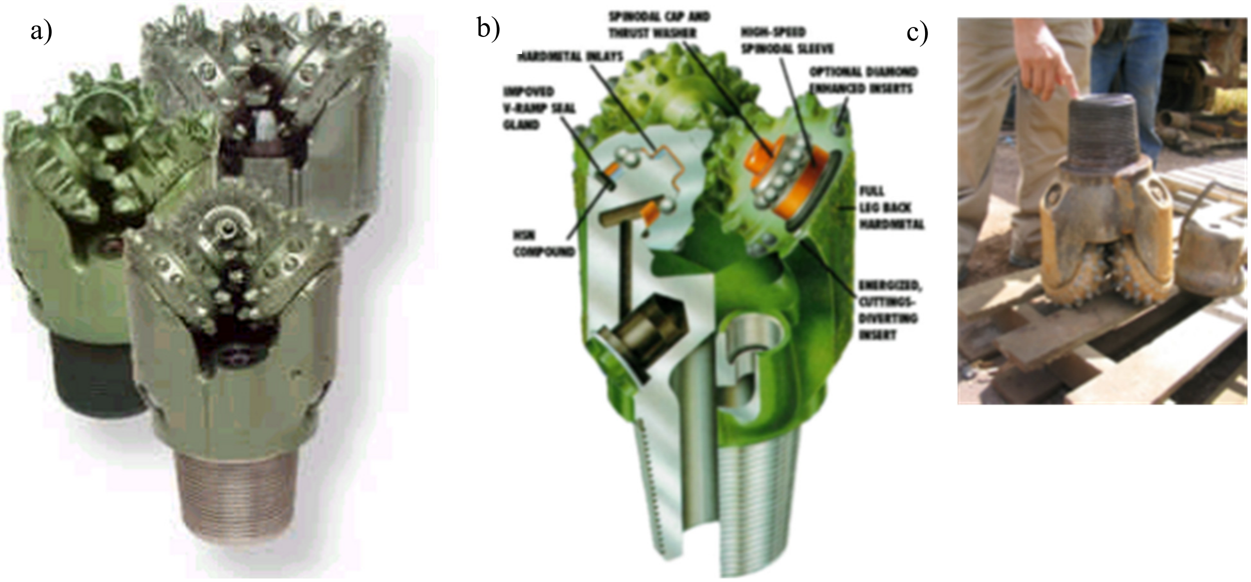

FIGURE 3: Drill bits: a) Tri-cone bits, b) Tri-cone bit, bearings, c) 12 ¼" Tri-cone bit

1.4 The drilled well

The drilling of a geothermal well is performed with a hole of a larger initial diameter and ends with a smaller diameter hole. This means that the construction is telescopic. The reason for this is because of the expected penetration, seeing as the best penetration normally occurs at greater depths with smaller diameter bits. A typical description of a drilled well is shown in Figure 4.

The first stage of drilling is carried out with the larger diameter formation cutting tool (for this particular case, 32" diameter). Drilling then continues with the second stage of 23", which is followed by a third stage of 17 ½" and ends with a 12 ¼" hole. For each of these drilling stages, a steel pipe casing is installed like so: for 32", a 24 ½" casing is provided; for 23", a 18 5/8" casing is provided; for 17 ½", a 13 3/8" casing is provided; and finally, for the 12 ¼" hole, the casing is a slotted liner (often simply referred to as "liner") which can be hung or supported until reaching the bottom of the well.

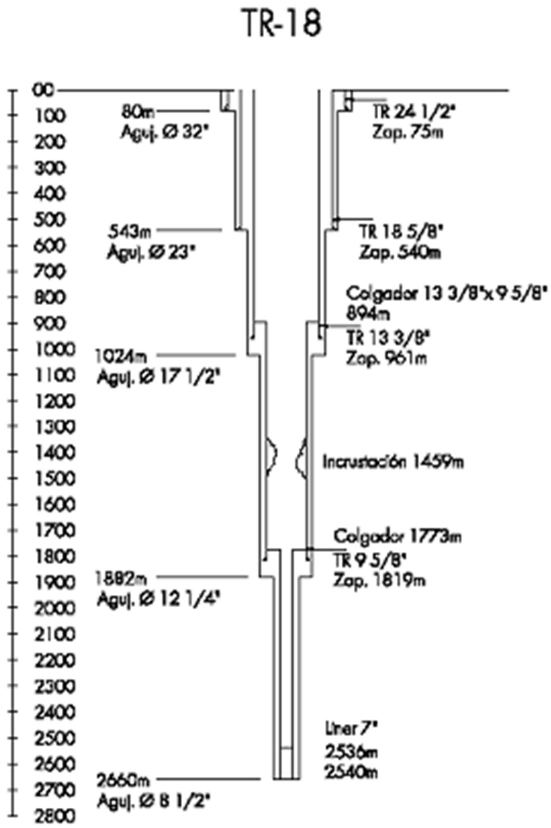

FIGURE 4: A typical description of a drilled well

2. DRILLING OPERATIONS

2.1 Mobilization and assembly of the rig

The mobilization of the drilling rig is the transportation from its storage base to the place where the well will be drilled. Where there already exist drilled wells in the platform, some additional procedures must be considered, which depend on the space available for the rig.

Sometimes it is necessary to assemble the rig in a place where it can be further skidded, depending on the space available.

(Video of the skidding of the Massarenti 6000 rig in the TR-18B well, Berlín geothermal field, 2012)

2.2 Drilling

2.2.1 Vertical Drilling

Vertical drilling is conducted in order to construct a vertical hole. The maximum permissible deviation should not exceed 5 degrees, and to verify this, tilt records (which mark the inclination angle of the borehole in a metal tablet) are performed every 100 drilled meters.

To try to maintain the verticality of the well, it is necessary to monitor and control the drilling parameters, such as the weight applied to the string, the string rotation, and the pumping flow of the drilling fluid, which may all influence the inclination to some extent.

2.2.2 Directional drilling

Directional drilling is used when the drill site is located in places where it is difficult to build platforms. It takes advantage of an existing well platform to drill directionally towards the objective, which may be a few meters away from the vertical axis of the well.

It also serves to better intercept the faults or fractures which may exhibit characteristics of production or feeding areas for geothermal resources, whether it be steam or a geothermal water-steam mixture.

To perform directional drilling of a well, one of the most widely used tools is called a downhole motor, which consists of a tubular tool that carries a helically shaped rotor in its interior, which in turn is rotated by the passing drilling fluid, also known as drilling mud.

In regards to directional drilling measurements, inclination angles are measured as well as the direction or orientation of the drilling string.

2.2.3 Aerated drilling

It is the drilling technique which uses air as a drilling fluid (Figure 5). Drilling is typically performed with a combination or mud-air, air-water, or air-foam, with the purpose of decreasing the weight of the hydrostatic head, as well as contributing to the reduction of circulation losses caused by fractures induced by the hydrostatic pressure of the drilling fluid column in the well.

This type of drilling has been applied with the purpose of better maintaining cleanliness in the borehole, as well as maintaining a continuous circulation of drilling fluid when passing through large fracturing areas that prevent the collection of cuttings from the bottom of the well.

FIGURE 5: Test of the production of a geothermal well with compressed air equipment for aerated drilling

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STRATIGRAPHIC, TECTONIC AND TEMPERATURE MAPPING THROUGH GEOLOGICAL WELL LOGGING: ICELANDIC EXPERIENCE

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ABSTRACT

When geothermal exploration turns from surface exploration to subsurface exploration this marks the onset of direct measurements of the properties of the geothermal reservoir through boreholes, but the objective is to gain information about the geological setting, temperature, pressure and fluid composition in the geothermal reservoir to prepare for future utilization. Geological samples in the form of drill cuttings and cores are collected during drilling of geothermal wells. Analysis of the rock samples is used both as guidance in technical aspects of drilling as well as to characterise the geological and thermal structure of the geothermal reservoir. Geothermal high temperature drilling has been carried out in Iceland for decades, but this paper will give a brief description of the types of geological investigations that performed in association with geothermal exploration in Iceland and provide examples of how they are applied to compile the volcanic and tectonic structure and thermal history of the geothermal field.

1. INTRODUCTION

The first step of exploring and developing geothermal resources is surface exploration, which typical includes geological mapping, geochemical and geophysical surveys. The objective of the surface exploration is to obtain initial estimates on: (1) the geological structure of the system (2) the fracture network that controls fluid flow within the system (3) the size of the system (4) subsurface temperatures (5) heat source and natural recharge to mention a few. The outcome of these investigations should be brought together to create a preliminary conceptual model of the geothermal area.

Provided that the results of surface exploration points towards a geothermal potential, the next step will eventually be to drill wells (exploration and production wells) into the geothermal reservoir in order to validate this initial conceptual model and confirm reservoir temperature, pressure, permeability and fluid composition.

The well gives access to the information about the subsurface. Geological samples are collected in the form of cuttings and/or cores, but these are analysed to determine the lithology and alteration of the rocks. Logging tools can be lowered into the well both during and after drilling, but they are used to measure and evaluate reservoir properties such as formation temperature, pressure, injectivity and production capacities as well as geophysical properties of the formation, while the reservoir fluid can be sampled and analysed, when the well is discharged.

This paper will address the information that is obtained through analysis of the collected geological rock samples, and how this is applied both during drilling and later to update the conceptual model. Other papers will be addressing the information obtained through logging and fluid sampling from the well.

Analysis of the cuttings and cores collected from the wells enables the well site geologist to map the stratigraphy of the geothermal reservoir, thus presenting the subsurface extension of the geological mapping at surface. Geological mapping of the subsurface through well cuttings and cores does not offer extensive surface exposures as the field geologist is privileged with. But the well site geologist can with advantage study fossil central volcanoes that have been exhumed by erosion. Examples of exposed sections through central volcanoes are found in Eastern Iceland (Figure 1), where the structure of the volcanic complex can be studied in detail such as relationships between intrusive complexes (dykes, sills, sheeted dyke complexes and plutons) and aureoles with hydrothermal alteration. Such studies enable the well site geologist to correlate observations from drilling cuttings and cores with the large scale geological structures characterising a geothermal system on which a conceptual model build upon.

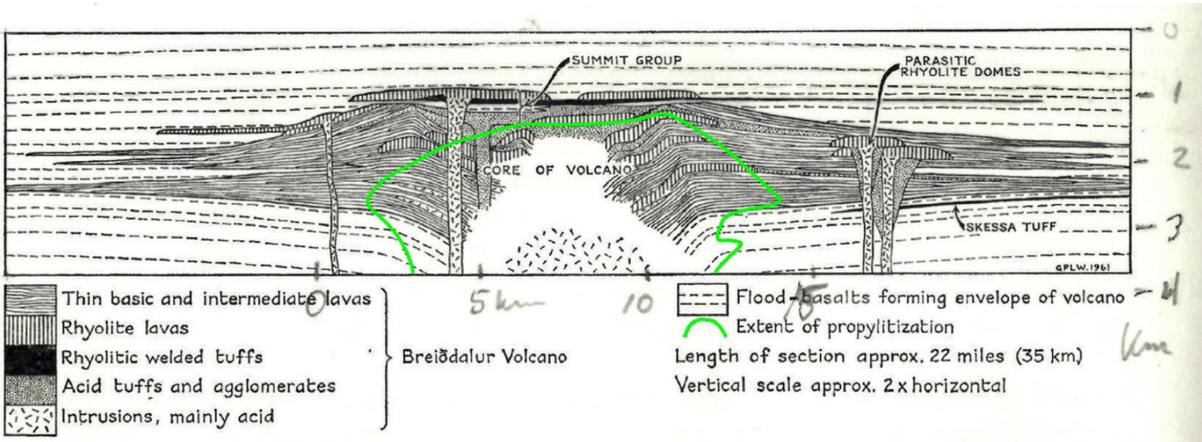

FIGURE 1: Graphic representation of Breiddalur central volcano, Eastern Iceland, but it has been exposed through erosion (Walker, 1963)

2. GEOLOGICAL WELL LOGGING – METHODS AND APPLICATIONS

During drilling into high temperature geothermal fields in Iceland drill cuttings are collected at 2 m intervals and petrographic analysis of the cuttings then forms the foundation for creating lithology and alteration logs of the well. The geologist is using a binocular microscope for the drill cuttings analysis, but first analysis is carried out in conjunction with drilling at rig site. Further and more detailed analysis is carried out when drilling is completed. In order to better characterise the hydrothermal alteration and alteration mineral sequences petrographic analysis is complemented with thin section analysis and XRD clay analysis, and this can be supplemented with fluid inclusion analysis at selected intervals.

The petrographic analyses are used to improve and refine the understanding of the geological setting within the geothermal reservoir as well as to assist with technical issues during drilling of the geothermal well.

Information gathered from drilling into the geothermal reservoir is used to extend the initial conceptual model into the geothermal reservoir, but the objective of petrographic analysis of drill cutting is to obtain information about:

1) temperature and temperature changes in the geothermal reservoir
2) geological control of permeability
3) formation porosity
4) fluid composition
5) rock type and stratigraphy e.g. characterise cap rock, reservoir rock and heat source
6) upflow, outflow and recharge zones
7) duration and thermal history of the geothermal system

During drilling petrographic cutting analysis is also used to assist with technical aspects of the well construction and drilling operation. Petrographic analysis of the cuttings is used to estimate, when the well has reached into sufficiently high temperatures in the reservoir before setting the production casing, ensure that all casings are set in solid formations as well as assisting with foreseeing or explaining drilling problems such as: a) blow outs due to over-pressured aquifers, b) stuck pipes due to swelling clays or unstable rock formation or c) drill bit performance is evaluated from cutting size, rock type, formation temperature and signs of metal fragment contaminations. In addition to analysing the drill cuttings the well site geologist is also using the drilling parameters to gain information about the reservoir conditions, e.g. circulation loss and temperature changes of the circulation fluid is monitored to identify, when the well is intersecting aquifers, while the formation hardness can be inferred from the drilling parameters. The drilling parameters are particularly valuable, when drilling with total loss of the circulation fluid, for instance are changes in parameters such as pump pressure and penetration rate used to identify whether the well has intersected new aquifers.

3. LITHOLOGY, STRATIGRAPHY AND PERMEABILITY

Analysis of lithology and hydrothermal alteration of drill cuttings are presented in logs, which are meant to give an overview of how the stratigraphy of the field is and how alteration of the rock is systematically changing with depth in the geothermal reservoir. The mud log is also showing the location of aquifers that the well has intersected, but aquifers are identified by measuring the circulation loss while drilling, through temperature measurements in the well and by observing changes in alteration in the drill cuttings, but the location of aquifers are closely compared to the lithology and alteration in the well in order identify whether the aquifers are tied to lithological contacts, intrusions or fractures and faults.

As more wells are drilled into the geothermal reservoir the lithology can be correlated between the wells in order to create a stratigraphic and structural model of the geothermal field. Correlation between wells can be difficult in volcanic terrains due to large variations in the lateral extent of the volcanic deposits and their at times rather homogeneous appearance. The geological model should depict the main rock formations of the geothermal field, what constitutes the cap rock and the reservoir rock as well as highlighting faults and fractures in the field. Surface faults can be hidden by recent volcanic deposits, so stratigraphic correlation between wells also attempt to identify hidden faults.

In Figure 2 is an example of a geological cross section through the Leirbotnar and Sudurhlídar well fields in Krafla, NE-Iceland. In correspondence with most high temperature fields in Iceland the cap rock consist of hyaloclastites interlayered with sequences of basaltic lavas. The hyaloclastites are formed by subglacial eruptions. Initially the hyaloclastite has a high porosity (20-50%). But it consists almost entirely of volcanic glass, which is highly susceptible to alteration, thus the porosity of the rock diminishes readily with alteration forming an impermeable roof zone of the geothermal reservoir. With depth pillow lavas and basaltic lavas (~10-15% porosity) become more prominent at the same time the intensity of intrusions increases, but they are dense with a porosity of 2-5%. This is particular conspicuous in the Leirbotnar and Sudurhlídar field in Krafla, but there the lower reservoir is situated in a dyke complex (Ármannsson et al., 1987) (Figure 2), which represents part of the heat source.

In Figure 2 is a schematic illustration of the geological structures permeability is tied to with depth in the geothermal reservoir in Iceland. At shallow levels where lavas and hyaloclastites are unaltered the permeability is mainly strata bound, but with depth within the geothermal reservoir the volcanics are less permeable due to alteration and permeability is mainly tied to intrusives such as dykes and sills and active faults and fractures or where these structures intersect.

In an extensional setting as in Iceland faults and fissures are almost vertical. Televiewer logging is the most powerful way to confirm the strike and dip of permeable faults and fissures to help refine the structural model of the field and for future well siting (Steingrímsson, 2013). However, as a first approximation strike and dip of faults and fissures can also be inferred through correlation between surface structures and the location of aquifers in deviated wells (Figure 3).

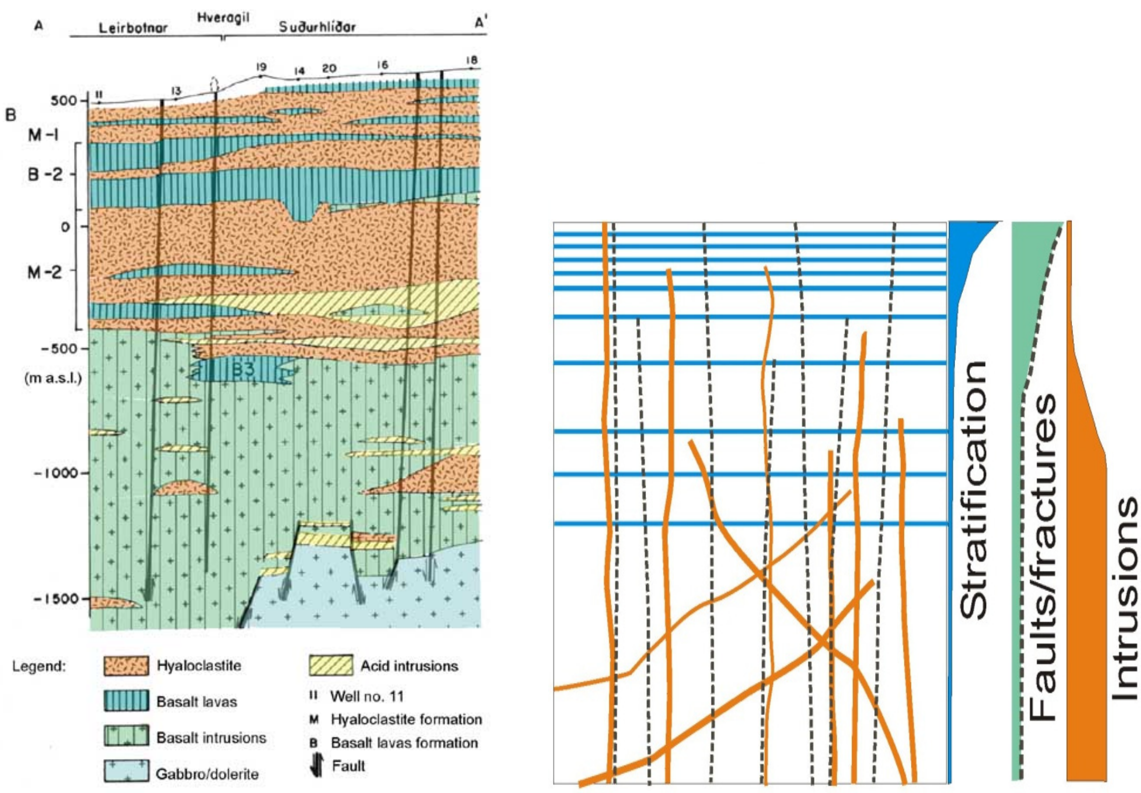

FIGURE 2: Left: Geological cross section W-E through Leirbotnar and Sudurhlídar well fields in Krafla (Ármannsson et al., 1987), the cap rock consist of sequences of hyaloclastites and basalt lavas, while the reservoir is situated in a dyke complex. Right: Schematic representation of permeability in high-T geothermal fields in Iceland, illustrating that permeability is mainly tied to faults/fractures and intrusions (dykes/sills) within the geothermal reservoir (Axelsson and Franzson, 2012)

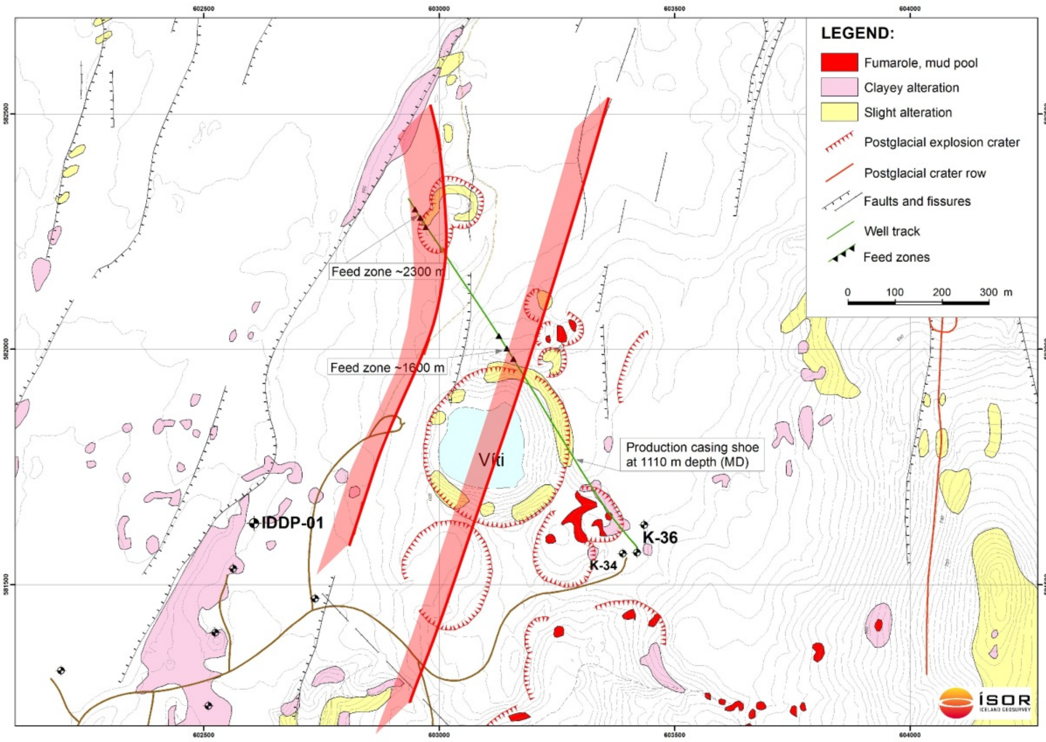

FIGURE 3: Map showing the correlation between fissure location at surface (red lines with shade pointing to the dip direction) and feed zone location in deviated well K-36 in Krafla verifying that the dip of the permeable fissures is ~3° to the west (Gudmundsson et al., 2008)

4. HYDROTHERMAL ALTERATION AND TEMPERATURE

Hydrothermal alteration in geothermal systems is a result of reaction between water and rock, but hydrothermal alteration is dependent on temperature, pressure, fluid composition, permeability, rock type and duration (Browne, 1978, 1984; Reyes, 1997). Dependent on the prevailing conditions within the geothermal reservoir hydrothermal alteration can occur either through precipitation, replacement or leaching.

Precipitation of hydrothermal alteration minerals is strongly controlled by temperature, thus systematic changes in alteration minerals assemblages with depth in the geothermal reservoir can be used as temperature indicators.

A large variety of hydrothermal alteration minerals have been identified in geothermal systems, but among the more common are carbonates (e.g. calcite), sulphides (e.g. pyrite), clays, oxides, and hydrated silicates. The most temperature sensitive alteration minerals are those, which contain OH or n.H_2O in their structure e.g. clays, zeolites, calcium silicates (e.g. epidote) and amphiboles, but in Table 1 is an overview of the temperature stability interval of the most common temperature dependent alteration minerals observed in geothermal fields Iceland.

The clay minerals are important index minerals not only due to their abundance and temperature sensibility, but also because there is a significant variation in the conductivity of the different types of clays (Flovenz *et al.*, 2005). In geothermal fields in Iceland the rocks are of basaltic composition, mainly tholeiites and olivine tholeiites, and therefore Mg- and Fe-rich clay types are prevalent such as smectite, mixed layer clays (MLC) and chlorite, while illite is scarce and only observed in association with more felsic rocks such as rhyolites.

This property of the clays to be sensitive to both temperature and conduction is of advantage to the resistivity surveys as this makes it possible to relate the resistivity structure in the ground to alteration temperature, where the conductive cap rock correlates to the presence of smectite and MLC clays, while the high resistive core of the geothermal reservoir corresponds to the presence of chlorite clays in the formation.

Table 1: Common temperature dependent alteration minerals in high temperature areas in Iceland (Kristmannsdóttir, 1979)

Minerals	Min. temp. °C	Max. temp. °C
zeolites	40	120
*laumontite	120	180
quartz	180	>300
*wairakite	200	
smectite		<200
**MLC	200	230
chlorite	230	>300
calcite	50-100	280-300
prehnite	240	>300
epidote	230-250	>300
wollastonite	260	>300
actinolite	280	>300

*Belong to the zeolite group.
**Mixed layer clay.

The systematic change in alteration mineral assemblage with temperature in the geothermal systems is used to create isotherm maps and cross sections (Figure 4). With these maps areas of upflow (most alteration) and their structural correlation may be highlighted. In Iceland the isotherm maps and cross sections are either based on a specific index mineral or defined alteration zones as exemplified in Figure 4, but the alteration zones represent the following temperature stability interval:

1. Smectite-zeolite zone: <200°C
2. MLC zone: 200-230°C
3. Chlorite zone: 230-250°C
4. Chlorite-Epidote zone: 250-280°C
5. Epidote-Actinolite zone: >280°C

The alteration cross section in Figure 4 is showing a marked change in the alteration zoning across the Leirbotnar and Sudurhlídar well fields in Krafla. In Sudurhlídar field to the east the alteration gradient is high and alteration has reached the chlorite-epidote zone at 200-300 m a.s.l. pointing towards an area with upflow, while to the west of the Hveragil fissure in the Leirbotnar field the alteration gradient is smaller. The chlorite-epidote zone appears first at 0 m a.s.l., while the chlorite zone is relatively thick, which is indicating an interval in the reservoir with constant temperature conditions. Deeper into the reservoir the epidote-actinolite zone appears at a similar depth in both well fields, suggesting that the temperature conditions in the reservoir converge with depth.

Geothermal systems are dynamic, where changes take place through time, e.g. cooling or pulses of heating, but such changes can be revealed by petrographic analysis of alteration minerals sequences, comparison between alteration temperature and current formation temperature or through fluid inclusion analysis.

Fluid inclusion analysis comprises measurement of homogenization and melting temperature of inclusions trapped in alteration minerals. The homogenization temperature reflects at which temperature the inclusion was trapped in the crystal; it can either have formed during crystal growth or later through deformation and recrystallization of the crystal, while the melting temperatures provide an estimate of the fluid salinity. Fluid inclusion analysis is carried out in several different crystals in order to attain a statistically representative temperature distribution.

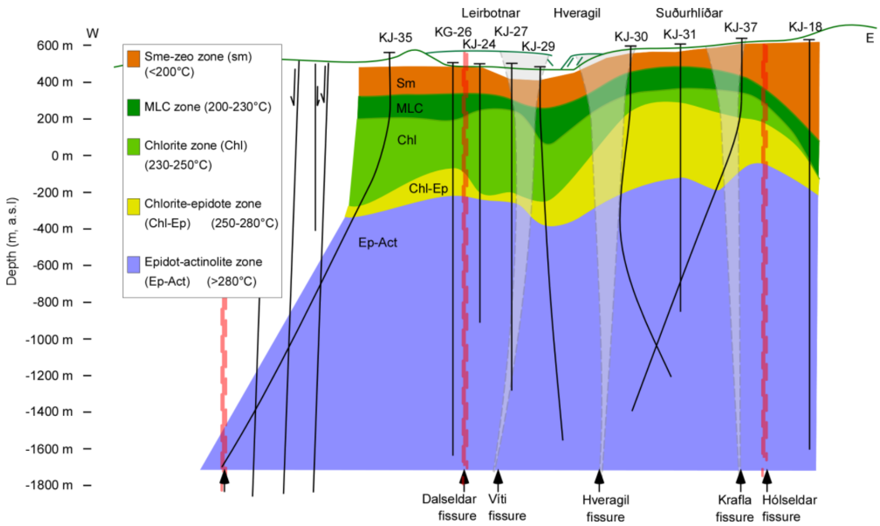

FIGURE 4: Alteration cross section W-E through Leirbotnar and Sudurhlídar well fields in Krafla (Ármannsson et al., 1987, Mortensen et al., 2009)

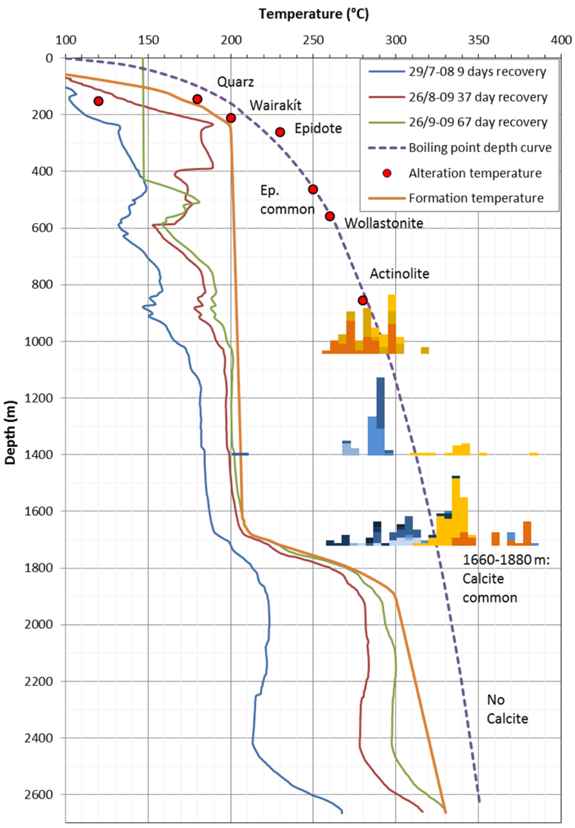

FIGURE 1: Comparison of formation temperature, boiling point curve and homogenisation temperature measured in fluid inclusions trapped in calcite (blue) and quartz (yellow) (Mortensen and Helgadóttir, 2009)

In Figure 5 results of fluid inclusion analyses from well KJ-38 in Krafla, are compared with selected temperature dependent alteration minerals, temperature logs, estimated formation temperature and the boiling point depth curve. Both fluid inclusion analyses and temperature based on first appearance of temperature dependent alteration minerals indicate that temperature has earlier stabilized near the boiling point curve with water level near surface. Temperature measurements indicate that formation temperature is 200-210°C down below 1600 m depth in the well. Indications of this cooling are scarce in the fluid inclusions, yet in calcite homogenisation temperature at 200-210°C is recorded in two inclusions, but this is pointing towards that minor changes in alteration have taken place in the reservoir since the upper part of the reservoir cooled. However, the transition between the upper and lower reservoir in Krafla (Ármannsson *et al.*, 1987) is at 1700-1800 m depth in well KJ-38 and precipitation of calcite characterise this transition zone and large temperature interval recorded in the fluid inclusion analyses points towards a zone, where heating of colder fluid from the upper reservoir results in boiling.

5. ALTERATION AND FORMATION TEMPERATURE IN CONCEPTUAL MODELLING

In geothermal fields were several wells have been drilled comparison between alteration temperature (appearance of selected temperature dependent alteration minerals) and the estimated formation temperature from temperature loggings in the well are used to highlight were the reservoir has been heating, cooling or is in equilibrium (Figure 6), but this method can be used to update the conceptual model of the geothermal system and highlight zones of upflow, outflow and recharge.

With continued reference to the geothermal field in Krafla NE-Iceland Figure 6 shows a comparison between the alteration zones and the formation temperature across the Leirbotnar and Sudurhlídar well fields in Krafla revealing that in the central part of Sudurhlídar field there is equilibrium between alteration and formation temperature. In the upper 1000 m of Leirbotnar field the reservoir has cooled, though the alteration has not been as high here as in the Sudurhlídar field e.g. due to higher permeability in upper part of the Leirbotnar reservoir. In the eastern part of the Sudurhlídar field comparison between alteration and formation temperature shows substantial cooling deep into the reservoir. Thus this relative simple comparison is highlighting an area of upflow and outflow from west into the Sudurhlídar field believed to be originating from the Hveragil fissure, which is marking the boundary between Leirbotnar and Sudurhlídar well fields. The eastern part of Sudurhlídar field is characterized by cooling and possible recharge, but the Hólseldar eruption fissure may act as an aquitard at shallow levels in the reservoir. The Leirbotnar field is characterised by an upper and a lower reservoir, but alteration and formation temperature is pointing towards sustained convection in the upper part of the reservoir.

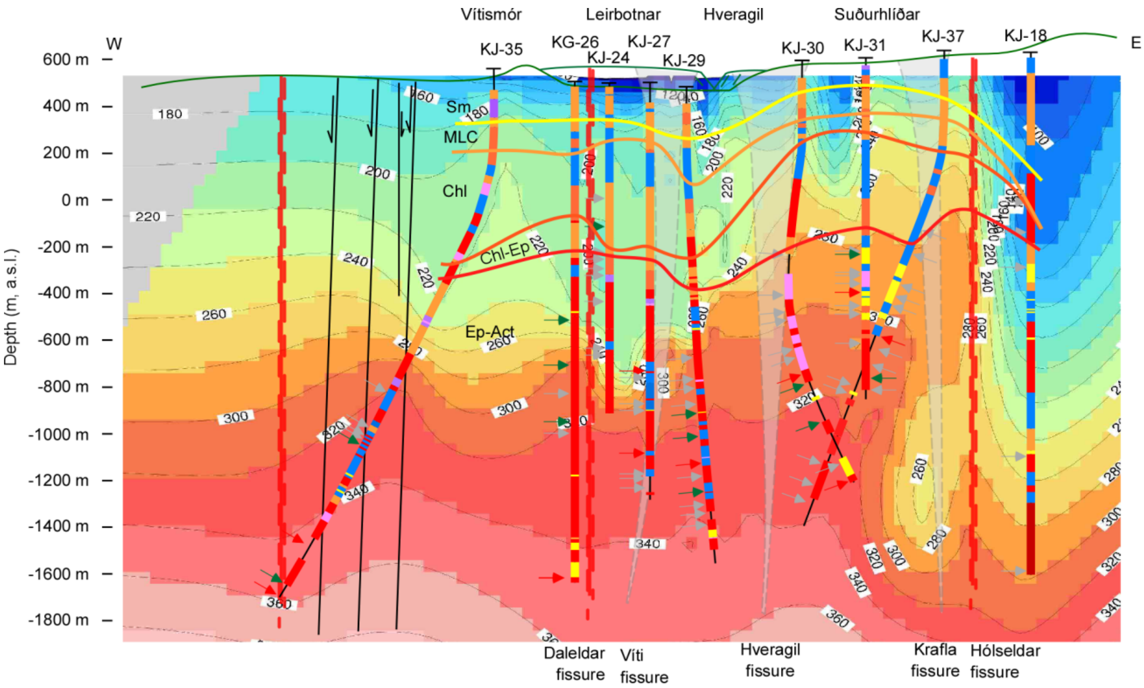

FIGURE 6: Comparison of temperature and alteration cross section W-E through Leirbotnar and Sudurhlídar well fields in Krafla. Lithology is also displayed along the well track and feed zone locations are indicated as arrows (red - major, green - medium, grey - small) (Mortensen et al., 2009)

6. SUMMARY AND CONCLUSIONS

This paper has highlighted the application geological logging in geothermal exploration, but it is not until the first wells are drilled into the geothermal reservoir that access is provided to obtaining rock samples and information about the subsurface. Geological logging of the samples collected while drilling is carried out with the objective to gather information about the geological properties of the reservoir, but petrologic analysis of the rock samples is used both to aid during the drilling process and also for further planning of the development and utilization of the geothermal field.

The main objective of petrologic analysis of the rock samples from the geothermal wells are manifold but focus on: characterising the geological formations of the reservoir, locating the stratigraphic and structural setting of aquifers with depth in the reservoir and identify temperature state and temperature changes characterising the dynamic, thermal history of the geothermal system. Petrologic information from analysis of the rock samples are merged with geochemical and geophysical data to establish a conceptual model of the field, but such a model form the basis for development of the well field and well siting in the geothermal reservoir.

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GEOTHERMAL TRAINING PROGRAMME

LaGeo S.A. de C.V.

STRATIGRAPHIC, TECTONIC AND THERMAL MAPPING THROUGH GEOLOGICAL WELL LOGGING IN EL SALVADOR

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ABSTRACT

Prefeasibility phase determines the most favorable site for drilling, with all the complementary geoscientific information such as geological mapping, geochemical analysis and geophysical surveys to allow a better understanding of the subsurface features of the geothermal resource.

The wells drilled provide geological information on fracturing, shearing evidence, porosity data, microfractures, hydrothermal alteration mineralogy; thermal gradient, permeable zones, thermal characteristics of the well which complement the construction of the conceptual model of the geothermal system.

This paper describes the procedures and considerations such as lithological units, hydrothermal alteration and structural features during geological well logging with a case study in Berlín geothermal field.

1. INTRODUCTION

From the geothermal exploration guidelines adopted by the Latin American countries (OLADE), the different stages on how to develop a geothermal project are: a) exploration and exploitation. Within the geothermal exploration stage, three phases are usually endorsed: a) reconnaissance, b) prefeasibility and c) feasibility.

After the reconnaissance phase, it is through the prefeasibility phase that the project determines the most favorable site for drilling, with all complementary geoscientific information such as geological mapping, geochemical analysis of fluids from surface manifestations, and geophysical surveys such as resistivity measurements, gravity and seismic profiling, to allow a better understanding of the subsurface features of the geothermal resource.

Wells are also drilled to obtain important information necessary to elaborate a conceptual model of the geothermal system, which includes the main features of geoscience: geology, geochemistry and geophysics.

Establishing the structural geological pattern of the area and differentiating recent and old faults are important to site a well because they are usually responsible for the direction and movement of geothermal hot fluids.

The availability of at least one geothermal gradient well, shallow or deep exploratory well, provides information about the stratigraphy, type of rock (by determining the cap rock and the host rock of the reservoir) as well as evidence of fracturing and porosity of the rocks. Data from hydrothermal alteration mineralogy, thermal gradient, permeable zones, thickness of permeable zones, thermal recovery data of wells, etc. provides complement in constructing the conceptual model.

With all of this information, an integration of the reservoir engineering aspects is possible for a conceptual reservoir model to be developed.

2. TYPES OF WELLS DRILLED IN A GEOTHERMAL AREA

Once a well site is determined, it is important to decide whether to drill thermal gradient wells, slim holes or shallow or deep exploratory wells

A brief summary of the different types of wells is given:

- Thermal gradient wells: usually drilled from 50-100 meter depth, with a borehole diameter less of 5 inches.
- Slim hole: of the smallest practicable size, drilled with less than normal diameter tools, used primarily as a seismic shothole and for structure tests and sometimes for stratigraphic tests. Traditionally, diamond-cored "slimholes" (usually 3-4 or 5 inches in diameter) have been used to measure temperature gradients while selecting sites for production size exploratory geothermal wells.
- Shallow exploratory wells: usually 50-300 m to measure temperature gradients in order to locate the up-flow zone of hot fluids in the geothermal reservoir in an attempt to conclusively determine the presence or absence of a geothermal resource. In the case of Berlin, 3 wells were drilled in the 70´s at a depth between 100-500 meters.
- Deep exploratory wells: drilled to test the presence of high temperature geothermal reservoir rocks for future exploration and development. The design is usually with conventional diameters in order to be tested and to allow the geothermal fluid to flow on surface.
- Commercially exploitable geothermal wells: depths between 500-2000 m where temperatures are around 150-300°C. Researchers recently believe it is possible to drill down to 10,000 m where temperatures can reach at least 374°C and water with a pressure of at least 220 bars.

Each of the mentioned wells provides geological information on fracturing, shearing evidence, porosity data, microfractures, hydrothermal alteration mineralogy present in the rock matrix, in microfractures and/or porosity, which can be used to determine the range of mineral stabilization temperature. This temperature is then compared with the stabilized temperature at the end of the thermal recovery of the well.

3. GEOLOGICAL LOGGING

Drilling is one of the principal tasks in the development of a geothermal resource, hence, it is important to have an appropriate design of the well as well as complete control of the subsurface lithology through cuttings and cores. Through the geological logging it is possible to know how the geological structures control the movement of geothermal fluids in the reservoir, as well as the relationship between the alteration minerals and the present-past conditions of the hydrothermal system.

Geological logging is the fine scale observation and recording of the sequence of rocks from cuttings as well as core samples obtained while drilling a geothermal well. All information obtained from surface geological mapping such as type of rock, chemistry of rocks, dating, structures and textures of the

outcrops described, correlation of rocks of different outcrops, etc, should be clear to the wellsite geologist who will perform the geological logging while the well is being drilled.
Information such as stratigraphy, tectonics and thermal mapping can be obtained from the wells and should correlate, as much as possible, with the information described on the geological map. If the geothermal field is in a volcanic environment, the evolution of the system should also be well understood.

3.1 Stratigraphy

Stratigraphy is a branch of the geology which studies rock layers and its sequence. It is primarily used in the study of sedimentary and layered volcanic rocks. It includes two related subfields: lithological stratigraphy or lithostratigraphy and biologic stratigraphy or biostratigraphy.

In this paper, the stratigraphy to study is mainly concerned with layered volcanic rocks. The type of volcanoes in El Salvador are mostly stratovolcanoes, therefore, it is common to find in the wells alternating layers of andesite – basaltic andesite lava flows with different types of volcanic tuffs.

The lithological information obtained from each of the wells drilled is useful to design the mechanical configuration of future injection or production wells. The setting of the casing shoes in stable formation with certain mechanical properties and hydrothermal mineralogy is the main purpose of the geological control during drilling.

To determine where to set the upper and production casings, a lithostratigraphic correlation of the lithological units encountered is definitely needed. These lithological units should have correspondence with the geological units mapped on surface, to be able to understand the volcanological evolution. The lithological units are defined through the geological analysis of cuttings and core samples obtained during drilling. Cutting samples are obtained when there is normal circulation of mud.

3.2 Lithological control

Cuttings are recovered from the circulated drilling fluid and are analysed to give a better overall picture of downhole changes in lithology and mineralogy. Cores, on the other hand, are extracted when the total circulation loss is encountered, which is mainly done in the production zone or the reservoir. Cutting samples are analysed every 2 meters and a lithological log is constructed where a small amount of representative cutting samples is placed in a wooden plate to be able to analyse it afterwards. When two or three deviated wells are placed in the same pad, the sampling is done every 4 meters as well as the macroscopic analysis, until the kick off point is reached. After this depth, the samples are then analyzed every 2 meters.

3.3 Methods of analysis

a) **Macroscopic Analysis:** The first study of cuttings is mainly done by a macroscopic analysis. It describes the color, texture and composition and it helps to determine the boundaries of the formations. A rock name is given to provide its origin as well as the mineral composition. This study is done using a binocular stereomicroscope. Drops of HCl acid (10% conc) is used to determine the presence of carbonate minerals.

   The clay content in cuttings is determined mainly to know if the formations encountered during drilling have swelling clay or content of shales that might react with water and cause blockage problems in the hole. The cutting sample is immersed in water to see the presence of swelling clays.

b) **Microscopic Analysis:** The microscopic study includes the description of the minerals (primary and secondary) and the classification of rock. A thin section is used to identify the rock texture and microstructural relationships of minerals. The optical characteristics observed under the microscope include color, color variation under plane polarized light (pleochroism) produced by the lower Nicol prism, or more recently polarizing films, fracture characteristics of the grains, refractive index (in comparison to the mounting adhesive, typically Canada balsam) and optical symmetry (birefringent or isotropic). These characteristics are sufficient to identify the mineral, and often to estimate its major element composition.

c) **Separation of components:**
- Separation of the fragments in cuttings is mainly done to obtain pure samples for analysis. It may be performed with a powerful, adjustable strength electromagnet to separate magnetite. A weak magnetic field attracts magnetite, then haematite and other iron ores. Finally, only the colorless, non-magnetic compounds, such as muscovite, calcite, quartz, and feldspar remain.
- Chemical methods also are useful: A weak acid dissolves calcite from crushed limestone, leaving only dolomite, silicates, or quartz. Hydrofluoric acid attacks feldspar before quartz and, if used cautiously, dissolves these and any glassy material in a rock powder before it dissolves augite or hypersthene.
- Methods of separation by specific gravity have a still wider application. This separation technique is applied when zeolites and clay analysis are to be achieved.

d) **X-Ray Diffraction Analysis**: X-ray diffraction (XRD) is a very useful technique to identify clay minerals and chlorite that are difficult to identify by other methods. It can also give quantitative information of the minerals present. Clay analysis by XRD is done in three stages: 1) untreated samples in a constant humidity with $CaCl_2$, 2) glycol saturated samples and 3) heating the samples to 550-600°C. The XRD analysis can be done every 10 meters or when a change in mineralogy is observed.

e) **Fluid inclusion analysis:** Fluid inclusions are microscopic bubbles of liquid and gas that are trapped within crystals. As minerals often form from a liquid or aqueous medium, tiny bubbles of liquid can become trapped within the crystal structure or in healed fractures within a crystal. These small inclusions range in size from 0.1-1 mm and are usually only visible in detail by microscopic study. The trapped fluid in an inclusion preserves a record of the composition, temperature and pressure of the geothermal fluids in the reservoir. An inclusion often contains two or more phases. If a vapor bubble is present in the inclusion along with a liquid phase, simple heating of the inclusion to the point of resorption of the vapor bubble gives a likely temperature of the original fluid. If minute crystals are present in the inclusion, such as halite, sylvite, hematite or sulfides are present, they provide direct clues as to the composition of the original fluid. The fluid inclusions can provide information if whether or not the geothermal fluids are in equilibrium with the geothermal system or not. It is useful to know if a geothermal field is active or fossil.

Once analyzed, cuttings can be grouped into formations with similar rock types, color, composition, textures, and structures. This group of formations must belong to the same sequence as in its volcanic evolution.

Grouping formations with similar characteristics allows correlations between wells, which is better applied when the geothermal system is situated in a volcanic environment. The correlation between lithological units is possible when dealing with a stratovolcano, where an interlayering of lava flows and tuffs either lithic, fine, crystal is present. Stratigraphic marker such as fine tuff with thickness of about 50-100 meters is very useful when correlating lithological units from one well to another with several hundreds of meters apart. Another marker to consider is the ignimbrite layering, a volcanic deposit and part of a caldera.

3.4 Information described during the geological control

3.4.1 Type of rock:

Cuttings are analyzed macroscopically and microscopically with a petrographic microscope to determine the mineralogical composition, texture, microfractures, porosity and rock type. They are sampled only when drilling uses bentonitic mud as circulation fluid. When total loss is encountered, drilling fluid enters the microfractures/fractures of the formation. If these permeable zones are not of interest, they are usually sealed or cemented to further continue drilling.

Cuttings are still sampled several tenths to a hundreds of meters below the casing shoe. Upon encountering the total loss of circulation when cuttings do not return to surface, aerated fluids, diluted mud or water with polymers and viscous plug are used. However, cuttings can return to the surface if the permeability of the reservoir is not high enough, and the exact location and depth of the sample it is not anymore known. Therefore, a core sample is then considered from 100 to 200 meters below the depth of the first total loss of circulation. Two to three cores can be extracted within a perforated interval of 600-800 meters depth.

Usually, a daily report of analysis in the field is presented using the logging software (Strater).

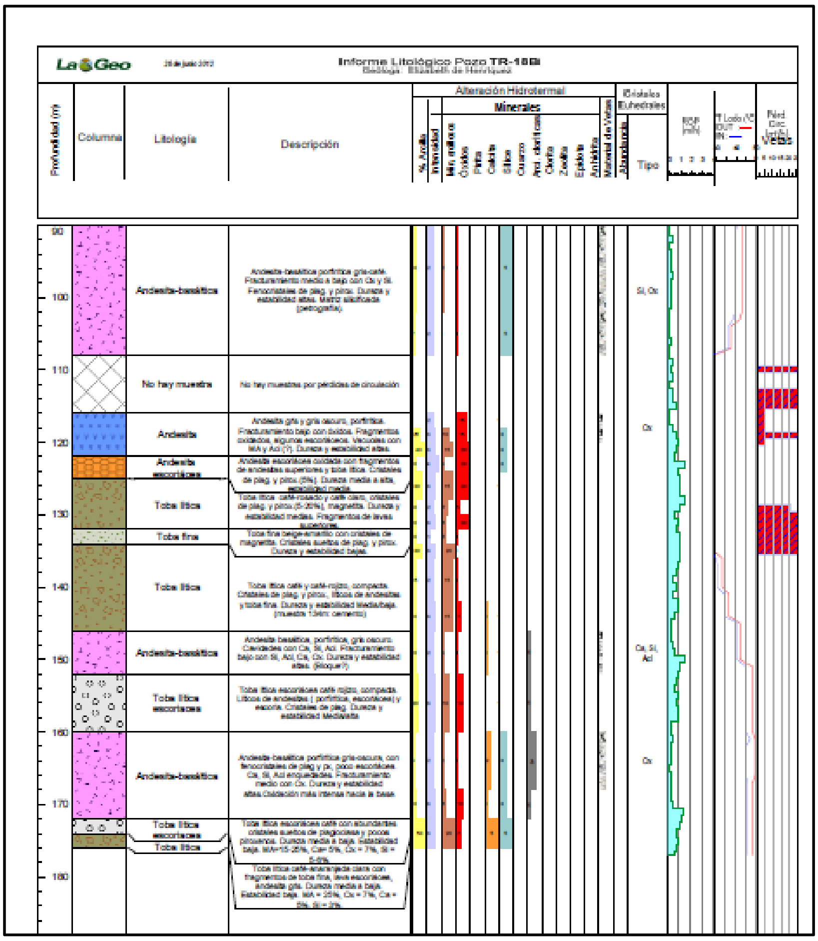

FIGURE 1: Schematic representation of a lithological log obtained from wells drilled

3.4.2 Hardness and stability of rock:

Hardness is a descriptive parameter to help define the strength and stability of the formation. It is usually done by exerting pressure on or squeezing fragments of cuttings using a metal tweezer. The hardness of a rock reflects the average hardness of the minerals present in them; therefore it is a relative description. Clay minerals tend to be soft, while rocks with abundant quartz can be very hard. It is usually described as low, medium and high.

The strength of a rock has an appreciable influence on drilling force required, as sufficient force is necessary to exceed the strength of the rock. Usually, the harder the rock, the higher the strength, however the existence fractures and bedding planes can destabilize the rock formation once drilling fluid enters the wellbore.

However, for descriptive purposes, stability of lava formation (or a solid rock) is considered high, rocks with few alteration or lithic tuff are medium and rocks with high content of clay minerals are considered low stability.

3.4.3 Hydrothermal alteration minerals:

Preliminary identification of hydrothermal minerals in the cutting samples is done at the wellsite during drilling to provide a first-hand information on the temperature and permeability of the well.

The detailed analysis of secondary minerals is usually based on microscopic analysis and the technique of X-ray diffraction. To complement the geologic information, fluid inclusion studies are currently undertaken.

Usually description of minerals include type of secondary minerals, occurrence (veins, replacing primary minerals, vesicles), abundance of veins and vesicles, and alteration intensity.

Primary minerals are mainly present in formations at shallow depth where the rock has not undergone great changes other than weathering. Secondary minerals start appearing when thermal gradient reveals higher temperatures at depth of 50-100°C. As the thermal gradient increases, primary minerals are transformed to secondary minerals, either by fluid rock interaction or by the influence of temperature itself (weak metamorphism).

Hydrothermal alteration of volcanic rocks involves the replacement of primary igneous glass and minerals (plagioclase, orthoclase, quartz, biotite, muscovite, amphibole and pyroxene) with alteration minerals stable at the conditions of alteration, generally in the temperate range of 50–400 °C. Alteration minerals where rock interaction has taken place ma y include quartz and other forms of silica (chalcedony, opal, amorphous silica), illite, sericite, smectite, chlorite, serpentine, albite, epidote, pyrite, carbonates, talc, kaolinite, pyrophyllite, sulfates (anhydrite, barite, alunite, jarosite), oxides (magnetite, hematite, goethite appear), and zeolites (chabasite, heulandite, laumontite, wairakite).

Alteration textures range from weak alteration of only some of the minerals or matrix in the host rocks, producing an earthy aspect to the overall rock, or to partially-altered phenocrysts. Such alteration may be difficult to distinguish from weathering in the field. Glassy rock matrix or fine-grained can be particularly susceptible to alteration and may be massively silicified or replaced by chlorite or sericite as alteration intensity increases. At high alteration intensity, rocks may be pervasively altered, in which all primary phases in the rock are altered to new hydrothermal minerals.

The degree and the amount of hydrothermal alteration or secondary minerals depend basically on the permeability of the rock, rock composition and temperature, chemical composition of the fluid and the age of the geothermal area.
Secondary minerals and mineral assemblages are defined in order to establish hydrothermal alteration zones or hydrothermal facies. The term “alteration zones” or “hydrothermal facies” are just two different ways of explaining the chemical processes a formation has suffered due to fluid-rock interactions within the geothermal system. The chemical and mineralogical distributions of hydrothermal alteration zones are generally the only direct evidence of fluid circulation pattern taking place in the system.

In Iceland for example, according to Kristmannsdottinr (1998), zonation of alteration minerals is the term currently used. Mineral chlorite becomes the dominant sheet silicate at rock temperatures of 230-

250°C and in geothermal areas where the maximum temperature does not exceed 240°C, chlorite is only found sporadically. The clay minerals such as smectitc are seldom recorded at rock temperatures above 200"C. Mixed layer clays of smectite and chlorite is dominant at 200-230°C.

According to Browne (1984) the minerals mostly used as geothermometers are the zeolites, clays, epidote and amphiboles. In Icelandic regions, most zeolites are common before 100°C and disappear before 200°C (stilbite, heulandite, mordenite). Laumontite replaces other zeolites at l00-120°C. Wairakite, just as in Cerro Prieto, Mexico, starts appearing at 180°C and is recorded up to 300°C (Kristmannsdottir, 1978; Elders, Cl al., 1979). On the other hand, in New Zealand wairakite is identified at temperatures between 200-250°C (Steiner, 1977).

Among the minerals that occur at higher temperatures (above 250°C), epidote seems to be the most reliable and consistent temperature guide. In Icelandic active geothermal fields, epidote occurs sporadically at 230-250°C, but it appears in high quantity at rock temperatures above 250"C. According to Browne, (1984), epidote first appears in many fields at 250°C and the lithology does not influence its formation. Variations regarding prehnite are seen in New Zealand, where it appears at temperatures more than 220°C. In Cerro Prieto, Mexico, it occurs, on the contrary, at higher temperature of 300°C. This is probably due to the difference in the pH and calcium contents of the geothermal fluids.

The intensity and type of alteration usually reveals the degree of permeability. Minerals such as adularia and albite are often related to permeable zones, especially if these are present individually in association with quartz and calcite, (Tongonan, Philippines and all New Zealand geothermal fields). This relationship can be used when these minerals are present in veins and fractures (Browne, 1984).

If they are, however, altering plagioclase, this relationship does not apply. A1bite is also a useful geothermometer only when it occurs in veins. Otherwise the albitization of plagioclase occurs within a wide range of temperatures (Reyes, 1990). It has been observed that in veins where both albite and adularia occur together, the permeability of the rock tends to decrease through self-sealing. Therefore, the former relationship should be used carefully. The original mineralogy of the rock seems to have a minor effect on the type of mineral assemblage in permeable zones. For instance the association of minerals such as albite, quartz, epidote, chlorite, adularia pyrite and illite (26O°C) occur in different geological environments. It is seen in andesitic rocks (Philippines and Indonesia), in rhyolites (New Zealand), alkaline lavas (Kenya) and sediments (Cerro Prieto). K-mica and K-feldspar is near absent in Icelandic geothermal fields and adularia less frequent than found elsewhere (e.g. Fridleifsson, 1984).

In all active geothermal fields, (New Zealand, Cerro Prieto, Iceland and Philippines), alteration zones were derived by empirical data found between rock temperatures and secondary minerals. For example, in Iceland, different alteration zones were obtained regarding the formation of smectites, mixed layer clays and chlorite than found elsewhere. The temperature ranges for these zones are 0-200°C, 200-230°C and 230-250°C respectively. In New Zealand other alteration zones concerning temperatures have been developed. For instance, smectites, mixed layer clays (smectite/illite) and illite give a temperature range of 0-140°C, 140-220°C and greater than 220°C respectively. These empirical relationships as well as the indicative minerals of temperature and permeability can be applied to other geothermal systems. Nevertheless, it is important, that each area develops its own local zonation of hydrothermal alteration mineralogy vs. temperature relationship.

Studies of alteration assemblages in El Salvador led to a series of commonly recognized alteration Facies: Argillic, Argillic-Phyllitic, Phyllitic, Phyllitic-Propylitic and Propylitic, with distinct mineralogy and increasing intensity of alteration when it’s close to the geothermal reservoir.

Typically, in geothermal fields in El Salvador, the abundance of wairakite, illite and pyrite indicate permeability, coinciding and occurring near the top of the reservoir, while epidote, wairakite, penninite and anhydrite describe the propylitic facies with temperatures greater than 250°C.

Mineralogical facies in the two fields in El Salvador show almost the same alteration minerals in each facies, with the only difference in depths. The Ahuachapán geothermal field has shallower reservoir from 800 – 1500m, while Berlín's reservoir is found at 1500 – 2500 m depth.

TABLE 1: Alteration minerals in Berlin geothermal field

Facies	Alteration Minerals	Temp. (°C)
Argillic	Clay minerals, Hem, Si, OM, Ca	50-120
Argillitic-phyllitic	Ca, Cl, Qz, Hem, Cl clays, OM, Clay minerals	120-180
Phyllitic	Ca, Illite, Cl, OM, Qz, Pen	180-220
Phyllitic-Propyllitic	Wai, Ca, Qz, Ser, Cl, Anhy, Preh, Illite	220-250
Propyllitic	Ep, Qz, Preh, Wai, Cl, Qz, Anhy	250-300

Thermometric measurements are carried out using LINKAM equipment with Linksys software. Temperature of melting (Tm) and temperature of homogenization (Th) are measured mostly in quartz and calcite crystals.

Summary of the results of microthermometric analysis of fluid inclusions of wells in Berlín geothermal field shows two-phase liquid with more liquid-rich inclusions (70 – 80%) and few vapor-rich inclusions (20%). It can also be seen that the original fluids of high temperature > 300°C are mostly at the southeastern part of the field. Recent fluids based on measured reservoir temperature show a decrease of at least 50°C at the southeastern part probably due to the percolation of cooler (meteoric) waters at the Berlín –Tecapa volcanic complex.

I. Drilling parameters:

A preliminary stratigraphic section is constructed by the analysis of cuttings which goes hand in hand with the drilling parameters such as drill bit weight of the load pressure on the drillstring, rate of penetration and mud temperature (in and out of the borehole), as they also affect the interpretation of all geological data collected at the wellsite.

One of the most useful "real time" geological tools is the rate of penetration, which depends upon formation porosity and rock matrix strength. Different bit types should also be taken into account; in general, longer toothed bits are used for softer formations.

The amount of weight on bit (WOB) that may be added on any bit is provided by and limited by bit size and the drillstring (especially the drill collars). Changes in the WOB, when not intentionally changed by the driller, often indicate changes in formation. Soft formations require little WOB, while hard formations require the maximum amount of WOB.

II. Completion tests:

After drilling a completion test is undertaken consisting of permeability assessment, temperature of formation and thermal recovery.

4. CASE STUDY BERLÍN

4.1 Regional tectonics – geology

The Berlin geothermal field is located 100 km east of San Salvador city, at the northern slope of the volcanic complex named Berlin-Tecapa. The area is influenced by a compressive stress due to the subduction of the Cocos plate under the Caribbean plate.

The subduction direction of the Cocos plate is to the NE, but due to the redistribution of stress in the on the back arc setting, the maximum horizontal stress in the vicinity of the Berlin field is NW-SE oriented. The evidence for this is from the earthquake focal mechanism shown on the present day stress map.

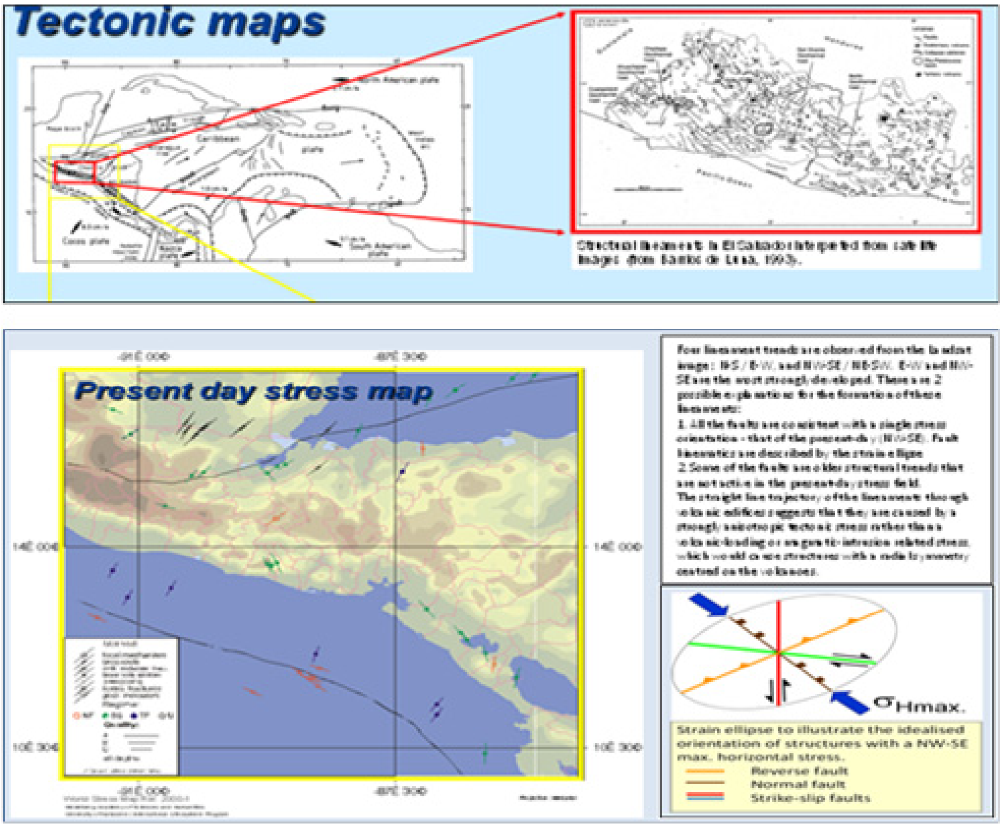

FIGURE 2: Present day stress map and tectonic map of El Salvador

This process originated a Caldera structure which is cut by the trending faulting E-W (Central America Graben), NW-SE faulting. The main lineament trends are running approximately at right angles. N-S/E-W, NW-SE and NE-SW. Of these trends, the E-W and NW-SE are strongly developed.

The intersections of several fault systems are potential drilling targets, therefore it is necessary to count on a reliable map to clearly see either the visible faulting sites on the ground, photo geological lineaments or discontinuities obtained either from Landsat images interpretation, aerial photographs or lineaments from a particular geophysical modelling (mainly electric, gravimetric). Digital model (DEM) of Berlin field is also important to locate structures, lineaments and morphological shapes.

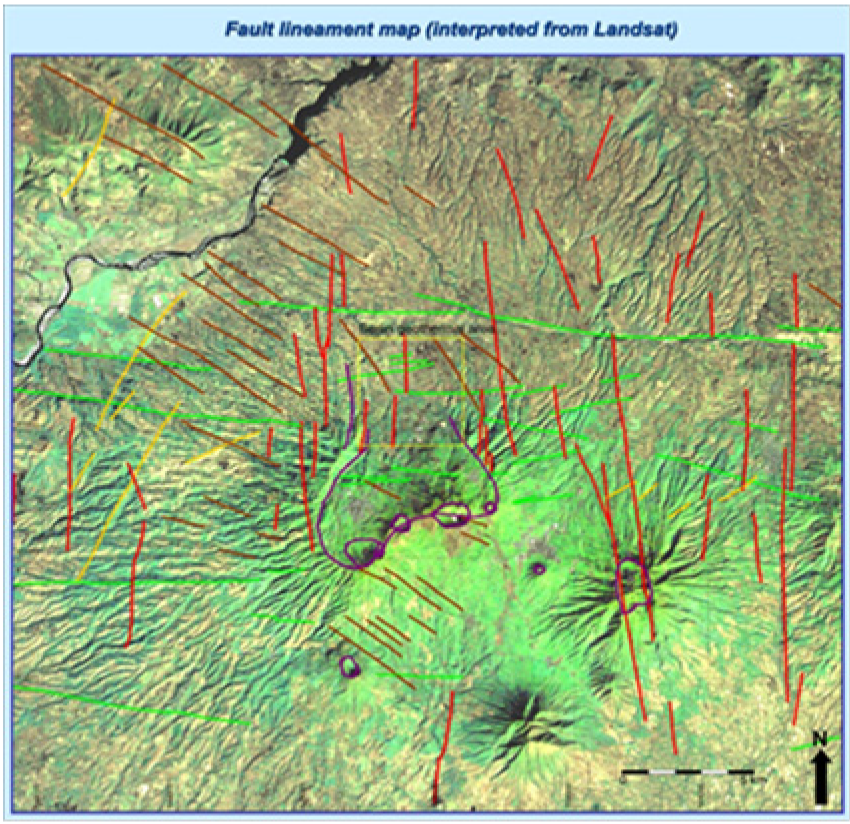

FIGURE 3: Structural lineaments gathered by Landsat satellite images

The Berlin area is affected by a quaternary calc-alkaline volcanism, where effusive events alternate with explosive events generating an interlayering of lava flows and tuffs. Pumice a deposit that correspond to the Caldera Blanca Rosa, is the only evidence of differentiation which covers most of the surface near the Berlin city. This layer is used as a guideline and is mapped in the Berlin and Chinameca areas.

Andesitic grey and black ignimbrite deposits originated from the Berlin Caldera structure covering most of the northern and southern slope of the Berlin area are stratigraphically correlated with the Blanca Roca pumice.

The only dating of a well, the one at the bottom of well TR_3 (paleomagnetic method), is 4.5 Ma. If this **dating** was substantiated, the reservoir rocks could belong to an earlier stage of activity (MioPliocene), also known at Ahuachapán. Central-American volcanism seems to have had two stages of activity, separated by a long lull: one, dating back to > 3 Ma, that led to the formation of the so-called basement (Balsamo formation), and another which developed about 1 Ma and is still active.
The identification of dykes, linear intrusions along fractures and/or discontinuity surfaces provide structural information. Dykes are observed not only on the western part of the caldera border but also in the wells drilled. The dykes are not evenly distributed but appear mostly in the northern section of the field, where the wells are less permeable and hence less productive.

The mapped formations on surface and stratigraphy relationships in the Berlin Geothermal Field are, starting from the oldest to the recent ones:

TABLE 2: Geological Units in the Berlin Geothermal Area

Geological Units	Description	Dating K/Ar	Regional formations
bo	Basaltic lavas and scorias that belong to the old Berlin Volcano	1.4-0.9 Ma	Balsamo formation
bi-gi	Black ignimbrite and Grey Ignimbrite	100 ka	San Salvador Formation
bm	Berlin intracaldera lava flows and scoria deposits		
by	Lava and scoria's from the young quaternary volcano Berlin-Tecapa	0.1 Ma	
ri	Blanca Rosa Ignimbrite	0.075 Ma	
	Surge deposits from El Hoyon	700 years	
	Distal Tefras from eruptive edifices		

4.2 Local Faulting systems

Fault System WNW-ESE
This fault system is the most important from the regional perspective, as it is responsible for the formation of the Central or Central graben and active volcanic chain and the country. Some of the more recent volcanoes such as Cerro Pelon, and Cerro Laguna de Alegría Alegría, are aligned in the same direction, indicating that this active tectonic system is not only found in the Berlin area, but throughout the country.

Fault System NW-SE
This system is considered the most recent and important asset, since allows the ascent of geothermal fluids from depth to the surface. Most demonstrations of hydrothermal in the geothermal field are found within this graben structure NNW-SSE.

Fault System NNW-SSE
It is a system of faults associated with NW-SE system and is responsible for the displacement of the north wall of the Berlin Caldera structure.

Fault System NNE-SSW
This fault system is not fully visible in the Berlin geothermal field, but its presence can be inferred based on the apparent alignment of fumaroles and small post-caldera volcanoes such as Cerro Las Palmas and Cerro Laguna Ciega.

Berlin Caldera System
It originated in the end stage of the ancient volcano eruption in Berlin, following the collapse of the largest volcanic structure. This structure was dislocated by normal faults trend NNW-SSE and NW-SE.

4.3 Lithostratigraphic units in wells

The lithological correlation is done using primary textures of rocks that differentiates between effusive and explosive products. Lithological columns constructed for each well using formation units obtained from macroscopic analysis and petrographic data do not change from wells drilled during the 70´s-80´s to wells drilled in the 90´s. The main differences are seen in depth of appearance and thickness for each unit, showing structural influence such as normal faulting and strike slip faulting.

Four geological units (I to IV) are defined by analyzing thin sections of cuttings and cores in a total of 27 wells drilled from the 70´s to the year 2003. The general description is in Table 3.

TABLE 3: Lithostratigraphic unit-Geological units in South and North sector of the geothermal field

Lithostratigraphic Unit/ /Gelogical unit	**Lithology**	**South sector**	**North Sector**	**Average Thickness (m) North-South**
UNIT I Surface Materials Outcrop name: (by , ,bm)	Alternate secuence of pyroclastics with a predominance of andesitic and basaltic andesite lava flows. Several levels of fine tuffs and lithic tuff.	Mainly lavas in TR4´s/TR5´s Wells. In some levels of pyroclastic at the surface is seen. No dykes observed	Thick pyroclastic deposits. At the top of this unit. Presence of sporadic dykes and sills.	600 a 800 (410 a 435 in Wells TR-11´s)
UNIT II Pyroclastic flows with thin layers of andesitic lava flows Outcrop name: (gi,bi)	Pyroclastic flows of various types (variation of lithic and cristalline tuffs with scorias interlayering thin and thick basaltic andesite lava flows.	In most Wells, it begins with an ignimbrite deposit (banded textures). Thick layers of tuffs mainly scoriaceous.	Thick layers of Tuffs with various thicknesses layers of andesitic lavas. Minor levels of scoria.	570 a 850 (985 in Wells TR-11)
UNIT III No outcrop: (tf)	Guide level composed by cineritic tuff, Green color with Plagioclase with sporadic thin layers of andesitic lava flows. Dykes are identified. Defined as cap rock of the geothermal reservoir.	Presents the best characteristics of this unit. It is observed in every well of the sector.	Characteristics are not totally complete. Crystal are bigger in size and with less thickness.	105 a 345 (365 in Wells TR-11)
UNIT IV Outcrop name: (bo)	Mainly andesitic lavas interlayerd with basaltic andesite, andesitic brecias and a variety of tuffs with abundant dykes /sills. Granodiorite and Granite rocks are present in several wells showing high permeability. Silicified tuff is present in some wells.	Thick layers of lavas of different composition interlayerd with thin packages of tuffs. Dykes and sills, as wells as Granodiorite and diorite rocks are present.	Thick packages of lavas interlayered with thin tuff packages. Dykes and sills with the higher thickness are present in this sector.	370 a 920 (210 a 730 in Wells TR-11)

The lithostratigraphic columns and the corresponding correlation were done analyzing thin films every 20 meters. With the information available to date from wells TR-1, TR-3 and TR-4, no substantial differences in the number and type of unit and only found some differences related to the depth of appearance and thickness of each unit (I to IV), and that the review was conducted lithological smaller intervals.

Thin sections of cuttings and cores were analyzed by optical microscopy. Petrographic analyzes conducted on <50% of the samples referred to rock wells representative of major geological units and hydrothermal alteration zones. The main rock types are analyzed: a) • andesitic and / or basaltic-andesitic lava and b) • Rocks shaped pyroclastic tuffs and / or ignimbrites.

The volcanic rocks are often altered by hydrothermal fluid circulation, zoning exhibiting mineralogical paragenesis associated with typical temperatures that increase with depth (Argilítica, Filítica, propylitic). The succession of these alteration facies disagrees with the stratigraphic units grouped as dependent on fluid flow and temperature flowing through the rock fractures.

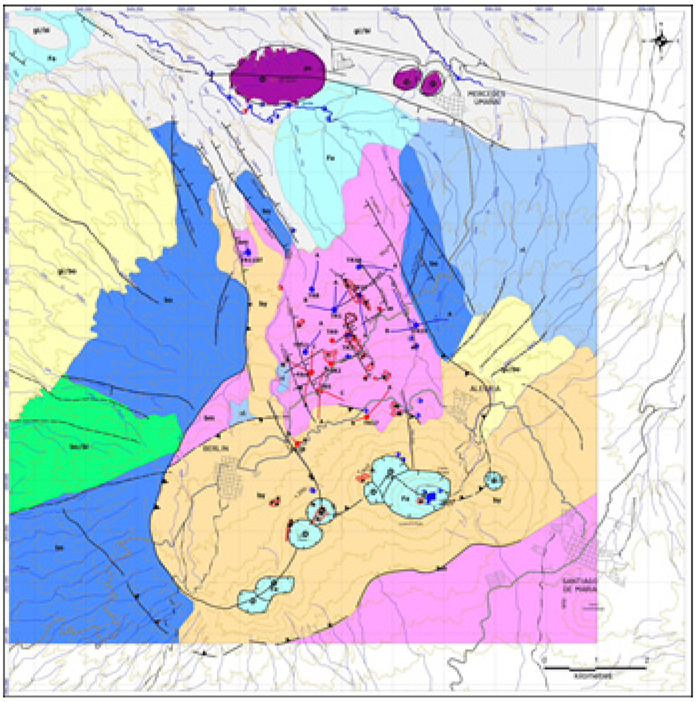

FIGURE 4: Berlin Structural and Geological map

4.4 Hydrothermal alteration minerals in Berlin

The alteration zones term used in Iceland, described in detail the type of minerals from chlorite clays found in depth. These are used as geothermometers as to identify possible cooling zones. In this description in addition to clay minerals, chlorite group, complete mineralogical association is considered. This report uses the term mineralogical facies, which then describes each: Facies: Argillic, Argillic-Phyllitic, Phyllitic, Phyllitic-Propylitic and Propylitic, with distinct mineralogy and increasing intensity of alteration.

Argillitic facies
It is characterized by the presence of the smectite clay minerals and zeolites low temperature, traces of quartz and calcite.Stabilization temperatures indicated generally between 50-150 ° C. South of the field lower limit of this facies are identified +500 m and north of the country to +150 m, with average thickness between 350-400 m.

Argillitic-phylitic facies
The characteristic minerals are clays, mixed layered clays. Minerals such as quartz, calcite and zeolite indicate stabilization temperatures between 150-180 ° C. South of the field the lower limit is identified between +100 m and to the north between the -100 m, showing an average thickness of 400 m.

Phyllitic facies
It is characterized by the appearance of chlorite mineral and mixed or interstratified layered clays decrease. Minerals such as calcite, quartz remain with the presence of zeolites of higher temperature The stabilization temperature is about 200-230°C. The lower limit of this facies is identified south of the field between -400 m and north between -700 meters, and has an average thickness of 600 m. Partial replacement of epidote + chlorite (propylitic zone before) with quartz, calcite, sericite and hematite. On average, this area is located at a depth of 500-1500 m.

Presence of epidote + chlorite and rocks partially replaced with quartz, calcite, hematite, show greater zones of fluid interaction in the reservoir rock. However, the appearance of epidote could be used to reconstruct the evolution of geothermal reservoir, which contributes to highlight the main volcano-tectonic structures responsible for the movement of geothermal fluids.

Phyllitic-propylitic facies
It begins the formation of epidote, full development of chlorite, presence of chlorite penninite type. The stabilization temperature in this zone is approximately 230-260°C. The lower limit of this facies is

identified south of the field between -950 m and north to -1200 m, showing an average thickness of 300 m.

Propylitic facies
It is characterized by the complete development of epidote and observed mineral are deposited mainly in fractures. It is also associated with minerals such as quartz, calcite and other minerals of high temperature. Stabilization temperatures are estimated between 260-300 ° C. No lower limit is identified and therefore its thickness is unknown. A wide presence of epidote, chlorite and adularia is generally at depths greater than 1500 m.

Advanced Argilítica alteration (combination of kaolin, alunite + S) is a fluid product which possess an acid pH (2-3). This disruption occurs at low temperatures of 100-130 ° C and is the result of condensation on the surface of H2S oxidation sulphate and acid sulphate final production fluids. In systems hydrothermal alteration prophylitic (generally have combinations of calcite + QZ + Ep + chlorite + adularia ± pyrite) is the result of the fluid circulation of sodium chloride at temperatures between 200 and 350 ° C.

The propylitic facies is defined as a variety of andesite strongly affected by volcanic gases. The dark green color of the rock is due to the formation of mineral abundant chlorite as alteration of primary minerals hornblende and biotite type.

4.5 Fluid inclusions

The data obtained from analyzes of fluid inclusions in core samples from wells in the center of the field, at depths greater than 1000 meters, show homogenization temperatures (Th) between 250 and 340 ° C and salinity of the fluid (Tm) between 2100 and 4300 ppm (Cl), which are consistent with the physicochemical properties of the produced geothermal fluids. The temperatures are always higher in the southern part of the field and decrease as it moves northward.

By correlating the information, from the petrographic analysis of well TR-17 did not observe minor minerals of temperature on the highest temperature, which may give information that lower temperatures can be found associated with a reservoir which may have occurred cooling by deep percolation in the intermediate aquifer as reservoir temperatures of wells TR17 sectors are 25-30 ° C lower than the temperatures of the wells TR4 / TR5.

TABLE 4: Summary of fluid inclusions wells TR4 and TR

Well	Depth (m)	Homogenization Temperature Range (Th) °C	Mineral	Comment
TR4	1700	301.6-342.9	Quartz	Th max > measured temperature
TR4	2000	299.2-346.2	Quartz	Th max > measured temperature
TR4B	1568.2 (MD)	231-264.9	Calcite	Th temperature similar with measured temperature
TR4B	2000 (MD)	278.4-284.8	Quartz	Th temperature similar with measured temperature
TR5	1600 (MD)	255.8-260.2	Calcite	Th < measured temperatuere
TR5A	1550 (MD)	198.4-236.9	Quartz	Th < measured temperatuere
TR5A	2008 (MD)	269-327.4	Calcite	Th max > measured temperatuere
TR17A	1750-1752.2	284	Quartz	Fluid inclusions range 275-294°C
	2050-2055	305	Quartz	Fluid inclusions range 330-310
TR18	1053-1057	291, 218	Quartz/Calcite	Fluid inclusions range 195-298°C
	2050-2055	314, 272	Quartz /Calcite	Fluid inclusions range 268-330°C
	2600-2603	328 , 258	Quartz /Calcite	Fluid inclusions range 249-338°C

4.6 Hydrogeology

At Berlin wells, four types of aquifers are identified with variations in temperature, host rock and permeability.

Possible Cold Shallow aquifer:
It does not have a freatic level and probably the total circulation losses are due to the presence of thick fractured andesitic lava flows. This is located between 10-50 m from the ground.

Intermediate aquifer:
It is located between 250 masl to -50 masl and has a temperature of 175-200°C. It is present in all wells in the field, but at the south sector it has the highest permeability. The aquifer is mainly located at the base of Unit I.

Thermal aquifer:
It is found only in the wells at the northern sector of the field, specifically in wells TR14´s and TR8´s at a depth between 85-150 m (+200 msnm y -300 msnm) and has a temperature of 90-100°C. Mainly located at top of Unit III:

Deep Hot Saline aquifer:
It is the reservoir of the field which is used for electrical generation. It has a temperature of 300°C at the south sector and 250°C at the north. The higher permeability of this aquifer is at the south sector and is located at -900-1200 masl.. Wells at the north sector (mainly injection Wells), encountered a less permeable well and at deeper elevations (-1300-1500 masl).

5. TEMPERATURE

All available temperature data (master logs, final well reports, temperature logs) were used to elaborate a temperature contour map.

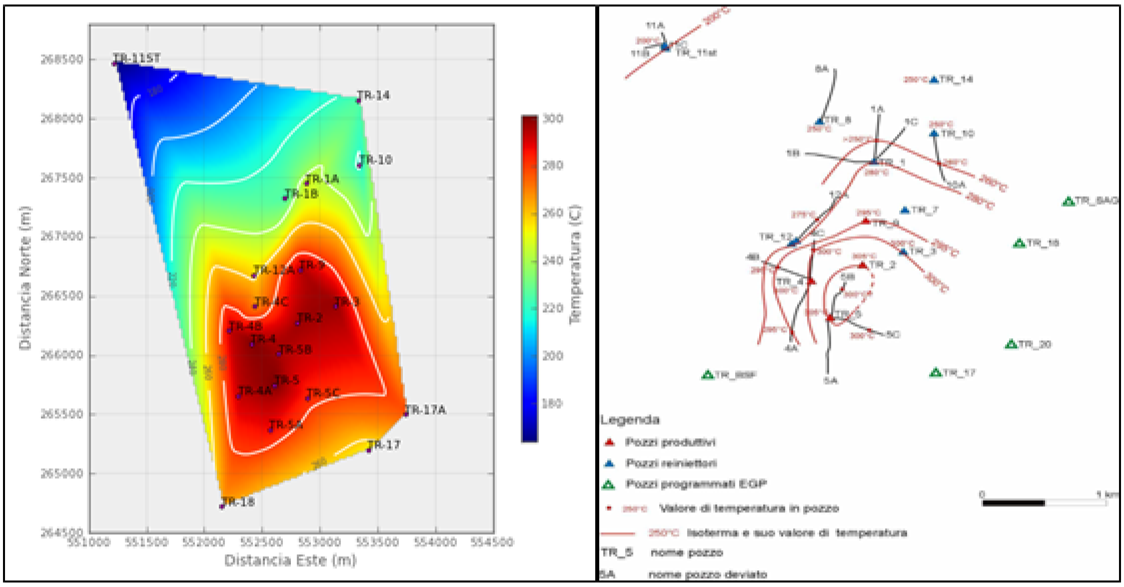

FIGURE 5: Areal temperature distribution of Berlin wells at -1200 masl and -1100 masl

6. CONCLUSIONS

1. The intersections of several fault systems are potential drilling targets, therefore it is necessary to count on a reliable map to clearly see either the visible faulting sites on the ground, photo geological lineaments or discontinuities obtained either from Landsat images interpretation, aerial photographs or lineaments from a particular geophysical modelling (mainly electric, gravimetric). Digital model (DEM) of Berlin field is also important to locate structures, lineaments and morphological shapes.

2. The degree and the amount of hydrothermal alteration or secondary minerals depend basically on the permeability of the rock, rock composition and temperature, chemical composition of the fluid and the age of the geothermal area.

3. Lithological columns constructed for each well using formation units are usually obtained from macroscopic analysis and petrographic analysis.

4. Microthermometric analysis by fluid inclusion studies can provide cooling or heating processes.

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UNITED NATIONS UNIVERSITY
GEOTHERMAL TRAINING PROGRAMME

LaGeo S.A. de C.V.

GEOPHYSICAL WELL LOGGING: GEOLOGICAL WIRELINE LOGS AND FRACTURE IMAGING

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ABSTRACT

Well logging is a highly advanced technique where complex electronics and sensors are placed inside a logging probe which is lowered on a wireline into a well to carry out measurements continuously or at discrete depth intervals as the probe is moved down or up the well. The objective of the logging can be for example, (1) to study the well, its geometry and completion, (2) to study the rock formation and fractures intersected by the borehole, (3) to determine the reservoir temperature and fluid pressures, and (4) to locate feed points connecting the well to the geothermal reservoir.

Well logging has been used systematically in Iceland since 1976 to study and explore geothermal wells, not only the classical logs of temperature and pressure, which the geothermal industry utilizes extensively, but also geological logging tools and logs that are used to study the construction and condition of the well. The present paper gives a brief description of geological wireline logs applied in geothermal exploration in Iceland as well as logs that create an image of the borehole walls. The latter (televiewer log) produces an acoustic "picture" of the wall of the well, where fractures can be easily mapped and their strike and dip determined and other properties of the fractures, whether they are permeable or not, can be studied and their slope and orientations can be determined. The geological wireline logs discussed are the electrical resistivity log of normal configuration, neutron-neutron porosity log and the natural gamma ray log. These logs give valuable information on the lithological section of the wells, the boundaries and thicknesses of the rock units and complement the drill cutting analyses.

1. INTRODUCTION

Drilling into the crust of the earth makes it possible for us to lower instruments into the boreholes and carry out in situ measurements in order to gain information on the physical properties of the rock formation surrounding the well, as well as the temperature and pressure within the well. This family of measurements recorded along the well is commonly called well logs or wireline logs to distinguish them from various other drilling logs. This is a very heterogeneous group of measurements that have the only thing in common that they are carried out within a well. The purpose of the logs is often divided into three categories. The first type contains logs that relate to the well itself i.e. the well design, geometry and completion. The second category contains logs which are used to study the rock formations outside the well and the fractures intersected by the well and finally there are logs that measure the temperature in the well at the time of measurement, fluid pressures and location of the feed zones intersected by the well.

Well logging in geothermal wells has been highly focused on temperature, pressure and spinner logs but the purpose of this paper is to look at wireline logs that informs on the geological formations intersected by the well and the fractures dissecting the formations. Geological wireline logging and fracture imaging consists of a very important technology in the oil well drilling and development where sophisticated (and expensive) well logging tools and interpretation methodology is applied to evaluate the geological structure around the oil wells, map permeable fractures and to determine the water, oil and gas content in the oil bearing formations. Application of these logs is still relatively limited in geothermal exploration in most countries, except in Iceland where we have since 1976 used oil well logging techniques for a systematic investigation of the geothermal wells. A logging truck is stationed at the drill site and one or two logging engineers are standby to carry out logging operations. As the drilling proceeds several logs are done in the well. The logs most relevant for the drilling operations are temperature, caliper and CBL logs and gyro surveys, but several geological wireline logs are also done to study the rock formations of the well and with pressure, the permeability (or transmissivity) of the well is determined through pressure transient tests.

The geological wireline logs are usually run "open hole" for each cased section of the well and when the production part of the well is completed and final depth is reached. The standard logging suit consists of:

- Temperature log to locate feed zones and feed points and to evaluate the heating up rate (heat recovery) of the well after circulation is stopped.
- Caliper log to locate washout zones and to estimate the volume of cement necessary to fill up the annulus between the casing and the formation.
- Resistivity logs (normal 16" and 64"), neutron-neutron logs (porosity), and natural gamma ray logs to evaluate the geological formations.

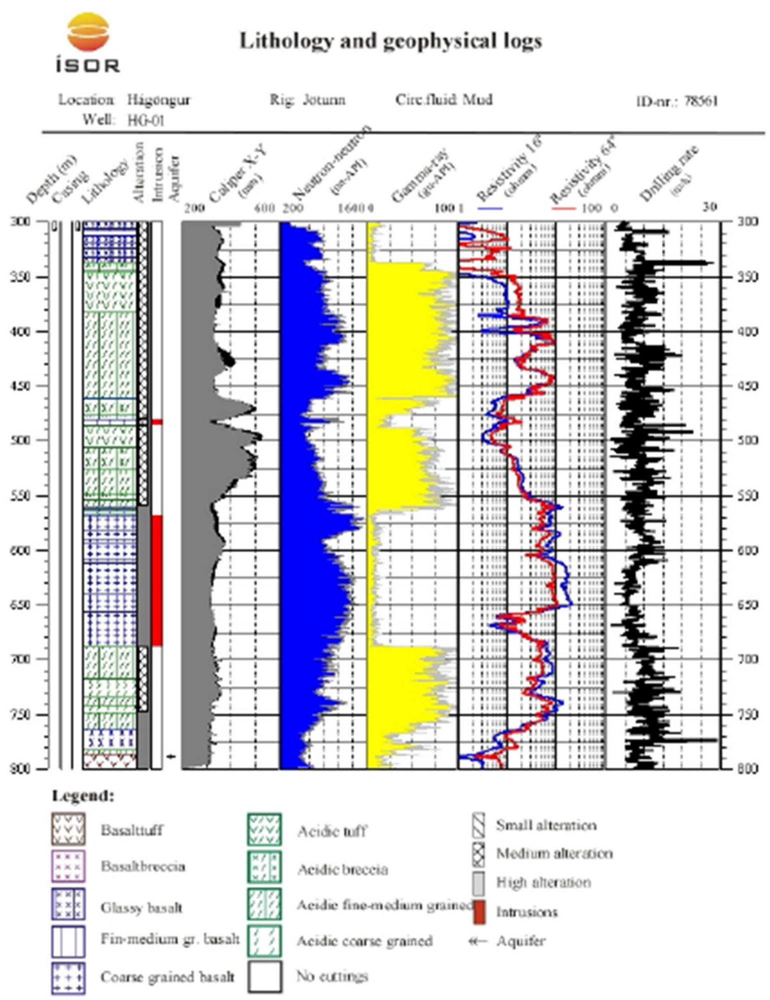

FIGURE 1: Examples of composite logs in a high temperature well in Iceland

An example of a suit of geological wireline logs from an Icelandic well is shown in Figure 1. The logs are plotted with and correlated to the lithology determined by the well site geologist through studies of drill cuttings. The locations of feed zones based on analyses of the temperature logs and circulation losses during drilling are marked on the lithology section and correlated to the formations. The feed zones/points are in most cases connected to active permeable fractures. For further evaluation of these fractures ISOR acquired few years back a "borehole televiewer" a fracture imaging acoustic tool developed in the oil industry some 40 years ago.

In the following sections a short description will be given of the geological wireline logs applied in Iceland i.e. the resistivity, gamma ray and neutron-neutron logs and the borehole televiewer fracture imaging tool. The discussion will be limited to the basic principles and the logging equipments. Examples of logs will be given and their applications discussed.

2. THE NORMAL RESISTIVITY LOG

2.1 Formation resistivity

The knowledge of the resistivity of the rocks is of great importance in geothermal exploration. The geothermal activity influences the formation resistivity through hydrothermal alteration of the rocks where the alteration minerals have different resistivities. Conductive minerals i.e. smectites and mixed layer clays formed at reservoir temperatures of 50-220°C. Minerals (e.g. chlorite, epidote) which are form at higher reservoir temperatures have on the other hand higher resistivity. This explains why surface electromagnetic soundings (TEM and MT) are the main methods of geophysical surface exploration of geothermal fields. The low resistivity anomalies outline the top and the outer boundaries of the geothermal reservoir where the medium temperature alteration conductive minerals have been formed. The high resistivity zone inside the resistivity low, maps the inner part, the core, of the geothermal reservoir where temperatures exceeding 230°C have formed resistive alteration minerals.

The specific electric resistivity of the reservoir formations is the result of two different factors; the resistivity of the rock matrix and the formation fluid. The electric resistivity of rock formations will therefore vary with the rock type, the water content, the salinity of the water and the temperature. The most common rock types in geothermal reservoirs are of volcanic origin but sedimentary reservoir rock formations are also found. An igneous rock matrix is generally a poor electric conductor with specific resistivity values of 10^4 -10^6 Ωm, whereas the resistivity in a sedimentary rock matrix is few orders of magnitude lower. The matrix resistivity can, however, be considerable lower, if it has undergone medium temperature hydrothermal alteration. The geothermal fluids, even of low salinity, are generally much more conductive (<10 Ωm) than the rock matrix and therefore the fluid resistivity will define the resistivity of the reservoir formations, except in very low porosity (<<1%) rocks or very conductive rocks.

The formation resistivity value depends therefore in general on the porosity (water content) as well as temperature and water salinity. Observations of various rock types, leads to an empirical law of the form: $R_o = F*R_w$; where F is called the *formation factor* and R_o and R_w are the formation resistivity, and the pore fluid resistivity, respectively. Several empirical relations between the formation factor F and the porosity have been suggested. The most famous is the Archie´s formula:

$$F= a*\Phi^{-m}$$

where, *a* is a constant; *Φ* is the porosity and *m* is a constant called *cementation factor*.

The constants *a* and *m* are found to be approximately fixed numbers for rocks of similar type and of similar inter-granular and inter-crystalline porosity. For sandstone, which is the common rock type in oil reservoirs, the typical values for *a* and *m,* based on measurements of core samples, resistivity logs and empirical studies are *a* ~ 1 and *m* ~ 2. Fractured igneous rocks are, however the most common rock type in geothermal reservoirs. Resistivity-porosity relations have been determined for fractured basaltic formations in Iceland. A cementation factor*, m* ~1 has been found in most cases. A cementation factor of 2 has, however, been found for sedimentary interbeds in the basaltic lava pile. (Stefansson et al., 1982). The constant *a,* seems, however, to be variable in igneous rock formations and values ranging from 1 to 15 have been reported (Stefansson et al., 1982 and Stefansson and Steingrimsson, 1980).

2.2 Resistivity logs

There are several measuring techniques used today to measure the resistivity of the formations intersected in wells. The set-up, which we have been using in Iceland, is what is called "the normal resistivity logging tool". This is a four-electrode array with two electrodes fixed on the logging probe. The third electrode is placed at surface (mud pit), and the armour of the logging cable is used as the fourth electrode. The cablehead and the first 20-25 m of the cable are electrically insulated to distance the armour electrode from the electrodes on the probe. This arrangement of the electrodes is shown 1n Figure 2. During logging, a constant electric current I is driven between the electrode A on the probe and the armour of the cable and the voltage between electrode M on the probe and the surface electron N (mud pit) measured. For the normal electrode array the specific resistivity of an infinite homogeneous medium is given by an Ohm's law relation with a geometric constant:

$$\rho = 4\pi * AM * V/I$$

where: ρ is the specific resistivity of the infinite homogeneous medium (in ohm metres)
AM is the distance between the two electrodes A and M on the logging probe.
I is the electric current flowing between electrodes A and B
V is the voltage measured between electrodes M and N.

For the normal logging probe it is common to have two M electrodes on the probe, one at a distance of 16" from current electrode A and the other at 64" distance.

The medium surrounding logging probe in a well is neither infinite nor homogeneous. The well is filled with fluid and the rock formations change every few metres of the well. The relation above is therefore not fully valid and the resistivity obtained using the relation will be a kind of average resistivity value within the radius of investigation of the resistivity tool. This value is called an apparent resistivity and the normal resistivity log will show apparent resistivity variations not true formation resistivity. To obtain the true resistivity one must correct the apparent values for well effects (fluid resistivity and well size/diameter) and limited bed thickness of the adjacent lithological units. The apparent resistivity logs obtained for two spacings, i.e. 16" and 64" show relatively different well effects. The 64" log has a larger radius of investigation and will be less influenced by the fluid in the well than the 16" log, which on the on the other hand will have better resolution for thin formation layers.

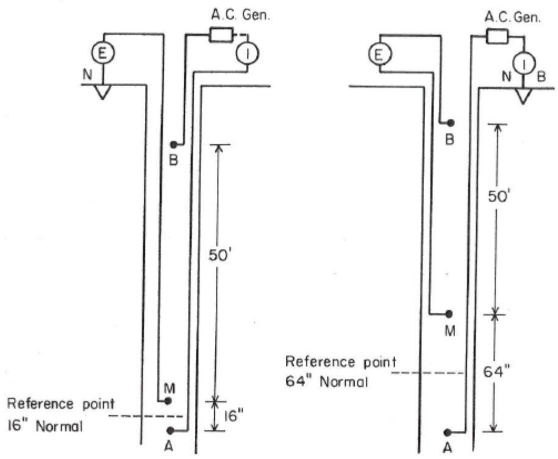

FIGURE 2: The configuration for the normal resistivity log (from Stefansson and Steingrimsson, 1980)

2.3 Applications of resistivity logs

Analyses and applications of resistivity logs can be divided into steps. The first step includes a qualitative observation of the data and comparison with other logging and geological information. For this purpose the log is plotted in parallel with other geological wireline logs, caliper and the geological section obtained through the drill cutting analysis (Figure 1). The logging data are used to define and locate accurately the contact between the various layers, to determine bed thicknesses and the results help in depth correlation of the drill cutting analysis and compliment the geological section. The apparent resistivity values are compared to the geological description based on the drill cuttings and evaluated whether the geological analysis (the rock types) are correct. A notable resistivity contrast is for example observed between volcanic lavas and intrusive units, which will help the geologist in differentiating between these types.

Further and more quantitative evaluation of the resistivity logs is to eliminate well effects to determine the true formation resistivity and then through the Archie´s equation calculate porosity values for the various formation units.

Finally the general resistivity structure on a larger depth scale is compared to the results of surface resistivity soundings (TEM and MT), and correlated to their resistivity depth models.

The discussion on resistivity logs has only been on the normal electric log. This log has been applied for close to one hundred years in oil development and in groundwater and geothermal exploration. Several other electric logs have been developed. Tools like the Laterolog, where the electric current is focused into the formation by specific arrangement of electrodes. This is done to minimize well effects which can dominate the normal log when the well fluid is very conductive. On the other hand the Laterolog obtains a larger radius of investigation into the formation as the focused electric current penetrates deeper into the formations around the well. Example of another electric tool is the Microlog, a tool with several pads, which are pushed against the wall of the well. Each pad is equipped with electrodes for individual resistivity logging and will measure the resistivity in the nearest layer under the pad. The Microlog has a very short penetration depth (depth of investigation) but very high resolution of the formation resistivity, not only in the depth direction but also on the circular surface of the well. Micrologs are used to measure the resistivity in the invasion zone of the drilling mud but they also reveal fractures intersected by the well. These tools are mainly used in the oil industry but the Microlog could be a very useful tool in geothermal investigations for studying fractures in the future.

3. THE NATURAL GAMMA RAY LOGS

3.1 Natural radioactivity of rocks

Rock formations and minerals contain radioactive isotopes that decay continuously emitting radioactive particles and radiation into the surroundings. These are; α- and β-particles and electromagnetic γ-radiations. The radioactive isotopes that are mainly found in the Earth's crust are potassium (^{40}K) and those involved in the decay series of uranium and thorium. The ^{40}K isotope emits gamma rays of an energy of 1.46 MeV through a single decay process whereas uranium and thorium decay in series emitting α- and β-particles and electromagnetic γ-rays in different proportions and with different energies in each step of the series. The γ- ray energy spectrum for all the isotopes is shown in Figure 3.

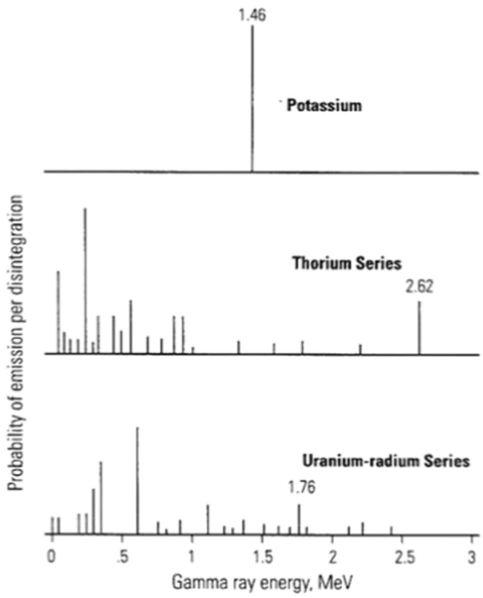

FIGURE 3: The distribution of gamma ray energy from the three naturally occurring radioactive isotopes (from Ellis and Singer 2007)

The radioactive isotopes are only found in very small quantities in rock formations and sediments. Their concentrations vary, however, widely in crustal rocks over several orders of magnitude (Hearst and Nelson, 1985). In igneous rocks the concentrations of all three radioactive isotopes are ten times greater in acidic rocks than in ultra basic rocks and the concentration of each isotope is generally proportional to the SiO_2 concentrations. In sedimentary rocks the relative concentrations of the three elements is variable but the total concentrations of the radioactive isotopes are different for different sediments and therefore also the radioactivity.

3.2 Gamma ray logging

Although the concentration of radioactive isotopes is very low, the γ- radioactivity of rock formations is easily detectable. The α-and β-particles have, however, a short penetration length in fluid and solid materials and this type of radioactivity can generally not be detected within wells. The measurement of γ- radiation in wells is called the natural gamma ray log and was first introduced in the 1930's in the oil well logging and was the first non electric geological log. The gamma ray log is a passive measurement, where a detector is lowered into the well to register the natural radiation from the surrounding geological formations. The detectors used are either Geiger-Muller tubes or scintillation counters. The GM-counter measures the total gamma intensity, but the scintillations counter can either measure the total intensity or the energy spectrum of gamma radiations. The log of the total radioactivity is the gamma ray log but when the energy spectrum is measured the log is called the spectral gamma ray log. In Iceland we have only been using the gamma ray logs in geothermal well.

As the efficiency of counters is different and can change in time for the same counter, it is necessary to calibrate the gamma ray tools regularly in order to compare gamma logs done with different counters or at different times with the same counter in order to obtain the true radioactive intensity of the formations. The American Petroleum Institute has established such industrial standard, an API γ- ray unit. It is defined as 0.5% of the difference in count rate registered between zones of low and high radioactivity in a test pit situated at the University of Houston (Texas, USA). The radioactivity of the concrete in the pit corresponds to about 200 API gamma units and contains about 4% K, 24 ppm Th and 12 ppm of U. (Stefansson and Steingrimsson, 1980).

3.3 Applications of gamma ray logs in Iceland

The application of gamma ray logs rely on the fact that the concentrations of radioactive isotopes varies from one rock type to another and that acidic rocks are more radioactive than the basaltic rocks.
The analyses of gamma logs as carried out in Iceland can be divided into steps similar to other logs. The main steps are the following:

- The logging data are reviewed, the count rate registered converted to API gamma ray units and depth scale correlated to other geological information from the well, before the log is stored in a database.
- The gamma ray log is plotted in parallel with other geological logs, caliper and the geological section obtained through investigation of the drill cuttings (Figure 1). Formation units showing elevated radioactivity are identified and the location of contact boundaries determined and the bed thickness. The units of elevated radioactivity should coincide with acidic (diorites, andesites, ryolites) rock units in the geological section based on the drill cuttings but variations in radioactivity can also be related to higher concentrations of radioactive isotopes in sedimentary interbeds in the basaltic pile or in formation of intense hydrothermal alteration.
- The gamma ray log is corrected for well effects and the relations between radioactivity and the acidity of igneous rocks (Figure 4).
- The Icelandic crust is mainly of basaltic composition. Acidic formations are therefore relatively rare and most wells intersect only few acidic layers. This makes it possible to use the acidic layers observed in gamma ray logs as lithological markers and trace these units from one well to another. The gamma ray logs might even be more informative in other parts of the world, like Latin America, where acidic formations dominate over basaltic ones and would therefore give a broader radioactivity spectrum than experienced in Iceland.

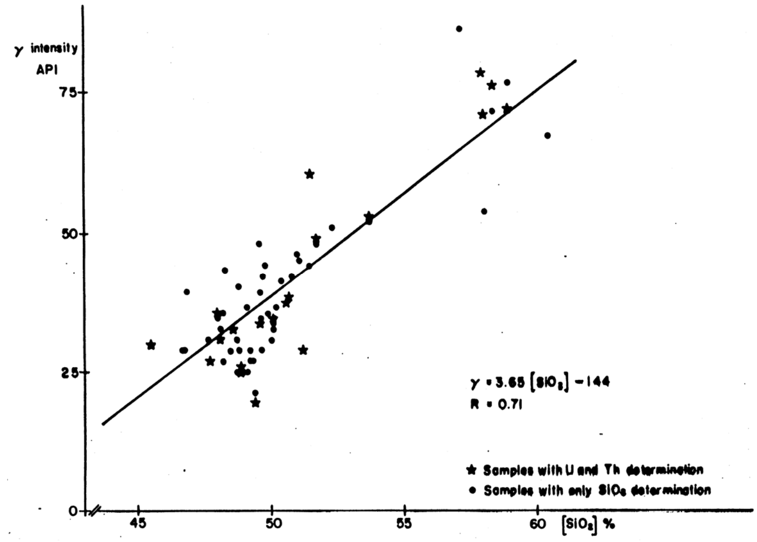

FIGURE 4: The relation between gamma ray intensity and SiO_2 in Icelandic rocks (from Stefansson et al., 1982)

4. NEUTRON-NEUTRON POROSITY LOGS

4.1 Scattering of neutrons in rock formations

The neutron is an electrically neutral elementary particle of approximately the same mass as a proton. The neutrons are found in the nucleus of the atomic elements but free (high energy) neutrons are generated in the decay of radioactive isotopes. The free neutrons are transient particles which interact with matter through elastic and inelastic collisions. The neutrons hit the nucleus of the matter and slow down to thermal velocities before being absorbed or captured by a nucleus, which in turn becomes radioactive and decays emitting a gamma radiation. The rate of which the fast neutrons are slowed down to thermal velocities depends on the chemical composition of the media they travel through.

In rock formation, the slowing down process is dominated by elastic (billiard) collisions between the neutrons and the nuclei in the surroundings, until thermal state is reached. It is well known from the collision theory that the incoming particle gives up more kinetic energy when colliding with a particle of similar mass. The nucleus in the surroundings with the mass closest to the mass of the neutron is the hydrogen nucleus which consists of a single proton. The hydrogen atoms in the formations are mainly found in the water molecules. The slowing down process of fast neutrons in rock formations is therefore primarily controlled by abundance of water in the surroundings either water in pores and fractures in the rock formations, or water bound in minerals i.e. geothermal alteration minerals in the case of geothermal. Hence the term “neutron porosity log” is not quite accurate, more correct would be to refer to it as a log that measures the total hydrogen content of the formation as water by volume. This effect of formation water on the slowing down of fast neutrons, is the basic physical principle, which the logging technique to evaluate “porosity” of rock formations is based on.

4.2 Neutron porosity logging

A simple neutron porosity logging tool (Figure 5) consists of a neutron source emitting high energy neutrons and a detector (sometimes two), sensitive to thermal neutrons, located on the probe at an appropriate distance (~30-40 cm) from the neutron source. The double detector tool is called compensated neutron tool, where the far detector is some 60 cm from the source.

The neutron tool used in Iceland is a single detector tool, where the neutron source is a mixture of radioactive Americium and Beryllium (AM-BE). The radioactive Americium emits alpha particles which collide with the beryllium cores and cause them to emit high energy neutrons. The energy level of the neurons is 4.5 MeV. This correlates to a neutron speed of some 30,000 km/s which will be reduced to some 500 km/s through the slowed down collisions when the neutrons become thermal and are detected counted by a ^{3}He-neutron detector. As for the gamma ray tool a standard calibration is used for neutron counters. It defines an API neutron unit as a part of the difference between two porous water saturated layers in a calibrations pit at the University of Texas in Houston, Texas.

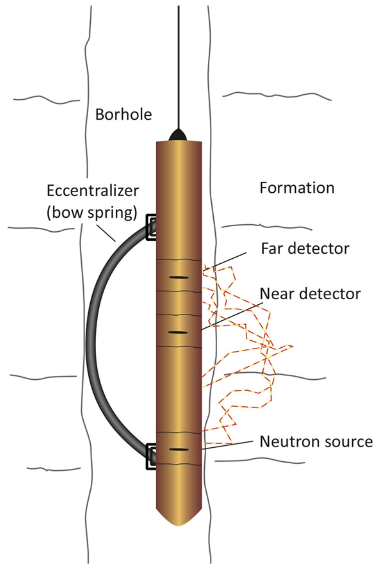

FIGURE 5: Neutron-neutron logging tool

4.3 Application of neutron logs in Iceland

Neutron porosity logs are primary carried out in "open" holes but will work in cased sections with some attenuation of the signal. The primary steps, in analysing the neutron logs, are similar to other logs. The logging data are calibrated and converted to API neutron units. The depth scale is correlated to other logs and stored in a database. The log is then plotted in parallel with other geological wireline logs from the same well (Figure 1) for determining the stratigraphy of the lithological section and comparison with other logs.

Further interpretation of the neutron log is an evaluation of well effects influencing the logging response. These are mainly effects caused by the water in the well. This effect must be subtracted from the log to obtain the "true" formation signal which in turn can be converted to formation "porosity". Calibration curves relating neutron logs and porosity have been developed in the oil industry based on porosity measurement on cores and neutron logs as well as resistivity log. They define what is called "limestone porosity" and are fairly accurate for sedimentary (limestone) oil reservoirs. Example of such curves is shown on Figure 6. These curves have been used in Iceland for many years to estimate porosity of rock formation from neutron logs. The Icelandic formations are, however, igneous rocks and it is therefore not obvious that the "limestone calibrations" are fully valid for igneous rock where the bound water contribution to the "porosity" might be quite different. Comparison of neutron

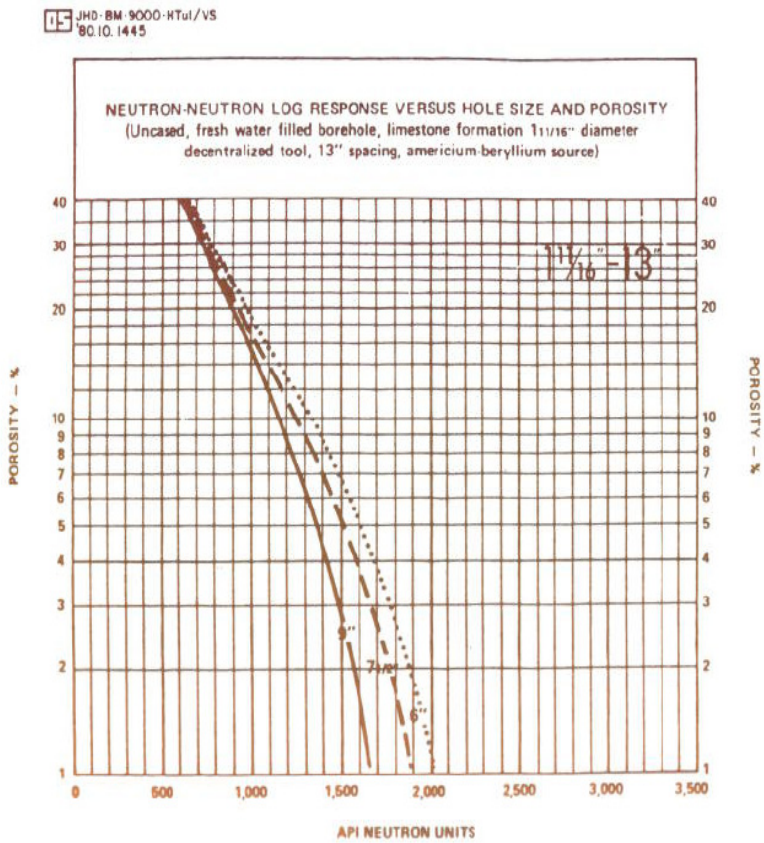

FIGURE 6: Limestone porosity and neutron-neutron logs. Example of calibration curves for 6", 7.5" and 9" diameter wells. (Stefansson and Tulinius, 1983)

logs in limestone and igneous rocks indicate, however, that the difference between limestone porosity and igneous rock porosity should not be more than 3% (Czubek, 1981).

5. BOREHOLE TELEVIEWER LOGS

The permeability of igneous rocks in geothermal reservoirs is dominated by fracture permeability opposite to many sedimentary reservoirs, where matrix permeability dominates. Mapping of permeable fractures in the geothermal reservoirs is therefore very important. Several logging tools have been developed in order to study fractures intersected by wells. These tools create an image, a kind of a "picture", of the wall of wells revealing the fractures and various features of the geology visible on the "picture". A tool of this type is the borehole televiewer, an acoustic tool, that was developed in the oil industry in 1970 and we have used successfully in Iceland for a few years with the main objective to map permeable fractures in geothermal wells.

5.1 Borehole televiewer

The borehole televiewer is a logging tool that produces an acoustic "picture" of the borehole (well) wall. The tool consists of (1) an acoustic transducer which acts both as a transmitter and a receiver of a signal, that is sent from the tool directly to the wall of the well and reflects from the wall back to the transducer; (2) a motor which turns the transducer so a reflected signal is obtained from the circumference of the well (the tool is centralized in the well) and (3) a magnetometer (compass) to provide information on the orientation of the tool with respect to the Earth's magnetic field and 3D accelerometers to determine deviation from vertical (see Figure 7). The signal from the transducer consists of 1500 very short acoustic pulses per second as the motor turns the transducer 3-7 revolutions per second while logging the well at a speed of 1-2 m/minute.

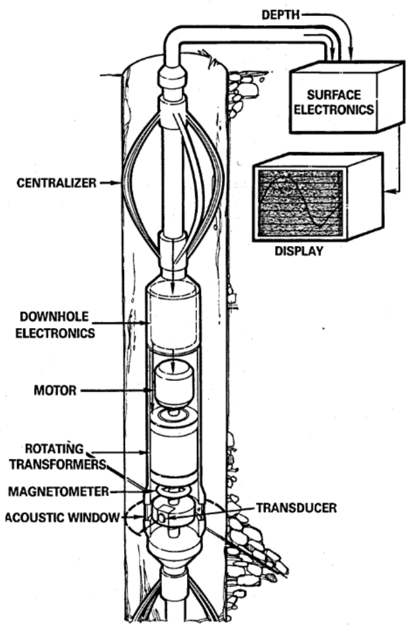

FIGURE 7: Acoustic Borehole Televiewer (from Heard and Bauman, 1983)

5.2 The acoustic picture and its applications

The acoustic picture obtained by the televiewer will depend on several factors including reflectance of the well wall which is higher for hard rock than soft rocks, roughness of the wall and the geometry of the well i.e. deviations from a circular form. The well fluid also affects the quality of the "picture". Muddy water will cause dispersion of the acoustic signal and result in a foggy "picture" although the acoustic wave is not as sensitive to dispersion as photographies, due to the longer acoustic wavelength compared to wavelengths of light.

Figure 8 shows a part of a televiewer log from a low temperature geothermal well in Iceland. The log is viewed in two ways on the figure, in a core view and as an unwrapped picture of the wall of the well. The log shows an open fracture at 1324-1325 m depth. The fracture appears as a dark line but it has been traced with a green line on the log. The log suggests a fracture opening of some 20 cm and shows NE-SW strike and a fracture dip of 7 degrees from vertical. This fracture was quite permeable and produced 60 l/s of 75°C hot water during a pump test.

Figure 8 demonstrates the main application of televiewer logs but there are other uses some of which are listed below:

- The televiewer log is viewed and analysed in order to detect fractures visible on the log. The orientation of the fractures is determined, both the dip angle and the strike direction. Fractures that coincide with known feed zones in the well are of special interest.
- Detection of hard and soft formations intersected by the well and the determinations of the contacts layers between beddings.
- Geometrical information regarding the shape of the well (distance to the wall,) and the roughness of the wall.
- Detection of key-seat forming of the well due to drill string erosion of the formation
- Detection of break-outs visible in the logs give information on stress conditions in the formation

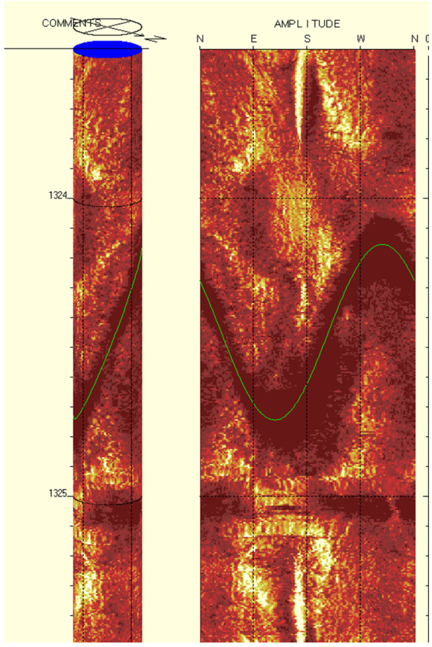

FIGURE 8: Televiewer log showing an open permeable fracture

6. CONCLUSIONS

The geophysical logs, resistivity, gamma ray and neutron-neutron log, discussed in this paper have the main purpose to study the lithological units intersected by a well, locate contacts of adjacent beds and determine the thickness of the units. The knowledge on the geological sections in geothermal wells is primarily obtained by studies of drill cuttings. The cuttings are formed at the well bottom and then flushed to the surface with the circulating fluid. The analyses of the drill cuttings must therefore take into account the time it takes to bring them to the surface and also the unavoidable different travel time for cuttings of different size and mixing of the cuttings as they are flushed to the surface. The three logs discussed have been used in Iceland since 1976 and have proven to be an important addition to the analysis of the drill cuttings for dividing the lithological column into different layers. In the case of blind drilling, i.e. drilling with total loss of circulation, these geological wireline logs and drilling penetrations rates (rock hardness) give the only geological information available for the blind sections, especially in order to define geological environment of the permeable formations.

The gamma ray log determines, in addition to rock stratification, the radioactive intensity of the rocks, which relates to the acidity of the rocks and somewhat to its hydrothermal alteration. The gamma ray log can therefore distinguish between acidic and basaltic formations and empirical relationship between the gamma ray logs and SiO_2 concentrations of rocks has been established for igneous rocks. The resistivity and the neutron logs have been found to be useful in pointing out hard, low porous formations (intrusions) and in general to estimate the porosity of the formations through empirical relations obtained through studies of drill cores and by comparison to logs in cored wells.

The permeability of the geothermal reservoirs is dominated by fracture permeability. Studies of permeable fractures are therefore very important in geothermal exploration. Several logging tools have been developed for fracture imaging. The tool that we use in Iceland is the borehole televiewer. We have used it in several wells during the past years and gained very valuable information for defining the inclination and direction of fractures intersected by the wells, knowledge very valuable for future targeting of wells.

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I thank my colleagues at ISOR, Hjalti Franzson and Svanbjörg H. Haraldsdóttir, for critical review of the paper and for their valuable comments and discussions now, but also through the many years that we have worked on interpreting geophysical wireline logs and compared them to other geological information from geothermal wells in Iceland.

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UNITED NATIONS UNIVERSITY
GEOTHERMAL TRAINING PROGRAMME

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GEOCHEMICAL CHARACTERIZATION AND INTEGRAL ANALYSIS OF DATA LAS PAILAS GEOTHERMAL FIELD, COSTA RICA

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ABSTRACT

This paper presents and discusses the geochemical information obtained in Las Pailas Geothermal Field, corresponding to the characterization of fluids during the development stage, as well as the evolution of the reservoir presented in less than two years of operation. This study focuses on the importance of integrating the information gained from other geoscience areas. This is necessary for the complete characterization of the reservoir and crucial to the detection of problems that occur during evolution, allowing early decisions leading to the sustainability of the field. In this case, geochemical data is integrated with information from Thermal-Hydraulic Studies team

1. INTRODUCTION

Las Pailas Geothermal Field (Figure 1) is located in the Cordillera de Guanacaste in north-western Costa Rica, on the southern flank of the Rincon de la Vieja Volcano. Commercial exploitation of the field began in July 2011 with the first production unit of 35 MWe. Las Pailas II is now being in the process of feasibility with a capacity of 55 MWe.

Las Pailas geothermal field has 20 wells drilled, 9 vertical and 11 directional (Figure 2). The unit Pailas I consists of a combined cycle binary plant for the production of 35 MWe, requiring 80 kg / s of steam and 380 kg / s of liquid and separated at a temperature of 160 ° C. They used a total of six production wells, three hot reinjection wells and two cold reinjection (alternative use), for plant condensate and brine from the lagoon collection. It is reinjected a mass of liquid 380 kg / s at 140 ° C.

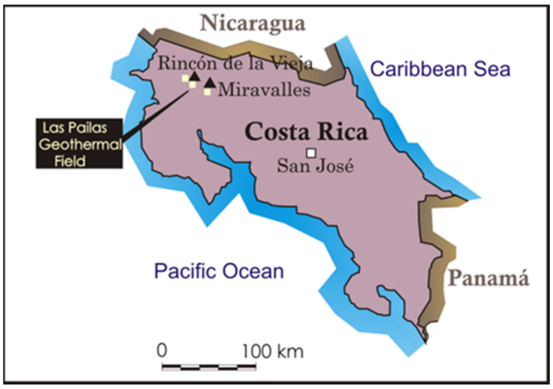


FIGURE 1: Location of Las Pailas Geothermal Field in Costa Rica

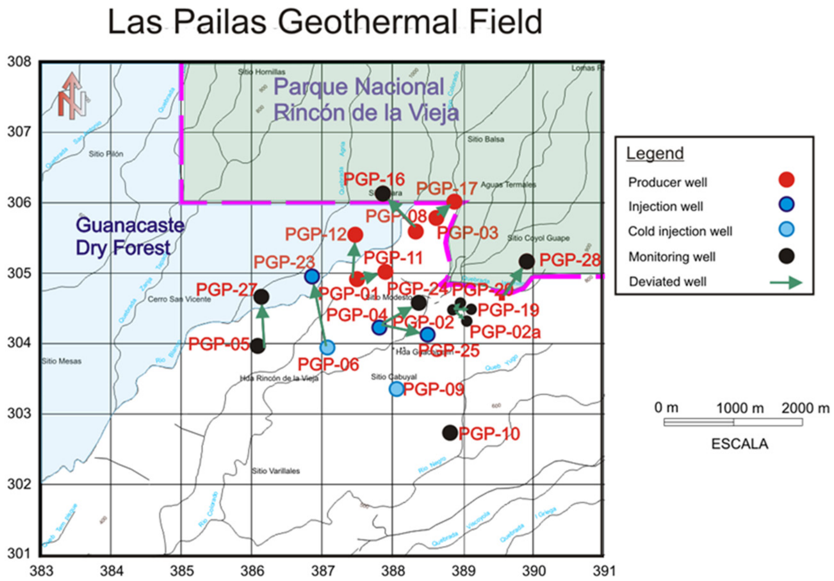


FIGURE 2: Location of the deep wells of Las Pailas Geothermal Field in Costa Rica

During the development stage was determined that the reservoir fluid is liquid dominant. The characterization of the wells in Las Pailas showed they produce fluids from aquifers chemically different as well with different temperature. However it can be said that the main zone fluids, from which they produce are NaCl, neutral, high salt content and with a low content of gases with temperatures ranging between 240 ºC y 255 ºC.

Due to a number of factors, as the location of the reservoir Las Pailas, the "Law of National Parks", permits from the owners of the area and the lack of permeability in peripheral areas, the reinjection zone was located very close to the main producing area. This, coupled with the complex hydrogeology of the system has caused in less than two years of operation of the Geothermal Field Las Pailas, there have been phenomena as a temperatures decrease in both the PGP-24(static conditions) as in the PGP-11 (dynamic conditions). The chemical complexity of the different production zones has not permitted monitor reinjection fluid using the original components of the fluid, this has led to the use of chemical tracers for studies aimed at characterizing hydrogeological system.

Due the above and tracer test results, it has generated the need of moving the reinjection of the central part of the field, to the east side. The migration process will be held in short term and will be implemented through a phased transition. New tracers tests will be held in parallel to obtain information to define the hydrogeology of the system, and thereby define production policies reinjection and ensuring the sustainability of the field.

2. Characterization of fluids of Las Pailas during the development stage

2.1 Liquid chemical composition

The results obtained in the different assessments of deep wells show that the fluid on surface present conductivities between 17000 to 20000 uS / cm. They are sodium-chlorinated, neutral and high salt content. They have values between: sulfate of 41 to 48 ppm; calcium of 129 to 159 ppm and total silica of 642 to 661 ppm for a total of STD of 12100 to 13510 ppm.

It is characteristic of these wells in the early hours of opening produce lower salinity fluids then make this area of higher salinity (20 000 uS / cm). The latter dominates in dynamic conditions, however in some wells depending on the conditions of production increases or decreases the contribution of one of either zone.

2.2 Calcium carbonate formation

As in the Miravalles Geothermal Field, bicarbonates is the limiting reagent for the formation of calcite fluids in Las Pailas. The contents of bicarbonate on surface in Las Pailas wells have values between 0,1 to 10 ppm. A test on the PGP-08 (well with higher content of bicarbonate in Las Pailas), said that in the current conditions there is not a tendency to form calcium carbonate in fluids from these wells. The test consisted in lowering inhibition system 100 m below the boiling zone injecting water over a period of one month. The capillary tube was then revised and inhibition head, being completely free of deposits. Continue with weekly monitoring of bicarbonates to detect a possible early entry to production zones with higher content of bicarbonates. Currently it is maintained the limit of 10 ppm, above this value there may be risk of calcium carbonate scale formation.

2.3 Chemical composition gas

The vapor of Las Pailas wells is characterized by low-condensable gases. The values are between 0,03 to 0,27.% w/w The C02 represents 99% and values are between 10 to 40 mmol/kg. In the eastern part of the field, sector to which the hot reinjection moved, wells PGP 19 and PGP-20 present a gas content of 0,87 to 1,27 %w/w respectively. The CO2 content of these wells is 140 mmol/kg. This indicates that these two wells are in a different geochemical context than the other wells (Table 1).

TABLE 1: Content gas wells Las Pailas

Well	% GasW/W 5,9 bar absolute
PGP-01	0,10
PGP-03	0,11
PGP-08	0,27
PGP-11	0,03
PGP-12	0,16
PGP-17	0,04
PGP-19	0,87
PGP-20	1,27

2.4 Types of aquifers identified in Las Pailas

The information obtained in the different chemical profiles of wells PGP-04, PGP-01 and PGP-03, revealed the existence in the field of various aquifers with different chemical characteristics. As shown in Figure 3, an aquifer was identified in common in the three wells, this corresponds to higher salinity aquifer containing chlorides between 4700-4800 ppm, its contribution dominates in production conditions. In the upper regions of the wells PGP-03 and PGP-04 presents a lower salinity content aquifer with a chloride content of 4200 ppm, its contribution is more important in static conditions Moreover, only in the PGP-01, in the upper zone has been determined under static conditions an aquifer containing approximately 1000 ppm chlorides and high bicarbonate content. It also identified another aquifer salinity equal to the aquifer present between -300 and -800 m, but different in increased calcium content, it occurs only in the deep zone of PGP-04.

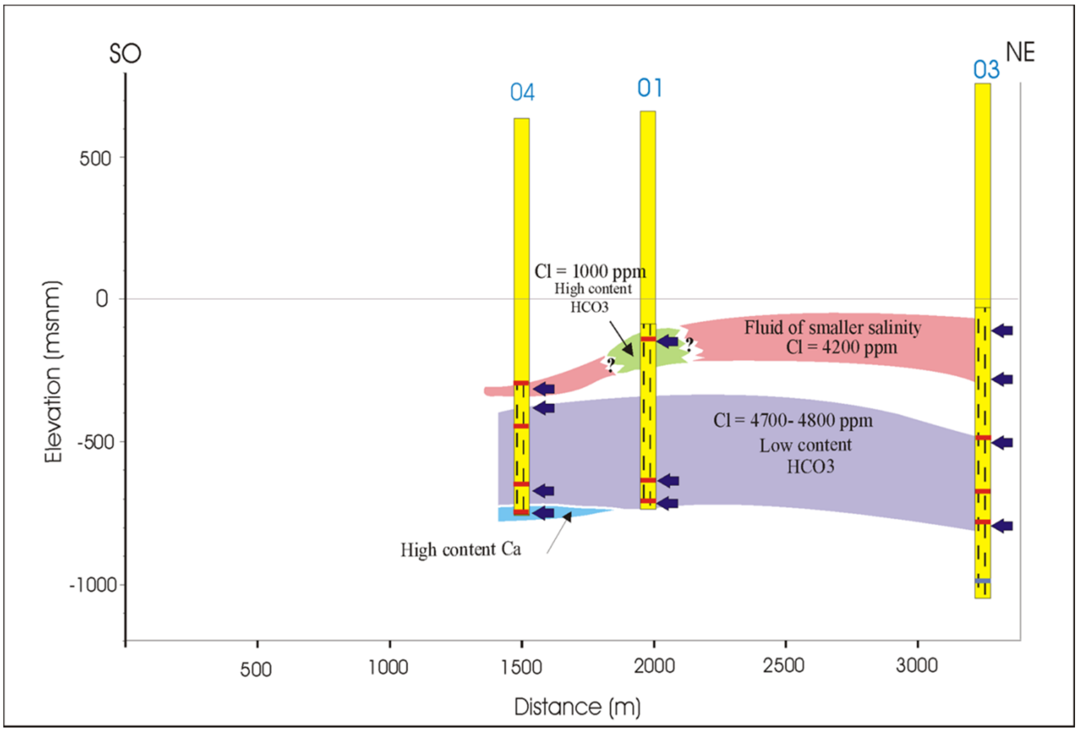


FIGURE 3: Chemical profile showing the different aquifers in the Las Pailas wells

Figure 4 shows a temperature profile measured by the Thermal-Hydraulic Studies team in static condition. It is noted that temperatures show a sharp drop towards the WSW and indicate that the site area comprises wells PGP-02 and PGP-04, while to the area where the wells are located PGP-06 and PGP-05, the conditions thermal strongly decrease. It can also be noted that in the PGP-04 there is a temperature inversion which could indicate that the well is located near the periphery of the reservoir.

Integrating information from chemical profiles downhole with Thermal-Hydraulic Studies team information shows that the contribution of fluids with higher calcium content characteristic of PGP-04, determined only in the depth of the PGP-04, could correspond to the aquifer that causes regression of the temperature which occurs in the well under dynamic conditions such as under static conditions.

Also the integration of this information suggests that the field Las Pailas presents a complex hydrology, wells have input from different aquifers, they have different chemical characteristics and different temperatures, the importance of knowing your existence is on the right track to be implemented, the contribution of these peripherals aquifers can invade at a given time product of exploitation, causing cooling processes and thus decrease production. On the other hand, also the input of another aquifer conditions can cause deposits of calcite saturation, among others, because some of the aquifers characterized are high in bicarbonates.

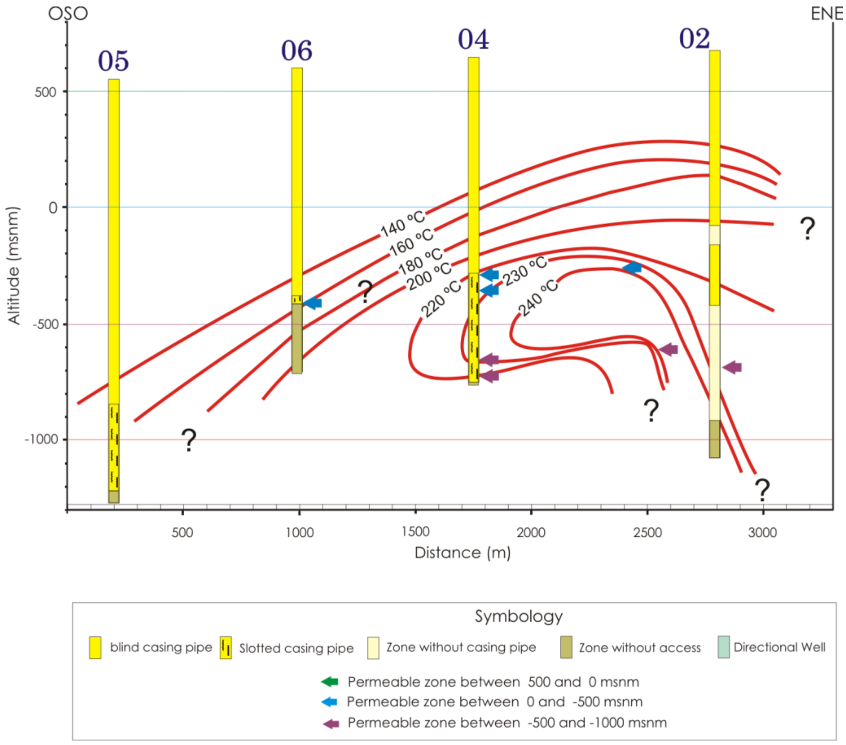


FIGURE 4: Thermal profile oriented WSW-ENE including wells PGP-05, PGP-06, PGP-04, PGP-02

3 Evolution of the fluids in the operating stage

3.1 Geochemical monitoring

Due to the characteristics described above, obtained during the development step, the chemical monitoring of certain chemical components is performed weekly. Additionally total samples are performed (liquid and gas) every three months and thermo-chemical-hydroaulic test assessments every 4 months. Wells static temperature and pressure profiles are performed by Thermal-Hydraulic Studies team every 6 months.

Figure 5 shows the chloride content of all the wells, this component being representative geothermal fluids in both Miravalles as in many other fields in the world has been used as a tracer natural. However, the chemical complexity of the different production zones of the Las Pailas field have not allowed reinjection monitor using original fluid components, so that an increase in chlorides not necessarily indicate return fluid reinjection, because it could be the contribution of one of these aquifers of higher salinity. As part of the detection of the input peripherals characterized aquifer or any other, components that can indicate invasion are monitored. These are: Ca, HCO3, SiO2 and SO4 among others.

3.2 Cooling in static conditions of the PGP-24 Case

Well PGP-24 consists of a directional well producer located in the courtyard of the reinjection zone centre (18,2 m from the reinjection well PGP-04 and 37 m from the reinjection well PGP -25.). It was assigned as a backup producing well. During characterization test produced fluids of: conductivity: 19235µS/cm, chlorides: 6655 ppm; sulphates: 36 ppm and calcium: 133 ppm. The well produced a total flow of 193 kg/s to a temperature measured in static conditions of 247ºC (January 22, 2010).

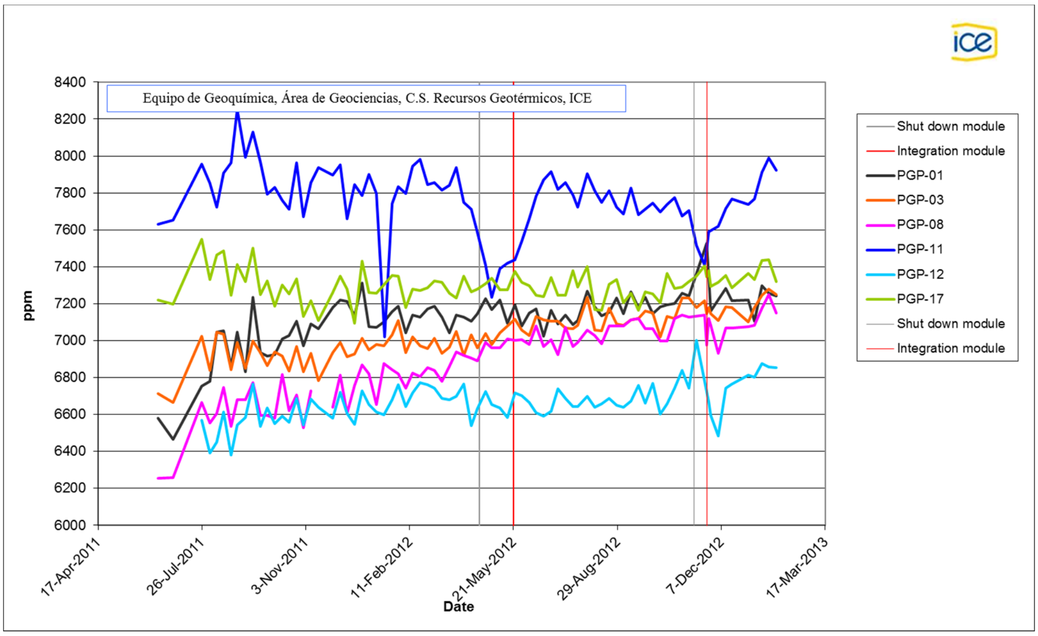


FIGURE 5: Evolution of chloride content in wells Las Pailas

After the entry into production of the unit I, a decrease in static temperature was identified of 247 °C to185°C between 1100 and 1030 m depth. We conducted a production test and initial conditions had changed, the fluids had an increased content of chlorides, sulfates and calcium reaching a value of: Cl: 7091 ppm; SO_4: 166 ppm and Ca: 221ppm. The well production declined in this test produce a total flow of 85 kg/s. Initially it was thought the reason of cooling was reinjection. The increased chloride content supported this hypothesis. However enrichment in calcium and sulphate content not coincide with increasing concentration corresponding to the loss of 20% of the vapor fraction. Subsequently, a series of chemical profiles and temperature profiles (Figure 6) determined that the cooling zone corresponds to the calcium sulphate zone, giving then a movement of fluids.

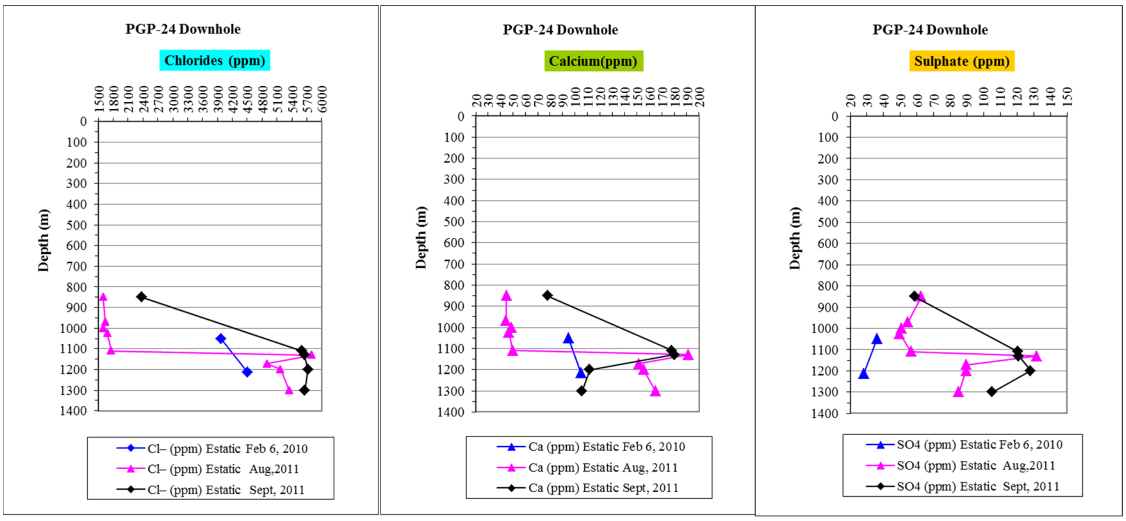


FIGURE 6: Chemical profiles PGP-24. They show increase in Cl, Ca an SO4 after stars Pailas I. The highest concentrations of these components are in cooling zone

3.3 Cooling in dynamic conditions of the PGP-11 case

The PGP-11 well is a production well directional, located 845 m from the well reinyector PGP-04 and 810 m from the reinjection well PGP-25. During characterization produced fluids of: conductivity:

18910 µS/cm, chlorides: 6643 ppm and sulphates and calcium containing: 36 ppm and 139 ppm respectively. The well produced a total flow of 132 kg /s with a temperature dynamics of 254 ºC, after the entry of production unit I, there has been a gradual decrease in temperature dynamics (Figure 7) coming to 213 ° C in the last profile performed the march 11, 2012.

Some chemical variations also presented. The PGP-11 corresponds to the well with higher chloride content in Las Pailas field (Figure 5). With the entry into operation of unit I this well has presented the same trend of a slight increase in chlorides, and also presents decreases in some point relating to production zones of lower salinity. The content of calcium and sulphate show a similar behaviour. During maintenance of the plant the PGP-25 was pulled from the reinjection system. Parallel to this, the content of Cl andSO_4 showed a tendency of decrease (Figure 8).

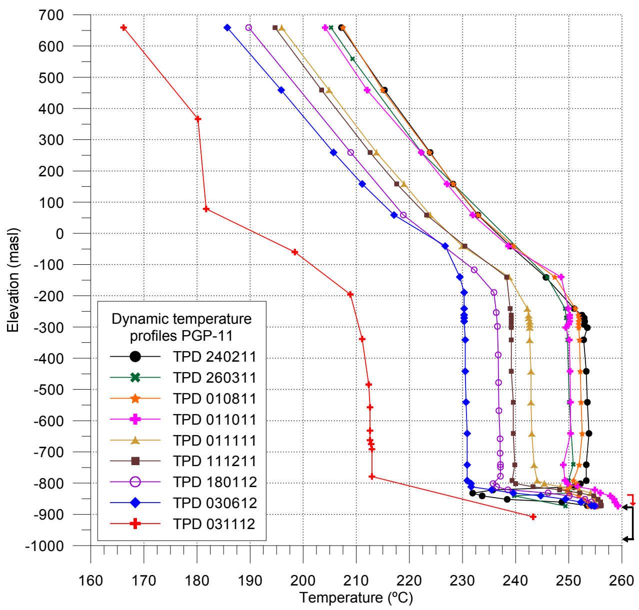


FIGURE 7: Temperature profiles PGP-11

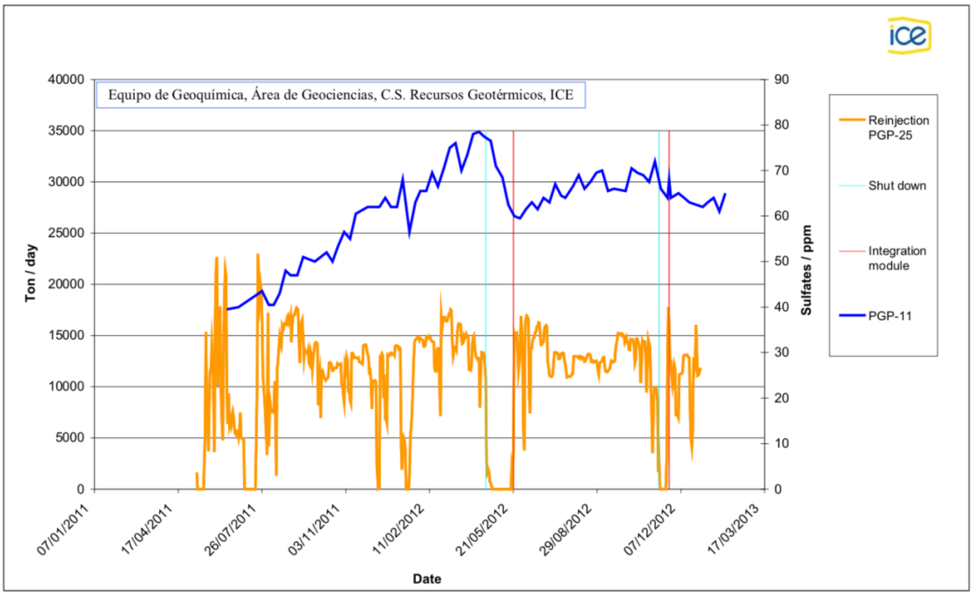
3.4 Results of tracer test

Due to the need to determine if the cause of cooling PGP-11 and PGP-24 were results of reinjection or invasion of another aquifer, and the urgency of know the hydrogeology of the system to define policies reinjection and production, a test tracer was performed by injecting sodium benzoate in the PGP-25, which could be responsible for the effects observed in the wells cited.

The tracer was detected in well PGP-11 twenty four hours after injection of the tracer and maximum concentration was reached after 42 hours (Figure 9), indicating a rapid connection between PGP-11 with the reinjection well PGP-25. In the case of the PGP-24 tracer also appears at 24 hours. The highest concentration of tracer was measured in the zone of 1300 m which does not correspond to the zone of lower temperature. However, because no sampling were realized in the zone characterized as sulphated and low temperature, we cannot determine if this zone had a direct influence from fluid reinjection.

Due to the above and because of the behaviour of temperature increase during the short output when PGP-25 was a reinjection well (Figure 10) it follows that the cooling zone of a PGP-24 was due by a invasion of a peripheral aquifer sulphated. The phenomenon that causes this may be linked to the following hypothesis:

1. That the effects of reinjection in the PGP-25 create conditions so that this aquifer sulphated lower temperature, with its own characteristics, becomes present.



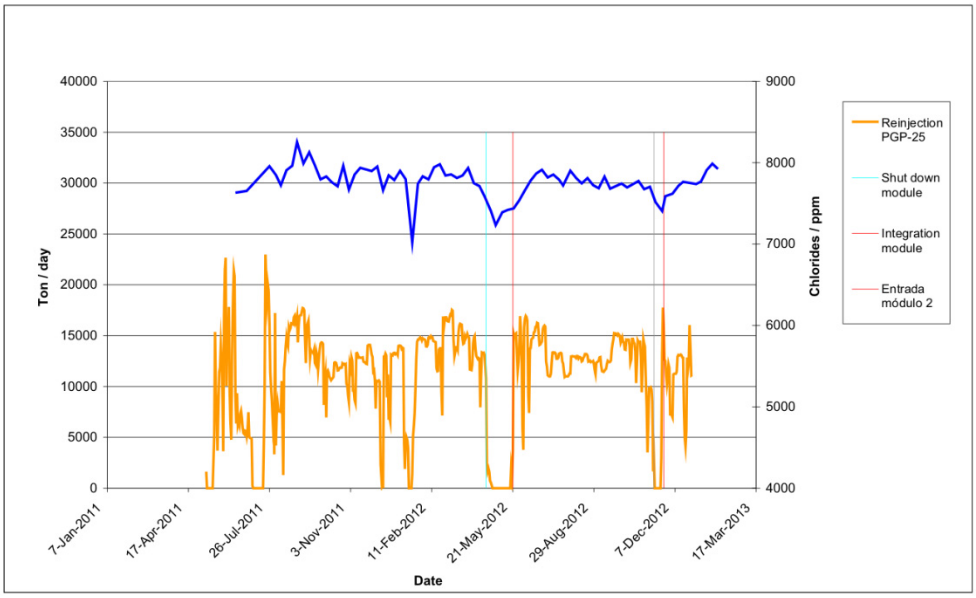


FIGURE 8: Evolution of SO_4 and Cl in PGP-11vrs mass reinjection into the PGP-25

2. Reinjection fluids are passing through an area rich in sulphates and are enriched in this component and the cause of cooling is reinjection that is emerging in this area, either from the PGP-25 or PGP-04.

These hypotheses will be corroborated in a second tracer test.

In the case of cooling the PGP-11, results indicate that the cooling effect could be caused by the reinjection of PGP-25. The information from the tracing test complemented the necessity of moving the reinjection of the central part of the field (PGP-25 and PGP-04) to the east side (PGP-19 and PGP-20). This process will take place in short time. Currently the measures taken were: a) to reduce the mass extraction of the PGP-11 and b) to decrease as much as possible reinjection into the well PGP-25 while running the transfer of reinjection. With the above measures the output of the plant is kept in the 35 MWe for which it was installed.

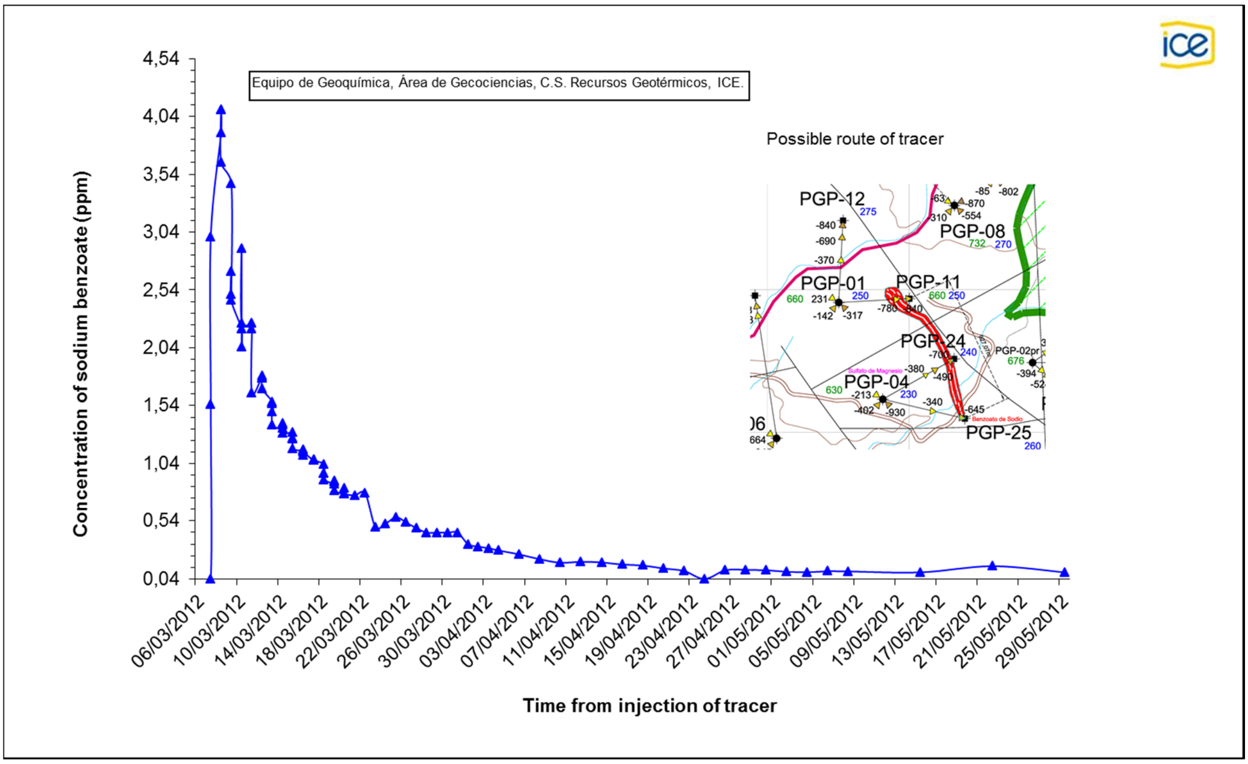


FIGURE 9: Tracer concentration in the PGP-11 (modified from Solis, 2012)

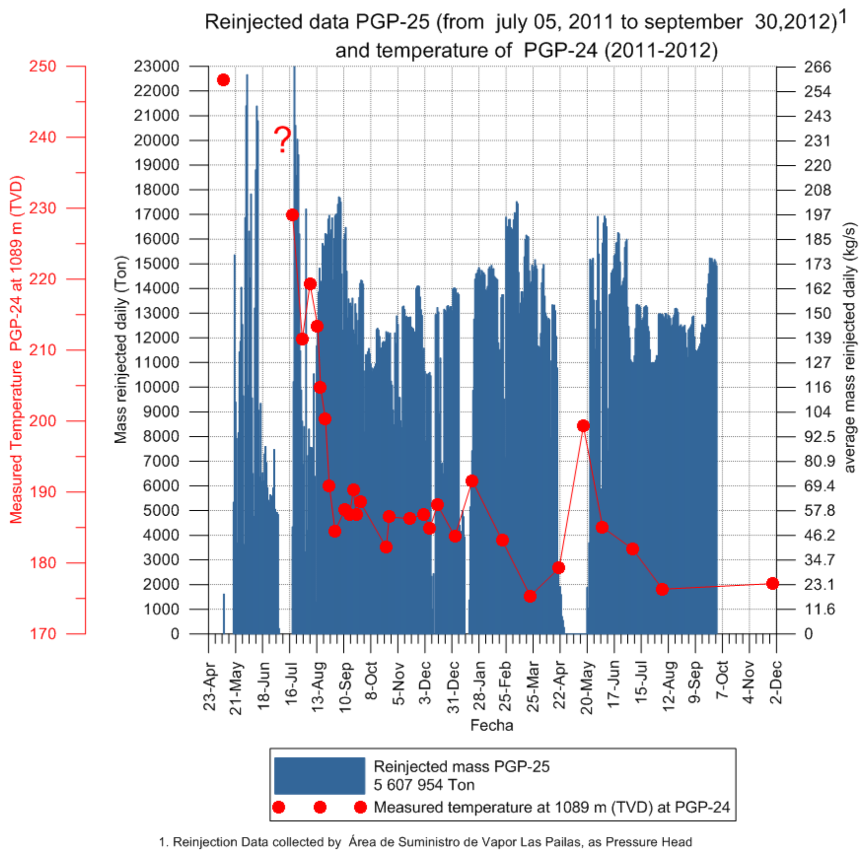


FIGURE 10: Static temperature evolution of PGP-24 and mass reinjection into the PGP-25

4. CONCLUSIONS

The information gained from the characterization of fluids in the stage of development and their integration with other geoscientific areas, allow to create a complete model of the initial conditions and the possible effects that may appear in the exploitation step of the field. This will allow to create a adequate monitoring programme.

Information acquired and the integral analysis of this during exploitation of the field are the key to identify problems and find solutions at an early stage, as invasion of aquifers peripherals, process cooling and other effects product complex hydrogeological conditions.

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GEOTHERMAL WELL LOGGING: TEMPERATURE AND PRESSURE LOGS

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ABSTRACT

Temperature and pressure logs are the most important well logs in geothermal exploration and development. They are used extensively throughout the life time of wells. Electronic tools with surface are used in low temperature wells (T< 150°C), but for wells with temperatures, in the range of 150-380°C, the geothermal industry have used mechanical Kuster/Amerada temperature gauges for decades. During the last ten years electronic high temperature tools have become available and the T&P tool that is most widely used in geothermal today is a K10G from Kuster Company, which is a memory tool with the electronics inside a Dewar flask to shield the electronics from the high well temperatures and maintain internal tool temperatures below 175°C for hours even at 350°C well temperatures.

The ultimate goal of temperature and pressure logging in geothermal investigation is to determine formation temperature and reservoir pressures, but even during drilling when the well temperatures are highly disturbed by drilling fluid circulation and cold water injection in to the well the temperature profiles provide valuable information on the location of aquifers (feed zones) and their relative size (permeability). Internal flow often exists in very permeable wells with multiple feed zones. This flow is clearly seen in temperature logs and sometimes the internal flow rate can be estimated based on temperature transients. Bottom-hole formation temperature is sometimes estimated by extrapolation of a short term heating up temperature survey at bottom using Horner plot or other extrapolation algorithms.

Pressure in wells is also influenced by fluid circulation, injection and production during drilling. Pressure transient test do, however, give information on well injectivity and productivity as well as other hydrological parameters.

The temperature and pressure disturbances in a well during drilling will fade away gradually when the drilling stops. The wells will heat-up and reach thermal equilibrium with the surroundings in matter of several months and the well pressures will also recover after drilling and reach equilibrium with the permeable feed zones of the well. Temperature and pressure logs during the heating/recovery period after drilling are the most important data to estimate formation temperatures and reservoir pressure. T&P logs at later stages can improve the estimates. Monitoring of temperature and pressure becomes an essential tool for the management of the reservoir, when utilization commences.

1. INTRODUCTION

Temperature and pressure logs are used extensively in geothermal exploration and development. Their application starts when the drilling commences with the first exploration in a green field development and is carried out in most if not all wells drilled later in the development. The temperature and the pressure logs are carried out during drilling of wells, during heating-up after drilling and during flow tests. The biggest challenge in analysing these logs is to define the temperature and pressure reservoir conditions by determining the formation temperature profile for each well and the pressure potential of permeable zones intersected by the wells. When several wells have been drilled in an area, maps can be drawn to show the formation temperature and the pressure distribution in the geothermal reservoir. Early in the development these maps will show the initial reservoir conditions prior to utilization. Later when production from the field commences, the mass withdrawal from the reservoir will lead to pressure drawdown and sometimes also temperature changes in the geothermal reservoir. Temperature and pressure logs are then used to monitor the changes and map the long term response of the reservoir to the utilization.

This short paper on temperature and pressure logging is divided into few chapters, starting with a brief description of the most common temperature and pressure gauges used in geothermal logging. The various applications and interpretation of temperature and pressure logs will then discussed with examples.

2. TEMPERATURE AND PRESSURE LOGGING TOOLS

A portable logging unit used in Iceland for temperature measurement is drawn schematically in Figure 1. A platinum temperature sensor (resistance) is connected to an electric single conductor logging cable. Part of the sensor and the connection is encased in a pressure steel pipe (water tight). A sheave on well head guides the cable into the hole but act as a depth meter as each rotation moves the cable 1 meter. The electronic package and batteries are encased in a box displaying the depth and the sensor reading. A calibration book is required if the display is not calibrated to show temperature.

A wide range of instruments have been used to measure temperature and pressure in geothermal wells since geothermal drilling became common about hundred years ago. The first thermometers used were maximum reading mercury meters, which were lowered repeatedly into the well on a line and stopped at one depth in each run. Several runs were therefore needed in order to have a temperature profile for the well.

Temperature sensing electric resistors (thermistors and platinum) became common in logging in the 1950ties for well temperatures up to 150°C. The most primitive method is to hook the sensor with waterproof connection to an electric cable and lower it into the well and measure the electric resistance in the sensor at regular intervals. The resistance measured is converted to temperature using a known from calibration curve

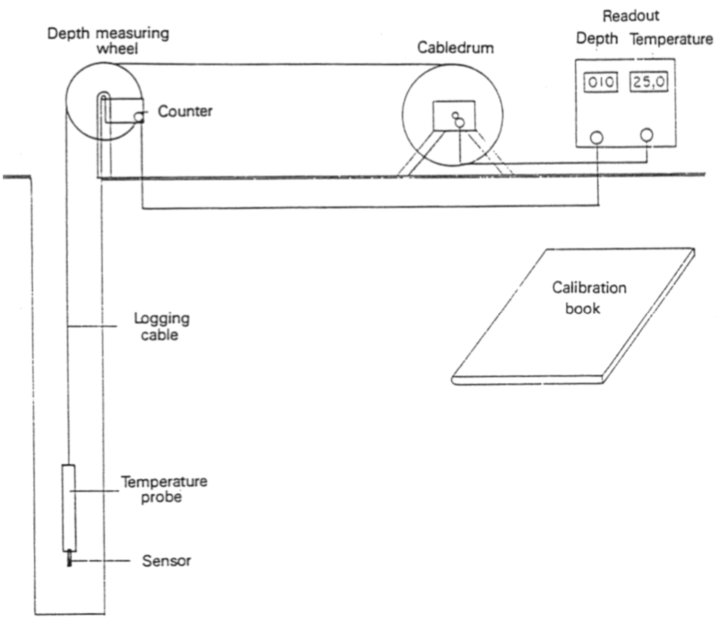

FIGURE 1: Portable temperature logging unit. Typical cable length 100-400 m

correlating the resistance of the sensor to the temperature. Later an electronic package was placed in the logging probe and the information on the temperature (the resistance in the sensor) sent through the logging cable as a pulsed signal where the temperature was given by the pulse frequency. Logging probes using this technique are still used Iceland but only for temperatures below 175°C.

Mechanical temperature and pressure gauges for high temperature use were developed in the oil industry in the 1930ties by an American company Geophysical Research Corporation. These gauges were called Amerada RPG and similar gauges were later produced by the Kuster Company (Kuster KPG). The Amerada temperature gauges sense the wellbore with a bourdon tube containing a special liquid which boils in the tube and build up pressure through a temperature interval (typically 100-300°C). The Kuster gauges used however a bimetal sensor for the temperature determination. Both the Amerada and the Kuster pressure gauges sense the well bore pressures with bourdon tube. The gauges were lowered into the well on a slick-line (steel wireline) and temperature (or pressure) recorded with a pen needle on a carbon coated brass foil inside a clock driven recorder. Several data points (20-30) could be recorded during one run. Typically the measurements were done at 100 m interval from top of the well to bottom. The gauges are robust and fairly reliable with an accuracy of +/- 2°C for temperature and +/-0.2% for pressure. Their limitation is mainly the few number of data point obtained. In modern logging we require data points at a couple of meters interval or so.

FIGURE 2:
K10 Geothermal

The Amerada and Kuster gauges were routinely used in Iceland till 2004 for temperatures up to 380°C.

Since the mid 1980s several high temperature electronic logging tools with surface readout have been developed. This includes tools that measure either temperature or pressure but also combination tools that measure simultaneously temperature and pressure (PT-tools) and even PTS-tools were flow is measured with a spinner. These tools were more like prototypes and their use rather limited in the geothermal industry and we Icelanders never had one. The Kuster Company developed however in the year 2000 an electronic PT gauge which they call K10 Geothermal (www.kusterco.com). The initial version of K10 was a memory tool to be lowered into wells on a slick-line and the data information stored in a memory inside the tool. The down-hole electronics, memory and battery package are encased in a pressure housing and a Dewar flask (heat shield) which protects the electronics from the hot environment for several hours. As an example, the tool can stay in 300°C for 6 hours before the internal temperature reaches the 150°C temperature rating of the electronics. The tool is typically lowered into the well at a speed of 30 m/min (0.5 m/s) and the data is collected into the memory every few seconds or at ~1 meter depth interval compared to every 100 m with the mechanical tool. The accuracy is also far better or +/- 0.5°C for temperature and +/-0.1bar for pressure.

In Iceland we have solely been using the K10 Geothermal tool (PT) in our high temperature wells since 2004 and most geothermal logging companies worldwide have done the same. K10, both PT and PTS, are now available for surface readout. They are, however, mainly used in low temperature wells as wireline logging trucks with high temperature logging cable are rare in geothermal. So today the K10 memory tool from Kuster is the temperature, pressure and spinner combination tools used for geothermal investigation

FIGURE 3: Logging of a high temperature well

3. TEMPERATURE LOGS IN GEOTHEMAL DEVELOPMENT.

3.1. Temperature logs run during the drilling of a well.

Geothermal wells suffer cooling during drilling due to circulation of cold drilling fluids. Fluid losses into permeable fractures intersected by the well will cool the fracture zones and the geothermal reservoir close to the well. Temperature logs are, however, commonly run in wells during drilling for various purposes even though they rarely show the actual formation temperature drilled through. In Iceland and elsewhere it is a standard procedure to log wells at casing depths and when final depth is reached. This includes temperature logs, various geophysical logs and finally, at the end of the drilling process, pressure logs when carrying out multi rate injection test. Each temperature log is evaluated and analysed to obtain information on the well. This includes:

1. Location of aquifers (feed zones) accepting water during injection and their relative size.
2. Cross flow between aquifers is common in very permeable wells with multiple feed zones and it is clearly seen in temperature logs.
3. Measurement of the cooling efficiency for a constant cold water injection on well head and the heating of the well when the injection is stopped. This is important for blow-out risk assessment.
4. Temperature determination prior running other logging tools or drilling equipment into the well, tool with limited temperature tolerance.
5. Monitoring of the temperature recovery at well bottom over a period of few hours up to a day can often be extrapolated to determine the true formation temperature at bottom. This is done at production casing depth to make sure that the production casing penetrates into the geothermal reservoir.
6. Wells that encounter low permeability in the production part are often stimulated to enhance the permaeability using various techniques, including cold water injection on wellhead or

through packers, heating and rapid cooling of the wells and acidizing. Comparison of temperature log before the stimulation will often tell whether the stimulation had any success or not.

Four typical temperature profiles in wells during drilling are shown in Figure 4. It is assumed in the schematics that three feed zones are active in the well. In profile A, water is injected into the well and is lost into the three feed zones. The temperature increases gradually with depth due to conductive heating of the down flowing water from the hot formations around the well. As we pass the first two feed zones the slope of the temperature curve changes slightly as some of water is lost into the feed zone and the continued flow down the well is slower than above the feed zone but the heat conduction rate unchanged. The down flow ends at the deepest feed zone. Often this is the most pronounced feed zone seen in the temperature log showing rapid heating below it. This does, however, not necessarily mean that it is the most permeable zone accepting more water than feed zones above. Profile A is the most common profile for the production part of geothermal wells during injection.

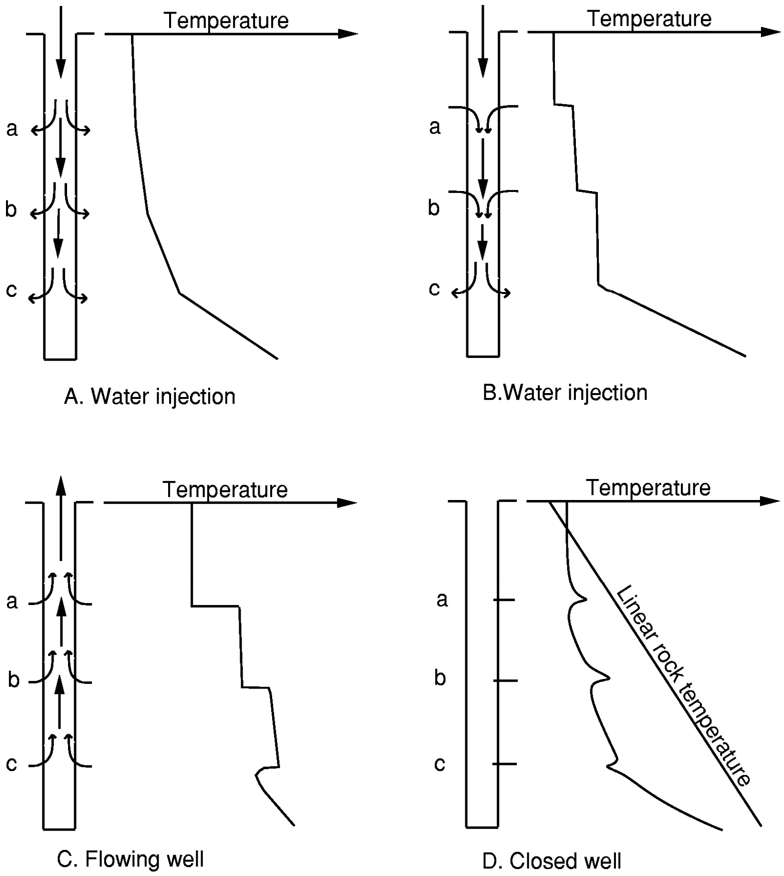

FIGURE 4: Schematic temperature profiles in wells during or just after drilling

Profile B is also measured with injection. It is typical for high permeable wells with multiple feed zones. The temperature log shows temperature steps at the shallow feed zones (a, b) due to inflow of warmer water mixing with the injection. The fluid mixture flows down the well and into the deepest feed zone. All the three feed zones are clearly seen in the log but it should be pointed out that possible outflow zones in the interval between feed b and c can't be excluded due to high flow in the well. Such out flow should show up in the log as a change in slope as in profile A. The reason for the inflow from the uppermost feed zones is the high permeability of the well so the injection into the well is sufficient to lift the pressure above the reservoir pressure at feed a and feed b. Increased injection will increase the pressure in the well an stop the inflow into out flow, first for the deeper feed zone (b) and eventually also feed a at very high injection rates. The temperature profile will then be like profile A. Profile B is therefore more common at low injection rates than high injection rates and for most wells a down flow from shallow to deep feed zones is observed in temperature logs after injection is stopped at the end of drilling and the well starts to heat-up.

An example of temperature logs during injection with inflow from shallow feeds is shown in Figure 5. This well is cased to 780 m and drilled to 1020 m. The figure shows temperature profiles for three injection rates 9.9, 17.8 and 27.1 l/s. The logs show inflows at 820, 950 and 960 m and an outflow very close to bottom. For the highest flow rate the inflow is minimal. The inflow for each fed zone can be evaluated. (1) From the temperature and flow rate above the mixing zone (T_1 and Q_1); (2) the inflow from the feed zone (T_{in} and Q_{in}) and (3) below the mixing zone (Q_2 and T_2).

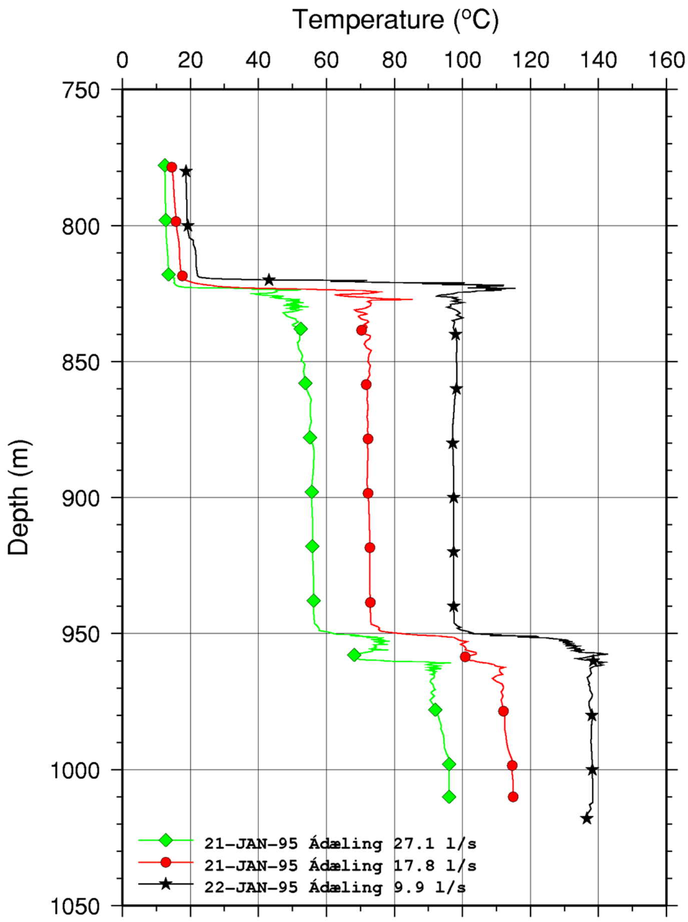

FIGURE 5: Example of a temperature logs during injection (9.9, 17.8 and 27.1 l/s)

The mass balance before and after will be:

$$(1)\quad Q_2 = Q_1 + Q_{in}$$

An energy balance will be:

$$(2)\quad T_2Q_2 = T_1Q_1 + T_{in}Q_{in}$$

assuming constant liquid specific heat capacity. Substitute, rearranging and solving for Q_{in}:

$$(3)\quad Q_{in} = Q_1\ (T_2\text{-}T_1)/(T_{in}\text{-}T2).$$

(In the equations above we have used temperature which is not quit correct as we should have used enthalpy. For liquid flow the temperature is accurate enough for the calculation but if the inflow is, however, two phase or steam only we must use the enthalpy of the flow instead of the temperature.

Exercise: *Look at Figure 5. All the parameters in equation (3) can be read from Figure 6, except Q_{in} and T_{in}. Assume inflow temperature of 200°C at 820 and 950-960m and calculate the inflow, Qin, at the two steps.*

Profile C in Figure 4 is typical for an artesian low temperature well during drilling. Three feeds zones have been intersected and all flow into the well. The inflow temperatures are different from the flowing temperature and therefore there are steps in the temperature profile as the inflow mixes with the well flow. This is similar to the steps in Profile B and if the inflow temperature is known the inflow can be calculated with equation (3). The cooling, below feed zone c is due to cooling during drilling and will disappear as the well heats to the formation temperature.

Profile D in Figure 4 is often seen in wells just after drilling when permeability is low. The well is cooled to bottom and there are some indications of permeability seen as temperature peaks at shallow depth and cooling spots deeper in the well. The permeability is, however, not sufficient to start a massive flow between feed zones. High temperature gradient is seen near bottom where the cooling from the drilling is minimal.

Knowledge of the formation temperature is important during the drilling in order to decide casing depths, as production casing is typically run into temperatures of at least 230°C and also decide the final depth. The most common way to obtain information on the formation temperature is to measure the temperature build up at the bottom of the well during breaks in the drilling, i.e. if the drilling is stopped over night or over a weekend which is common in low temperature drilling in Iceland. The drilling of high temperature wells is, however, a continuous operation and the drilling not stopped for temperature build-up measurements unless absolutely necessary in order to determine the formation temperature at the planned depth for the production casing. Drilling and water circulation is then stopped and the temperature tool run to bottom to monitor the temperature build up for a short period of time typically 12 hours up to 2 days. Various methods have been developed to extrapolate the temperature build-up data at a certain depth (bottom) to formation temperature. In Iceland we use two semi analytical methods, Horner plot and the Albright method. Both methods assume that the heating is controlled by heat conduction and there is now fluid flow in the well at the measuring depth. The latter method is fairly accurate for heating up histories less than 24 hours but the Horner plot usually requires few days of heating up for accurate determination of the formation temperature. Example of Horner plot data will be shown during the presentation.

3.2. Temperature logs after drilling. Estimation of formation temperatures

The heating of geothermal wells after drilling is monitored carefully by regular temperature and pressure logs. The objective is to obtain further information on location of feed zones, to study flow between feed zones and to estimate the size (permeability) of individual feeds. The main objective in analysing the temperature logs after drilling is, however, centre towards the estimation of the temperature of the formations surrounding the well. Low permeability wells will heat slowly over a period of several months as the heating rate is controlled by heat conduction alone and will eventually reach equilibrium temperatures matching the formation temperatures. Example of heating profiles in a low permeable well is shown on Figure 6. The well intersected two warm water aquifers at 175 and 230 m yielding 3 l/s of 25°C water. Cooling zones at 350 and 520 m indicate infiltration of cooling water into the formation but no fluid flow is observed in the temperature logs at these depths and the permeability in the well from 230 m to bottom at 600 m negligible. The well heats rapidly during the first week after drilling and has reached equilibrium temperatures with the formation in the log done six months after drilling. The well was then plugged at 510 m but the formation temperature from there on to bottom can easily be determined using Horner plot or the Albright method. The formation temperature, in the flowing section above 230 m, can, however, not be determined but following constraints are set by the logs.

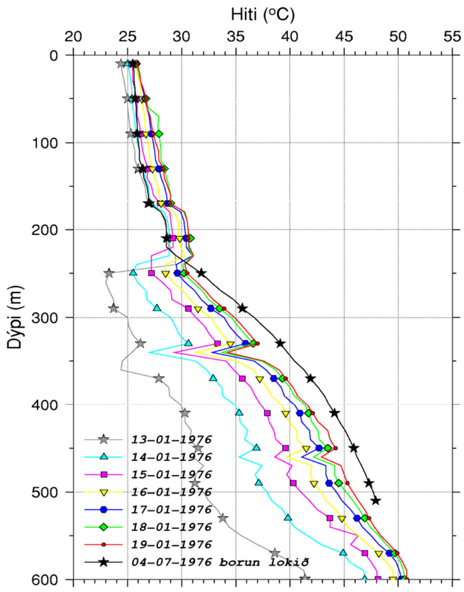

FIGURE 6: Heating profiles for a low temperature well

1. The flowing water cools as it flows upwards the well indicating conductive heat loss. The formation temperature from surface to 230 m depth is therefore lower than the measured temperature in the well.
2. The step in the temperature a 175 m is due to inflow of cooler water at this depth.
3. The surface temperature is expected to be 2°C, the annual mean temperature in the area in Iceland.

Example of temperature logs in a high temperature well is shown in Figure 7. The logs are done over a period of ten years, starting with a log during injection at the end of the drilling process and followed by several logs during two moths heating and after six months flow testing of the well. The logging dates are omitted on the graph. The well is drilled through ground water system into a very hot and deep high temperature reservoir. The ground water system was cased and production casing set at 800 m, before the well was drilled to 1804 m. Analyses of the temperature logs are the following:

1. The log during 25 l/s injection (brown asterix) shows that the injection flows to a feed zone at 1795 m. Inspection of the slope of the curve indicates water losses at 1100-1200 m and at 1300-1500 m.
2. The logs during two months heating period show interzonal flow from feed zones at ~1100 m and 1300-1400 m, to the feed zone at 1795 m.
3. The well was not fully heated after two months, when it was stimulated to flow and flow tested for six months.
4. The logs after the flow testing show consistent temperatures for years and are considered to show the formation temperature curve for the well.
5. Comparison of the temperature and the pressure in the well show that water temperature is below the boiling point at all depths.
6. The change in the profile at 800 m is due to fluid convection at the top of the liner.

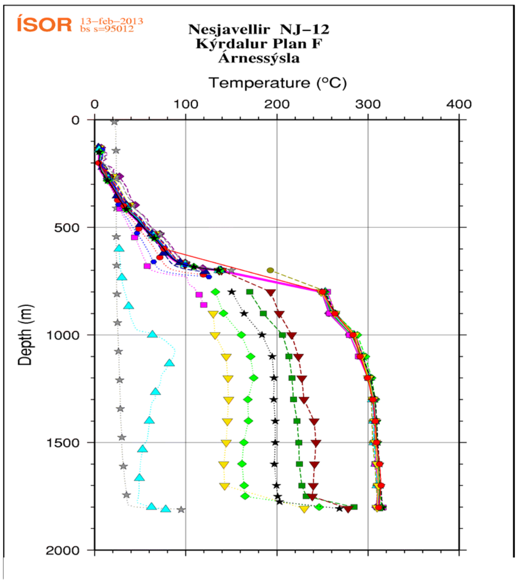

FIGURE 7: Temperature logs in well NJ-12 and formation temperature

The temperature logs in well NJ-12 in Figure 7 define fairly accurately the formation temperature at all depths in the well. It should though be emphasized that the estimation of formation temperature for geothermal wells is often more difficult than in the examples in Figures 6 and 7. The most difficult cases are high temperature wells where massive internal flow and boiling in the wells controls the temperature conditions in the well, even though the well is shut in. To interpret the temperature profiles in such wells can be difficult if not impossible.

The procedure applied in Iceland for estimating formation temperature is to collect all available temperature logs from the well under study and group them into logs during drilling, during heating after drilling, during flow test and production and monitoring logs. Analyse each group of logs and plot them. For high temperature wells the boiling point depth curve (BPD-curve) is often plotted as a reference as this curve defines the maximum possible formation temperature for the hydrothermal system. If the temperature logs do not define accurately the formation temperature further analyses, interpretation, assumptions or pure guesses are necessary in order to estimate the formation temperature for the well. The main steps in the analyses are as follows:

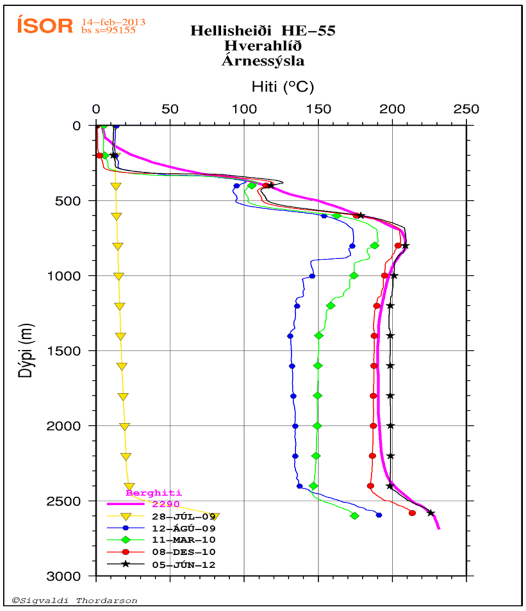

FIGURE 8: Formation temperature in a well with internal down flow

1) Select logs carried out with the well shut-in and determine what processes in the well are screening away the formation temperature. Interzonal flow is common in permeable wells and screens out the formation temperature

from the shallowest feed zone in the production part of the well to the deepest feed. Boiling in very high temperature wells is also common and rising steam bubbles from the boiling region deep in the well will heat the water column higher up in the well as the steam condenses and eventually creates a high pressure and high temperature steam (and gas) cap in the top section of the well suppressing the water level several hundreds of meters into the well.

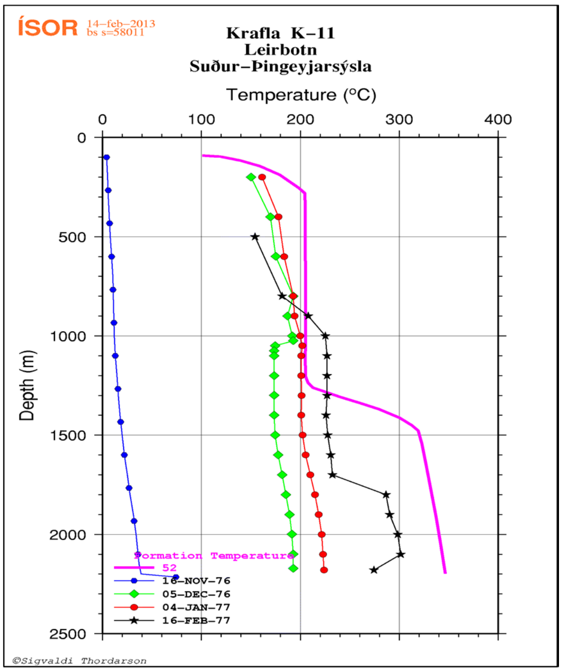

FIGURE 9: Temperature logs and formation temperature in KJ-11

2) If internal flow controls the well's temperatures, estimate the formation temperature of sections of the well which are not disturbed by the internal flow i.e. up in the casing and down to the upper most feed zone and in the bottom section below the deepest feed zone. This can be done from logs during heating after drilling, using Horner plot or other extrapolation methods or using the actual measured temperature for these sections when the well has fully recovered after drilling (Figure 8). Connecting the formation temperature curve across the internal flow section can only be done roughly. Steps in the temperature logs (inflow) and the slope of the curve are indicative whether the formation temperature is higher or lower than the measured temperature in the flow section. Analyses of the temperature logs in HE-55 in Figure 8 indicate that the interzonal flow is a down flow from 900 to 2400 m. Minor cooler inflows into the well from 1000 to 1400 m and a small negative slope suggests that the formation temperature is slightly lower than the most resent log. We therefore suggest the pink profile in Figure 8 is a reasonable estimate for a smooth formation temperature curve for well HE-55 from available data. A temperature log during flow or just after a well is being shut-in after flow, often helps analysing the internal flow sections. Well HE-55 is not productive and has never been flow tested. Another example of a down flow in a high temperature well is shown in Figure 9. The logs show down flow in the well from a feed zone at ~1200 m to the bottom of the well. The true temperature of the bottom region of the well can't be estimated from the heat up logs (green and red curves in Figure 9) but positive slope indicates that it is higher than the well temperatures. The well was flow tested. The initial discharge enthalpy corresponded to water temperatures of ~200°C, in good agreement with the well temperatures before the discharge but after 10-12 hours discharge the bottom feed zone kicked in and the fluid enthalpy rose from 850 to over 2000 kJ/kg indicating very high temperature inflow from the bottom feed zone. It was not possible to run a temperature tool into the well during discharge but a temperature log just after the well was shut-in (black profile in Figure 9) showed temperatures up to 300°C. This temperature value was, however, transient as the down flow from 1100 m starts immediately when the well is closed and pushes the hot fluid back into the bottom feed zone. The log just after discharge confirmed similar formation temperature profile for KJ-11 as for other wells in the Leirbotnar area in Krafla. The profile is shown in Figure 9 as pink line. It shows the existence of a shallow ~200°C hot convective reservoir zone down to ~1200 m and a deeper boiling reservoir from there on to the 2200 m at least, where the temperature rises from ~200°C at 1200 m to 300°C at 1400 m from there on to 345°C, at bottom.
3) High temperature wells often develop during heating after drilling high pressures on wellhead with steam/gas extending from the wellhead and several hundreds of meters down the well. The steam zone temperature is then dictated by the pressure in the steam zone as the boiling point

temperature at that pressure. The steam zone is maintained by continuous boiling and degassing deeper in the well. The temperature in the upper part can often be estimated from temperature logs during drilling, for example by analysing logs done at casing depth but also from the first logs during heating before the well comes under pressure and the steam cap develops. The formation temperature below the boiling steam/gas cap be estimated from Horner plots or other extrapolation methods or directly from temperature logs carried out after the well has fully stabilized in temperature. Examples of temperature logs in a high temperature well under pressure are shown in Figure 10. This is well ÞG-3 at Þeistareykir in north Iceland. The well heated rapidly after drilling in 2006. A log at first casing depth measured on August 23rd suggested very high temperatures close to surface. The first logs during heating after drilling confirmed this and suggested boiling formation temperatures from surface down to at least 700 m. The well came under pressure and developed a steam cap of up to 55 bar pressure and 270°C temperature from the wellhead down to more than one km depth in the well. This steam cap screens out the formation temperature in this interval but the formation controls the temperature below the steam cap. In the case of well ÞG-3, stabilized temperature logs exist as seen in Figure 10. The estimated formation temperature curve is shown in the figure. It is actually made of two boiling point curve corresponding to two boiling reservoir zones. A shallow boiling zone with water level close to surface or even slightly over-pressured, extending to ~700 m depth and a deeper reservoir zone extending to 2.5 or 3 km. The temperature in the deeper zone is also a boiling point curve but the deep reservoir pressures potential is about 20 bar lower than the pressure potential of the upper zone.

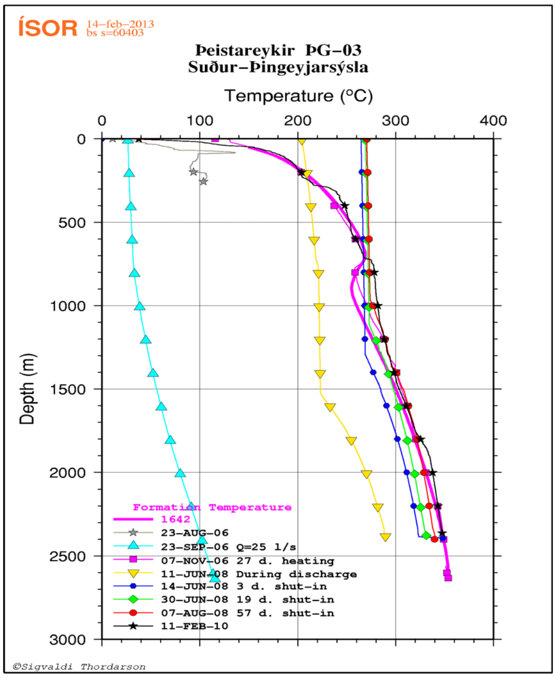

FIGURE 10: Temperature logs and formation temperature for well ÞG-3

We have discussed and showed few examples on how formation temperatures are estimated from temperature logs. We should, however, remember that indications on the formation temperature indications are available from other studies of geothermal wells. The geologists investigate the thermal alteration of the formation from studies of the drill cuttings and cores and define a formation temperature profile based on the alteration minerals seen in the samples. Fluid inclusion studies are also important method to study formation temperatures and finally the geochemists estimate reservoir temperatures based on the chemical content of the reservoir fluid using various geothermometers. These results should be considered in conjunction with the temperature logs when formation temperatures ate estimated.

The temperature distribution in geothermal systems is determined by heat and fluid flow (water and steam) through the system. To understand how the system works and set up a conceptual model it is imperative to map the reservoir temperature as accurately as possible. The estimation of the formation temperature is the first step in this direction. Figure 11 shows various types of formation temperature curves in some geothermal wells in Iceland. Each type tells a story on fluid flow conditions in the vicinity of the wells:

1. **Linear profiles** as seen in Figure 11 (Vestmannaeyjar, Þorlakshöfn and Akranes) indicate little or no vertical fluid flow in a low permeability formation. The heat transfer is dominated by heat conduction and the slope of the temperature log, called the geothermal gradient, is determined by the heat conductivity of the formation and the heat flux through

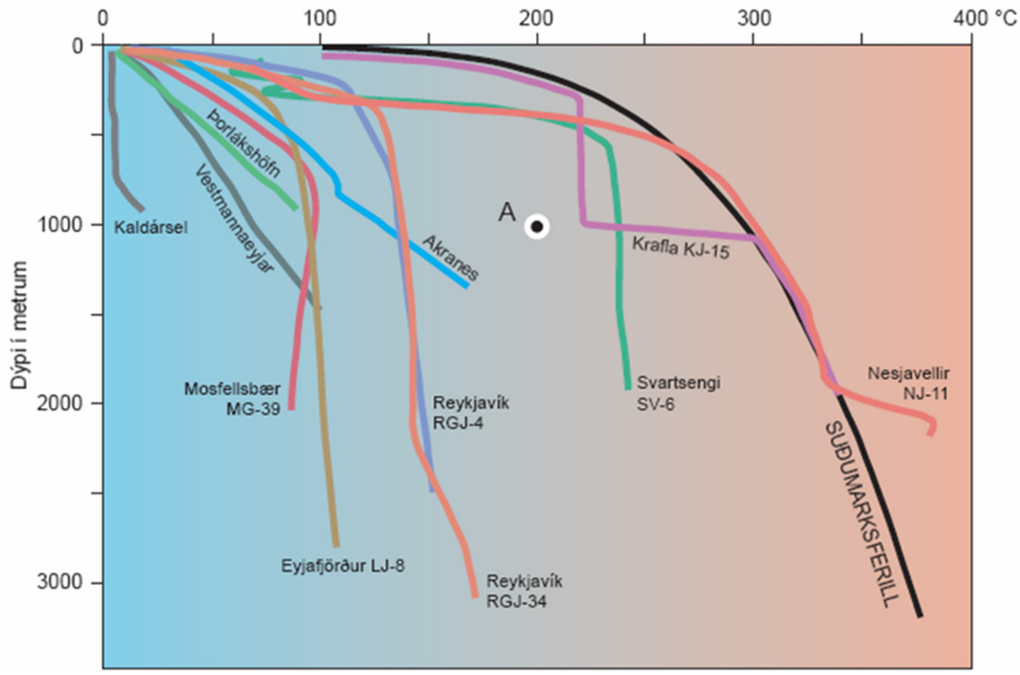

FIGURE 11: Various formation temperature profiles for Icelandic geothermal wells. The black curve is the BPD-curve and the point A on the graph is set at 200°C at 1 km depth, which distinguishes between high and low temperature systems

the crust upward to the surface at the location of the well. The average geothermal gradient in the shallowest part of the Earth's crust is 30°C/km. The gradient of the three linear logs in Figure 11 are much higher or 60 to 140°C/km which is much higher than the world average due to much higher heat flux from volcanic active regions in Iceland.

2. Isothermal formation temperature profiles are found in regions of deep infiltration, circulation, convection, of the fluids. The Kaldársel well is located in a volcanic fracture zone where meteoric water infiltrate to great depths whereas in wells, in Eyjafjörður, Reykjavík and Svartsengi, hydrothermal convection dominates the heat transfer as the fluid mines the heat down to several kilometres depth and pump it up towards the surface. These systems are fractured and their vertical permeability is high. The isothermal formation profiles are typical for all major liquid dominated geothermal reservoirs for temperatures up to 250°C. The steam dominated systems are also isothermal and most of them have a reservoir temperature of 240°C and reservoir pressure of 35 bar.
3. Boiling formation temperature profiles are common in geothermal system with reservoir temperatures in the range of 300°C. These reservoirs are fractured and highly permeable so the heat transfer is dominated by fluid convection and up flow of steam.
4. Temperature reversals are sometimes seen in formation temperature curves (well MG-39 in Figure 11). This is usually explained to be due to horizontal or tilted flow of hot water in the underground. This could be up-flow along a non-vertical fracture or that the well is located in the outflow zone of a geothermal reservoir. Temperature reversal is also seen in cold recharge zones to geothermal reservoirs. This is the explanation to the reversal in well MG-39 and other well sin that area.

3.3 Temperature maps of geothermal reservoirs

In the preceding chapters we have discussed temperature logs in geothermal wells and how they are analyzed to obtain formation temperature profiles. Plotting these data in a plan view or a section and drawing isothermal contours produces a map showing how the temperature varies within the reservoir and at the reservoir boundary areas. Such maps indicate location of conductive and convective zones inside the geothermal system and divide it into recharge areas, upflow zones and out flow areas. The formation temperatures maps, drawn before any exploitation starts from the reservoir, define the natural thermal state of the reservoir but maps based on temperature data from reservoir under exploitation will reveal temperature changes caused by the production through pressure drawdown, induced fluid recharge and boiling. Temperature maps are very important in the development of conceptual models of geothermal reservoirs. Several examples of temperature maps and cross sections will be shown during presentations at the Short Course but to conclude the discussion here a temperature cross section for the Krafla field in Iceland is shown in Figure 12.

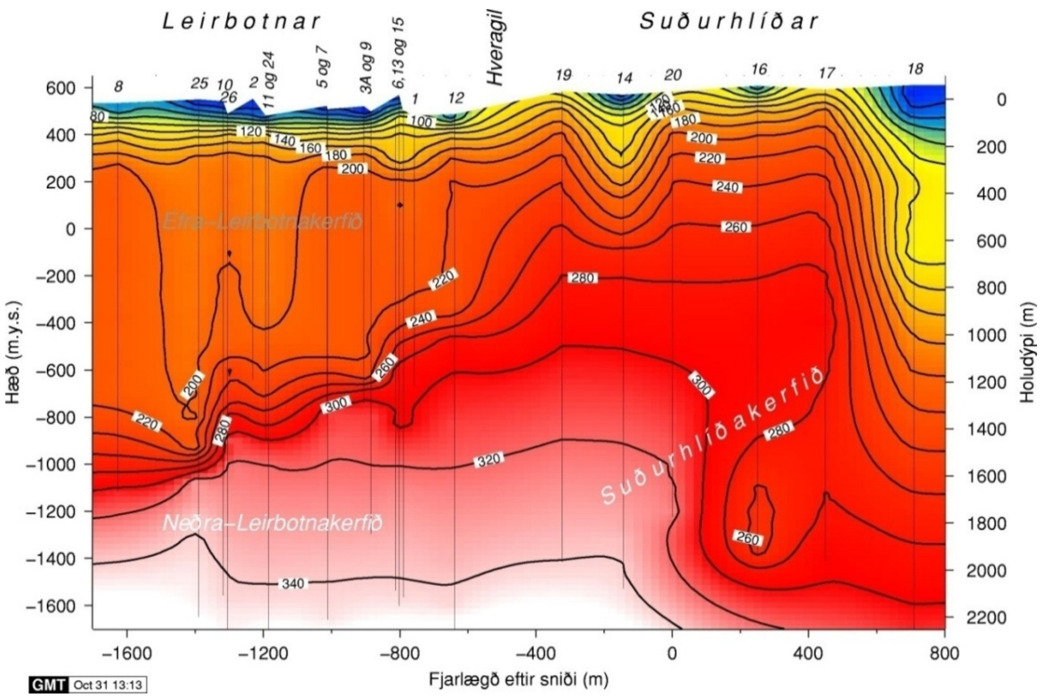

FIGURE 12: West to East Temperature Cross Section for the Krafla field

4. PRESSURE LOGS

4.1 Introduction

Pressure is an essential parameter in geothermal reservoir studies. It is a property that is tied directly to the fluid. Global pressure variations in the reservoir are the driving force for fluid flow and time variations of the pressure reflect changes in the flow pattern and the fluid reserve of the reservoir. Fluid production/injection will change reservoir pressures in time. Monitoring of reservoir pressures is therefore important to estimate the response of the reservoir to utilization.

Pressure is a readily measured parameter and pressure logging is an important tool in geothermal exploration. The logging is carried out in order to study well conditions (fluid flow, boiling etc.), in order to map reservoir pressures and to study transient pressure variations due to fluid injection or production and monitoring of long term pressure changes due to exploitation.

4.2 Pressure in boreholes.

The pressure gradient in a flowing geothermal well will change with depth (z direction) according to the following equation:

$$dP/dz = (dp/dz)_{friction} + (dP/dz)_{acceleration} + (dP/dz)_{hydrostatic} \tag{4}$$

If there is no fluid flow in the well the first two terms are zero and the pressure gradient becomes only the hydrostatic (gravity dependent) term or:

$$dP/dz = (dP/dz)_{hydrostatic} = \rho g \tag{5}$$

where ρ is the density of the fluid (water/steam) and g is earth's gravitational acceleration.

The fluid column in geothermal wells consists of liquid, steam gas and air, media with very different density. The density of each phase will also change with temperature. If, however, we assume isothermal conditions in the well equation can be solved the result being:

(6a) $P(z) = P_0 + \rho g z$ for liquid full well with pressure P_0 on the wellhead.

or

(6b) $P(z) = \rho g(z-z_0)$ for well fluid level at depth z_0 below the wellhead.

The pressure profile of a geothermal well is commonly measured using mechanical Kuster tool or K10 gauges. A hydrostatic calculation of the pressures profile can though be integrated from equation (5) if the temperature dependent density profile of the well is known.

There is distinguished between several type of wells depending on their pressure and phase conditions. The main types of static (no-flowing) wells are:

(1) Artesian wells: Liquid water wells with wellhead pressure. These wells will flow spontaneously when opened.
(2) Non Artesian wells (dead wells): Liquid water wells with down-hole water level.
(3) Pressurized high temperature wells: Pressure as high as 80 bar on wellhead and steam/gas cap in the well to a certain depth and water from thereon to bottom. Boiling and degassing at depth maintains the steam/gas cap. The temperature in the cap will be the boiling temperature of water at the cap's pressure if this is pure steam but lower if the gas fraction increases.
(4) Steam wells: Wells full of steam from top to bottom. Due to the very low density of the steam phase the pressure at bottom is only slightly higher than the wellhead pressure.

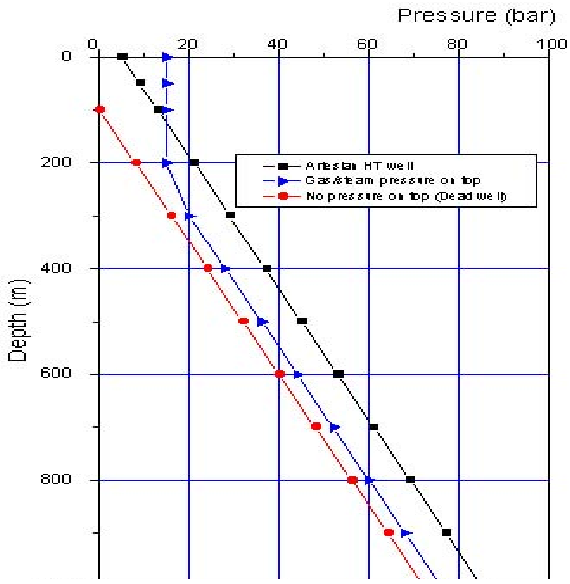

FIGURE 13: Types of pressure profiles in geothermal wells

Figure 13 shows examples of Artesian and Non-Artesian pressure profiles together with pressure profile in a well with steam/gas cap in the uppermost 200 m of the well.

The pressure gradient in a static (no-flow) well is controlled by the fluid density, which varies with temperature. The hydrological connection between a geothermal well and the geothermal reservoir is through the feed zones (fractures) intersected by the well. During the drilling operation with water circulation, injection or production the well pressures are varied and controlled by the operators but when the operation is stopped and the well shut-in the pressure in the well changes towards equilibrium with reservoir pressure. In the ideal case of a well with only one feed zone, the pressure at the feed zone depth will change and become equal to the reservoir pressure in short period of time with no flow between the well and the reservoir. The pressure in wells with multiple feed zones will also change towards equilibrium with the reservoir pressure when the well is shut-in after the drilling. The water temperature in the well at the end of drilling and therefore the hydrostatic pressure gradient are different than the temperature and the hydrostatic pressure gradient in the reservoir. This means that the well's pressure can't find equilibrium in a way that the pressure matches the reservoir pressure at each feed zone. Usually one feed zone will dominate and therefore the equilibrium point will be close to the "best" feed zone. The mismatch between the temperature and the pressure inside the well and the reservoir pressure will therefore lead to fluid flow between the well and the reservoir. As the well temperatures are, at the end of drilling, always lower than reservoir temperatures the hydrostatic gradient will be higher in the well than in the reservoir. As the cold water column in the well adjusts towards equilibrium with feed zones reservoir pressures the well pressure become lower than the reservoir pressure at the shallower feed zones and higher at the deeper feed zones. This will lead to flow into the well through shallower feed zones and down the well to the deeper feed zones. This is what is called interzonal flow and is seen in all high temperature wells with multiple feed zones. The flow can easily be of the order of tens of l/s in wells with many high permeable feed zones. Example of this is well ÖJ-1 in Figure 5 where the interzonal flow was prominent even during cold water injection into the well.

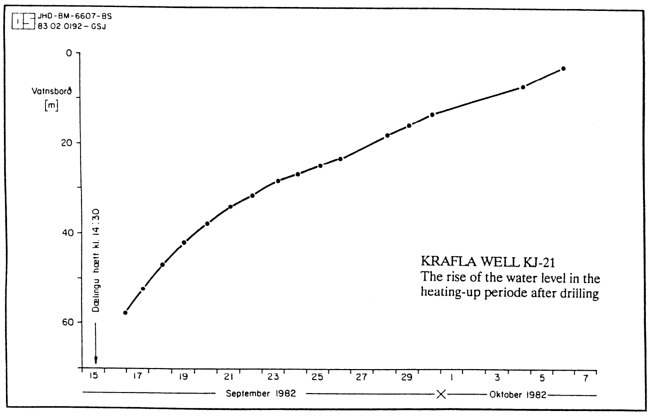

FIGURE 14: Rising of water level in KJ-21 in Krafla during heating after drilling

The first response of the well after shut-in after drilling is pressure equilibrium between the well and the reservoir. This usually takes few days. At the same time the well bore fluid heats up accompanied by changes in fluid density. The pressure at the "best" feed zone is, however, fixed at the reservoir pressure. The water column in the well will therefore expand resulting in rising of the water level in the well during the heating and the pressure profiles measured in the well in the heating period will pivot about the depth of the "best" feed zone.

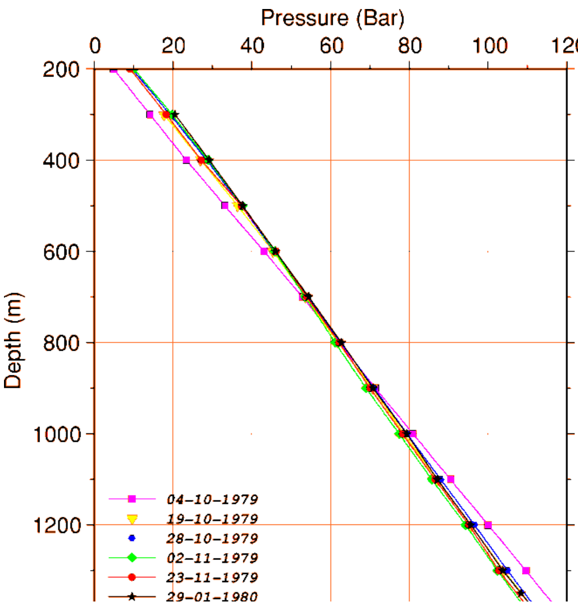

FIGURE 15: Pivot point in pressure logs during heating

Example of the rise in water level in a high temperature well during heating up period is shown in Figure 14 where the water level was at 90 m depth after drilling but rose almost to surface during three weeks of heating.

Information on the feed zones of a well and their relative size is found in the drilling records on circulation losses and gains and in flow meter surveys done during injection and production and last but not least in temperature logs done at the end of drilling, during heating after drilling and during production test. Most wells have several feed zones and in that case, the pivot point is between the feeds, typically closest to the best feed zone. The pivot point is therefore an indicator of the location of best (most permeable) feed zone in wells and determines the reservoir pressure at that depth. Figure 15 show several pressure logs during heating of a well after drilling. The pivot point is at about 800 m and the reservoir pressure at that depth is 62 bars.

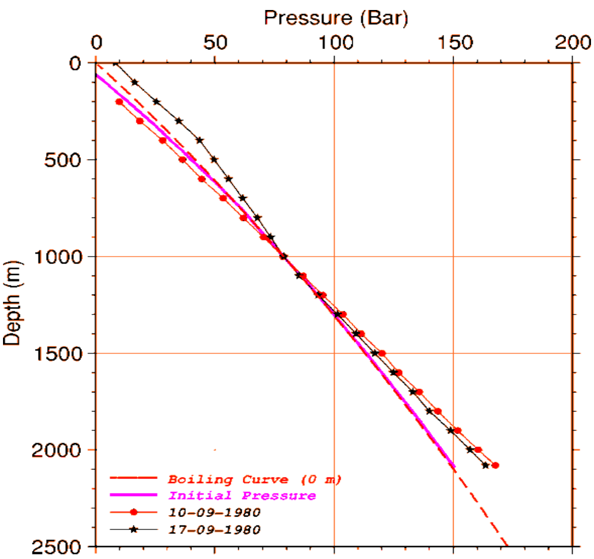

FIGURE 16: Reservoir pressure curve estimated from the pivot point using hydrostatic extrapolation

6.3. Reservoir pressures.

The pivot point, in pressure logs during heating after drilling, determines the reservoir pressure at that specific depth. The next step in the pressure log analyses is to determine or estimate the reservoir pressure profile for the well. This pressure profile can be measured in the well if the temperature profile at the end of the heating period is identical to the formation (reservoir) temperature. That is, however, rare in high temperature wells due to inter zonal flow and boiling. The reservoir pressure profile for the well can then be estimated by hydrostatic extrapolation from the pivot point depth pressure value using the formation temperature curve for the well to determine the water density as a function of depth. Figure 16 shows pressure log from well KJ-14 in Krafla which was drilled in 1980. The pivot point in the well during heating was at 1200 m and the pivot point pressure was 90 bar. The pink curve is the estimated reservoir (initial) pressure based on hydrostatic extrapolation but the red curve is the boiling point depth pressure curve with water level at surface.

Estimating the reservoir pressure profile for all wells in the same field is an important step in comparing the pressure values in different wells and different depths and visualizing the pressure distribution in the reservoir.

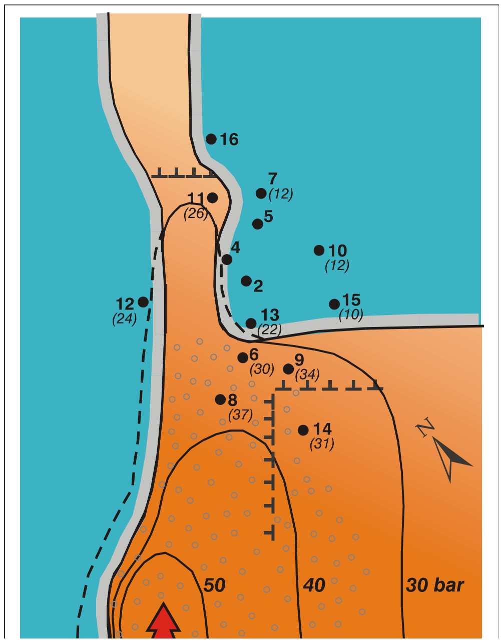

FIGURE 17: The Nesjavellir Geothermal Field. Pressure map at sea level (~200 m depth)

6.4 Pressure maps.

Estimating the reservoir pressure profile for all wells in the same field is an important step in comparing the pressure values in different wells and at different depths and visualizing the pressure distribution in the reservoir. The data are plotted in a similar manner as the formation temperature data i.e. in plan views and cross sections and iso- pressure contours drawn to produce maps showing how the pressures vary within the reservoir. These maps will indicate fluid flow directions in the reservoir in the natural state prior to exploitation and after exploitation starts the pressure maps will show pressure drawdown in the reservoir. Figure 17 shows simulated pressure map for the Nesjavellir field in the natural state. The figure shows high pressures in the recharge zone (upflow-zone) and declining pressures towards north east. Well locations are shown as black dots and well pressures at sea level depth are given in parenthesis. Several example pressure maps will be shown during the presentations at the "Short Course".

7. CONCLUDING REMARKS AND RECCOMENDED LITTERATURE

This paper has presented a brief description of geothermal well logging for temperature and pressure and the most common interpretation methods. Few general textbooks are available on the subject. The best reference book is probably *Geothermal Reservoir Engineering by Malcolm A. Grant and Paul F Bixley.* The first edition of the book was published by Academic Press in 1982 but a revised second edition became available 2011. Another booklet is "*Geothermal Logging, An Introduction to Techniques and Interpretation",* which was published in Iceland in 1980 and has been used in the annual introductory course at UNU for years. These books are recommended to the participant in the Short Course for further studies of temperature and pressure logs.

Presented at "Short Course V on Conceptual Modelling of Geothermal Systems",
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UNITED NATIONS UNIVERSITY
GEOTHERMAL TRAINING PROGRAMME

LaGeo S.A. de C.V.

GEOTHERMAL WELL TESTING

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ABSTRACT

Geothermal wells are fundamental components in geothermal research and utilization and improved understanding of geothermal systems during the last century coincided with geothermal wells becoming the main instruments of geothermal development. Geothermal wells provide access deep into the systems, not otherwise possible, which enables a multitude of direct testing and measurements of conditions at depth. The testing made possible through wells includes well testing, one of the main tools of geothermal reservoir physics/engineering. Through well testing and consequent pressure transient analysis the main reservoir parameters, such as permeability and storativity, can be estimated along with reservoir boundary conditions, if a test is sufficiently long-lasting. Such estimates consequently provide key information for conceptual model development. Pressure transient analysis is performed on the basis of appropriate reservoir models, often the well-known Theis model, and involves in fact model simulation of the pressure transient data collected. Well tests range from very short step-rate injection or production tests, via longer production (discharge or pumping), pressure build-up and interference tests to long-term (months – years) reservoir testing, often involving several wells. Tracer testing, also a kind of well testing, is the most important tool for the purpose of assessing the danger of production well cooling during long-term reinjection, if combined with comprehensive interpretation and cooling predictions (reinjection modelling).

1. INTRODUCTION

Wells or boreholes are vital components in both geothermal research and utilization, since they provide essential access for both energy extraction and information collection. The breakthrough of increased geothermal utilization and improved understanding of geothermal systems during last century coincided in fact with geothermal wells becoming the main instruments of geothermal development. Wells enable a drastic increase in geothermal energy production, compared to natural out-flow, and provide access deep into the systems, not otherwise possible. As the latter they can provide much more detailed and specific information than the various surface exploration methods, information which is fundamental for conceptual model development and revision (the subject matter of this short course), once they become available.

Geothermal wells play a variable role during both development of a geothermal resource and during their utilization. The main roles are either as temperature gradient, exploration, appraisal, production, step-out, make-up, reinjection or monitoring wells. Wells also play an essential role in all geothermal reservoir physics (or reservoir engineering) research. Such research would be particularly ineffective without the access into geothermal systems wells provide. Geothermal reservoir physics is the scientific discipline that deals with mass and energy transfer in geothermal systems and geothermal wells. It attempts to understand and quantify this flow along with accompanying changes in reservoir conditions, in particular those caused by exploitation, mainly through applying different modelling techniques (Axelsson, 2013). During the exploration stage of a geothermal resource research focuses on analysis of surface exploration data; mainly geological, geophysical and geochemical data (Axelsson and Franzson, 2012). This emphasis changes to reservoir physics research during development and utilization, with geothermal reservoir physics e.g. having the potential to play a key role in geothermal resource management.

The purpose of geothermal reservoir physics is, in fact, twofold: To obtain information on the nature, reservoir properties and physical conditions in a geothermal system and to use this information to predict the response of reservoirs and wells to exploitation. Based on the latter the energy production capacity of a geothermal resource can be assessed. Response predictions also aid in the different aspect of the management of geothermal resources during utilization (Axelsson, 2008). Geothermal reservoir physics emerged as a separate scientific discipline in the 1970s even though some isolated studies of the physics of geothermal systems had been conducted before that in countries like Iceland, New Zealand and the USA (Grant et al., 1982). Geothermal reservoir engineering, as well as geothermal technology in general, draws heavily from the theory of ground water flow and petroleum reservoir engineering, the former having emerged in the 1930’s. However, geothermal reservoirs are in general considerably more complex than ground-water systems or petroleum reservoirs. The different aspects of geothermal reservoir physics are e.g. discussed by Bödvarsson and Witherspoon (1989), Grant and Bixley (2011) and Axelsson (2012).

The testing made possible through wells includes well testing, one of the main tools of geothermal reservoir physics. It is more correctly called pressure transient testing because it involves disturbing the pressure state of a reservoir, through mass extraction or injection, and observing the resulting pressure transients. Through well testing and consequent pressure transient analysis the main reservoir parameters can be estimated along with reservoir boundary conditions. Such estimates consequently provide key information for conceptual model development. Pressure transient analysis is performed on the basis of appropriate reservoir models. Well tests range from very short step-rate injection or production tests, via longer production (discharge or pumping), pressure build-up and interference tests to long-term (months – years) reservoir testing, often involving several wells.

Tracer testing, which is also a kind of well testing, yet not pressure transient testing, is the most important tool to study the connections between reinjection wells and production wells and to assess the danger of production well cooling during long-term reinjection, if combined with comprehensive interpretation and cooling predictions (reinjection modelling).

This paper starts out by reviewing the different types of geothermal wells, as background information. After that it discusses the main methods of pressure transient well testing used during geothermal research and development, along with other reservoir research conducted through wells, and consequently the main pressure transient analysis methods. Subsequently the paper discusses briefly the application of tracer testing in reinjection research and their subsequent analysis. The paper is concluded by general conclusions and recommendations.

2. GEOTHERMAL WELLS

2.1 General

Wells or boreholes are vital components in both geothermal research and utilization, since they provide essential access for both energy extraction and information collection, as already mentioned. Deep geothermal drilling didn’t really commence on a large scale until the middle of the 20th century even though some geothermal drilling had already started a century before that. Deep (150–200 m) geothermal drilling started in Larderello, Italy, in 1856 (Grant and Bixley, 2011) and the first deep (~970m) geothermal well in Hungary was drilled in Budapest from 1868 to 1878 (Szanyi and Kovács, 2010).

The design, drilling and construction of geothermal wells are discussed in the geothermal literature, e.g. in the proceedings of a short course held by UNU-GTP and LaGeo in San Salvador in March 2012 (see http://www.unugtp.is/page/sc-14/). Sarmiento (2007) discusses drilling practises in The Philippines in particular, where extensive experience has accumulated during the countries extensive geothermal development. Typically the upper parts of a geothermal well are closed off by a series of casings; to stabilize the well, to close off non-geothermal hydrological systems and for safety reasons. The deeper parts of the well are either fully open or cased with a so-called liner, which is not cemented in place but perforated in selected intervals, to allow fluid (water and/or steam) to flow from the reservoir into the well. The most significant difference between geothermal and petroleum wells are the following:

(i) Geothermal wells are most often drilled in hard, igneous rocks, which are more difficult to drill than the sedimentary environment of petroleum wells.
(ii) The open production sections of geothermal wells are quite long in comparison with those of petroleum wells, ranging from a few hundred metres to more than 2 km.
(iii) Yet geothermal wells usually have some discrete in-flow sections (feed-zones, see below).
(iv) Geothermal wells often encounter high temperatures and pressures, sometimes associated with blow-out danger due to explosive boiling.
(v) Water is commonly used as drilling fluid for open sections in contrast with drilling mud most commonly used in petroleum wells to avoid clogging any feed-zones (also reduced pollution danger).
(vi) The drilling of successful geothermal wells often involves large, or even total, circulation losses.
(vii) Geothermal production wells are generally of larger diameter (up to a few tens of cm's) than petroleum wells, because of greater flow-rates involved.

Grant and Bixley (2011) discuss some of these in more detail.

A geothermal well is connected to the geothermal reservoir through feed-zones of the open section or intervals. The feed-zones are either particular open fractures or permeable aquifer layers. In volcanic rocks the feed-zones are often fractures or permeable layers such as interbeds (layers in-between different rock formations) while in sedimentary systems the feed-zones are most commonly associated with a series of thin aquifer layers or thicker permeable formations. Yet fractures can also play a role in sedimentary systems. In some instances a well is connected to a reservoir through a single feed-zone while in other cases several feed-zones may exist in the open section, but often one of these is the dominant one.

Geothermal wells can be classified as one of three principal types:

(a) liquid-phase low-temperature wells, which produce liquid water at well-head (pressure may be higher than atmospheric, however),
(b) two-phase high-temperature wells where the flow from the feed-zone(s) is liquid or two-phase and the wells produce either a two-phase mixture or dry-steam or
(c) dry-steam high-temperature wells where the flow from the feed-zone(s) to the well-head is steam-dominated.

In the liquid-phase and dry-steam wells the inflow is single phase liquid water or steam, respectively, while two-phase wells can be furthermore classified as either liquid or two-phase inflow wells. In multi feed-zone two-phase wells one feed-zone can even be single-phase while another one is two-phase.

In general the productivity of geothermal wells is a complex function of:

(1) well-bore parameters such as diameter, friction factors, feed-zone depth and more,
(2) feed-zone temperature and enthalpy,
(3) feed-zone pressure, which depends directly on reservoir pressure and reservoir permeability,
(4) well-head pressure or depth to water level during production and
(5) temperature conditions around the well.

Most of these parameters can be assumed approximately constant for reservoirs under production, except for the reservoir pressure (3), which varies with time and the overall mass-extraction from the reservoir. The feed-zone temperature and enthalpy may also vary with time in some cases, albeit usually more slowly than reservoir pressure. Axelsson and Steingrímsson (2012) discuss the multidisciplinary research conducted during drilling, testing and monitoring of geothermal wells, research not discussed here.

Finally it should be mentioned that geothermal wells are often stimulated following drilling, either to recover permeability reduced by the drilling operation itself, to enhance lower than expected near-well permeability or to open up connections to permeable structures not directly intersected by the well in question. Axelsson and Thórhallsson (2009) review the main methods of geothermal well stimulation with emphasis on methods applied successfully in Iceland. The methods most commonly used involve applying high-pressure water injection, sometimes through open-hole packers, or intermittent cold water injection with the purpose of thermal shocking. Stimulation operations commonly last a few days while sometimes stimulation operations have been conducted for some months. The stimulation operations often result in well productivity (or injectivity) being improved by a factor of 2-3.

2.2 Types of geothermal wells

The different types of geothermal wells are listed and described briefly below (see Axelsson and Franzson, 2012):

(1) **Temperature gradient wells** are generally both slim and quite shallow, most often only around 50 m in depth, even though in some instances they may reach a few hundred metres depth. Their main purpose is to study shallow temperature conditions (temperature gradient) and estimate heat flow. In contrast with other geothermal wells temperature gradient drilling can in fact be classified as a surface exploration tool.
(2) **Exploration wells** are deeper wells intended to extend into the geothermal system being explored, i.e. to reach a specific target. Their main purpose is to study temperature conditions, permeability and chemical conditions of the target. Exploration wells are either so-called slim wells with diameter < 15 cm, which are drilled for the sole purpose of exploring conditions at the target depth, or exploration wells designed as production wells (full diameter wells). The former can be used to estimate the capacity of production wells later drilled to reach the same target(s). The latter can later be converted to production wells, however, if successful.
(3) **Production wells** are wells drilled with the sole purpose of enabling production of geothermal energy (as hot liquid, two-phase mixture or steam) from a specific target, or a geothermal reservoir. Their design is of paramount importance, e.g. the casing program applied. Production wells are either designed for spontaneous discharge through boiling (high-temperature reservoirs) or for the application of down-hole pumps (lower temperature reservoirs).
(4) **Step-out wells** are either exploration or production wells drilled to investigate the extent, of a geothermal reservoir already confirmed. A step-out well either approaches the edge, or boundary, of a reservoir or is drilled beyond it. A number of step-out wells in different directions may be required if a given reservoir is extensive in area.
(5) **Make-up wells** are production wells drilled inside an already confirmed reservoir, which is being utilized for energy production, to make up for production wells which are either lost

through damage of some kind (collapse, scaling, etc.) or to make up for declining capacity of wells.

(6) **Reinjection wells** are used to return energy-depleted fluid back into the geothermal system in question or even to inject water of a different origin as supplemental recharge. The location of reinjection wells is variable as reinjection can either be applied inside a production reservoir, on its periphery, above or below it or outside the main production field, depending on conditions and the purpose of the reinjection.

(7) **Monitoring wells** are used to monitor changes in geothermal systems, mainly after utilization starts, mostly pressure and temperature changes. These are in most cases already existing wells, such as exploration wells or abandoned production wells. Active production wells are sometimes used for monitoring purposes (chemical content, temperature and pressure). Carefully designed and comprehensive monitoring is the key to successful management of geothermal resources during utilization.

(8) **Unconventional wells** are either wells of unconventional design or wells drilled into parts of geothermal systems generally not used for energy production. Examples are wells that are deeper than normal, well drilled into magma or wells drilled into supercritical conditions.

The different types of wells play a role during different stages of geothermal research and development, and all types can contribute data used in conceptual model development. Pressure transient testing can e.g. be performed in all well-types while tracer tests are commonly performed between reinjection and production wells. The key to the successful drilling of any type of geothermal well is, furthermore, correct siting and design of the well based on a clear definition and understanding of the drilling target aimed for, founded on all information available at any given time. This is best achieved through a comprehensive and up-to-date conceptual model incorporating, and unifying, the essential physical features of a geothermal system. Geothermal drilling targets and well siting are discussed in a separate presentation at this short course (Axelsson et al., 2013). It may also mbe mentioned that Stefánsson (1992) analyses the success of geothermal development, which depends to a great extent on the success of drilling.

3. RESERVOIR RESEARCH CONDUCTED THROUGH GEOTHERMAL WELLS

3.1 During drilling

The principal research conducted during drilling of geothermal wells is achieved through logging of the wells, often called wireline logging. This involves measuring various contrasting, partly unrelated, parameters for different purposes as a function of depth. Some of these are drilling technology related, others for logging geological parameters and still others for reservoir physics purposes. The following are the main logging methods applied during geothermal well drilling (see Axelsson and Steingrímsson (2012) for more details):

(A) Caliper and cement bond logging aimed at measuring variations in well diameter and assessing the integrity of casing cementing. In addition imaging of casings and other parts of wells by video cameras is increasingly being used.

(B) Geophysical logging (resistivity logs, neutron-neutron logs, gamma-gamma logs, sonic logs and natural gamma ray logs) aimed at estimating different physical properties of the rock formations intersected by the well. This type of logging supplements drill cutting analysis, in particular for depth intervals where drill cuttings aren't available.

(C) Fracture imaging is increasingly being used to study specific fractures and fracture distributions in wells. The method most often applied is televiewer logging, which provides an extremely valuable addition to other logging methods, and circulation loss analysis, aimed at understanding feed-zones in wells.

(D) Temperature and pressure logging can be viewed as the main reservoir physics logging performed during drilling. In addition spinner logging is often applied to estimate fluid flow in wellbores as well as inflow or outflow through feed-zones.

Pressure transient well testing (the subject of this paper) is usually not applied during drilling. Exceptions include situations when the outcome of a drilling operation needs to be assessed before drilling is completed, which can be done through short-term step-rate injection or production testing, comparable (often shorter, however) to tests normally applied at well completion (see below). The results of such testing are sometimes used to determine whether a drilling operation should be terminated or not.

During the drilling phase of a well temperature and pressure logging has a few different research purposes; firstly to evaluate well conditions regarding the drilling operation itself, secondly to locate feed-zones (inflow or outflow zones) and thirdly to estimate reservoir temperature and pressure. During drilling temperature and pressure are, however, lowered by drilling fluid circulation as well as being often affected by inflow or outflow through feed-zones or internal flow between feed-zones, and it's difficult to estimate reservoir temperature and pressure accurately. Axelsson and Steingrímsson (2012) discuss the methods used for that purpose.

3.2 At well completion

At well completion reservoir physics research kicks in at full force, including well testing, with the main purpose being to assess the result of the drilling operation. If the outcome is deemed satisfactory the drilling operation is stopped, otherwise drilling may be continued to greater depth, or a program of well stimulation may be initiated (see later). The main phases of conventional completion program for a geothermal production well are as follows:

(1) Temperature and pressure logging, sometimes accompanied by spinner logging, to evaluate location and relative importance of feed-zones as well as temperature conditions prior to later phases of the completion test (due to temperature limitations of instruments used).
(2) Geophysical logging and fracture imaging of the production part of the well.
(3) Step-rate well-testing; through injection in high-temperature wells or production in low-temperature wells. Pressure (and sometimes temperature) transients are preferably measured down-hole.
(4) Temperature and pressure logging is normally performed after, sometimes even during step-rate testing. Spinner logging can be beneficial to assess feed-zones.

The purpose of the step-rate well-testing, which is the main reservoir physics research conducted at the end of drilling a well, is to obtain a first estimate of the possible production capacity of a well and to estimate its production characteristics. In the case of high-temperature wells this estimate is only indirect since it's not performed at high-temperature, production conditions. Step-rate well-testing usually lasts from several hours to a few days. The following are the parameters usually estimated on basis of step-rate test data:

(a) Injectivity index, defined as $\boldsymbol{II} = \Delta \boldsymbol{q}/\Delta \boldsymbol{p}$, with $\Delta \boldsymbol{q}$ the change in flow-rate and $\Delta \boldsymbol{p}$ the change in down-hole pressure, usually based on measured values at the end of each step. In the case of low-temperature wells tested through production step testing a comparable index is defined, termed productivity index (***PI***). A productivity index is also estimated during production testing of high-temperature wells. This will be discussed later in the present chapter.
(b) Formation transissivity or permeability-thickness (***T*** or ***kh***, respectively), to be discussed in Chapter 4 below.
(c) Formation storage coefficient (***S***) or storativity (***s***), also to be discussed in Chapter 4.
(d) Skin factor of a well and wellbore storage capacity (see Chapter 4).

The injectivity index (as well as the productivity index) is a simple relationship, approximately reflecting the capacity of a well, which is useful for determining whether a well is sufficiently open to be a successful producer and for comparison with other wells. It neglects, however, transient changes and turbulence pressure drop at high flow-rates. For liquid phase low-temperature wells a more accurate productivity relationship can usually be put forward relating mass flow-rate (***q***) and well pressure (***p***):

$$p = p_0 - b(t)q - Cq^2 \tag{1}$$

The pressure can either be measured as down-hole pressure, depth to water-level if pumping from the well is required, or well-head pressure if flow from the well is artesian. The term $\boldsymbol{p_0}$ represents the initial well pressure before production starts, $\boldsymbol{b(t)q}$ transient changes in well pressure reflecting transient changes in reservoir pressure (addressed in Chapter 4) and $\boldsymbol{Cq^2}$ turbulent and frictional pressure changes in the feed-zones next to the well, where flow-velocities are at a maximum, and in the well itself. The term $\boldsymbol{b(t)}$ depends on the properties of the reservoir in question, such as permeability and storativity. The injectivity/productivity index is, therefore, in fact an approximation of this term. To be exact the term will also include interference (due to production and/or reinjection) from other nearby wells. Figure 1 shows examples of productivity curves (often also called deliverability or output curves) for three liquid-phase low-temperature geothermal wells with vastly variable production characteristics, based on real Icelandic low-temperature examples.

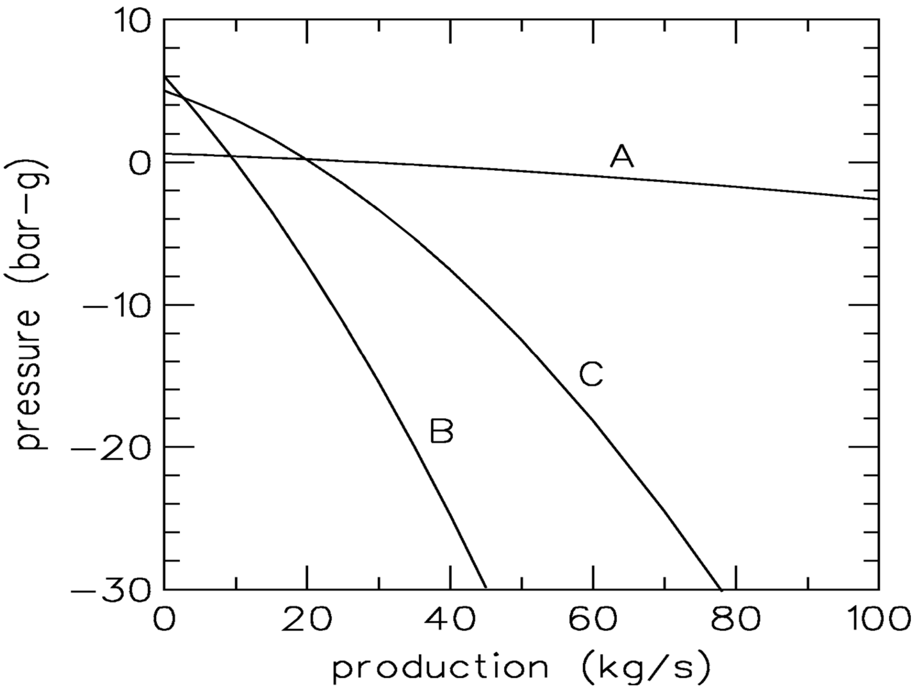

FIGURE 1: Examples of productivity curves (i.e. Equation (1)) for liquid-phase low-temperature geothermal wells with varying characteristics. Based on real Icelandic examples (see Axelsson and Gunnlaugsson, 2000)

It may be mentioned that Rutagarama (2012) presents a good treatise on the role of well-testing in geothermal resource assessment while Sarmiento (2011) discusses completion testing in more detail than done here, based on examples from high-temperature geothermal fields in the Philippines. Pressure transient analysis of step-rate well test data, collected during either injection or production, is discussed in Chapter 4 below and some examples presented.

3.3 Stimulation related testing

Geothermal wells are often stimulated following drilling, either to recover permeability reduced by the drilling operation itself, to enhance lower than expected near-well permeability or to open up connections to permeable structures not directly intersected by the well in question. Axelsson and Thórhallsson (2009) review the main methods of geothermal well stimulation with emphasis on methods applied successfully in Iceland. The methods most commonly used involve applying high-pressure water injection, sometimes through open-hole packers, or intermittent cold water injection with the purpose of thermal shocking. Chemical stimulation (mostly applying acid) methods are also used. Experimental procedures, such as using deflagration to stimulate wells and propellants to maintain stimulation achieved, have also been tested (Axelsson and Steingrímsson, 2012). Stimulation operations commonly last a few days while in some instances stimulation operations have been conducted for some months. The stimulation operations often result in well productivity (or injectivity) being improved by a factor of 2-3.

Emphasis is placed on careful reservoir monitoring during stimulation operations. Seismic monitoring has e.g. provided valuable information in some few cases. Further research and “state of the art” technology are needed to better understand stimulation processes, however, and to improve the outcome of geothermal stimulation operations. The results of stimulation operations are usually assessed through repeated step-rate well-tests (see Section 3.2) and by comparing injectivity (or productivity) indices estimated before, during and after stimulation operations. Changes in skin factor can also be used to evaluate the outcome of such operations.

3.4 During well warm-up and production testing

After the drilling of a geothermal well is completed a well is usually allowed to recover in temperature (heat up) from the cooling caused by drilling fluid circulation and cold water injection. How long depends on local conditions and the development project being followed, but this usually takes a few months. The principal reservoir engineering research conducted during this period is repeated temperature and pressure logging. The temperature data thus collected is used to estimate the undisturbed system temperature, often called formation temperature, as wells usually don’t recover completely during the recovery period. Different methods can be used for this estimation, but the method most often applied is the so-called Horner method (see Axelsson and Steingrímsson, 2012). No pressure transient testing is conducted during the warm-up period.

After a well has been allowed to warm up sufficiently it is ripe for output testing. In the case of high-temperature wells this usually involves spontaneous discharge through boiling at depth in the wellbore, which creates the pressure drop necessary to drive the flow of geothermal fluid from the reservoir, through the well, and to the surface (discharge testing). In the case of lower temperature wells either sufficient overpressure in the reservoir, which creates free-flow (artesian) from wells, or pumping, is required for output testing. In many cases high temperature wells need to be discharge stimulated through a variety of methods before discharge can be sustained. Such methods are e.g. discussed by Sarmiento (2011).

Measuring the well discharge of single-phase (liquid water or dry steam) wells is relatively straight-forward whereas measuring the discharge (both mass- and energy-flow) of a two-phase well is much more complex. This involves measuring, or estimating, two out of four key parameters; liquid-flow ($\boldsymbol{q_w}$), steam-flow ($\boldsymbol{q_s}$), total flow ($\boldsymbol{q_{total}}$) or enthalpy of the flow ($\boldsymbol{h_t}$). Once any two have been determined the other parameters can be estimated based on the following equations:

$$X = q_s / q_{total} \tag{2}$$

$$q_{total} = q_w + q_s \tag{3}$$

$$h_t = Xh_s + (1 - X)h_w \tag{4}$$

Here $\boldsymbol{X}$ is the mass-fraction of steam and $\boldsymbol{h_s}$ and $\boldsymbol{h_w}$ enthalpy of water and steam, respectively, at separation conditions on surface.

The following are the main methods used to estimate the output of two-phase wells at surface (see also Grant and Bixley, 2011):

(1) Liquid and steam phases are separated (in a separator) and each phase measured separately. Probably the most accurate method but requires the most complex instrumentation.
(2) This method applies to wells with liquid inflow and known feed-zone temperature. Liquid flow is measured after separation and enthalpy of flow estimated on basis of feed-zone temperature.
(3) This method also applies to wells with liquid inflow and known feed-zone temperature. Total flow estimated by the Russel James method and enthalpy of flow on basis feed-zone temperature. The Russel James method is an empirical method, relating total flow and flowing enthalpy, based on measuring the critical lip-pressure at lip of a pipe discharging the two-phase mixture (James, 1970; Grant et al., 1982).
(4) A combination of using the Russel James method on the total flow and consequently measuring the liquid flow-rate after separation.
(5) Using two different chemical tracers to measure the flow-rate of each of the phases in a pipeline (Hirtz et al., 2001). This method is increasingly being used with success, as it doesn't require disruption of power production.

Figure 2 shows an example of discharge test data from the Olkaria Domes field in Kenya. It shows a typical behaviour resulting from the well heating up, actually continuing from the warm-up period after drilling, i.e. enthalpy increases and water flow decreases as the test progresses. In this case the test lasted about a month, but ideally discharge tests should last until an approximate equilibrium is reached, which often may take several months. In some cases equilibrium is not attained. The behaviour of discharging wells is, however, quite variable, depending on the nature of the geothermal reservoir involved and well properties, as e.g. discussed by Bödvarsson and Witherspoon (1989) and Grant and Bixley (2011).

The productivity of geothermal wells is often presented through a simple relationship between mass flow-rate or production (measured as mentioned above) and the corresponding pressure change, either in down-hole or well-head pressure, as a first-order approximation, as already discussed (see discussion on injectivity/productivity above). This relationship is often termed production characteristics or well deliverability (output curve). In general the productivity of geothermal wells is a complex function of well-bore parameters (diameter, friction factors, feed-zone depth, skin factor, etc.), feed-zone temperature and enthalpy, feed-zone pressure, reservoir permeability and storativity, well-head pressure or depth to water level during production and temperature conditions around the well. For two-phase high-temperature wells a simple relationship as given by Equation (1) can't be set up between flow-rate and well-head pressure.

Figure 3 shows examples of productivity curves for two types of two-phase high-temperature geothermal wells with vastly variable production characteristics. It exemplifies a clear distinction between wells with single phase feed-zone inflow, which show typical bell-shaped curves like liquid-phase wells (Figure 1), and wells with two-phase inflow, which show little variation in output with changes in well-head pressure. The possible reasons for the characteristics of the latter wells have been discussed by Stefánsson and Steingrímsson (1980) as well as Bödvarsson and Witherspoon (1989).

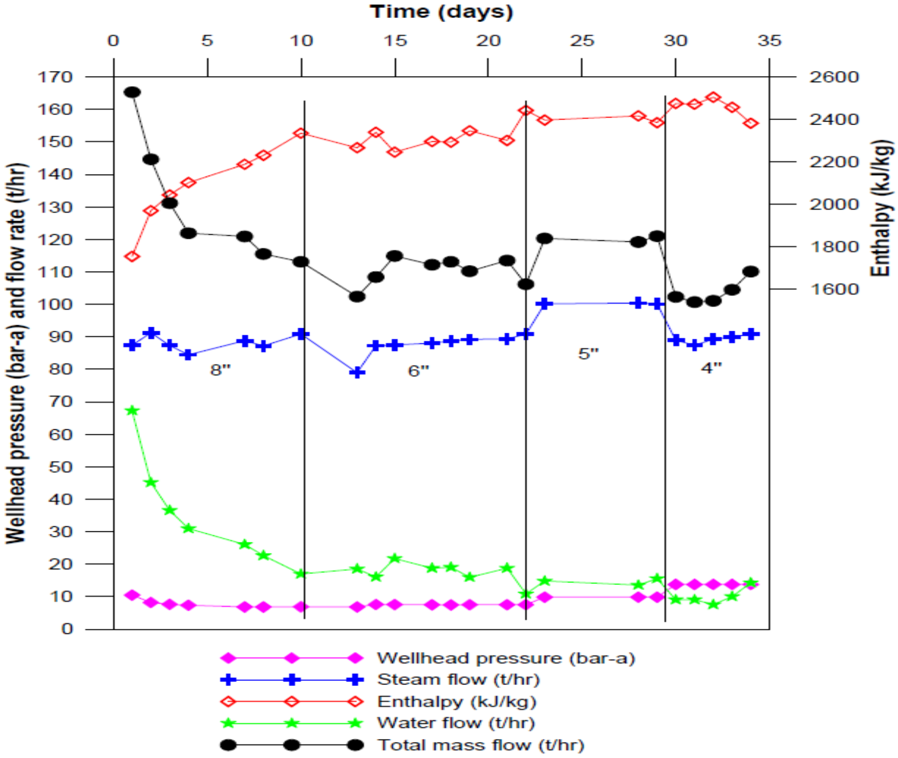

FIGURE 2: Discharge test data from well OW-915A in the Olkaria Domes field in Kenya (Mwarania, 2010)

When analysing data from flowing two-phase wells researchers need to resort to so-called wellbore simulators, i.e. computer software which numerically solves the relevant physical equations to simulate flow-, pressure- and energy conditions in the wells in question. These include mass conservation, pressure changes due to acceleration, friction and gravitation as well as energy conservation. The *HOLA* wellbore simulator is a good example of such software (Björnsson and Bödvarsson, 1987) while several other newer wellbore simulators also exist.

An extremely important part of discharge testing is monitoring of down-hole pressure during testing, either continuously or intermittently. This is not done in nearly all cases, however, as it may be technically difficult and/or quite expensive. If such data are available it is common to define a productivity index (***PI***) simply as the ratio between a change in mass flow-rate and a corresponding change in well pressure, preferably measured at the main feed-zone of a well, as first-stage analysis. For low-temperature, single-phase wells the productivity index is normally quite comparable to the wells injectivity index,

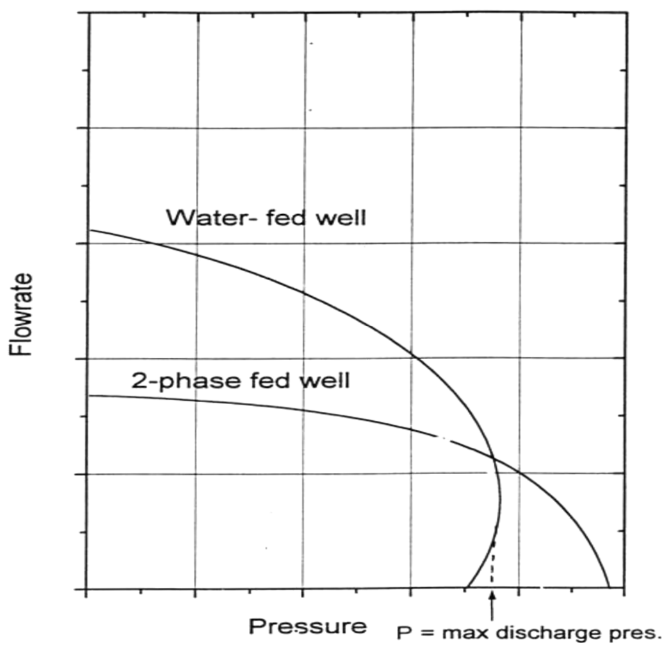

FIGURE 3: General examples of productivity curves for two types of two-phase high-temperature geothermal wells (Axelsson and Steingrímsson, 2012)

if that has been estimated. This is, however, not the case for high-temperature, two-phase wells because of drastically contrasting conditions during injection of colder fluids and high-temperature production. This can be seen clearly in Figure 4 which shows a comparison of productivity and injectivity indices for a number of high-temperature wells worldwide. The figure shows a considerable scatter, at least not a clear one-to-one relationship. A conservative relationship assuming that $\boldsymbol{PI} = \boldsymbol{II}/3$, which has been suggested, is supported by the figure. This is logical in the case of two-phase wells where boiling causes a much greater pressure draw-down than during injection. Yet it seems evident that in the case of highly productive wells the productivity index is considerably larger than the injectivity index (Axelsson and Thórhallsson, 2009).

Conventional pressure transient analysis of down-hole pressure data measured during discharge testing is of course a more accurate method of analysis than the estimation of a productivity index. The analysis methods described in Chapter 4 may be used for this purpose; they are in fact the same methods as used for the analysis of step-rate well-test data.

In addition to simple monitoring of down-hole pressure during discharge testing, supplementary pressure transient testing is sometimes performed. This involves in particular pressure recovery monitoring after discharging wells are shut in and pressure interference monitoring in near-by monitoring wells. Such data add greatly to the reservoir physics analysis of discharge tests. It should be noted, however, that in the case of high-temperature, especially two-phase, reservoirs pressure propagation is very slow so pressure interference may be limited. In lower temperature, liquid-dominated, reservoirs interference testing is extremely valuable.

3.5 Long term monitoring

Management of geothermal resources relies on adequate knowledge on the corresponding geothermal system and the monitoring of their response to long-term utilization is therefore essential (Monterrosa and Axelsson, 2013; Axelsson, 2008). Production response monitoring provides in fact some of the most important data on the nature and characteristics of geothermal systems, information which is also indispensable for the development of geothermal conceptual models. It is, in particular, essential for the revision of conceptual models previously developed on the basis of exploration and well data. If the understanding of a geothermal system is adequate, monitoring will enable changes in the reservoir to be seen in advance. Timely warning is thus obtained of undesirable changes such as decreasing generating capacity due to declining reservoir pressure or steam-flow, insufficient injection capacity or possible operational problems such as scaling in wells and surface equipment or corrosion. The importance of a proper monitoring program for any geothermal reservoir being utilised can thus never be over-emphasised. In addition utilization and monitoring can be viewed as really long-term reservoir testing, i.e. a continuation of the production testing discussed above, even though that type of testing is not performed under controlled conditions. Long-term pressure transients monitored during years of utilization, together with data on the mass extraction (always variable) causing it, constitutes, in particular, long-term pressure transient testing.

Monitoring the physical changes in a geothermal reservoir during exploitation is in principle simple and involves measuring the (1) mass and heat transport, (2) pressure, and (3) energy content (temperature in most situations). This is complicated in practise, however (Axelsson and Gunnlaugsson, 2000). Measurements must be made at high-temperatures and pressures and reservoir access for measurements is generally limited to a few wells, and the relevant parameters can't be measured directly throughout the remaining reservoir volume. Monterrosa and Axelsson (2013) and Axelsson and Steingrímsson (2012) discuss response monitoring in more detail, including the parameters that need to be measured, as well as presenting several relevant examples. It should be mentioned that such physical monitoring data are essential for calibration of models of geothermal systems used to assess their production capacity and for long-term management purposes.

In addition to monitoring physical changes the chemical content of produced water and/or steam also needs to be monitored. Finally repeated indirect monitoring, which involves monitoring the changes occurring at depth in geothermal systems through various surface observations (mainly geophysical surveying, e.g. combined surface deformation and micro-gravity monitoring), can provide valuable additional information, such as on changes in the mass balance of a geothermal system (Axelsson and Steingrímsson, 2012; Axelsson, 2008).

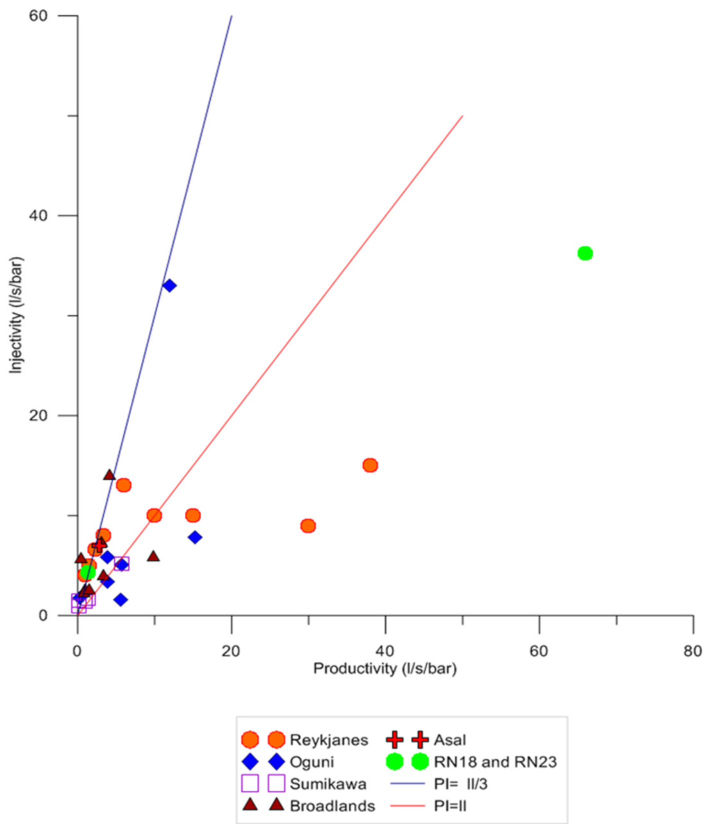

FIGURE 4: The relationship between productivity and injectivity indices for several high-temperature geothermal wells worldwide (Rutagarama, 2012). The red line represents $PI = II$ while the blue line represents $PI = II/3$

3.6 For reinjection wells

In the case of reinjection wells, either drilled specifically as such or other types of wells converted into reinjection wells, much of the same reservoir physics research is conducted as described above. The main difference is that reinjection wells don't need to be discharge tested so a step-rate injection test suffices. After well completion injection testing needs to be continued for a long period, usually several months. During this long-term injection testing tracer test are often conducted to study the connection between the designated reinjection well and near-by production wells, with the danger of cooling of the production wells in mind. Tracer testing in geothermal operations is discussed in Chapter 5 below, while a more detailed discussion of other aspects of reinjection well testing and research is presented by Axelsson (2012b). It may be specifically mentioned, however, that the injectivity of reinjection wells sometimes continues to increase during long-term injection, most likely due to thermal stimulation.

4. PRESSURE TRANSIENT ANALYSIS

Pressure transient analysis of pressure transient well-test data is performed to estimate the principal hydrological parameters of the geothermal system around the well(s) being studied. It actually constitutes modelling, or simulation of the pressure transient data by the calculated pressure changes in a relevant model, driven by a given mass extraction from a production well or injection into a reinjection well. Geothermal pressure transient analysis is discussed in detail by Bödvarsson and Witherspoon (1989) and Grant and Bixley (2011).

The main reservoir and well parameters estimated through pressure transient analysis are the following (see also section 3.2):

(a) Formation transissivity or permeability-thickness defined as $\boldsymbol{T = kh/\mu}$ (or $\boldsymbol{kh\rho/\nu}$) and $\boldsymbol{kh}$, respectively, with $\boldsymbol{k}$ the formation permeability, $\boldsymbol{h}$ the reservoir thickness, $\boldsymbol{\mu}$ and $\boldsymbol{\nu}$ the dynamic and kinematic viscosity of the fluid, respectively, and $\boldsymbol{\rho}$ the fluid density.
(b) Formation storage coefficient defined as $\boldsymbol{S = sh}$ (or $\boldsymbol{shg}$), with $\boldsymbol{s}$ the storativity of the geothermal reservoir involved, $\boldsymbol{h}$ its thickness again and $\boldsymbol{g}$ the acceleration of gravity. The storativity (with units kg/(m^{3}Pa)) describes the storage capacity per unit reservoir volume and depends on rock and fluid/steam compressibility, free surface mobility or phase change activity (two-phase storativity).
(c) Skin factor of the well, which describes an additional pressure drop next to a well due to so-called wellbore damage, often caused by clogging of formation pore-space by drilling mud. A negative skin factor, however, reflects a well with stimulated near-well permeability.
(d) Wellbore storage capacity, which simply depends on wellbore volume and the well-fluid compressibility.

Axelsson (2012a) as well as Grant and Bixley (2011) discusses permeability and storage capacity in detail. The permeability of the reservoir rock reflects the flow resistance of the flow paths in the rock (fractures and pores) and is the reservoir property that most greatly influences the reservoir response to production. The reservoir fluid-flow may in most cases be described by Darcy's law, which relates the underground fluid-flow with the pressure gradient and permeability. Storage describes the ability of a reservoir to store fluid or release it in response to an increase or lowering of pressure. The storativity gives the mass of fluid that is stored (released) by a unit volume of a reservoir as a result of a unit pressure increase (decrease). Even though storativity is a function of reservoir porosity different kinds of reservoirs have different storage mechanisms:

i. The storativity of confined liquid dominated reservoirs (i.e. not connected to shallower hydrological systems) is controlled by water and rock compressibility.
ii. The storativity of unconfined (free-surface) liquid dominated reservoirs is controlled by free-surface lowering, in the long-term.
iii. The storativity of dry-steam reservoirs (rare in reality) is controlled by the compressibility of dry steam, which is much larger than the compressibility of liquid water.
iv. The storativity of two-phase (boiling) reservoirs depends only weakly on porosity, but is controlled by the phase change resulting from the pressure change. When pressure increases some steam condenses allowing the rock to store more fluid. In addition the heat released during the process heats up the rock surrounding the pores and fractures of the rock. Note that two-phase storativity doesn't depend on compressibility at all.

It should be noted that storativity varies by several orders of magnitude between different kinds of reservoirs, compressibility-storativity (i) being the smallest and two-phase storativity (iv) being the greatest.

The basic differential equation, which is used in geothermal reservoir physics to evaluate the mass-transfer in models of geothermal reservoirs as well as estimate reservoir pressure changes, is the so-called *pressure diffusion equation*. It is derived by combining the conservation of mass (involves storativity) and Darcy's law for the mass flow, which in fact replaces the force balance equation in fluid mechanics. This results in:

$$s\frac{\partial p}{\partial t}=\nabla\cdot\left(\frac{k}{\upsilon}\nabla p\right)-f(x,y,z,t) \tag{5}$$

with $\boldsymbol{p}$ the reservoir pressure, $\boldsymbol{\upsilon}$ the kinematic viscosity of the reservoir fluid and $\boldsymbol{f}$ a mass source density simulating mass extraction from wells as well as injection into reinjection wells. By defining the geometry of a problem, and prescribing boundary- and initial conditions, a mathematical problem has been fully defined (i.e. a model). Theoretically a solution to the problem will exists, which can be used to calculate pressure changes and flow in the model, e.g. for pressure transient test analysis.

The pressure diffusion equation discussed shows what role each of the key parameters, permeability and storativity, play in overall pressure variations and fluid flow. In general it can be stated that permeability controls how great pressure changes are and that storativity controls how fast pressure changes occur and spread.

It should be kept in mind that permeability and porosity of geothermal reservoirs is both associated with the rock matrix of the system as well as the fissures and fractures intersecting it. Overall permeability in geothermal systems is usually dominated by fracture permeability with the fracture permeability commonly being of the order of 1 mD (milli-Darcy) to 1 D (Darcy) while matrix permeability is much lower or 1 μD (micro-Darcy) to 1 mD. Yet fracture porosity is usually of the order of 0.1 – 1% while matrix porosity may be of the order of 5 – 30% (highest in sedimentary systems). Therefore, fissures and fractures control the flow in most geothermal systems while matrix porosity controls their storage capacity. It should also be mentioned that in more complex situations permeability can be anisotropic and needs to be represented by a tensor in equation (5).

The pressure diffusion equation is in fact a parabolic differential equation of exactly the same mathematical form as the heat diffusion (conduction) equation. Therefore, the same mathematical methods may be used to solve these equations (see e.g. Carslaw and Jaeger, 1959). Pressure diffusion is, however, an extremely fast process compared to heat conduction. Strictly speaking, Darcy's law, and consequently the pressure diffusion equation, apply only to porous media such as sedimentary rocks. Yet in most cases fractured reservoirs behave hydraulically as equivalent porous media. This is because how fast the pressure diffusion process is and how rapidly pressure changes diffuse throughout a reservoir. The fractured nature is only relevant on a much smaller spatial and temporal scale. The fractured nature of most geothermal reservoirs can't be neglected when dealing with heat transfer, however (see Chapter 5).

Various solutions to the pressure diffusion equation, for corresponding models, provide the basis for the different tools of geothermal reservoir physics, or engineering. This includes models used to interpret well-test data such as the well-known Theis model (see later). Many such models actually originate from ground-water hydrology or petroleum reservoir engineering, where Darcy's law and the pressure diffusion equation are also applicable.

The permeability-thickness and storage coefficient are estimated through an analysis of pressure transients measured during different kinds of well-tests, ranging from very short step-rate injection or production tests, via longer production (discharge or pumping), pressure build-up and interference tests to long-term (months – years) reservoir testing, often involving several wells. In the case of completion well-tests (Section 3.2) pressure transient analysis is a more accurate analysis than involved in the simple estimation of an injectivity/productivity index. The same analysis methods (actually models) can also be used to analyse data from the longer transient well tests.

The analysis (or modelling) methods most often applied in the geothermal industry have been inherited from groundwater science (they have also been adopted by petroleum reservoir engineering). These classical methods will not be discussed in detail here but instead the reader is referred to the works by Bödvarsson and Witherspoon (1989) and Grant and Bixley (2011). The foundation of the methods is the

Theis model, a sketch of which is presented in Figure 5, along with sketches of a few variants of the basic model. The Theis model comprises a model of a very extensive isotropic, homogeneous and horizontal permeable layer of constant thickness, confined at the top and bottom, with two-dimensional, horizontal flow towards a producing well extending through the layer.

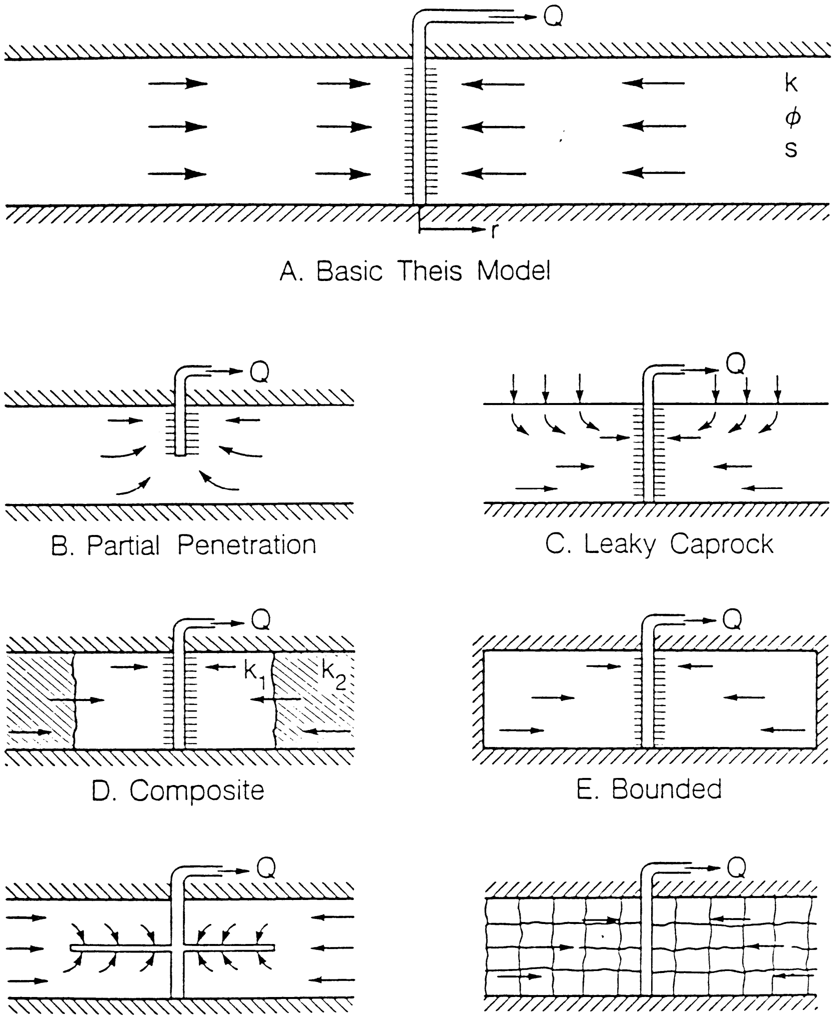

FIGURE 5: A sketch of the basic Theis-model (top) used to analyse pressure transient well-test data along with several variants of the basic model (Bödvarsson and Whiterspoon, 1989)

Well-test data are analysed on basis of the Theis model, and its variants, by fitting the pressure response of the model to observed pressure response data. Consequently the parameters of the model provide an estimate of the parameters of the reservoir being tested. Historically this fitting has been done by using semi-logarithmic plots or the type-curve method. The former method is still used as it is quite simple and effective, in spite of simplifying assumptions; Figure 6 shows the calculated responses of the Theis model and its variants in Figure 5, on a semi-logarithmic plot. The type-curve method has been replaced by more modern, computerized fitting, which today is often applied through an inverse approach, automatically yielding best fitting reservoir parameter estimates. The WellTester software (Júlíusson et al., 2008) has e.g. been used extensively to analyse well-test data from geothermal fields in Iceland, as well as from a variety of other geothermal fields worldwide. Various other well-test analysis software are available, both open-source and commercially.

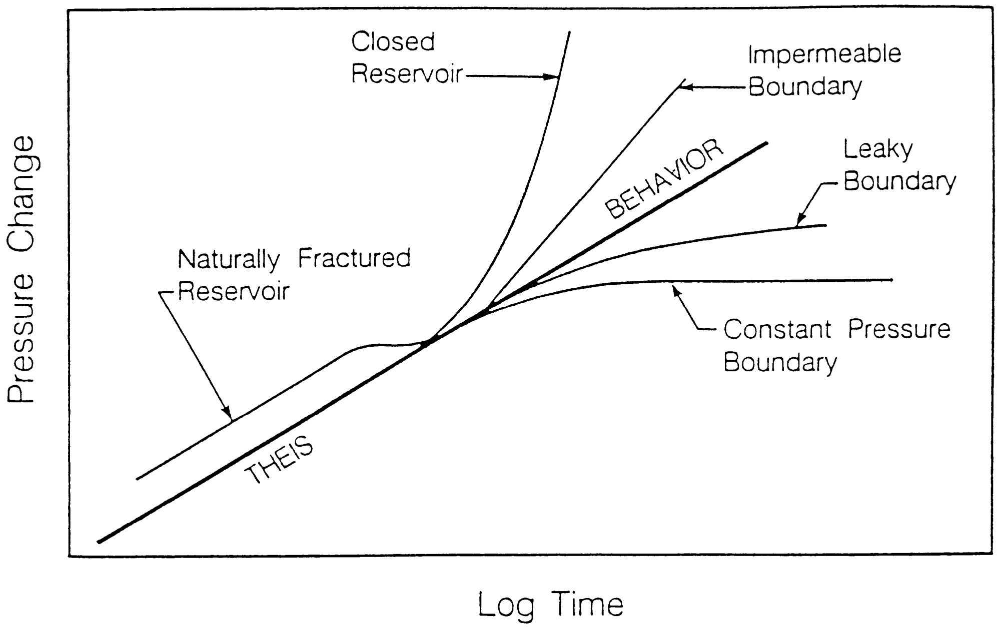

FIGURE 6: Responses of the models in Figure 5 plotted on a semi-logarithmic plot (linear pressure change vs. logarithmic time) demonstrating the linear behaviour, which is the basis of the semi-logarithmic analysis method (Bödvarsson and Whiterspoon, 1989)

Figure 7 shows one of the first examples of the results of computerized fitting of step-rate injection data, from a well drilled into the Krafla volcanic geothermal system in Iceland. It may be mentioned that today combined fitting of the pressure transients and their derivative (derivative analysis) is increasingly being used. Figures 8 and 9 present the results of such an analysis for a high-temperature geothermal production well in the Hengill geothermal region of SW-Iceland, with Figure 8 presenting the pressure transient data collected during a step-rate injection test and Figure 9 a comparison between the corresponding observed and simulated data for one of the steps.

Figures 10 – 12 present two other examples of the analysis, or simulation, of pressure transient data, both involving interference tests during which mass is produced from a certain production well and the resulting pressure transients (interference) observed in a separate monitoring well. Such tests provide the most accurate estimates of the permeability-thickness and storage coefficient, as the analysis of single well pressure transient data doesn't yield unique estimates of the storage coefficient, in addition to the fact that interference tests are generally longer than completion well-tests, providing estimates of reservoir parameters over considerably larger reservoir volumes than the latter. Figures 10 and 11 present data collected during an interference test conducted in the Kawerau geothermal field in New Zealand and Figure 12 presents an interference test example from the Oguni geothermal field in Japan.

The same applies to longer term well-testing, such as discharge testing, as to interference testing (see above). Their analysis also yields estimates of permeability-thickness and storage coefficient, estimates which should be representative for larger reservoir volumes than estimates based on step-rate well-test data, because of the much longer time scale involved. In addition discharge testing is performed at reservoir temperature conditions instead of lower temperature conditions, with an associated viscosity ambiguity, as during step-rate testing.

It should also be stressed that the analysis method for geothermal well-test data reviewed above (Theis model) is based on particular, simplifying assumptions, which are not always applicable. This applies e.g. to the assumption of two-dimensional flow, while three-dimensional flow may be important in many geothermal situations. Therefore, the results of geothermal well-test analyses should be viewed with the model applied in mind. In other words the results are actually model-dependent.

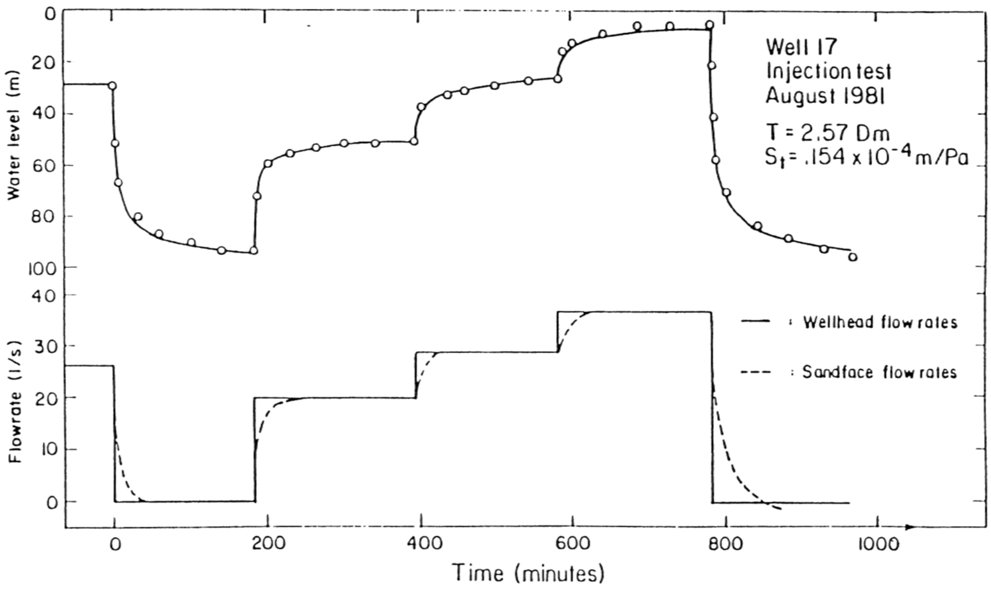

FIGURE 7: An early example of the results of computerized simulation of step-rate injection test data by a Theis-model response (Bödvarsson et al., 1984). Data from a high-temperature production well in the Krafla volcanic geothermal system in N-Iceland

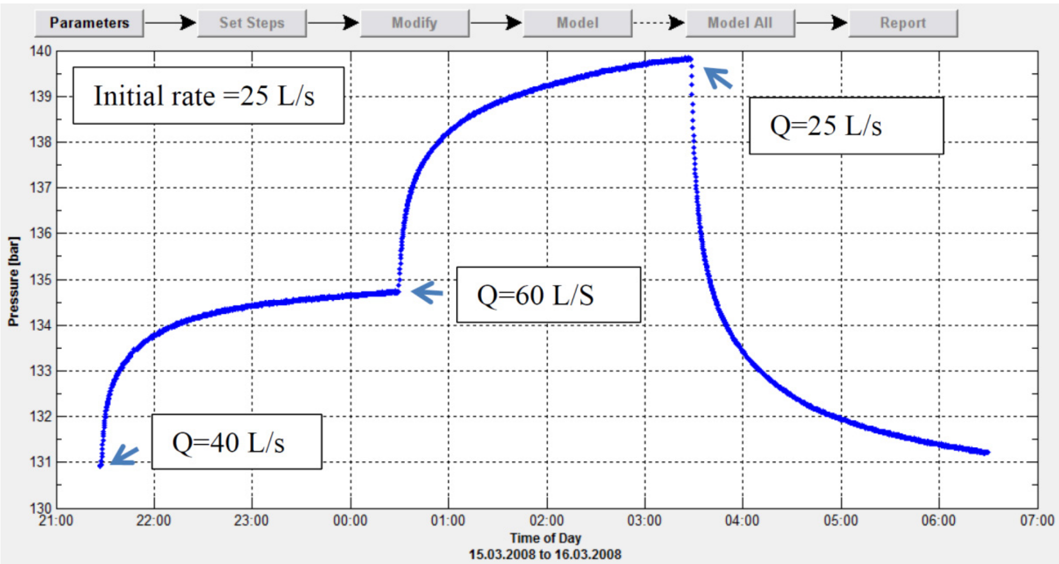

FIGURE 8: Pressure transients measured at 1750 m depth in well HE-41 in the Hengill geothermal region in SW-Iceland during a three-step injection test conducted at the end of drilling (Syed, 2011)

Finally it should be noted that in addition to the conventional reservoir analysis performed on the well data discussed above, the pressure transient data are extremely valuable for the calibration of different kinds of dynamic reservoir models (see Axelsson, 2013), i.e. numerical reservoir models. The simulation of pressure and mass output data by such models is, in effect, pressure transient analysis.

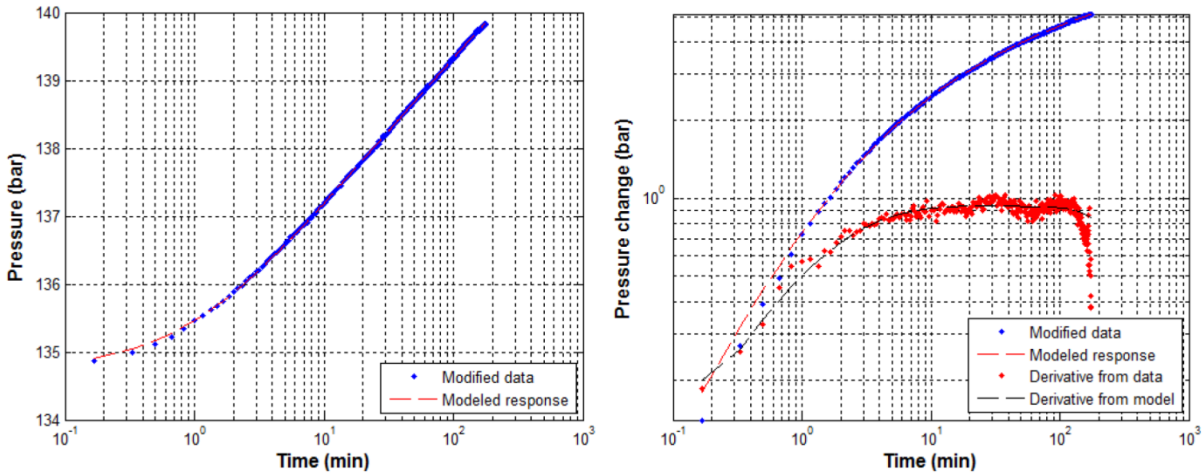

FIGURE 9: Pressure transient data from well HE-41, from the second step of Figure 8, simulated by the WellTester software (see text) and the response of a Theis model variant with a constant pressure boundary (Syed, 2011). The left hand side shows the observed and simulated pressure on a log-linear (semi-logarithmic) scale while the right hand side shows both the observed and simulated pressure, as well as the pressure derivative on a log-log scale. The simulation yields the following parameter estimates: $\boldsymbol{kh}$ = 1.8×10^{-12} m^2 (1.8 Dm), $\boldsymbol{sh}$ = 3.6×10^{-5} kg/(Pa·m^2) and skin-factor = -3.5

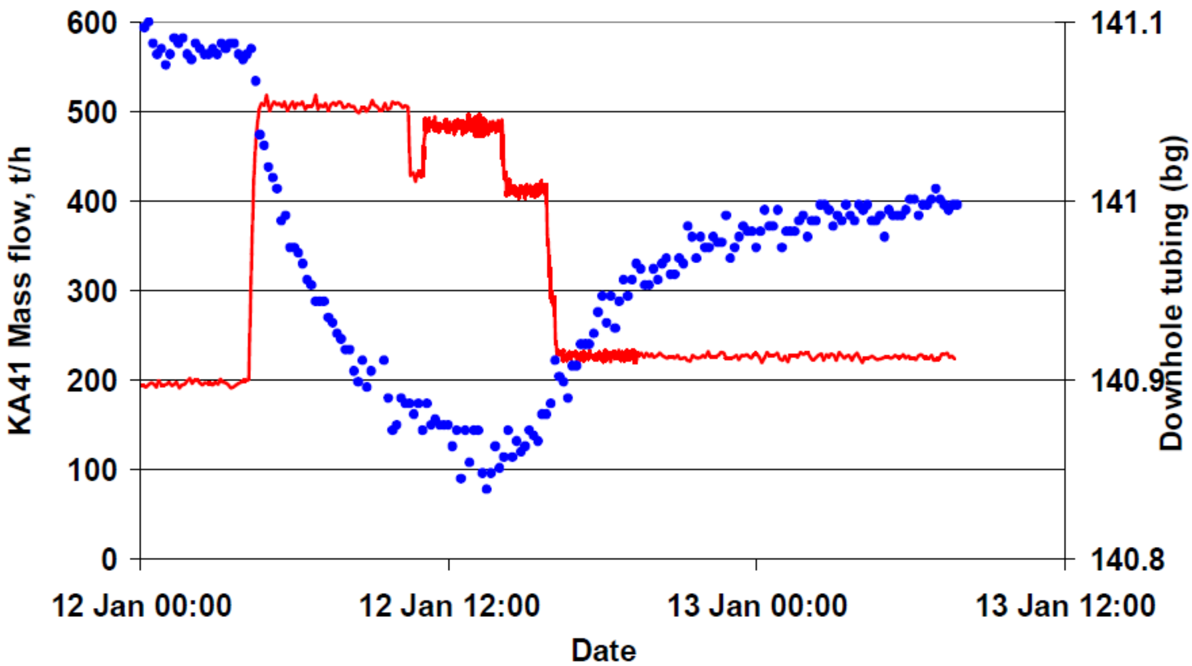

FIGURE 10: Pressure interference test data from the Kawerau geothermal field in New Zealand involving wells KA-41 (production) and KA-6 (pressure observation), see analysis in Figure 11 (Grant and Wilson, 2007)

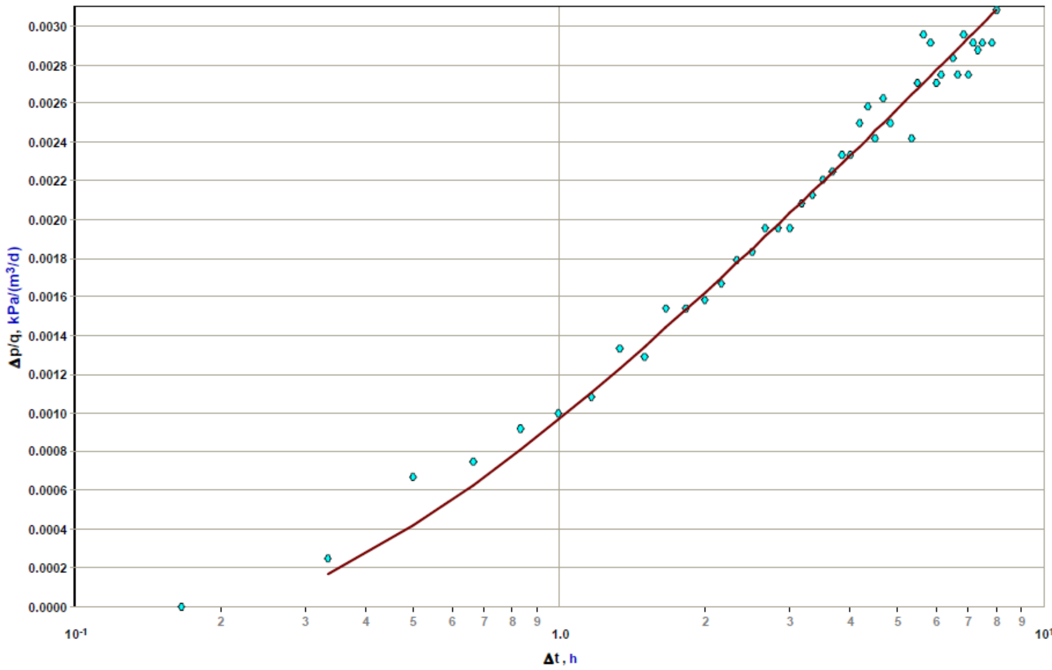

FIGURE 11: Simulation of the pressure response in well KA-6 (see Figure 10) based on the Theis model (Grant and Wilson, 2007). The simulation yields the following parameter estimate: ***kh*** ~ 100×10^{-12} m^2 (~100 Dm) but estimates for the storage coefficient are not reported

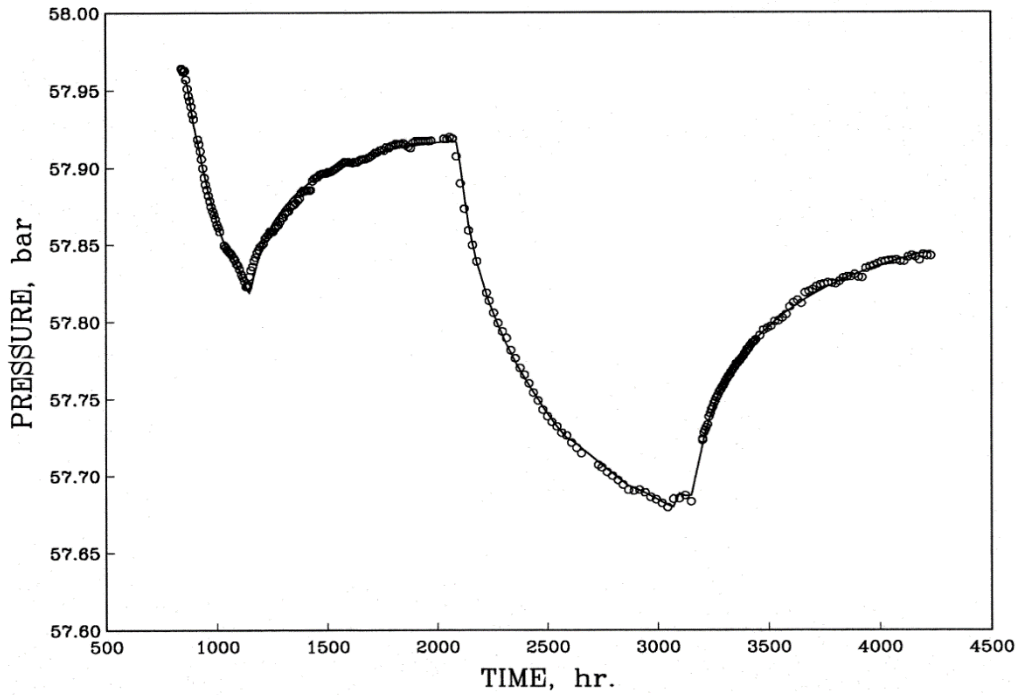

FIGURE 12: Comparison of measured pressure transients (symbols) in slim hole GH-4 in the Oguni geothermal field in Japan with computed response (line), using a Theis model variant with a no-flow boundary, due to production from wells GH-20 and GH-11 (Garg and Nakanishi, 2000). The simulation yields the following parameter estimates: ***kh*** = 150×10^{-12} m^2 (150 Dm) and ***sh*** = 1.6×10^{-3} kg/(Pa·m^2)

5. TRACER TESTING AND ANALYSIS

5.1 General

Tracer testing has become a highly important tool in geothermal research, development and resource management, with its role being most significant in reinjection studies. This is because tracer tests provide information on the nature and properties of connections, or flow-paths, between reinjection and production wells, connections that control the danger and rate of cooling of the production wells during long-term reinjection of colder fluid. Enabling such cooling predictions is actually what distinguishes tracer tests in geothermal applications (studies and management) from tracer tests in ground water hydrology and related disciplines. This information is understandably also important for conceptual model development and revision, when available. This chapter reviews geothermal tracer testing by discussing its general role, by introducing an efficient method of tracer test interpretation and for predicting production well cooling, by presenting a few examples as well as by introducing recent developments and advances in geothermal tracer testing (see also Axelsson, 2012).

Tracer tests are used extensively in surface and groundwater hydrology as well as pollution and nuclear-waste storage studies. Tracer tests involve injecting a chemical tracer into a hydrological system and monitoring its recovery, through time, at various observation points. The results are, consequently, used to study flow-paths and quantify fluid-flow. Tracer tests are, furthermore, applied extensively in petroleum reservoir engineering. The methods employed in geothermal applications have mostly been adopted from these fields.

Tracer testing has multiple applications in geothermal research and management:

1) The main purpose in conventional geothermal development is to study connections between injection and production wells as part of reinjection research and management. The results are consequently used to predict the possible cooling of production wells due to long-term reinjection of colder fluid.
2) In EGS-system development tracer testing has a comparable purpose even though it's rather aimed at evaluating the energy extraction efficiency and longevity of such operations through studying the nature of connections between reinjection and production wells.
3) For general hydrological studies of subsurface flow, such as flow under undisturbed conditions and regional flow.
4) For flow rate measurements in pipelines carrying two-phase water mixtures.

The power of tracer tests in reinjection studies lies in the fact that the thermal breakthrough time (onset of cooling) is usually several orders of magnitude (2–4) greater than the tracer breakthrough time, bestowing tracer tests with a predictive power. This is actually what distinguishes tracer tests in geothermal applications (see 1) and 2) above) from tracer tests in ground water hydrology and related disciplines. Numerous references on tracer tests in geothermal research and development can be found through the web-page of the International Geothermal Association (http://www.geothermal-energy.org), i.e. at World Geothermal Congresses held every 5 years. The reader is also referred to a special issue of the international journal Geothermics devoted to tracer tests (Adams, 2001) and a paper by Axelsson et al. (2005).

Geothermal tracer tests are mostly conducted through wells and can involve (i) a single well injection-backflow test, (ii) a test involving one well-pair (injection and production) as well as (iii) several injection and production wells. In the last setup several tracers must be used, however. The geothermal reservoir involved should preferably be in a "semi-stable" pressure state prior to a test. This is to prevent major transients in the flow-pattern of the reservoir, which would make the data analysis more difficult. In most cases a fixed mass of tracer is injected "instantaneously", i.e. in as short a time as possible, into the injection well(s) in question. Samples for tracer analysis are most often collected from producing wells, while down-hole samples may need to be collected from non-discharging wells. The duration of a tracer test is of course site specific and hard to pinpoint beforehand. The same applies to sampling plans, even though an inverse link between required sampling frequency and time passed can often be assumed (Axelsson et al., 2005).

The tracer selected needs to meet a few basic criteria: It should (a) not be present in the reservoir (or at a concentration much lower than the expected tracer concentration), (b) not react with or absorb to reservoir rocks (see however discussion on reactive tracers below), (c) be thermally stable at reservoir conditions, (d) be relatively inexpensive, (e) be easy (fast/inexpensive) to analyse and (f) be environmentally benign. In addition the tracer selected must adhere to prevailing phase (steam or water) conditions. The following are the principal tracers used in geothermal applications (not a complete list):

Liquid-phase tracers:

- Halides such as iodide (I) or bromide (Br);
- Radioactive tracers such as the isotopes iodide-125 (^{125}I) and iodide-131 (^{131}I);
- Fluorescent dyes such as fluorescein and rhodamine;
- Aromatic acids such as benzoic acid;
- Naphthalene sulfonates.

Steam-phase tracers:

- Fluorinated hydrocarbons such as R-134a and R-23;
- Sulphur hexafluoride (SF_6).

Two-phase tracers:

- Tritium (^3H);
- Alcohols such as methanol, ethanol and n-propanol.

Sodium-fluorescein has been used successfully in numerous geothermal fields, both low- and high-temperature ones (Axelsson et al., 2005). It meets most of the criteria listed above and, in particular, can be detected at very low levels of concentration (10-100 ppt). In contrast the detection limit of halides is several orders of magnitude higher.

The main disadvantage in using fluorescein is that it decays at high temperatures, a decay which becomes significant above 200°C. Therefore new tracers with higher temperature-tolerance, but comparable detection limits, have been introduced, in particular several polyaromatic sulfonates (Rose et al., 2001). These are increasingly being used in geothermal applications. Having several comparable tracers also enables the execution of multi-well tracer tests. Rose et al. (2001) present the temperature-tolerance of several of these compounds, which in some cases exceeds 300°C.

Radioactive materials are also excellent tracers since they are detectable at extremely low concentration (Axelsson et al., 2005). Their use is limited by stringent transport, handling and safety restrictions, however. When selecting a suitable radioactive tracer their different half-lives must be taken into account. Iodide-125 and iodide-131 have half-lives of 60 and 8.5 days, respectively, for example.

It should be mentioned that for flow-rate measurements in two-phase pipelines (Hirtz et al., 2001) fluorescein or benzoic acid are commonly used for the liquid phase. Naphthalene sulfonates are also promising as such. Steam-phase measurements are commonly done using SF_6 or a suitable alcohol.

Special techniques, of differing complexity, have been developed for sampling and analysing geothermal tracers. A discussion of these is beyond the scope of this paper, however.
Figures 13 – 15 show three examples of the results of tracer tests conducted in geothermal systems of quite contrasting nature, also presented by Axelsson (2012). These are just presented as concise examples, without specific field details. Two more examples, with interpretation results, are presented below.

Figure 13 shows the tracer recovery during an unusually long tracer test conducted in the Hofsstadir low-temperature (reservoir temperature 85-90°C) geothermal system in W-Iceland already mentioned twice in this paper. The test involved tracer injection into an operating reinjection well about 1200 m from the production well. The relatively slow recovery indicates that reinjection induced cooling will be limited. This awaits confirmation through comprehensive interpretation and modelling.

Figure 14 shows the tracer recovery during a tracer test conducted in the Krafla high-temperature (reservoir temperature 200-400°C) geothermal system in N-Iceland. The test involved tracer injection into a temporary reinjection well about 200 m from a production well. The relatively rapid recovery was interpreted as indicating a considerable danger of cooling of the production well. Therefore the reinjection well was abandoned as such.

The third example involves tracer tests conducted at the Soultz EGS site in N-France during stimulation and testing between 2000 and 2005 (Sanjuan et al., 2006). The tests involved 4 wells ranging in depth from 3600 to 5300 m. A few different tracers very used, including fluorescein and some naphthalene sulfonates. Figure 15 shows the recovery during the test between wells GPK-3 and GPK-2 separated by 650 m, in which fluorescein was successfully used. It showed the most direct connection in the system.

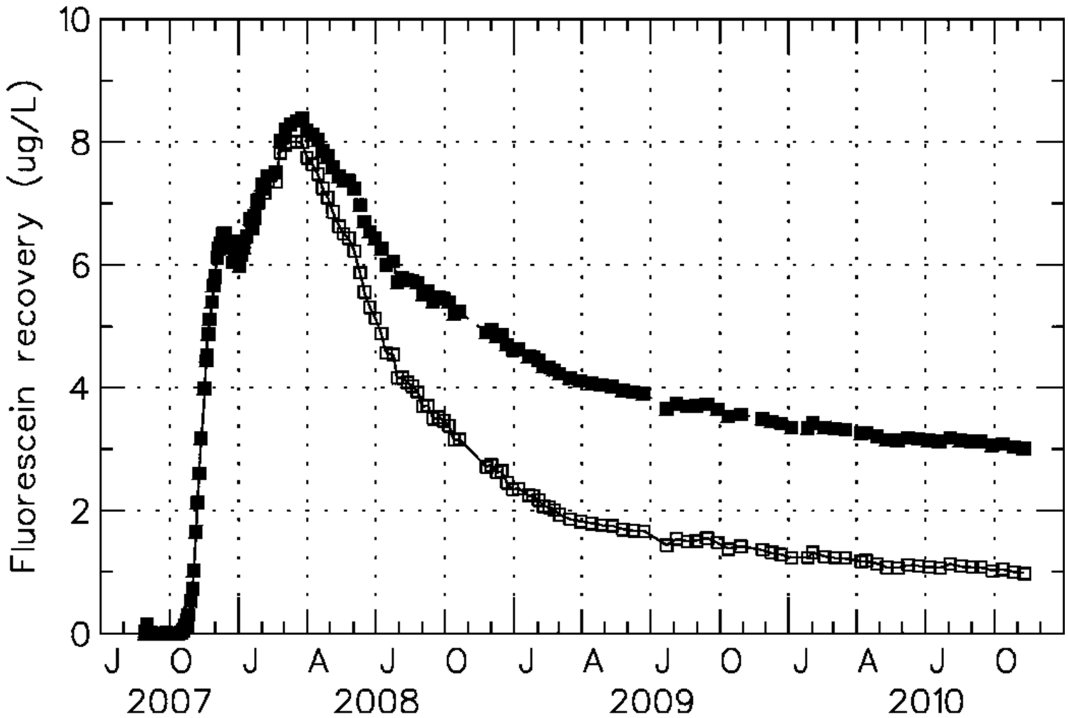

FIGURE 13: Fluorescein recovery in production well HO-1 in the Hofsstadir low-temperature system in W-Iceland, following the injection of 10 kg of the tracer into reinjection well HO-2 (from Axelsson, 2011). The test lasted 3.5 years. The lower curve shows the recovery corrected for the tracer being reinjected (recirculated) after production from HO-1. About 70% of the tracer was recovered during the test

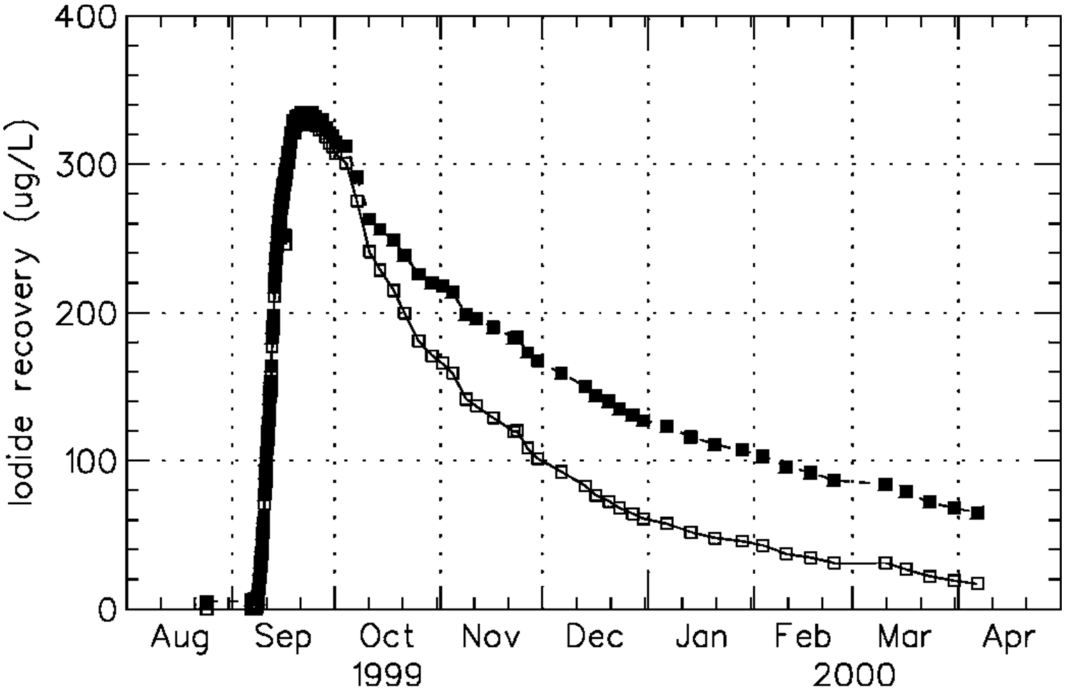

FIGURE 14: Iodide recovery in production well K-21 in the Krafla high-temperature system in N-Iceland, following the injection of 200 kg of KI into well K-22 (from Axelsson, 2011). The test lasted 7 months. The lower curve shows the recovery corrected for the tracer being reinjected (recirculated) after production. About 30% of the tracer was recovered during the test)

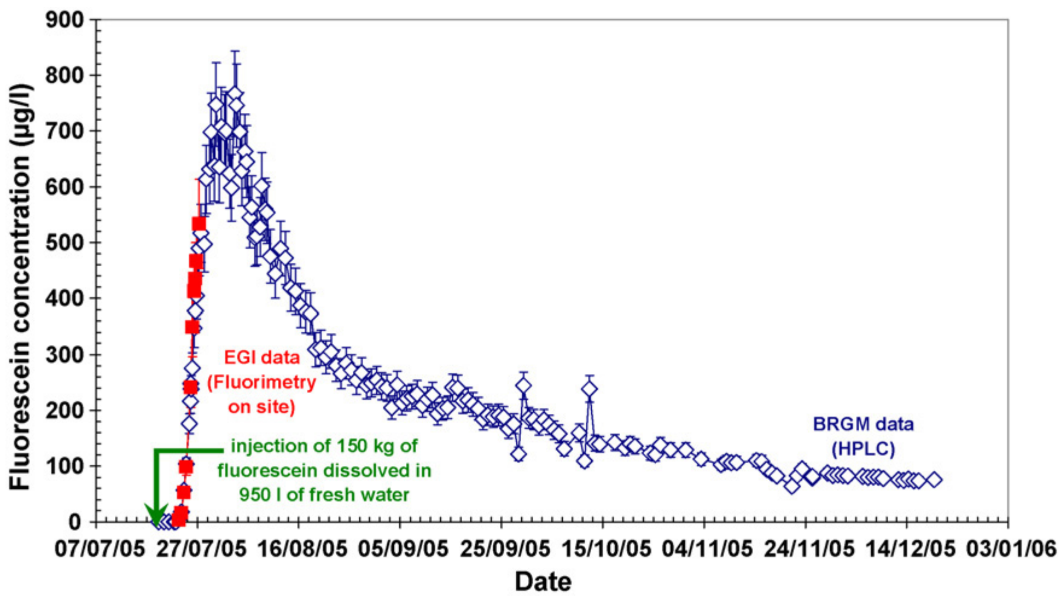

FIGURE 15: Flourescein recovery in well GPK-2 at the Soultz EGS-site in N-France, following the injection of 150 kg of fluorescein into well GPK-3 (figure from Sanjuan et al., 2006). The test lasted 5 months. About 24% of the tracer was recovered during the test

The above are examples of geothermal tracer test data without any quantitative interpretation. Below a specific interpretation method will be presented along with two interpretation examples.

5.2 Interpretation method and examples

Comprehensive interpretation of geothermal tracer test data, and consequent modelling for management purposes (production well cooling predictions), has been rather limited, even though tracer tests have been used extensively. Their interpretation has mostly been qualitative rather than quantitative. Axelsson et al. (2005) present a simple and efficient method that may be used for this purpose. It is based on simple models, which are able to simulate the relevant data quite accurately. They are powerful during first stage analysis, when the utilization of detailed and complex numerical models is not warranted. The more complex models become applicable when a greater variety of data become available that may be collectively interpreted.

The method of tracer test interpretation referred to is conveniently based on the assumption of specific flow channels connecting injection and production wells. It has been used to analyse tracer test data from quite a number of geothermal systems in e.g. Iceland, El Salvador, the Philippines, Indonesia and China and consequently to calculate cooling predictions (Axelsson et al., 2005). It has proven to be very effective. This method is based on simple models, which are nevertheless able to simulate the relevant data quite accurately.

The tracer transport model involved assumes the flow between injection and production wells may be approximated by one-dimensional flow in flow-channels. These flow-channels may, in fact, be parts of near-vertical fracture-zones or parts of horizontal interbeds or layers. The channels may be envisioned as being delineated by the boundaries of these structures, on one hand, and flow-field stream-lines, on the other hand. In other cases these channels may be larger volumes involved in the flow between wells. In some cases more than one channel may be assumed to connect an injection and a production well, for example connecting different feed-zones in the wells involved.

The interpretation method involves simulating tracer return data, such as presented above, on basis of equations presented by Axelsson et al. (2005). The simulation yields information on the flow channel cross-sectional area and dispersivity as well as the mass of tracer recovered through a given channel (equal to, or less than, the mass of tracer injected). In the case of two or more flow-channels the analysis yields estimates of these parameters for each channel. Through the estimates of flow channel cross-sectional area(s) the flow channel pore space volume(s) has (have) in fact been estimated. The tracer interpretation software *TRINV*, included in the *ICEBOX* geothermal software package, can be used for this simulation (Axelsson et al., 2005).

It should be emphasised that this method does not yield unique solutions and that many other models have been developed to simulate the transport of contaminants in ground-water systems, and in relation to underground disposal, or storage, of nuclear waste. Many of these models are in fact applicable for the interpretation of geothermal tracer tests. It is often possible to simulate a given data-set by more than one model; therefore a specific model may not be uniquely validated.

In addition to distance between wells and volume of flow-paths, mechanical dispersion is the only factor assumed to control the tracer return curves in the method presented above. Retardation of tracers by diffusion from the flow-paths into the rock matrix is neglected. It is likely to be negligible in fractured rock except when fracture apertures are small, flow velocities are low and rock porosity is high.

The main goal of geothermal tracer testing is to predict thermal breakthrough and temperature decline during long-term reinjection, or the efficiency of thermal energy extraction in EGS operations, as already stated. This is dependent on the properties of the flow-channel(s) involved, but not uniquely determined by the flow-path pore-space volume (Axelsson et al., 2005). The heat transfer (cooling/heating) mainly depends on the surface area and porosity of the flow-channel(s). Therefore, some additional information on the flow-path properties/geometry is needed, i.e. geological or geophysical in nature (see also later discussion of recent advances).

To deal with this uncertainty heat-transfer predictions may be calculated for different assumptions on flow-channel dimensions, at least for two extremes. First for a small surface area, or pipe-like, flow channel, which can be considered a pessimistic model with minimal heat transfer. Second a large surface area flow channel, such as a thin fracture-zone or thin horizontal layer, which can be considered an optimistic model with effective heat transfer. Additional data, in particular data on actual temperature changes, or data on chemical variations, if available may be used to constrain cooling predictions.

Figures 16 – 18 present examples of the results of geothermal tracer test analysis using the interpretation method discussed above. The results are only presented briefly here with some numerical findings presented in figure captions. More details can be found in the references cited. Figure 16 shows the fluorescein recovery through a production well in the Laugaland low-temperature geothermal system (reservoir temperature 90-100°C) in N-Iceland, conducted in 1997, simulated by the method presented above (Axelsson et al., 2001). This was during initial reinjection testing in the field, since then reinjection has been part of the management of the system. Figure 17 shows production temperature predictions calculated by a pessimistic model based on the tracer recovery simulation presented in Figure 16. They show that the long-term cooling of the well in question should be minimal, in particular in view of the considerable increase in productivity of the Laugaland system when reinjection is applied (Axelsson et al., 2001).

The final interpretation example is from the Los Azufres high-temperature geothermal system (reservoir temperature ~280°C) in the state of Michoacán in Mexico. It involves interpretation of a tracer test conducted in late 2006 (Figure 18) in which SF_6 was used due to the fact that a steam zone has developed in the system and that production wells involved (NE-part of the field) produce mostly steam (Molina-Martínez and Axelsson, 2011). Cooling predictions based on the interpretation indicate that well AZ-5 may cool as much as 14°C during 30 years of 8 kg/s reinjection into AZ-64 (compared with 21 kg/s production from AZ-5), cooling which is probably not acceptable.

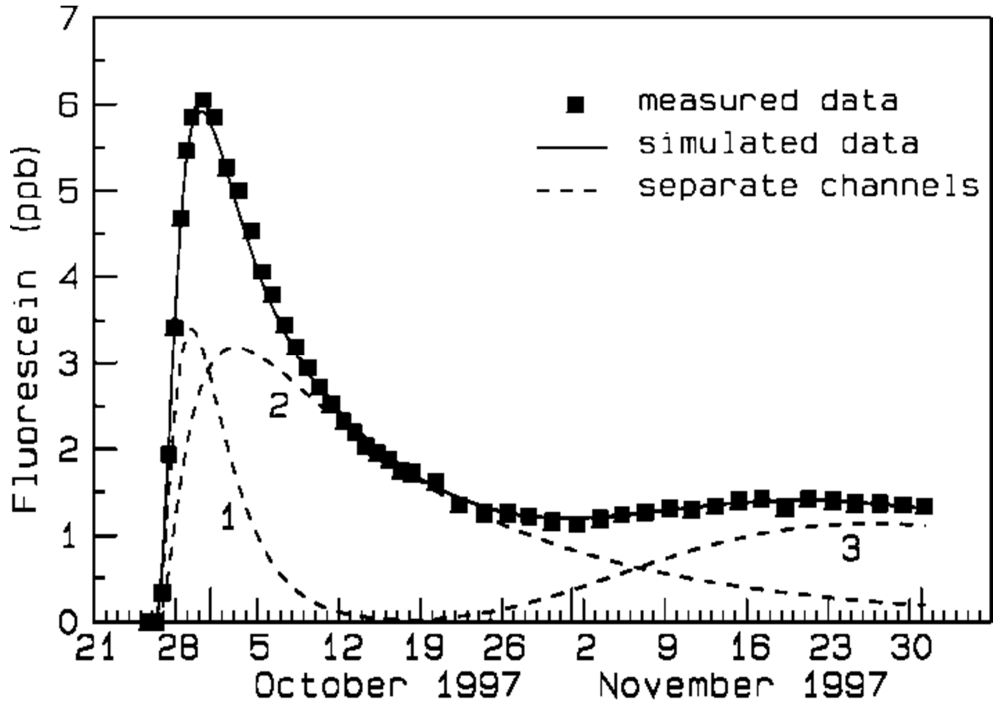

FIGURE 16: Observed and simulated (three flow channels) fluorescein recovery in well LN-12 at Laugaland in N-Iceland during a tracer test in 1997 (figure from Axelsson et al., 2001). Spent geothermal fluid was reinjection into well LJ-08 and production was from well LN-12 about 300 m away. According to the simulation only about 6% of the tracer injected is recovered through this well and the combined flow-channel volume is estimated as 20,000 m^3, assuming 7% porosity

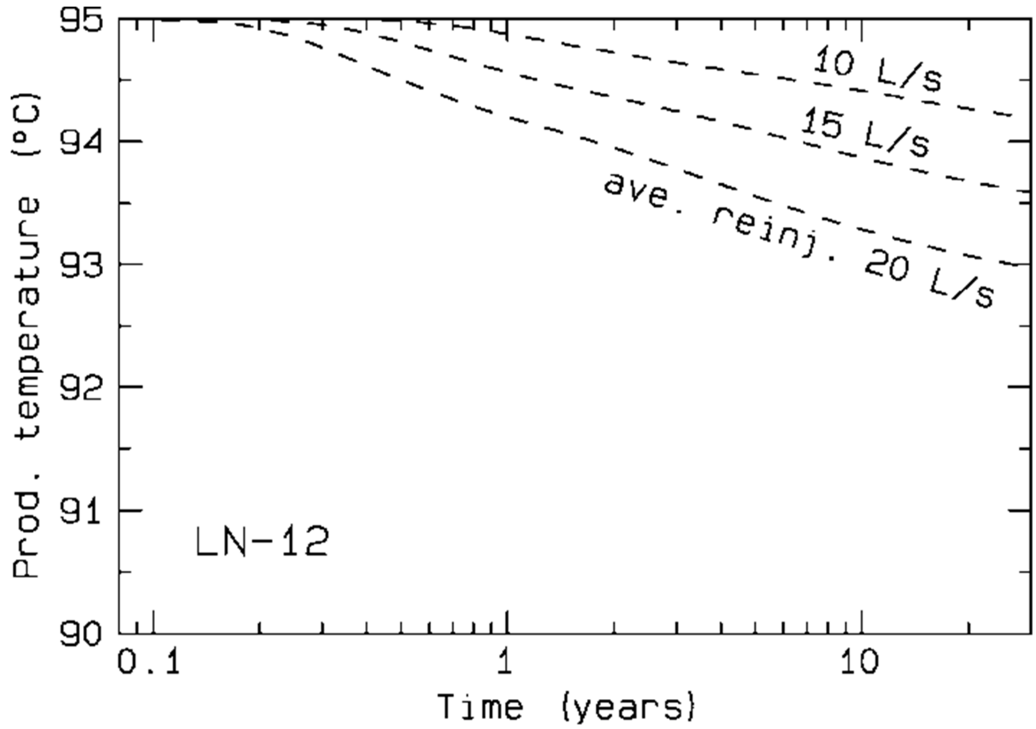

FIGURE 17: Estimated production temperature decline of well LN-12, due to flow through the three channels simulated (Figure 12), for three cases of average long-term reinjection into well LJ-8 and an average long-term production rate of 40 L/s (figure from Axelsson et al., 2001)

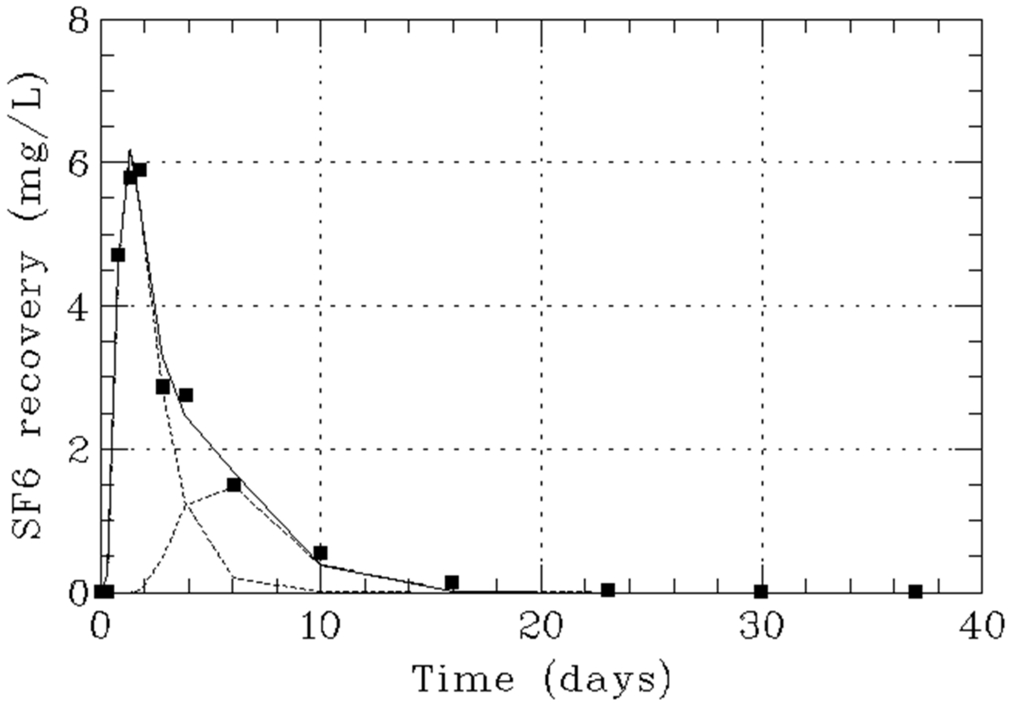

FIGURE 18: Observed and simulated (two flow channels) SF_6 recovery in well AZ-5 in the Los Azufres high-temperature field in Mexico, following injection into well AZ-64 200 m away (Molina-Martínez and Axelsson, 2011). The very rapid recovery is attributed to steam-phase transport. Almost 50% of the tracer was recovered through a combined flow channel volume of 200,000 m^3 (~10% porosity)

5.3 Recent advances

The main uncertainty in reinjection operations and EGS development involves the heat-transfer efficiency of flow-channels between reinjection and production wells. This depends on the surface area of the flow-channels, information which conventional tracer testing using conservative tracers does not yield. Therefore, emphasis has been placed on the introduction of reactive tracers, in particular in EGS-research, as they can provide this information. This includes high-tech tracers such as nano-particles and quantum-dots (see e.g. Rose et al. (2011). By applying two tracers, one conservative and the other reactive, it should be possible to estimate both the flow-channel pore-space volume and its surface area (the transport of the reactive tracer depends on the available surface area as well as the volume).

6. CONCLUSIONS AND RECOMMENDATIONS

This paper reviews the main methods of testing geothermal reservoirs through wells, generally termed well-testing. Both pressure transient testing, which is one of the main tools of geothermal reservoir physics/engineering, and tracer testing are reviewed. Through pressure transient well testing and consequent pressure transient analysis the main reservoir parameters, such as permeability-thickness and storage coefficient, can be estimated along with reservoir boundary conditions (if a test is sufficiently long-lasting). Such estimates consequently provide key information for conceptual model development and revision.

Pressure transient analysis is performed on the basis of appropriate reservoir models and it involves, in fact, model simulation of the pressure transient data collected. Various models are available for this purpose, but most often the well-known Theis model, or variants of that model, are used. Using the Theis model makes it possible to compare results for different wells as well as different geothermal systems, yet the Theis model is based on quite specific assumptions that may not be correct, in particular regarding the reservoir and flow-field geometry (two-dimensional and radial). Therefore, the results of geothermal well-test analyses should be viewed with the model applied in mind. In other words the results are actually model-dependent. Employing different models is therefore recommended during pressure transient analysis, with the conceptual model of the system in question in mind. Using different variants of the Theis model (see above), and selecting the one that best fits the data, is a step in the right direction.

Well tests range from very short step-rate injection or production tests at well completion, via longer production (discharge or pumping), pressure build-up and interference tests to long-term (months – years) reservoir testing, often involving several wells. The longer the test the more valuable the information derived is, because an increasingly larger volume of the reservoir being tested is sensed with increasing test length. Long-term monitoring (mass extraction and pressure in particular) actually constitutes extra long-term pressure transient testing, albeit under uncontrolled conditions (often variable mass extraction). Long-term interference testing provides by far the most important information, as the analysis of single well tests doesn't yield fully unique parameter estimates.

Tracer testing plays an important role in geothermal research and management, in particular concerning heat-transfer efficiency in reinjection operations and EGS development. Advances have been made in the introduction of new tracers, which both add to the multiplicity of high-sensitivity tracers available as well as being increasingly temperature tolerant. But the geothermal industry needs to follow advances in other disciplines and adopt those which are beneficial. This applies, in particular, to advances in modelling of tracer return data, which has been limited so far, especially modelling of reactive tracer data, which can yield information on flow-channel surface areas in addition to their volumes.

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RESERVOIR RESPONSE MONITORING DURING PRODUCTION

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ABSTRACT

Comprehensive monitoring and the application of appropriate field management technics must be implemented to achieve sustainable utilization of geothermal resources. Production response monitoring provides some of the most important data on the nature and characteristics of geothermal systems, information which is indispensable for the development of geothermal conceptual models. It is, in particular, essential for the revision of conceptual models previously developed on the basis of exploration and well data. This paper summarizes the main physical parameters to be measured, recorded and interpreted in a continuous manner, as well as their important role in field and resource management. Three examples of response monitoring data, collected during long term exploitation, are presented along with their analysis and significance for the management of the respective fields. The Miravalles geothermal system in Costa Rica, the Momotombo system in Nicaragua and the Berlin system in El Salvador, all have more than 20 years of commercial operation. In spite of some lack of important monitoring data the main effect of long-term utilization on these geothermal resources have been steam discharge decline, both reservoir boiling and reservoir cooling as well as some scaling due to chemical reactions.

1. INTRODUCTION

Hydrothermal geothermal reservoirs are characterized by the presence of a quasi-balance between hot recharge (up-flow) and discharge (out-flow), on a geological time-scale, which creates conditions of high pressure and temperature in the permeable reservoirs where exploitable geothermal resources are located. When large scale (relative to the natural discharge) exploitation commences underbalanced conditions are to be expected, with pressure as well as temperature declining. This depletion, or degradation as several authors have called it, implies the reduction in energy contents of the reservoir. The level of energy reduction depends on how large the energy extraction is, how large the reservoir is as well as how extensive the hot recharge is. The permeability and storage capacity of the geothermal reservoir represent the main parameters controlling the extent of the pressure draw-down and its pace, respectively. In contrast the enthalpy changes depend mainly on inflow from surrounding aquifers (mostly colder), or the relevant boundary conditions, as well as reservoir boiling controlled by permeability effects. Both the hot recharge and the cooler inflow constitute aspects of the renewability of the corresponding geothermal resource.

The sustainability of the utilization of the geothermal system in question depends on the reservoir factors affecting the depletion, or degradation, of the system. This depletion, which can seriously reduce the reservoir conditions, is perhaps the main constraint to resource development while controlling, and minimizing, the degradation is the goal of geothermal field management during utilization. Comprehensive monitoring and the application of appropriate field management technics must be implemented to achieve sustainable utilization of geothermal resources. Production response monitoring provides some of the most important data on the nature and characteristics of geothermal systems, information which is indispensable for the development of geothermal conceptual models. It is, in particular, essential for the revision of conceptual models previously developed on the basis of exploration and well data.

This paper discusses the monitoring of the response of geothermal systems to long-term utilization. It summarizes the main physical parameters to be measured, recorded and interpreted in a continuous manner, as well as their important role in field and resource management. Three examples of response monitoring data, collected during long term exploitation, are presented along with their analysis and significance for the management of the respective fields. The Miravalles geothermal system in Costa Rica, the Momotombo system in Nicaragua and the Berlin system in El Salvador, all have more than 20 years of commercial operation.

2. FIELD MONITORING – ESSENCE OF RESOURCE MANAGEMENT

Management of a geothermal reservoir relies on adequate information on the geothermal system in question (Stefánsson *et al.*, 1995). Data yielding this knowledge through appropriate interpretation is continuously gathered throughout the exploration and exploitation history of a geothermal reservoir (see other presentations at this short course). The initial data come from surface exploration, i.e. geological, chemical and geophysical data. Additional information is provided by exploratory drilling, in particular through logging and well testing. The most important data on a geothermal system's nature and properties, however, are obtained through monitoring of its response to long-term production. These data provide essential input for the development of conceptual models, for the siting of geothermal wells and geothermal reservoir modelling. Conceptual models, and in particular reservoir models, constitute some of the key tools of geothermal resource management (see chapter 3).

Careful monitoring of a geothermal reservoir during exploitation is, therefore, an indispensable part of any successful management program. If the understanding of a geothermal system is adequate, monitoring will enable changes in the reservoir to be seen in advance. Timely warning is thus obtained of undesirable changes such as decreasing generating capacity due to declining reservoir pressure or steam-flow, insufficient injection capacity or possible operational problems such as scaling in wells and surface equipment or corrosion. The importance of a proper monitoring program for any geothermal reservoir being utilised can thus never be over-emphasised.

Monitoring can be divided into physical and chemical monitoring, with the former being discussed in the present paper and the latter in other presentations at the short course. Physical monitoring can, moreover, be divided into direct and indirect monitoring (see below).

Monitoring the physical changes in a geothermal reservoir during exploitation is in principle simple and only involves measuring the (1) mass and heat transport, (2) pressure, and (3) energy content (temperature in most situations). This is complicated in practise, however (Axelsson and Gunnlaugsson, 2000). Measurements must be made at high-temperatures and pressures and reservoir access for measurements is generally limited to a few boreholes, and these parameters cannot be measured directly throughout the remaining reservoir volume.

The parameters that need to be monitored to quantify a reservoirs response to production may, of course, differ somewhat, as well as methods and monitoring frequency, from one geothermal system to another (Kristmannsdóttir *et al.*, 1995; Axelsson and Gunnlaugsson, 2000). Monitoring may also be either direct or indirect, depending on the observation technique adopted. Below is a list of directly observable basic aspects that should be included in conventional geothermal monitoring programs.

(1) Mass discharge histories of production wells (pumping for low-temperature wells).
(2) Temperature or enthalpy (if two-phase) of fluid produced.
(3) Water level or wellhead pressure (reflecting reservoir pressure) of production wells.
(4) Chemical content of water (and steam) produced.
(5) Injection rate histories of injection wells.
(6) Temperature of injected water.
(7) Wellhead pressure (water level) for injection wells.
(8) Reservoir pressure (water level) in observation wells.
(9) Reservoir temperature through temperature logs in observation wells.
(10) Well status through diameter monitoring (calliper logs), injectivity tests and other methods.

Some of the above parameters are monitored through temperature and pressure logging, which is described in detail in other presentations at the present workshop. Monitoring programs have to be specifically designed for each geothermal reservoir, because of their individual characteristics and the distinct differences inherent in the metering methodology adopted. Monitoring programs may also have to be revised as time progresses, and more experience is gained, e.g. monitoring frequency of different parameters. The practical limits to manual monitoring frequency are increasingly being offset by computerised monitoring, which actually presents no upper limit to monitoring frequency, except for that set by the available memory-space in the computer system used. Data transmission through phone networks is also increasingly being used. Axelsson (2012) shows examples of different kinds of direct monitoring data.

Indirect monitoring involves monitoring the changes occurring at depth in geothermal systems through various surface observations and measurements. Such indirect monitoring methods are mainly used in high-temperature fields, but also have a potential for contributing significantly to the understanding of low-temperature systems. These methods are mostly geophysical measurements carried out at the surface; airborne and even satellite measurements have also been attempted. All these methods have in common that a careful baseline survey must be carried out before the start of utilisation, and repeated at regular intervals.

Some of the indirect monitoring methods are well established by now, while others are still in the experimental stage or have met limited success. A review of the geothermal literature reveals that the following methods have been used (Axelsson and Gunnlaugsson, 2000):

(a) Topographic measurements.
(b) Micro-gravity surveys.
(c) Electrical resistivity surveys.
(d) Ground temperature and heat-flow measurements.
(e) Micro-seismic monitoring.
(f) Water level monitoring in ground water systems.
(g) Self-potential surveys.

The reasons why these monitoring methods are seldom used in low-temperature fields are the fact that physical changes in low-temperature systems are generally not as great as in high-temperature systems as well as relatively high costs. A few of the methods are rather widely used in high-temperature fields, such as (a), (b) and (e).

Topographic measurements are carried out to enable detection of ground elevation changes, mostly subsidence. This may occur in all geothermal systems during exploitation because of compaction of the reservoir rocks, following fluid withdrawal. Re-injection may also cause topographic changes (uplift). Recently satellite radar interferometry (INSAR) has been increasingly used for surface deformation studies. Such studies for the Krafla volcanic- and geothermal system in N-Iceland provide a good example (Sturkell *et al.*, 2008).

Micro-gravity monitoring has been used successfully in a number of geothermal fields (see a separate presentation at this short course). Changes in gravity can provide information on the net mass balance of a geothermal reservoir during exploitation, i.e. the difference between the mass withdrawal from a field and the recharge to the reservoir. The mass-balance effects of enlarging steam-zones may also be seen through gravity monitoring. In addition, the mass-balance effects of re-injection may be detected by gravity monitoring. Methods for analysing gravity changes in geothermal fields are presented by Allis and Hunt (1986). Eysteinsson et al. (2000) present an example of the results of gravity and subsidence monitoring in the Svartsengi high-temperature geothermal field in SW-Iceland. Nishijima *et al.* (2000 and 2005) also provide good examples from Japanese high-temperature fields of the application of repeated micro-gravity monitoring for reservoir monitoring.

Repeated *electrical resistivity surveys* have not been conducted in many geothermal fields, but might help delineate cold, fresh-water inflow into geothermal reservoirs, induced by production. Such surveys may also be helpful in locating reservoir volumes affected by re-injection.

Surface activity and heat flow may either decrease or increase during production from a geothermal field. Monitoring of these changes is, however, more often associated with monitoring of the environmental effects of geothermal exploitation. These may be monitored through repeated (a) ground temperature measurements, (b) airborne infrared measurements, and (c) observations of thermal features (hot springs, fumaroles, mud pools, etc.).

The purpose of *monitoring seismic activity* may be two-fold. Firstly, to monitor changes in seismic activity in an already active area, this may be considered environmental rather than reservoir monitoring. Secondly, to delineate the regions in a geothermal reservoir affected by exploitation or re-injection, because in some cases the pressure and thermal changes associated with geothermal exploitation and re-injection may be sufficient to generate some micro-seismic activity.

Water level changes in shallow ground water systems above geothermal reservoirs are monitored in some geothermal fields. *Self-potential monitoring* has been proposed as a tool to study the changes in geothermal reservoirs due to mass extraction and re-injection.

Finally, it may be pointed out that a combination of indirect monitoring with numerical reservoir simulation should enhance the reliability of such models, as wells as aiding in the correct understanding of the nature of the geothermal system involved.

3. RESOURCE MANAGEMENT AND SUSTAINABLE UTILIZATION

In the broad sense geothermal resource management is an extension of geothermal reservoir engineering. Whereas the former addresses key issues such as heat in place, reservoir performance, well deliverability, heat recovery, water injection and reservoir life, reservoir management aims at optimised exploitation strategies in compliance with technical feasibility and economic viability and environmental safety requirements. Pressure decline and temperature depletion with continued steam and heat production raise the essential problem of the reservoir life, a main concern of geothermal reservoir engineers and managers.

Geothermal resource management is also increasingly incorporating aspects pertaining to sustainable geothermal utilization and more general sustainable development. The longevity of the heat extraction should be through a properly balanced production schedule and designed water injection strategies in order to achieve sustainability. This is indeed a challenging accomplishment in which reservoir/ resource management takes on an important role (Ungemach et al., 2005).

Comprehensive and efficient field management is an essential part of any successful geothermal resource utilisation endeavour. Such management can be highly complicated; however, as the energy production potential of geothermal systems is highly variable. The generating capacity of many geothermal systems is, furthermore, poorly known and they often respond unexpectedly to long term energy extraction. This is because the internal structure, nature and properties of these complex underground systems are poorly known and can only be observed indirectly. Successful field management relies on proper understanding of the geothermal system involve, which in turn relies on adequate information on the system being available (Axelsson, 2008).

**An important element of geothermal resource management involves controlling energy extraction from a geothermal system so as to avoid over-exploitation of the underlying resource. When geothermal systems are over-exploited, production from the system has to be reduced, often drastically. Over-exploitation mostly occurs for two reasons. Firstly, because of inadequate monitoring and data collection, understanding of the systems is poor, and reliable modelling is also not possible. Therefore, the systems respond unexpectedly to long term production. Secondly, when large flow rate and consequently heat is delivery from the reservoir larger than hot recharge and any or limited field management have being undertaken.

Geothermal resource management may have different objective, such as (Stefansson et al., 1995):

I. To minimise the operational cost of a given geothermal resource
II. To maximise the energy extraction from a given resource
III. To ensure the security of continuous energy delivery
IV. To minimise environmental effects
V. To avoid operational difficulties like scaling and corrosion
VI. To adhere to the energy policy of the respective country

Real management objectives are often a mixture of several of the objectives listed above. In such cases, the objectives must be placed in an order of importance, since they may in fact be counteractive. One of the more difficult aspects of reservoir management is to determine the most appropriate time span for a given option. There are cases, for example, where depleting a given reservoir in a few year time is more advantageous from a purely financial point of view. This is usually unacceptable from a political and sociological point of view, where a reliable supply of energy for a long time is considered more valuable.

Some of the management options, which are commonly applied in geothermal resource management are:

1) Changed exploitation strategy (increase/reduction production)
2) Implementation of a reliable and effective injection strategy
3) Drilling of make-up and/or stand by wells
4) Changes in well-completion programs (large diameter, changes in casing program, etc.)
5) Search for new production and injection areas
6) Implementation of appropriate scaling control(s) (silica-scaling, calcite-scaling, etc.)

Geothermal utilization involves extracting mass and heat from the geothermal reservoir involved. Mass and heat transfer are, therefore, the dominating processes during the undisturbed natural state, with this transport driven by global pressure variations in the geothermal system. During production, the mass and heat transport forced upon the system causes spatial as well as transient changes in the pressure state of a reservoir. Therefore, it may be stated that pressure is one of the most important parameters involved during exploitation.

Energy content, either represented as internal energy or enthalpy, is the other crucial parameter of during exploitation. In single phase situations, this depends on temperature only, and pressure and temperature define the state of the reservoir. In two phase situations, pressure and temperature are related and an additional parameter is needed, such as water saturation or enthalpy.

The energy production potential of a geothermal system is predominantly determine by pressure decline due to production, but also by the available energy content. The pressure decline is determined by the rate of production, on one hand, and the size of the system, permeability of the rock and hot recharge (i.e. boundary conditions) on the other hand.

The nature of geothermal systems is such that the effect of "small" production is so limited that it can be maintained for a very long time. The effect of "large" production is so great, however, that it cannot be maintained for long. Pressure declines continuously with time, particularly in systems that are closed or with low hot recharge. Production potential is therefore, often limited by lack of water rather than lack of thermal energy.

Water or steam extraction from a geothermal reservoir causes, in all cases, some decline in reservoir pressure. The only exception is when production from a reservoir is less than its natural recharge. Consequently, the pressure decline manifests itself in further changes, which may be summarised in a somewhat simplified manner as follow:

(A) Direct changes caused by lowered reservoir pressure, such as: decreasing well discharge, increase boiling in high enthalpy wells, lowered water level, changes in surface activity.
(B) Indirect changes caused by increase recharge to the reservoir, such as: changes in chemical composition of the reservoir fluid, changes in reservoir temperature conditions, changes in temperature/enthalpy of reservoir fluids

4. LONG TERM RESPONSE MONITORING EXAMPLES

4.1 The Miravalles geothermal field, Costa Rica

The Miravalles geothermal field is located in Costa Rica and went in commercial operation in March 1994, when Unit 1 of 55 MW_e was commissioned. At the moment the installed capacity is 163 MW_e with 5 operating units (2 x 55 MW_e, 1 x 19 MW_e, 1 x 19 MW_e and 1 x 5 MW_e). The annual average electrical production is around 1,200 GW_e. The present steam production field extends over an area of 21 km^2 of which 15 km^2 are dedicated to steam production and 5 km^2 for brine injection. Fifty three geothermal wells have been drilled to date in Miravalles with depths ranging from 900 to 3,000 m; the average production of production wells ranges from 3 to 12 MW_e and injection rates are in the range of 70 – 450 kg/s per well (Moya et al., 2010).

Figure 1 presents the mass extraction history of Miravalles where the beginning of operation of individual units is also indicated.

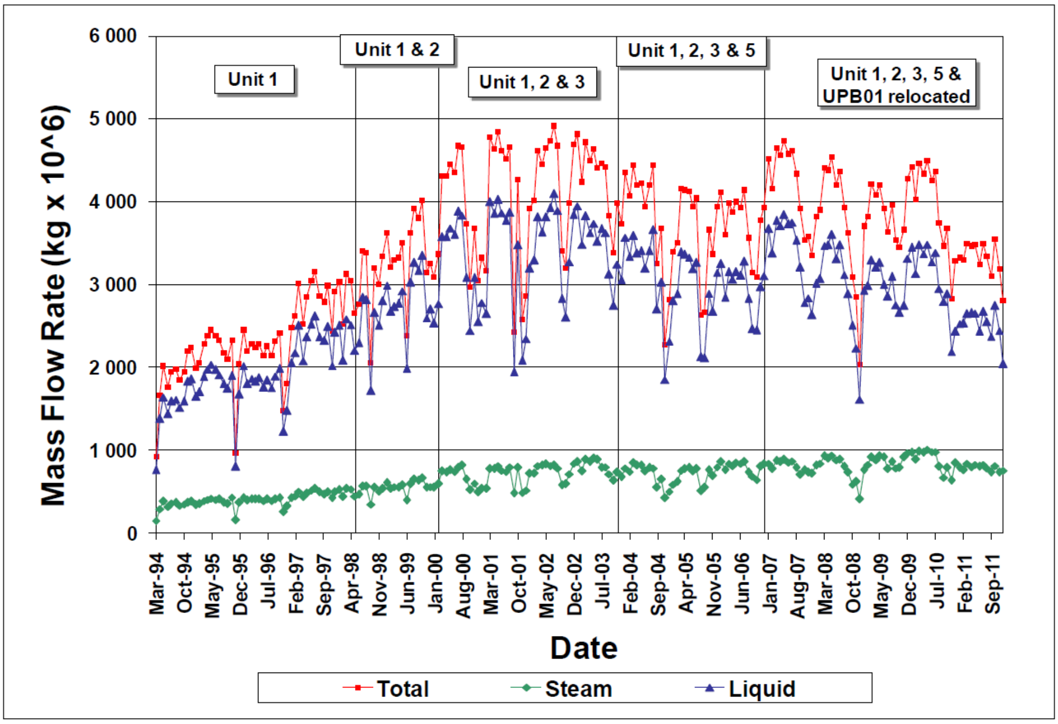

FIGURE 1: Production history of the Miravalles geothermal field in Costa Rica (from Moya et al., 2012)

The main effects observed in the Miravalles field, through monitoring, after 16 years of commercial exploitation, may be summarised as follow:

a) The reservoir temperature has decrease from 240 to 230°C, most evidently in the centre of the main steam production field.
b) The pressure draw-down observed in the reservoir has been of the order of 1.7 bar/year (1.7, 2.0, 1.8, and 1.3 for the respective production periods, see Figure 2).
c) The steam flow delivered from producer wells has declined during the whole exploitation period.
d) Increasing non-condensable gases content in steam, from 0.4 to 1.6%.
e) No data are available regarding calcite scaling due to boiling in the reservoir.
f) The main process affecting the whole reservoir appears to be increased boiling, mainly in the centre of steam field.
g) There is no data available regarding silica scaling in injection wells and pipelines.
h) The possible effects of production and reinjection on micro-seismic activity is being observed in the field.

4.2 The Momotombo geothermal field, Nicaragua

The Momotombo geothermal field is located in Nicaragua and went in commercial operation in 1983 when a condensing type unit of 33 MW_e was commissioned; the presently installed capacity is 77 MW_e while the running capacity has not exceeded 32 MW_e in recent years. Figure 3 presents the production history of the Momotombo power plant.

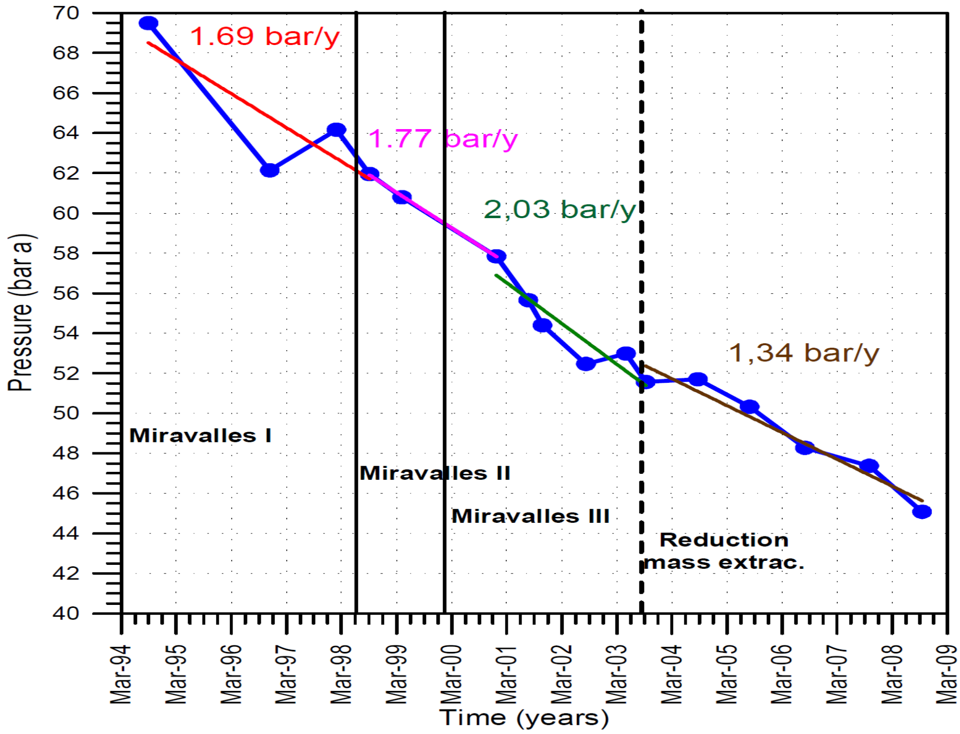

FIGURE 2: Observed pressure decline (monitored in well PGM-31) in the Miravalles geothermal reservoir (Castro, 2010)

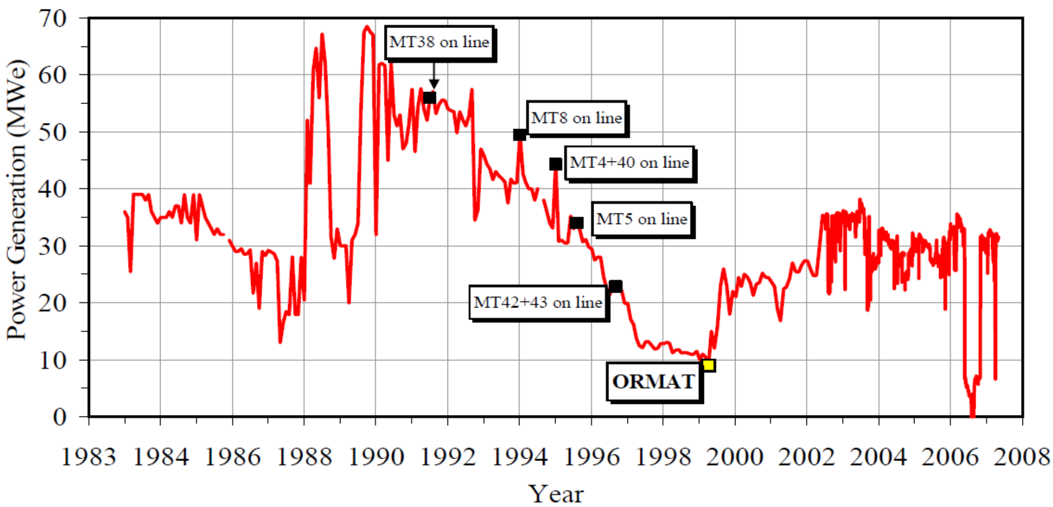

FIGURE 3: Production history of the Momotombo geothermal field in Nicaragua (Porras, 2008)

The main effects observed during long term exploitation of the Momotombo geothermal system can be summarized as follows:

a) Fast decline of steam delivered to the power plant after exploitation started with a corresponding decrease in observed discharge enthalpy, as shown in Figure 4.
b) Cooling effects have been observed in a shallow part of the reservoir since beginning of utilization.
c) Some boiling has also been observed in the shallow reservoir, in spite of the cold water inflow into the system.

d) There are no data available regarding average pressure and temperature drawdown.
e) Some calcite scaling due to boiling appears to be affecting some production wells.
f) There are no data available regarding seismicity related to the exploitation.

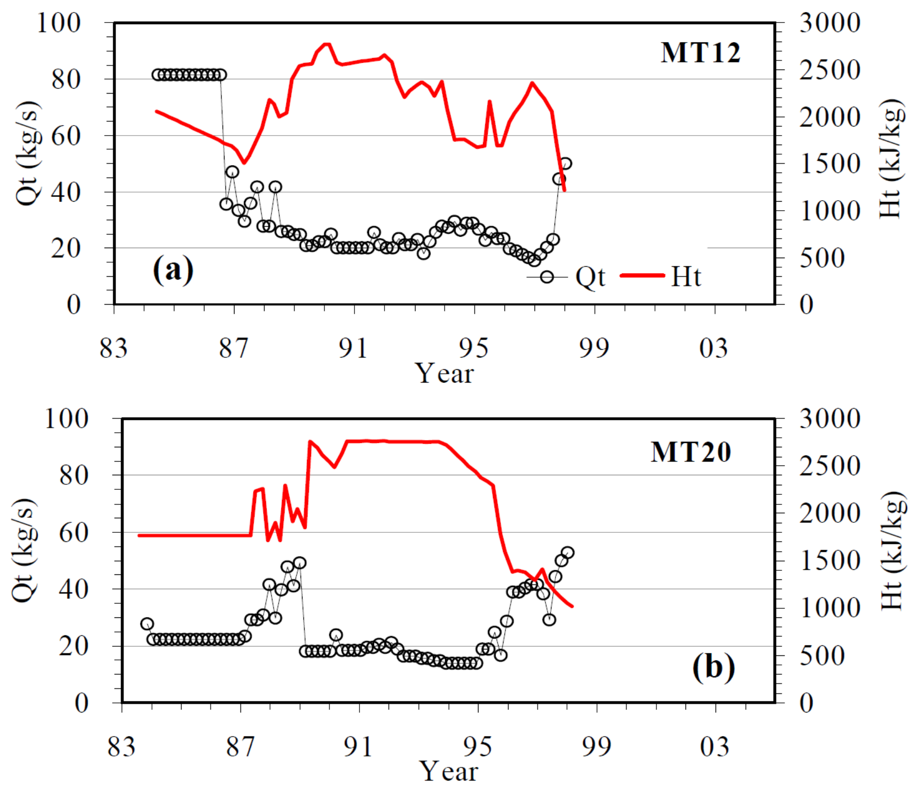

FIGURE 4: Steam flow rate and enthalpy changes monitored in selected wells in the Momotombo field (Porras, 2008)

4.3 The Berlin geothermal field, El Salvador

The Berlin geothermal field is located in El Salvador and went into commercial operation in 1992 when 5 MW_e back-pressure well-head units went on line. Later on the same year two 28.6 MW_e condensing type units were commissioned. In 2007 another condensing type unit of 44 MW was additionally commissioned, and later a 9.2 MW_e bottoming binary unit completed the current total installed capacity of 109.2 MW_e.

At present 38 wells have been drilling in the Berlin field, 14 of them are used as producers and 20 are injectors (4 wells in addition have been abandoned). Figure 5 presents the total mass extraction history of the Berlin system. The total mass extraction has ranged up to 870 kg/s; the steam delivered to the power plant is approximately 220 kg/s at full capacity and the injected brine is 650 kg/s, which is partially injected using a high pressure pumping system located at the site of well TR-1 (Monterrosa 2012).

The total pressure drawdown in the geothermal system is approximately 18 bar, however over the last 12 years the decline has been less than 10 bar, the discharging enthalpy has been fairly constant in most production wells and no evidence of cooling due to injection has been observed in the field. Some boiling is perhaps the main process affecting the reservoir, however.

Some aspects affecting sustainable utilization of the Berlin geothermal system are related to calcite scaling in well TR-18, weakening steam cap in the southern part of the steam field, high concentration of non-condensable gases in well TR-18A and silica plugging of injection wells and pipe-lines, in-particular those connected to the binary unit. As part of the field management several actions have been initiated to reduce the impact of these issues.

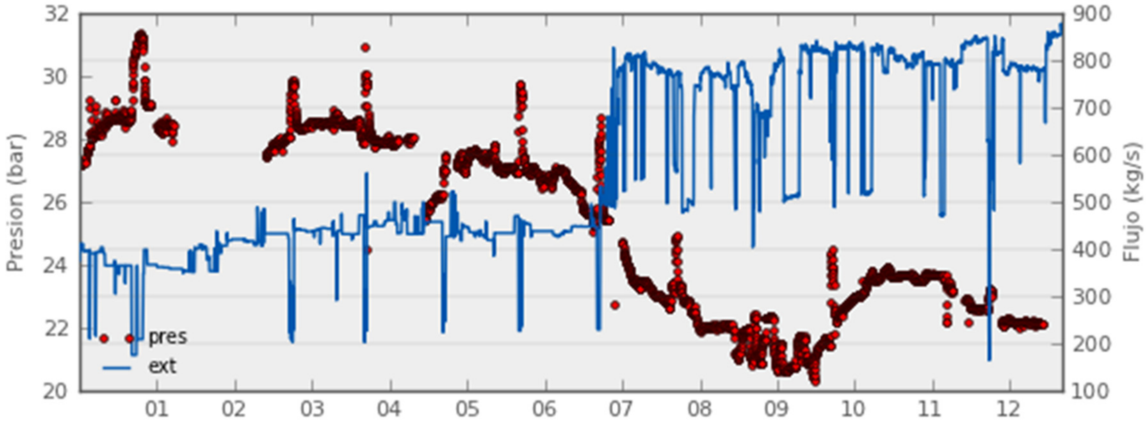

FIGURE 5: Mass extraction and reservoir pressure histories of the Berlin geothermal system (Monterrosa, 2012)

The main effects observed during long term exploitation of the Berlin system can be summarized as follows:

a) The pressure draw-down has reached almost 18 bar and temperature has declined an average 5 – 10°C.
b) The main process affecting the reservoir is increased boiling.
c) There is no evidence of large scale cooling due to injection or due to cooler inflow from surrounding aquifers.
d) The steam delivered to the power plant has declined due to reservoir pressure and temperature decrease, but also due to scaling in the formation around wells.
e) Calcite and silica scaling has been observed in production and injection wells and chemical treatment and/or mechanical cleaning is being used for resource management operations.
f) After 10 years of seismic monitoring no conclusive evidence of micro seismicity related with the exploitation has been observed.
g) High precision topographic level monitoring doesn't indicating any significant effect due to mass extraction from the field.

4.4 Other case histories

Numerous other long-term physical monitoring histories are available, with some published in the geothermal literature. The histories presented above are for high-temperature, volcanic geothermal systems while some histories are available for low-temperature systems as well. The histories of the convective, facture-controlled, low-temperature systems discussed by Axelsson (2011) can e.g. be pointed out as well the history of the Paris sedimentary, low-temperature system (Lopez et al., 2010). The high-temperature case histories of the Ahuachapan geothermal system in El Salvador and Olkaria in Kenya presented by Monterrosa and Montalvo (2010) and Ofwona (2008), respectively, are also noteworthy.

5. CONCLUSIONS

Geothermal reservoirs are affected by mass and energy extraction, mainly causing some decline or degradation of thermodynamic reservoir parameters, steam flow decrease, reservoir cooling, increased boiling and/or chemical scaling in pipelines, wells and/or reservoir formations. Production response monitoring aims at evaluating these changes, but concurrently the monitoring provides some of the most important data on the nature and characteristics of geothermal systems, information which is indispensable for the development of geothermal conceptual models. It is, in particular, essential for the revision of conceptual models previously developed on the basis of exploration and well data.

Reservoir response monitoring is an essential by providing the basis for future predictions and consequently to prevent severe degradation and extensive depletion of the corresponding resource. The main parameter to be monitored are down-hole pressure and temperature for all relevant wells, mass-flow rate and enthalpy of discharging wells, indications of reservoir temperature changes, due to cold recharge or reinjection, and the chemical content of produced fluid. Indirect monitoring, repeated at regular intervals in time, such as accurate monitoring of gravity changes and monitoring of micro-seismic activity, can also be extremely valuable.

A sufficiently high, yet site-specific, monitoring frequency must be implemented to ensure a sufficiently comprehensive data collection. The overall field and resource management, the monitoring is part of, must also be implemented as soon as the energy extraction commences. Changes in operational strategies must be also implemented to attain sustainable utilization.

Similarities can be seen in the production responses of the three geothermal systems, with long production histories presented above. All show indications of some degradation/depletion, yet to a varying degree. Field management programs can be implemented in those fields, however, which will permit their continued operation.

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UNITED NATIONS UNIVERSITY
GEOTHERMAL TRAINING PROGRAMME

LaGeo S.A. de C.V.

RESERVOIR CHANGES DURING EIGHTEEN YEARS OF EXPLOITATION IN THE MIRAVALLES GEOTHERMAL FIELD, COSTA RICA

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ABSTRACT

The Miravalles geothermal field has a liquid dominated two phase reservoir with temperatures of 220-250ºC. Miravalles started to operate in March 1994 with a 55 MWe power plant; nowadays, it produces a maximum of 150 MWe, using three condensing units (131 MWe), one back-pressure unit (5 MWe) and a binary plant (14 MWe). This production represents approximately a 12% of the total energy consumption of the country.

This report includes a brief description and analysis of the data related to the reservoir changes in Miravalles, obtained by the study of different methods. Data were obtained from pressure and temperature monitoring in production and observation wells, from output curves carried out in production wells and from seismic stations located in the zone.

Data analysis shows several changes registered at the reservoir as consequence of the extracted and injected masses in different zones of the field. Some of the most important variations are related with pressure, temperature, enthalpy and seismic activity:

1. INTRODUCTION

Costa Rica is located in the southern part of the Central American Isthmus. The Miravalles geothermal field is located in the southwestern side of the Miravalles volcano (Figure 1). Miravalles was the first field developed in the country, and was inaugurated in March 1994, and today is producing 150 MWe from a combination of three single flash units, a back-pressure unit and a binary power plant.

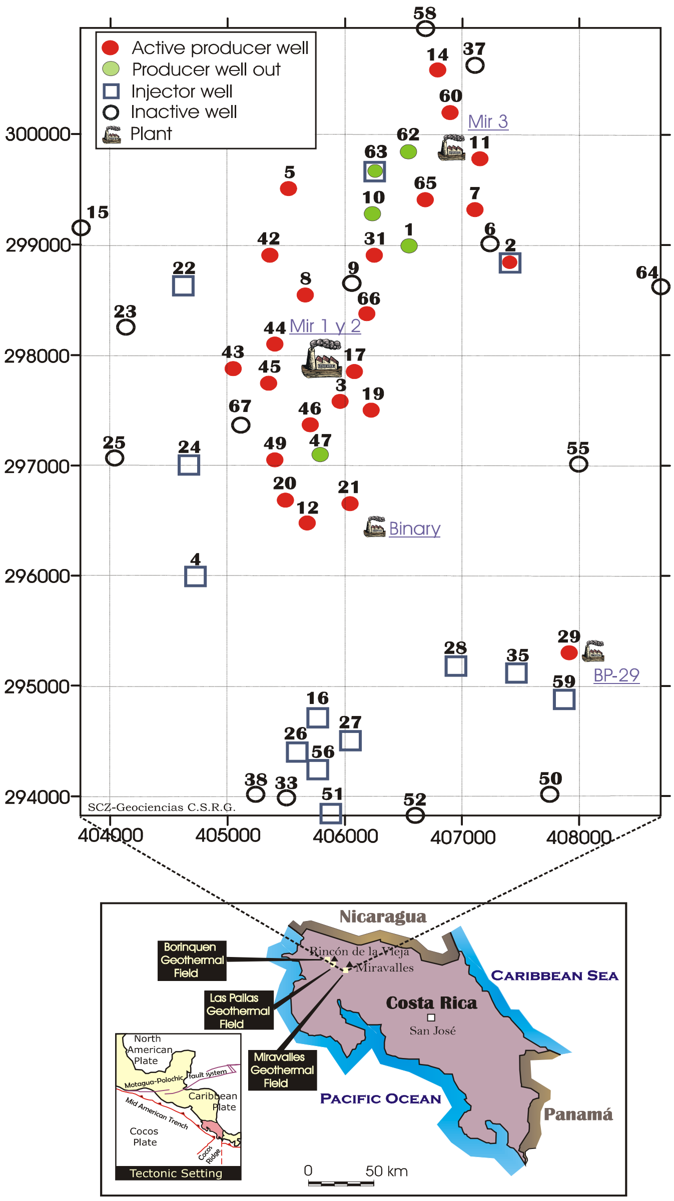

FIGURE 1: Tectonic setting, Costa Rica borders, location of the Guanacaste Geothermal Fields and location of the wells in the Miravalles Geothermal Field (modified from Chavarría, 2003)

After eighteen years of continuous operation, Miravalles has shown significant changes in some of the most representative parameters such as mass, temperature, pressure, enthalpy and seismicity, which have been collected by different methods and/or instruments that allow a analyzing trends in each case.

The calculation of the masses extracted and reinjected into the field was based on information gathered from separation units on the field and it was considered productive assessment conducted annually in each well. Furthermore, the reinjected flow is obtained by measuring the flow regularly sent to each reinjection well using calibrated flowmeters, or from injection curves made for that purpose.

The evolution of the reservoir properties such as temperature and pressure was monitored in the producing and observation wells using Kuster mechanical devices. Data were taken with a frequency of once or twice a year, while information from the producing wells were obtained annually through output tests using the Russel James method.

2. RESULTS

2.1 Extracted and injected mass

The total mass extracted and reinjected into Miravalles reservoir are presented in Figures 2 and 3. Analysis of data indicates that the difference between the sum of the two masses is 17%, this corresponds to the mass fraction of steam that was used to move the turbine at the different plants. Annual values indicate that between 1994 and 2003 occurred a steady increase in the masses used, whereas later, until 2010 flows tended to decrease and stabilize, and finally, for the last two years the masses have fallen substantially.

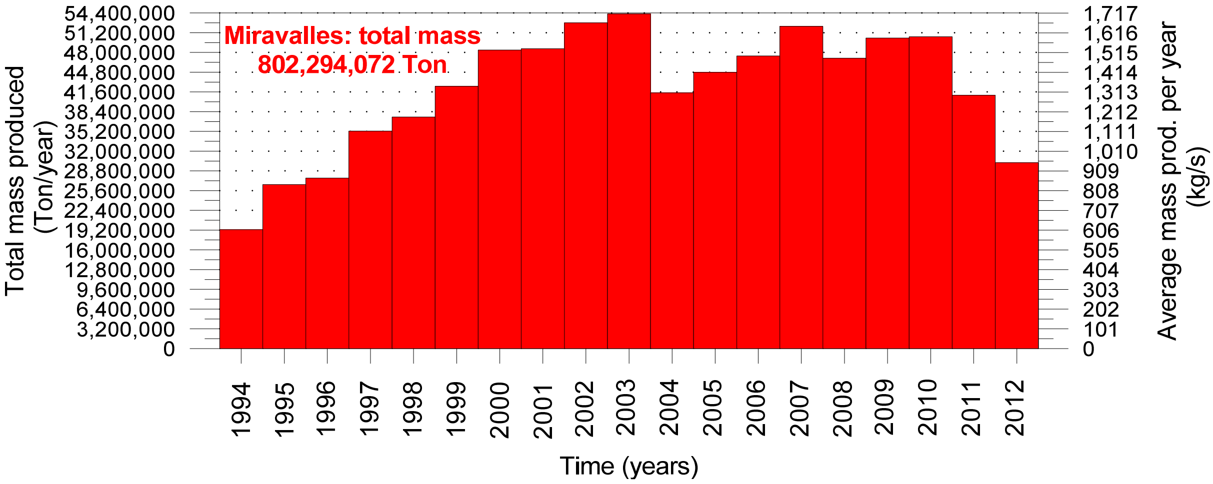

FIGURE 2: Total mass extracted in Miravalles during period 1994-2012

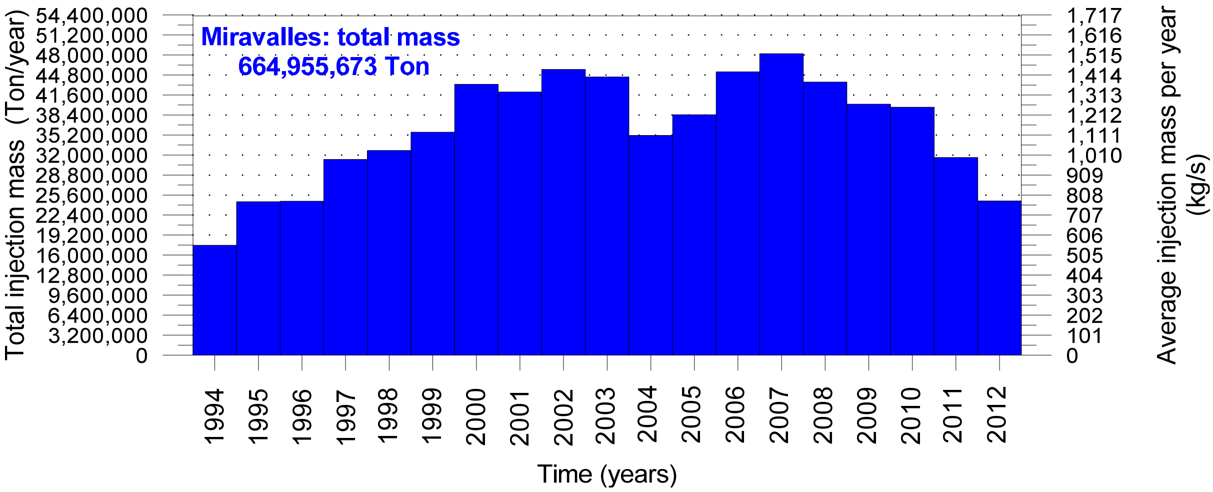

FIGURE 3: Total mass injected in Miravalles during period 1994-2012

Figure 4 shows a map of the masses that have been extracted and reinjected into all wells used in Miravalles. It is noted that the most important producing wells have been the PGM-21, PGM-45, PGM-46 and PGM-17, which provided more than 50 million tons each, while wells PGM-56, PGM-26, PGM-22 and PGM-24 have accepted more than 90 million tons each.

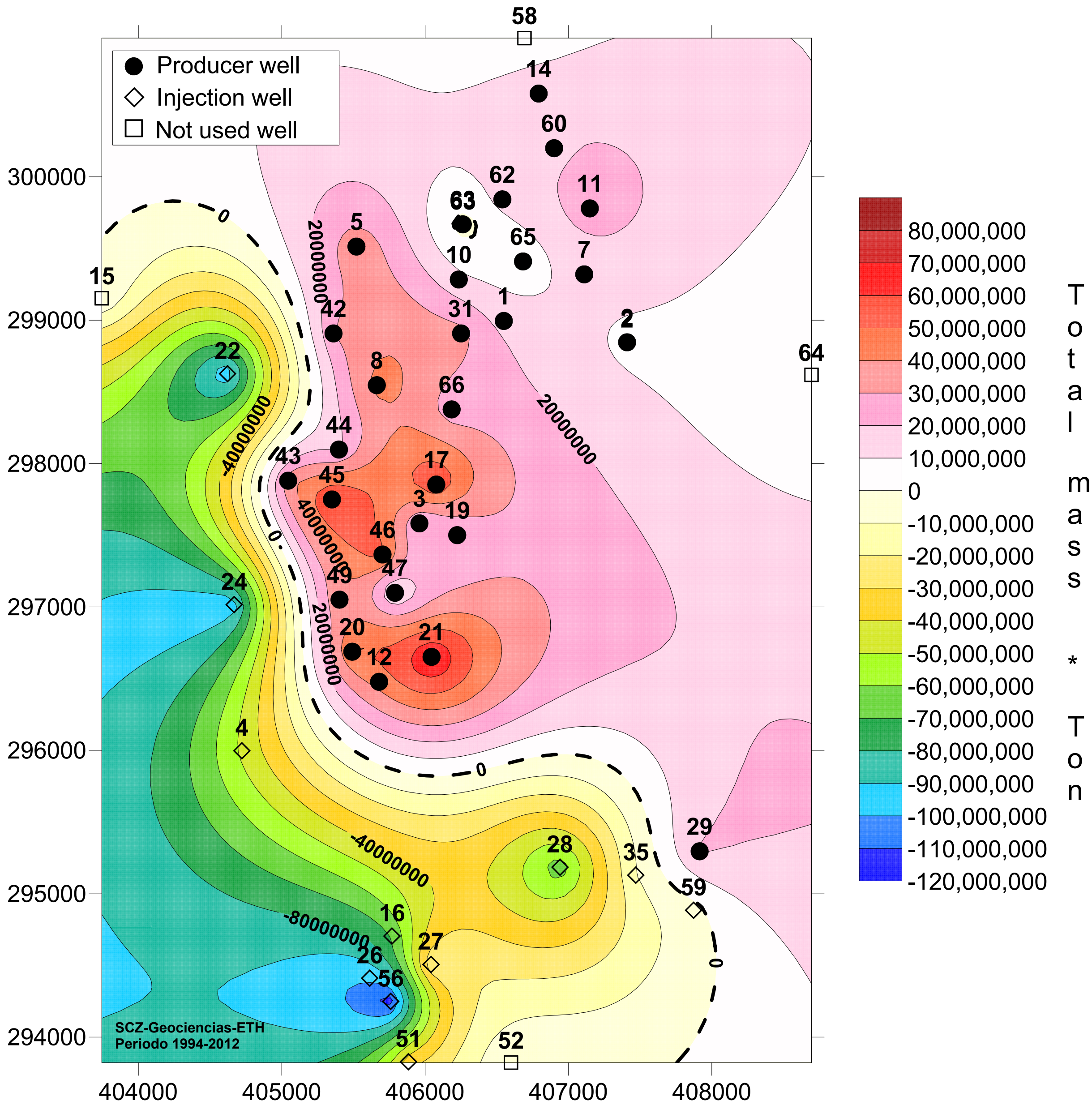

FIGURE 4: Total masses extracted and reinjected in Miravalles during period 1994-2012

2.2 Pressure behavior

Figure 5 shows the static pressure profiles of four producing wells that are located in different areas of the field. Included are profiles taken in the years 1994, 2004 and 2012, in order to observe the total fall during the 18 years of operation and also the difference in falls between the periods 1994-2004 and 2004-2012. The reduction in pressure drop between the two periods is due to both a reduction of the total mass extracted, as the increase of the vapor fraction obtained from the production wells.

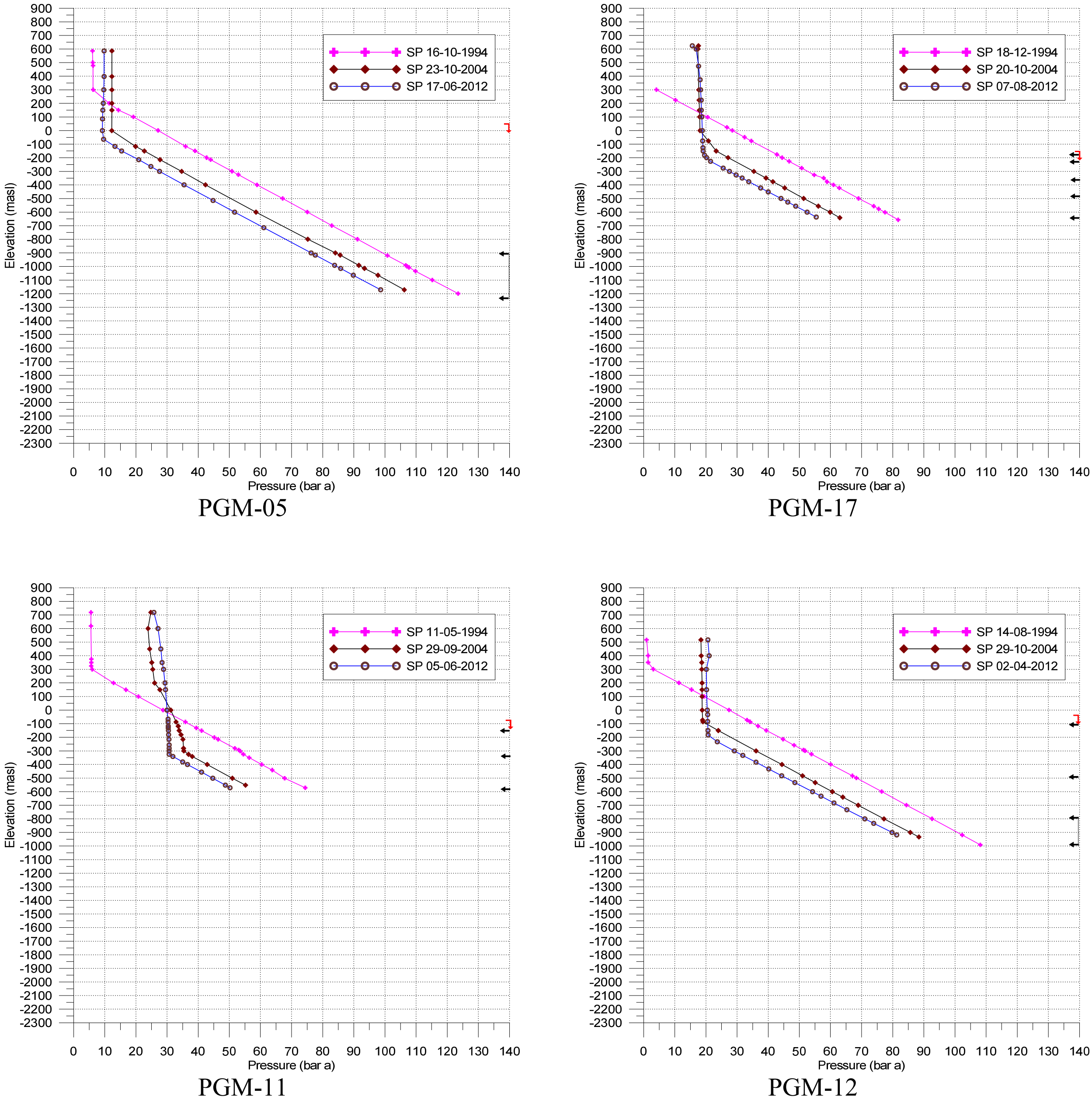

FIGURE 5: Static pressure profiles taken at PGM-05, PGM-11, PGM-12 and PGM-17

Table 1 shows the registered pressure values to the elevation indicated in each well available in 1994 and 2012. It is observed that the pressure drops ranged between 16.2 and 30.3 bars, with an average value of 23.7 bars. These data indicate that in Miravalles occurred an average drop of 1.3 bars per year, which means that the hydraulic level has dropped about 15 m per year.

TABLE 1: Total pressure decrease in the static profiles carried out in some wells of Miravalles

Well	Elevation measure (masl)	Pressure 1994 (bar a)	Pressure 2012 (bar a)	Pres. differ. 1994-2012 (bar a)
PGM01	-215	47.0	22.4	24.7
PGM05	-599	75.1	51.7	23.4
PGM08	-300	52.9	27.7	25.2
PGM09	-1059	114.7	89.9	24.8
PGM10	-700	89.4	59.1	30.3
PGM11	-400	60.4	36.6	23.8
PGM12	-799	92.6	71.0	21.6
PGM14	-97	35.9	10.9	25.0
PGM15	-1000	111.3	95.1	16.2
PGM17	-601	77.5	52.5	25.0
PGM20	-803	93.1	72.6	20.5
PGM21	-921	105.7	81.3	24.4
PGM25	-1543	159.4	134.4	25.0
PGM29	-726	86.3	65.8	20.5
PGM31	-500	69.5	44.8	24.7
PGM47	-694	84.8	63.2	21.6
PGM49	-601	78.7	53.0	25.7

Based on the data of the differential pressure column 1994-2012 of Table 1, was made the map presented in Figure 6, which shows that higher pressure drops are located in the north-central region of the field while the south and west have the lowest pressure drop.

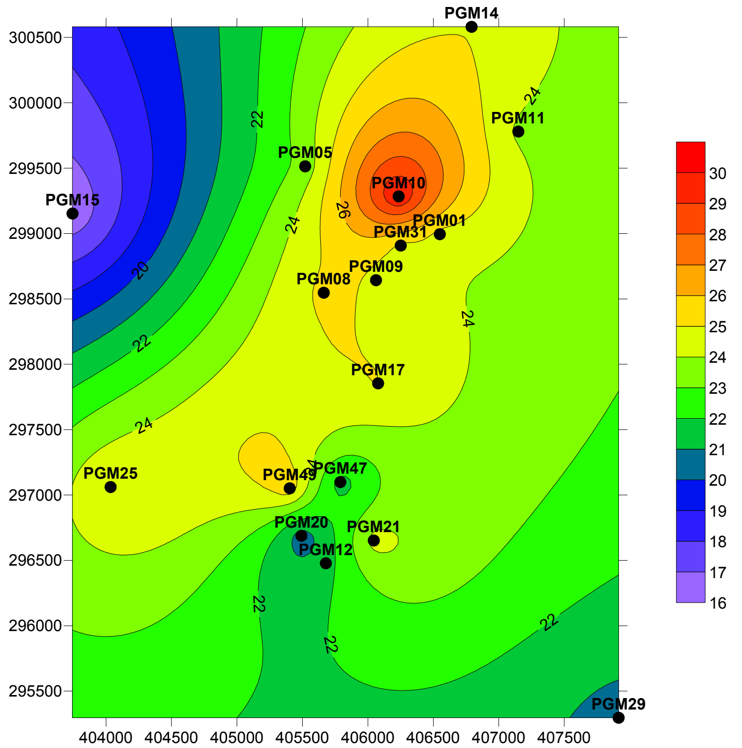

FIGURE 6: Static pressure decline in the period 1994-2012 in Miravalles

2.3 Temperature behavior

The dynamic temperature profiles of the four producers wells identified in the previous section are presented in Figure 7. Included are profiles taken in the years 1994, 2004 and 2012, in order to observe the trend that has presented this parameter in the periods indicated. It is noted that the temperature reduction has varied in each well described, being the PGM-12, the well has a greater cooling and which seems to indicate the influence of fluid reinjection, while in other cases, the behavior may indicate a loss of temperature related to the long period of operation of the wells.

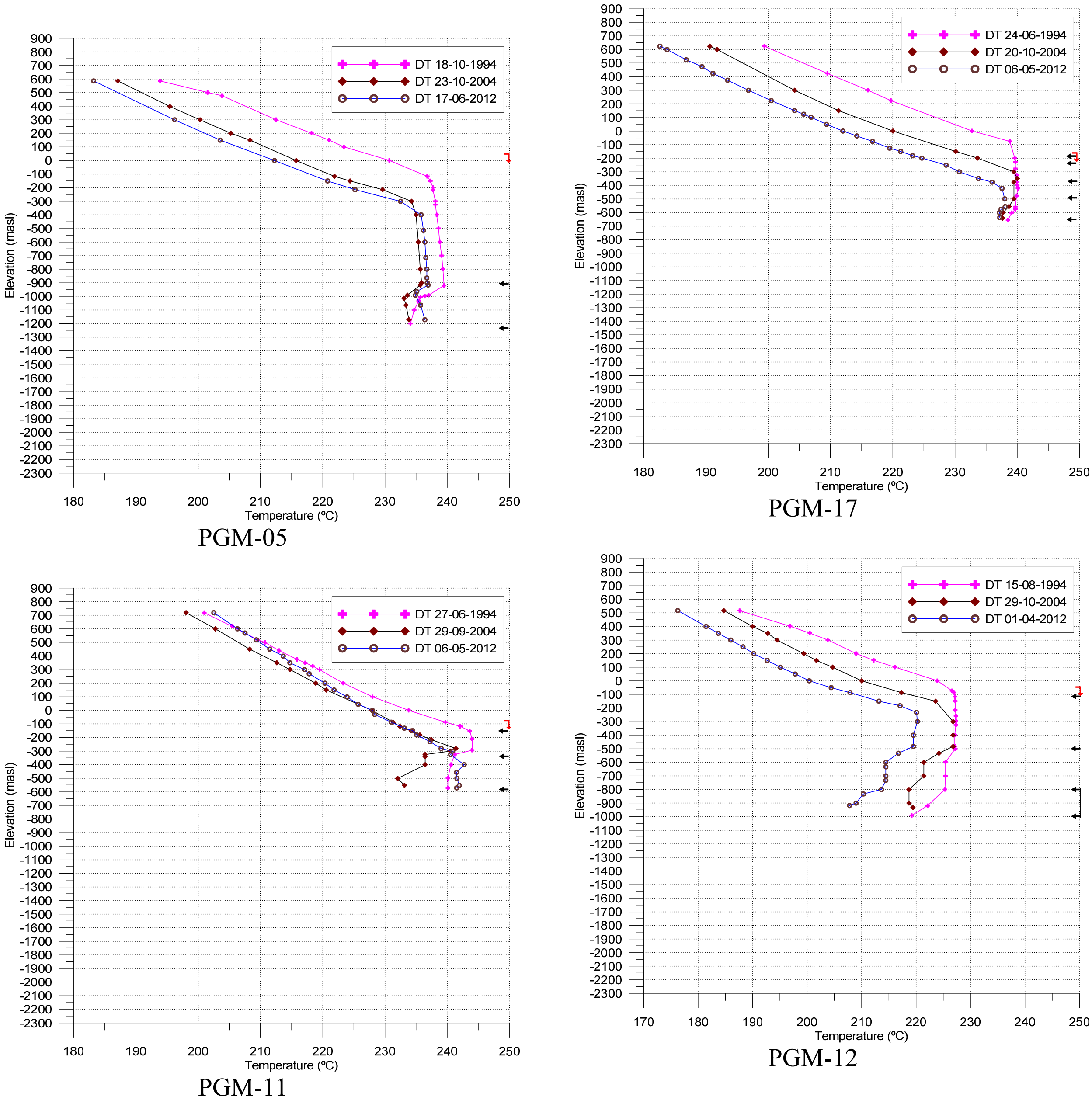

FIGURE 7: Dynamic temperature profiles carried out at wells PGM-05, PGM-11, PGM-12 and PGM-17

Table 2 shows the maximum values of the dynamic temperature recorded in nine wells in 1994 and 2012. Note that this parameter has a variable behavior, with wells that have experienced sharp declines (PGM-49 and PGM-12), others with small decreases (PGM-05, PGM-11 and PGM-17), while the rest wells have produced a slight increase in temperature of between 1 and 3 ° C.

TABLE 2: Temperature variation in dynamic profiles carried out in some wells of Miravalles

Well	Dynamic temperature 1994 (ºC)	Dynamic temperature 2012 (ºC)	Temp. differ. 1994-2012 (ºC)
PGM05	239	237	-2
PGM11	244	243	-1
PGM12	227	220	-7
PGM17	240	238	-2
PGM20	232	233	1
PGM21	231	233	2
PGM29	230	233	3
PGM31	236	239	3
PGM49	232	206	-26

Based on the data of the column temperature difference recorded between 1994 and 2012 in Table 2, was made the map presented in Figure 6, showing the largest decreases in temperature are located in the western and south of the field, while in the central and northern areas the temperature has remained stable.

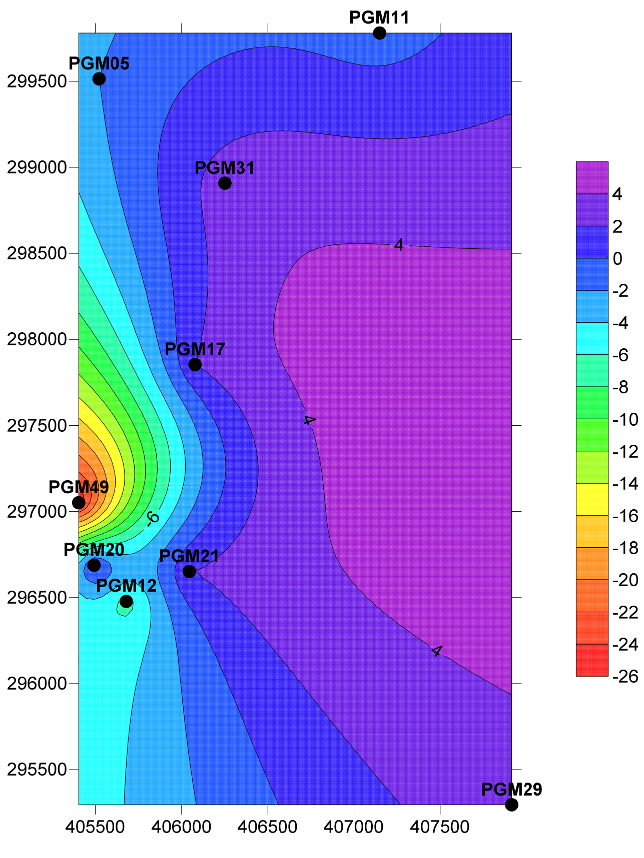

FIGURE 8: Variations in dynamic temperature in the period 1994-2012 in Miravalles

2.4 Enthalpy

Variations in the enthalpy of the fluid produced by the wells, indicates reservoir areas in which there has been an enrichment of steam and those that have been affected by low temperature aquifers, or, by the arrival of brine reinjection. Table 3 lists the values of enthalpy of wells with data from 1994 and 2012, and the fourth column shows the difference in enthalpy between the two years.

TABLE 3: Enthalpy variations in some wells of Miravalles

Well	**Enthalpy**		**Enth. differ.**
	1994 Max. Fl. (kJ/kg)	**2012** Max. Fl. (kJ/kg)	**1994-2012** Max. Fl. (kJ/kg)
PGM02	955	1015	60
PGM03	1190	2007	817
PGM05	1104	1030	-74
PGM08	1030	1197	167
PGM10	1130	1512	382
PGM11	1145	1065	-80
PGM12	1043	944	-99
PGM14	1010	968	-42
PGM17	1025	1048	23
PGM19	1208	967	-241
PGM20	1130	1020	-110
PGM21	992	1000	8
PGM29	981	1105	124
PGM31	1008	1199	191
PGM45	1032	1788	756
PGM46	1009	969	-40

Enthalpy differences described in Table 3 were plotted on the map in Figure 9. The graph shows that the steam enriched zone is located in the central and north-central of the field, while the north and south have seen a reduction of the enthalpy of the fluid.

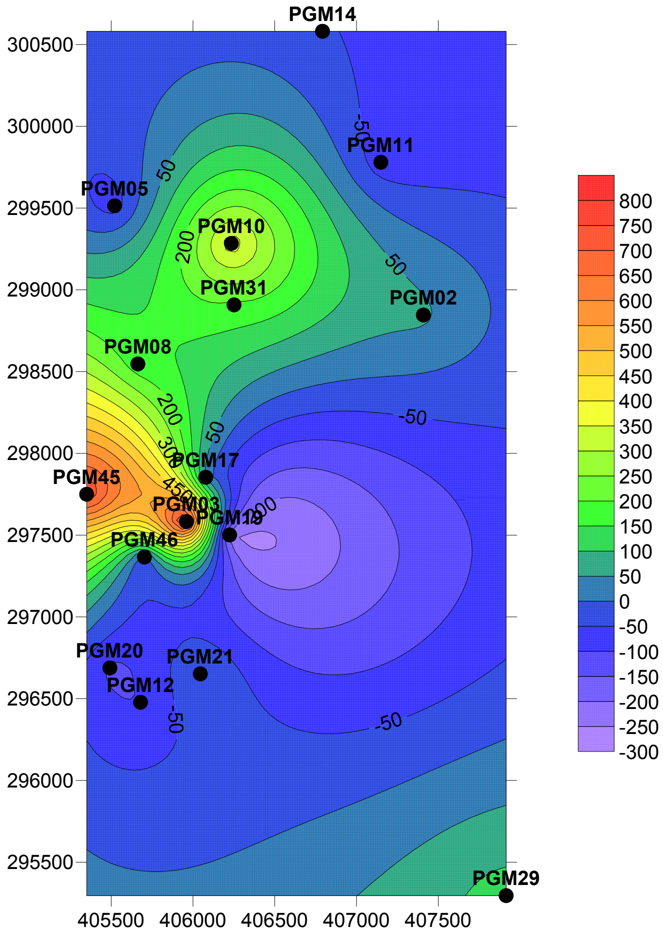

FIGURE 9: Variations in enthalpy in the period 1994-2012 in Miravalles

2.5 Seismic response to exploitation

Due to the large volumes that are mobilized in a geothermal reservoir in the process of exploitation, seismicity must be monitored to analyze the effects on the reservoir itself, and also from the social point of view, on the neighboring towns.
In Miravalles prior to start of operations in 1994, placed several seismic equipment that have provided detailed information on the frequency, magnitude and location of earthquakes.

Figure 10 shows the summary of the number of earthquakes recorded per year during the 18 years of operation of Miravalles. According to the number of earthquakes can define three periods:
- 1994-2000: the seismicity was very small
- 2001-2005: occurs a significant increase in seismicity
- 2006-2012: The number of earthquakes increases significantly

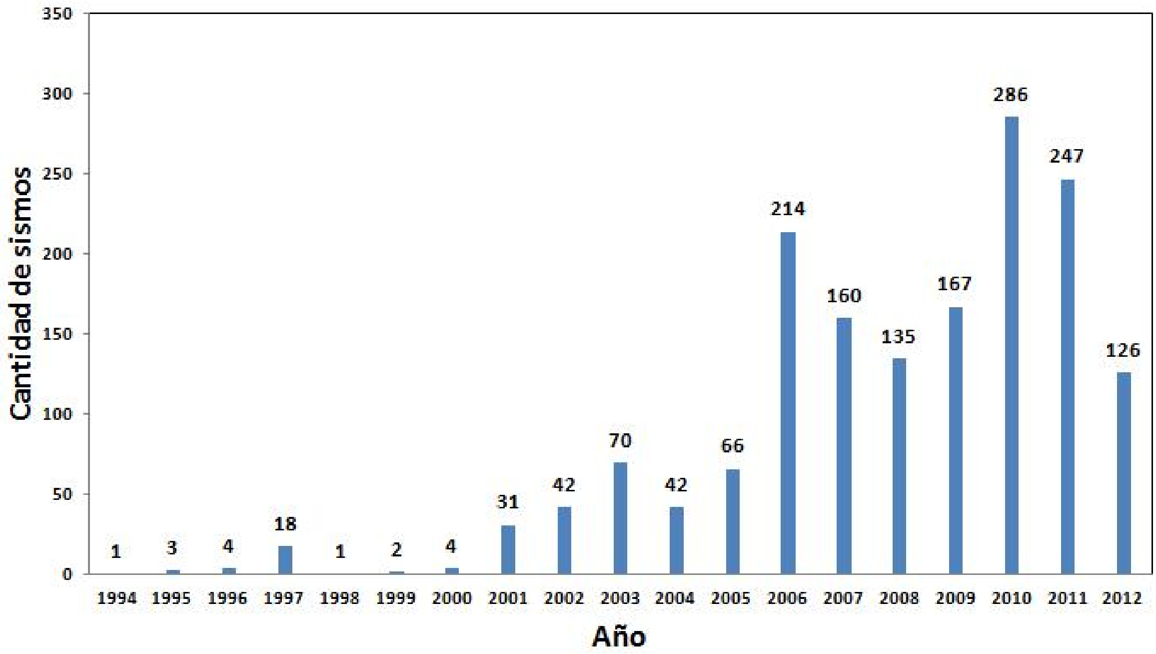

FIGURE 10: Seismic events registered per year in the period 1994-2012 in Miravalles

Figure 11 shows a map of the earthquakes recorded in Miravalles in 2011. It is observed that most seismic activity was located in the central and southern sectors of the field, but in the north also took a significant amount of earthquakes.

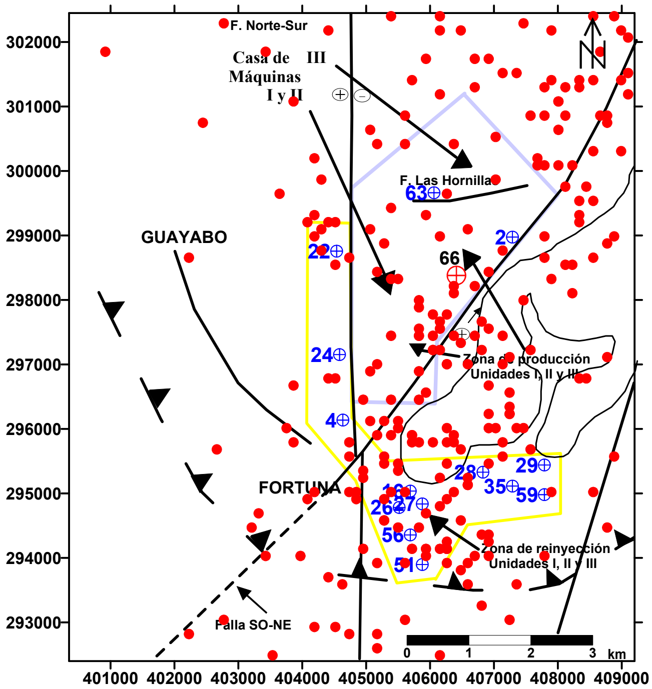

FIGURE 11: Map of seismic events registered in 2011 in Miravalles

3. CONCLUSIONS

Initially the Miravalles geothermal reservoir was a liquid dominant type with some isolated steam zones, which practically no were used in the first stage of field use. After 2000, when the three main plants of the field were incorporated and the amount of fluid extracted grew significantly, several wells showed positive anomalies of enthalpy and in some cases, became in steam producing wells. Furthermore, it has been observed that some wells located near reinjection zones, presented a reduction of the enthalpy confirming reinjected back flow towards the production zone.

Due to the massive extraction of geothermal fluid for 18 years of operation, the reservoir has presented a number of changes that have directly affected the policies of exploitation of the field. Some of the parameters have shown changes are:

-, Static pressure has dropped an average of 23 bars, which indicates that the hydraulic level is about 230 m depth from 1994.

- The dynamic temperature showed a variable behavior but tended to be very similar to that reported in 1994 (average variation + / - 5 °C), however, some wells near reinjection zones have shown a direct effect of these fluids which has caused a drop in temperature greater than 10 °C.

- Due to the hydraulic level abatement in reservoir and the consequent emergence of shallow steam zones in the central and north-central areas of the field, the enthalpies of several producing wells have increased significantly, while in the areas close to reinjection the enthalpies have fallen consistently.

- The recorded seismicity Miravalles area is directly related to the beginning of the exploitation of the reservoir in 1994. Since then the seismic activity has shown an increasing trend in both the number and the magnitude of the events recorded.

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UNITED NATIONS
UNIVERSITY
GEOTHERMAL TRAINING PROGRAMME

LaGeo S.A. de C.V.

CHEMICAL RESPONSE MONITORING DURING PRODUCTION

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ABSTRACT

The chemistry of geothermal fluids plays an important role in the knowledge of the conceptual natural state model of the geothermal field at the initial steps of development, and in the conceptual dynamic model taking into account the evolution against time due to the extraction-reinjection regimes. The geochemical parameters along with the thermodynamic data are periodically and systematically monitored, following the reservoir response to production. A case study for Ahuachapan geothermal field is presented but some particular examples for Berlin geothermal field are also included. Development of the Ahuachapan field has resulted in changes in the chemistry of the discharged fluids, induced by the reservoir´s pressure drawdown. The pressure decline in Ahuachapan wells is mostly located at the central part of the field, where boiling and inflow of a cold recharge is found, resulting to the increase of the shallow steam (steam cap). Influence of peripheral waters is observed in the new southern producing zone, where wells with calcite scaling potential are located.

1. INTRODUCTION

The way a reservoir changes with time has been described as its response to the production load. Geothermal reservoirs change with time as a result of their exploitation. In the natural state, there is a balance of recharge and discharge flows. Through these flows reservoir pressures are kept in dynamic equilibrium with surrounding aquifers. When a reservoir is exploited, the quantity of fluid produced greatly exceeds natural discharge and pressures in the reservoir decrease (or are "drawdown") so that they are no longer in equilibrium (D'Amore, 1991).

Pressure drop with a cold recharge into the reservoir causes alterations in the geothermal system at some extent. In the most extreme condition, cold recharge may cause the reservoir to become unproductive, but only moderate changes are usually observed, e.g. decrease in well discharge, changes in surface activity, water level decline, increased boiling, increased recharge (usually cold water), surface subsidence, changes in fluid chemistry and temperature/enthalpy variations.

Therefore, reservoir monitoring is a key factor in the development and sustainability of geothermal resources. It should start prior to the commencement of exploitation (baseline) and continue throughout its productive life, providing the most valuable source of information to define the best management strategies such as the extraction-reinjection regimes and well operation points.

2. RESERVOIR MONITORING PROGRAMME

The parameters to be measured are different from one system to another, because a particular exploitation regime applied in a particular reservoir will affect differently the chemical, physical and thermodynamic properties of fluids. However, major aspects for monitoring in almost every reservoir include: a) production properties of wells (water and steam flow-rate, well-head pressure, separation pressure, discharge enthalpy, b) chemical composition of discharged fluids, c) downhole pressure and temperature profiles.

Each of the analyzed components provides information on changes in the reservoir conditions. An integrated assessment of available chemical and thermodynamic data from production wells provides understanding of likely downhole processes e.g. boiling and dilution; reinjection effects and evolution of mineral scaling potential.

3. MONITORING CHEMICAL AND THERMODYNAMIC PARAMETERS

Chemical and thermodynamic data from production ad injection wells are necessary for the understanding of main flow-pattern of deep fluids and likely downhole processes. Chemical studies of produced fluids from geothermal wells provide information on the temperature, salinity, physical state and flow of fluids in the reservoir. In the case of wells sunk into a boiling geothermal aquifer, chemical composition of discharged fluids also contribute to the assessment of the reservoir response to the production load as regards recharge and enhanced boiling.

Changes in the chemical composition of water and steam discharged from wells in exploited geothermal systems provide information on the response of the reservoir to the production load with respect to the source of the water recharging producing aquifers (Arnórsson et al., 2000). Data on fluid composition may also provide useful information on the depth level of producing horizons of individual wells. Gas compositions can be used to estimate the initial steam fraction in the aquifer fluid (Arnórsson, 2000), i.e. the steam fraction in the aquifer fluid beyond the depressurization zone that forms around producing wells.

3.1. Geochemistry in the first geothermal development stage

With the new wells, it is necessary to carry out chemical surveys prior to their operation (as a base line), in order to assess the natural reservoir chemistry of the fluids, and thus estimate the type of fluids, the thermal potential, the main operation points (e.g. separation pressure) and the mineral scaling and corrosion potentials of the fluids. Amongst key chemical parameters to be monitored are chloride, Tquartz, TNaKCa, gas content and enthalpies, along with the production characteristics and thermodynamic data.

For instance, according to the results for the Berlin well TR-9 downhole samples from 1991 (Figure 1), chloride content showed a possible feed zone at -1700 m depth, in agreement with temperature data giving a maximum temperature of 290/°C. In most cases, measured temperature was close to quartz temperature and higher than Na/K and Na-K-Ca temperatures.

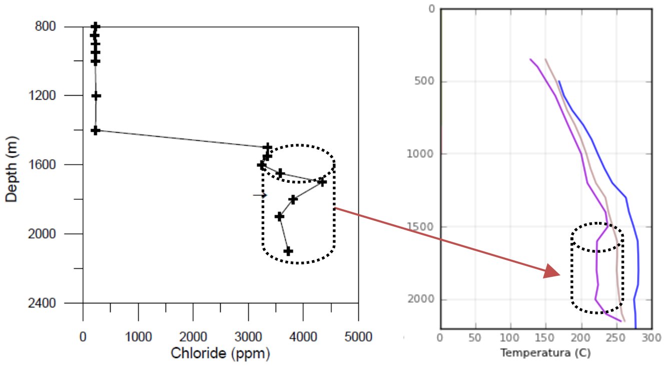

FIGURE 1: Chloride content vs. depth and thermal recovery for well TR-9

3.2 Geochemistry during the exploitation

Periodic chemical sampling of production wells is necessary to evaluate the evolution of the reservoir´s fluid composition. The chemical composition of the total well discharge is estimated through the chemistry of collected samples of both water and steam at the measured separation pressure, and the corresponding steam fraction.

Calculations are carried out as follows:

If the heat content of the total well discharge and its composition is the same as those of the water entering the well, then the mass of any component "*i*" is:

$$m_{i,1}^{d} = m_{i,1}^{s} Y_{l} + m_{i,1}^{w}\left(1 - Y_{1}\right) \quad \text{(Arnorsson, 2000)}$$

In this equation m^d, m^s and m^w stand for the mass of the *i* component in the total discharge, steam and water, respectively. Y_1 is the steam fraction at a particular pressure P_1, and $(1-Y_1)$ the water fraction at that pressure. When availability of chemical data is limited, a practical assumption for solving the former equation is that dissolved solids are negligible in the separated steam phase, as well as non-condensable gases in the separated water phase.

3.2.1 Geothermometry

In a producing field, downhole temperatures may be conveniently estimated through the use of chemical geothermometers, which constitute a very important tool during exploitation in monitoring the response of geothermal reservoirs to the production load.

Fluid geothermometers depend on temperature sensitive reactions of fluids with rock minerals or fluids components. Thus, in a producing field, downhole temperatures may be conveniently estimated through the use of geothermometers applied to analyses of produced fluids, provided the geothermometer reaction is in equilibrium at downhole conditions.

Water geothermometers may be broadly classified into two groups: (1) those which are based on temperature-dependent variations in solubility of individual minerals, e.g. silica, and (2) those which are based on temperature-dependent exchange reactions, which fix ratios of certain dissolved constituents, such as the Na-K-Ca geothermometer.

3.2.2 Chemical changes with time.

Monitoring of the chemical composition of water and steam discharged from wells in exploited geothermal fields provides information about the response of the reservoir to the production load. For this purpose, time evolution plots of geochemical and thermodynamic parameters are normally used.

Since geothermometers are based on reactions with specific kinetic rates, comparison of some geothermometer temperatures may indicate reservoir processes such as boiling or mixing. For instance, different rates of response of the Na-K-Ca and quartz geothermometer combined with the discharge enthalpy provide indications of fluid state and of fluid temperature near and far from wells. Aquifer chloride provides additional indications for dilution and boiling processes. (Truesdell A.H. et al, 1989).

Decrease in the Cl concentration in the discharged water indicates relative increase in recharge into producing aquifers of colder water; however, an increase in Cl indicates recharge from hotter zones. When a well discharges (consisting of components with different temperatures), the result is a discrepancy between geothermometers. The cause of discrepancy may also be a variable departure from equilibrium for individual geothermometers (Arnorsson, 2003).

3.2.3 Boiling and dilution

Geothermal reservoir in the natural state haa a balance of recharge and discharge flows. Through these flows, reservoir pressures are kept in dynamic equilibrium with surrounding aquifers. When a reservoir is exploited, the quantity of fluid produced greatly exceeds the natural discharge and pressures in the reservoir decrease (or "drawdown") so that they are no longer in equilibrium. The volume of fluid removed must be replaced by inflow of colder waters outside of the reservoir or by boiling and formation of vapor. Whether cold water entry or boiling occurs, it usually depends on the permeability of channels to other aquifers. If channels are tight (relatively impermeable), the fluid boils; if they are open, cooler water will enter the reservoir (D'Amore, 1991).

Extensive boiling modifies the composition of the water, which occurs in response to steam formation and degassing, in addition to changes in temperature and pressure, leading to changes in the saturation state of the water with respect to minerals (Arnorsson, 2003).

Boiling and dilution can be estimated through geochemical indicators such as chloride content, and comparison of geothermometers with discharge enthalpy.

3.2.4 Mineral saturation and scaling potential

The mineral scaling potential of geothermal fluids is commonly estimated through the mineral saturation index of aqueous speciation for the aquifer fluid composition at a selected temperature. Based on this approach, oversaturated waters are likely to result on mineral deposition, whereas unsaturated waters are believed to be without scaling potential.

Mineral saturation indexes are calculated with the computer programs specifically suited to handle chemical data (liquid, vapor, gases) from two-phase wells.

3.2.5 Isotopic composition of geothermal fluids

Isotope studies in geothermal contribute to identify the recharge, discharge zone and also other physical processes like boiling, dilution or mixing with inflow of colder waters or reinjection fluids.

As an example, the baseline of the water's isotopic composition at initial conditions in the Berlin geothermal field (see Figure 2) reflects that the water-rock interaction process yields more positive values of δ18O with respect to the isotopic composition of the groundwater. Because of interaction with silicates of andesitic rock instead of carbonic sediments, this process is not locally predominant. For most of the wells with respect to hot springs, the observed slope of δ2H vs. δ18O is positive. The plot also shows the evolution of new wells towards the reservoir´s area. Reinjection wells are located to the right hand side of the plot, clearly apart from production wells, indicating reinjection has no influence in the producing area.

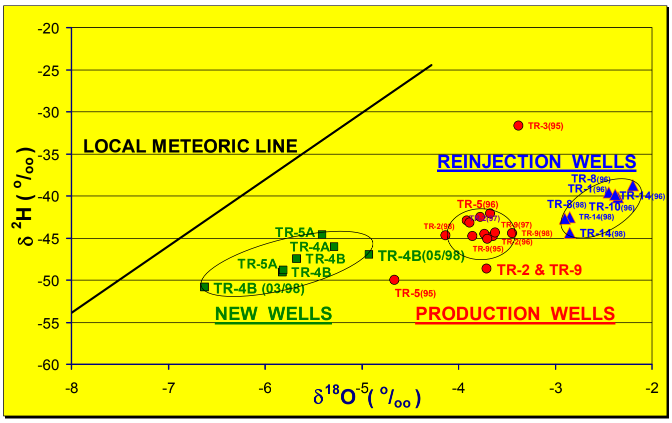

FIGURE 2: Water's isotopic composition at initial conditions in the Berlin geothermal field

4. CASE STUDY: THE AHUACHAPAN GEOTHERMAL FIELD

4.1 General features

The Ahuachapán geothermal field (AGF) came on line in 1975, and was the first geothermal power plant in Central America. The AGF is located in the northwest part of El Salvador (Fig. 1) in a weak tectonic zone, where the movements of fluids are conducted mainly by a fault structure system. The production well field covers an area of 4 km^2 with 53 drilled wells with varying depths between 591 and 1,645 m. Their average elevation is around 800 m a.s.l.

The Ahuachapán reservoir is still considered as liquid dominated. The initial salinity prior to exploitation was 22,000 ppm and the measured fluid temperatures ranges from 214 to 250 °C, with inferred minimum recharge temperatures of 245-250 °C, based on discharge fluid geothermometry (Aunzo et al., 1989).

Since the initial commercial exploitation of the AGF, a monitoring programme of chemical and thermodynamic properties of productive wells has been carried out. Through years, such source of information has been used to improve the understanding of the Ahuachapan reservoir, estimate the reservoir response to changes during exploitation, select potential expansion areas, decide the number of new wells to be drilled to fulfill production requirements, and forecast the most promising production scenarios that guarantee a sustainable use of the geothermal resource.

4.2 Conceptual model

In general, the conceptual model of the geothermal system indicates that hot fluids recharge the reservoir from the S-SE; possibly the upflow zone is found beneath the Laguna Verde volcanic complex. The hot fluids feed the field through major faults, and flows laterally along the permeable Ahuachapán andesites. Some of the geothermal fluids discharge initially through surface manifestations in the Ahuachapán-Chipilapa area; the main discharge of geothermal mixed fluids occurs at El Salitre springs some 6 km N of Ahuachapán field (Figure 3).

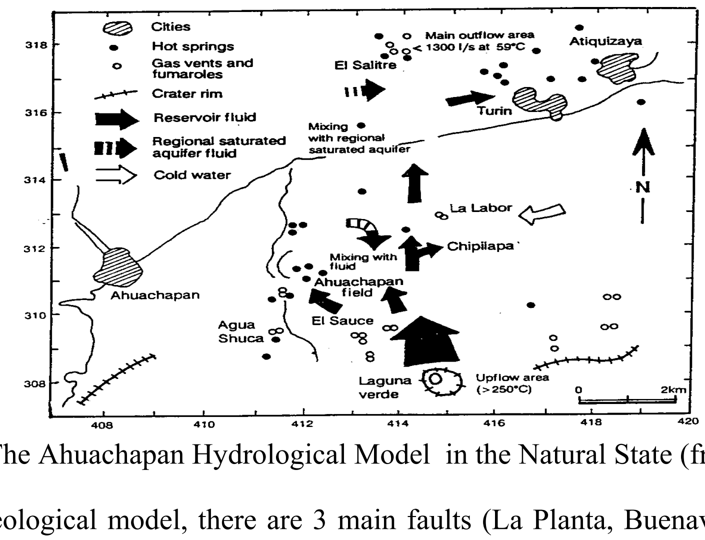

FIGURE 3: The Ahuachapan Hydrological Model in the Natural State (from LBL, 1988)

According to the geological model, there are 3 main faults (La Planta, Buenavista and Agua Shuca) responsible for the upflow to the production reservoir and other secondary faults that control the outflow in the geothermal system. The geothermal reservoir is pressurized with respect to the shallow aquifer and the saturated regional aquifer. This is the reason why, a colder downflow fluid has been identified in the fluid monitoring (geochemical data) during the history of the field, especially in the first years of exploitation.

4.3 Pressure drawdown

Prior to exploitation, the pressure in the geothermal reservoir was near-uniform (about 36 bar-g). Later on, the intensive mass extraction during the early exploitation of the field resulted to large changes in the thermodynamic conditions of the reservoir, mainly a significant pressure drawdown and temperature decline. All changes in the reservoir have been mainly produced by the drop of the initial reservoir´s pressure from 34 bar-g to about 20 bar-g in 1989, and to 18.4 bar-g at present (Figure 4). The stabilization of the reservoir´s pressure achieved in recent years is attributed to a more conservative extraction strategy, as well as the injection of residual waters into the Chipilapa Field.

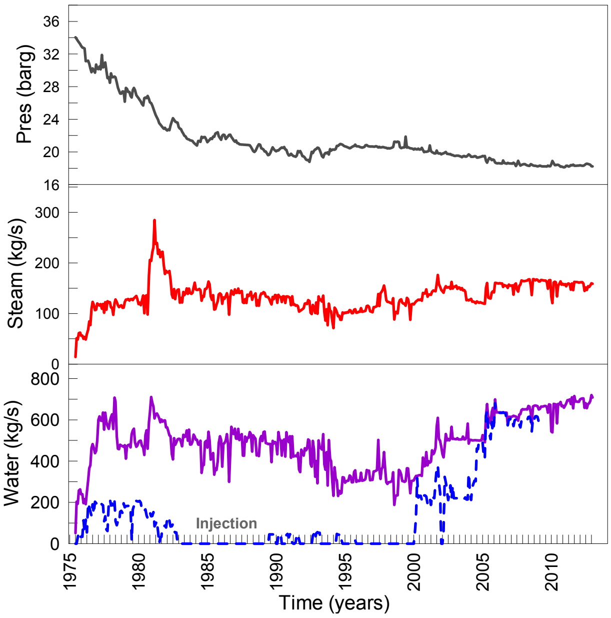

FIGURE 4. Pressure and mass extraction rate in the the Ahuachapan geothermal field

4.4 Production history and reservoir response

It has been established that the dominant physical processes governing the evolution of the reservoir over time, mostly in the first 10 years of operation, consist of boiling in shallower parts of the reservoir (with development of excess enthalpy), and dilution due to recharge of peripheral lower salinity fluids. Estimation of these downhole processes is carried out through interpretation of geochemical and thermodynamic parameters e.g. time comparison of geothermometers, enthalpies, chloride, gas content; distribution of conservative elements; stable isotopes profiles.

4.4.1 Enthalpy vs. time

In the case of the Ahuachapan production wells, estimation of likely downhole processes such as boiling or dilution is carried out through a time series comparison of the temperature indicators Na-K-Ca cation geothermometer, quartz-saturation geothermometer, and discharge enthalpy.

The chemical indicator sequences applied are based on those proposed by Truesdell et al. (1989), except for the use of enthalpies instead of temperatures. The enthalpies are abbreviated as H-NaKCa, H-Sil and DH indicating Na-K-Ca, quartz and discharge enthalpies, respectively.

The enthalpy patterns of some wells such as AH-6 and AH-23 suggest fluid boiling during flow to the well in response to decrease in well bottom pressure (DH > H-NaKCa > H-Sil). According to the results, well AH-6 is a dominant boiling well greatly affected by the depressurization zone with high and constant discharge enthalpy values, whereas well AH-23, whose discharge enthalpies have persistently declined during the last years, is also presently affected by mixing with cooler water. Well AH-31's evidence of dilution, with a dominant pattern HNaKCa > HSil > DH, likely caused by the entry of cooler water into the well through a shallow feed zone, where it mixes with the reservoir fluids. (Figure 6).

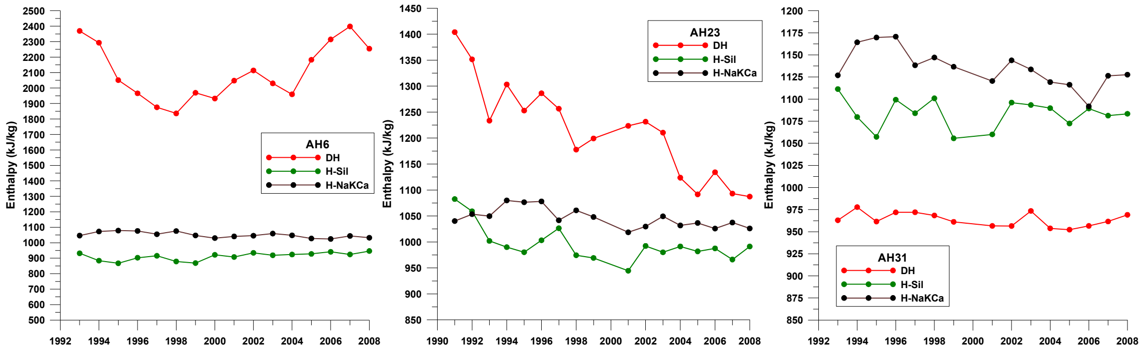

FIGURE 6: Enthalpy vs. time plots for wells AH4Bis, AH-21 and AH-31. Abbreviations: Discharge enthalpy (DH), Quartz enthalpy (H-Sil), Na-K-Ca enthalpy (H-NaKCa)

4.4.2 Water and gas chemistry vrs.time.

Besides geothermometers, other chemical species and ratios are plotted against time using the chemical data collected in the wells, from the start of exploitation until the present.

A decrease of conservative elements such as chloride indicates dilution or mixing of reservoir waters with a cooler recharge, while an increase of chloride is usually related to boiling. When the increase of chloride is accompanied by temperature reduction, some reinjection effect should also be considered.

For example, since year 1999, well AH-6 has shown a clear aquifer chloride increase, suggesting boiling is the main downhole process. On the contrary, well AH-23 has exhibited some decrease of chloride, probable related to the intrusion of less saline water. As mentioned earlier, this well has also experienced a decrease in its discharge enthalpy, a further evidence of dilution. Well AH-31 has shown aquifer chloride declining during the last ten years, probably due to the decreased pressure in the central part of the field, which allows the breakthrough of less saline and cooler water (Figure 7).

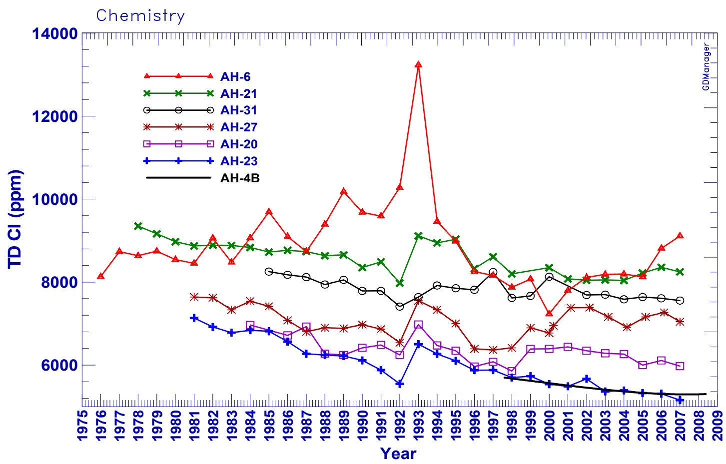

FIGURE 7: Total discharge chloride vs. time for wells AH-6, AH-21, AH-31, AH-27, AH-20, AH-23 and AH-4Bis

In the Ahuachapan geothermal field, the average T Na-K-Ca has decreased over time, suggesting downflow of cooler fluids from the overlying regional saturated aquifer due to pressure decline. On the other hand, CO2 content has not declined after thirty years of exploitation, suggesting an open system with constant inflow of deep geothermal fluids (Figure 8). Chloride and O16 distribution through the geothermal field show a general gradient from southeast to west. The higher values suggest deep reservoir fluids in the central western part of the field. To the east, a cold water inflow lowers the chloride and isotope contents (Figure 9).

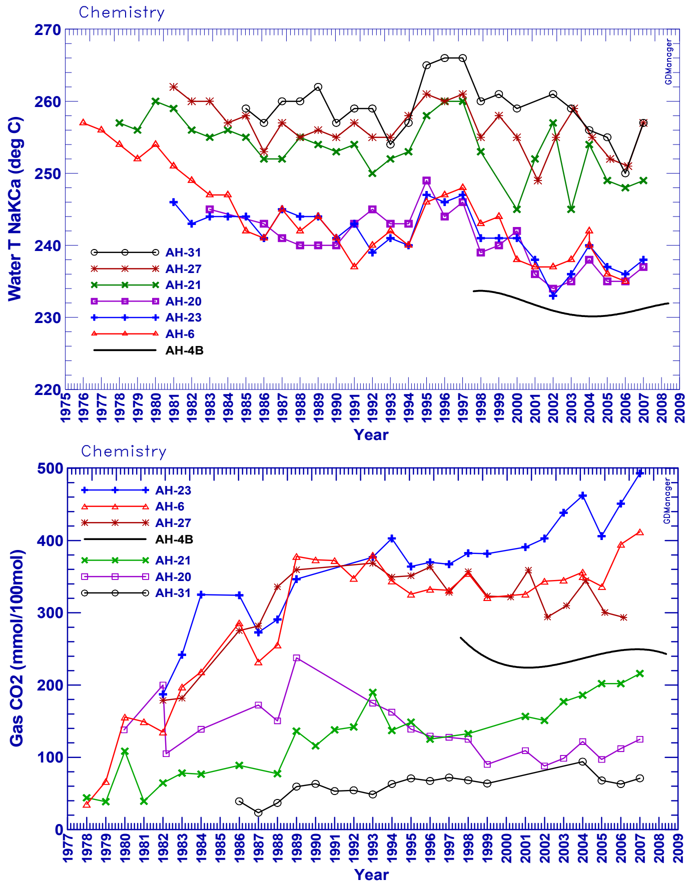

FIGURE 8: Evolution of Na-K-Ca temperature and CO2 content in production wells of the Ahuachapán geothermal field

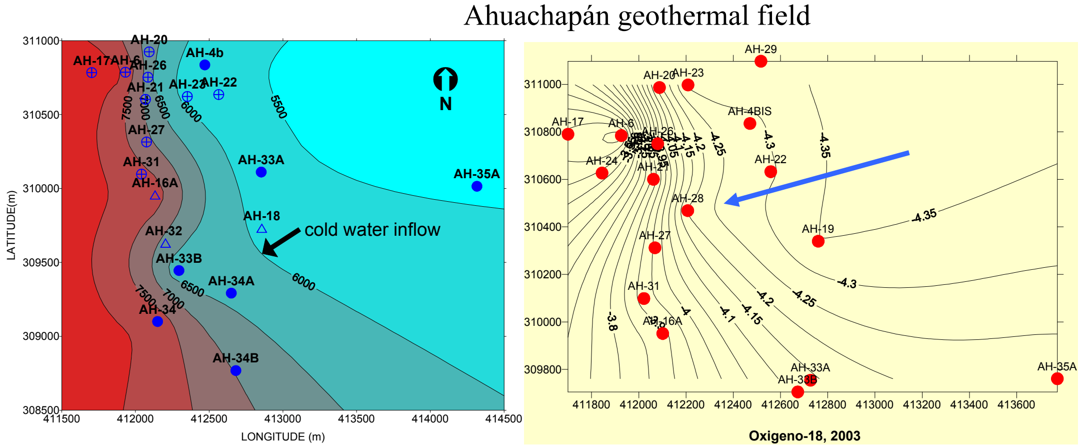

FIGURE 9: Left hand side: Chloride distribution through the Ahuachapan geothermal field. Right hand side: O18 profile in AH production wells

4.4.3 Mineral saturation and scaling potential

Mineral saturation indexes are calculated with the software Watchworks. This allows the study of the chemical changes due to boiling within the well up to surface conditions (100°C,) and how these changes affect the solution/mineral equilibria. The mineral saturation indexes are computed as log (Q/K), where negative values indicate undersaturation, zero stands for equilibrium, and positive values suggest oversaturation (except for calcite, with a scaling potential starting at IS > 0.3).

The major expected minerals in Ahuachapan production wells are anhydrite, calcite, amorphous silica and quartz (Figure 10). According to the results, all fluids are unsaturated with respect to anhydrite and amorphous silica at wellbore conditions. Quartz is in equilibrium within the aquifer, and becomes oversaturated while discharge waters cool down during boiling. Only calcite exhibits different behaviour through the field, with saturated values for southern wells AH-33B, AH-35A, AH-35B and AH-35C, but unsaturated or equilibrium values for the rest of the wells (Figure 10).

All the wells with calcite scaling potential are located in the new expansion area at the southern part of the field. They operate with calcite inhibition systems in order to prevent calcite blockage (Figure 11).

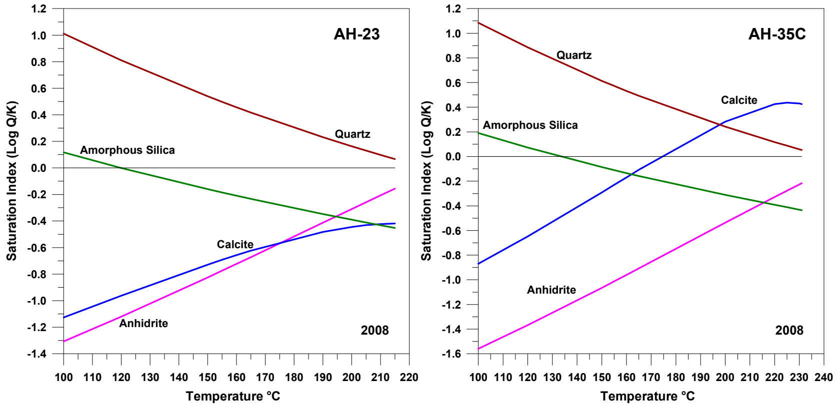

FIGURE 10: Mineral saturation indexes in discharged fluids from wells AH-23 and AH-35C

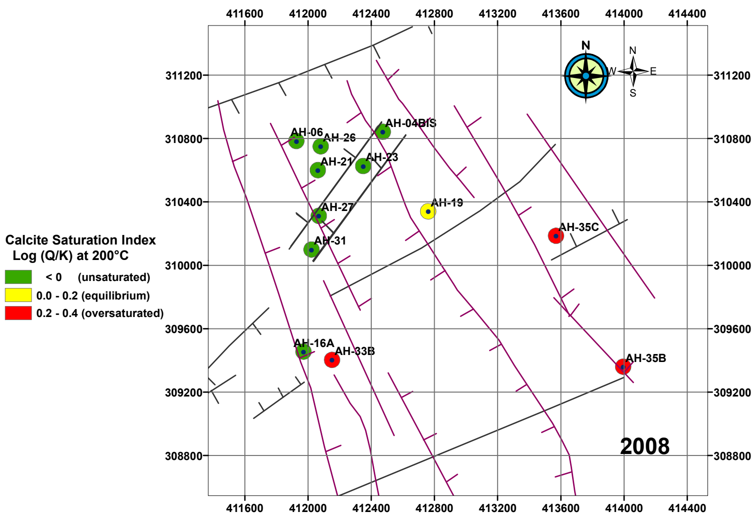

FIGURE 11: Distribution of Calcite saturation indexes through the Ahuachapan wellfield. Wells in red color are calcite oversaturated at 200˚C, and are likely to result on calcite scaling if are operated without any calcite inhibitor

The only reported case of a silica scaling problem in the production area occurred in 1990, specifically in well AH-17, a dry steam well. The origin for silica scaling problems only can be related to the contamination of the upper steam zone by the lower liquid feed zone above, but due to the lack of chemical history it is not possible to do a detail analysis. After cleaning in 1992, well AH-17 has being operating at higher well-head pressure and without any evidence that the problem has returned. Figure 12 shows the well head pressure decline during the scaling problem.

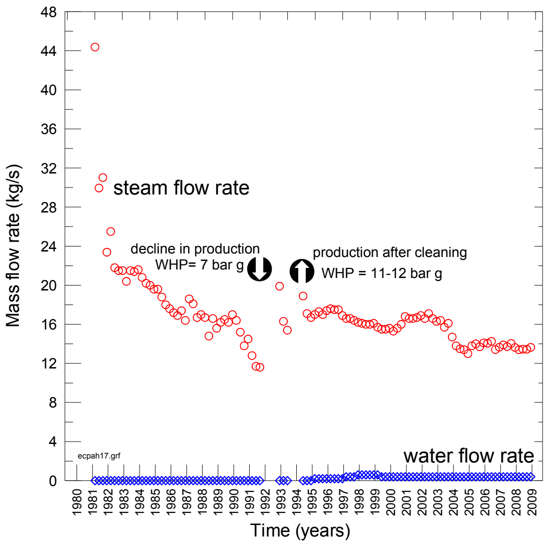

FIGURE 12. Decline in steam flow rate due to the pressure drawdown and scaling problems

4.4 Hydrogeological conceptual model under exploitation

Through the years, the extraction of fluids has affected several geochemical parameters. Significant changes occurred mainly in the early years of operation due to dilution, as the reservoir chlorides decreased from 9000 to 6000 ppm and the content of silica was lowered from 600 to between 350 and 500 ppm. However, some wells exhibited a boiling process as chlorides increased above 9000 ppm and the content of non-condensable went from 0.3 up to 1 wt%. The cationic geothermometers have remained rather constant but that of silica has decreased in recent years in most wells, ranging from 215-220 °C, in accordance with the measured temperatures and as a result of cooling caused by the aforementioned processes. The average temperature measured in the reservoir has dropped between 15-20 ° C.

Wells located at the western and northwestern parts of the field discharge a mixture of fluids from a hotter feed zone and a cooler feed zone, the first ones likely related to the steam cap. Presently, the depressurization zone has extended to most of the shallow and old wells in the field and it seems to promote boiling and mixing; some wells exhibit both processes.

Geochemical data suggest dilution in a north-south trending zone that coincides with several major faults suggesting downflow of cooler fluids from the overlaying saturated aquifer. The chloride content and geochemical thermometers show higher values in the western part of the production field (about 8000-9000 ppm and 260 °C) than in the eastern part (about 7000 ppm and 240 °C), suggesting that the dilution process occurs mainly from the N-NE direction. However, a diluted fluids supersaturated with calcite has been founded at the S-SE part, despite the fact that the highest measured temperature (250°C) is also registered in the new expansion area (Figure 13).

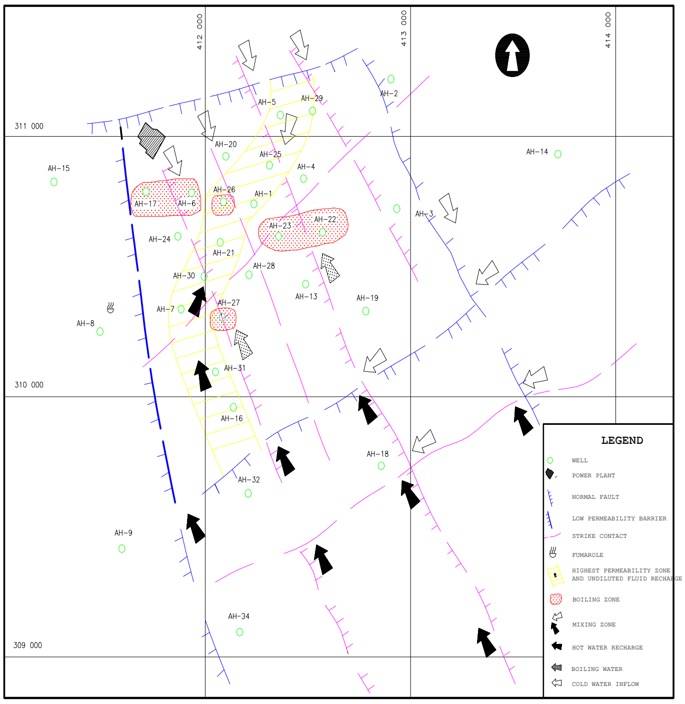

FIGURE 13. Hydrogeological Exploitation Conceptual Model of the Ahuachapan geothermal field

5. CONCLUSIONS

The normal behavior of a liquid dominated reservoir is to reduce the reservoir pressure during the early stage of exploitation, this it is not a dramatic situation if there is injection into the system and a complete monitoring is available. The monitoring must include at least mass extraction and injection, chemistry of fluid, reservoir pressure monitoring, tracer tests and geothermal surface monitoring
Two main processes are affecting the reservoir of the AGF: a) boiling is present in the shallow part of the system, characterized by increasing enthalpy in the production wells, higher gas and water chemical content; b) dilution or cold water inflow occurs in some part of the reservoir where the declining pressure induce inflow from neighboring aquifers (lateral or above).

The injection could produce effects like boiling and dilution together, and must be carefully analyzed and monitored. Tracer test could be helpful to determine how the injection process is affecting the neighboring wells; chemical and isotopic monitoring must also be undertaken.

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MICRO SEISMIC MONITORING DURING PRODUCTION UTILIZATION AND CASE EXAMPLES FOR MEXICO

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ABSTRACT

Seismic networks in the geothermal fields of México have operated since the 1990's. This paper reports the results and applications of the micro seismicity recordings in Los Azufres, Los Humeros and Las Tres Virgenes Geothermal fields in México. The information generated in those fields is useful since micro seismicity is a support tool for defining drill targets of production and injection wells, as well as to identify fluid movement in the subsurface, which can be related to permeable zones. It has been shown that seismic activity within the Mexican geothermal fields, associated with the production and injection strategy, does not exceed the 3.5 degree magnitude, so no major events associated with the operation of the reservoir are produced, that may constitute a risk to people or infrastructure.

1. INTRODUCTION

Geothermal energy in Mexico is almost entirely used to produce electricity, since its direct uses are still under development and currently remain restricted to bathing and swimming. The net installed geothermal-electric capacity in Mexico as of December 2010 is 958 megawatts (MW). This capacity is currently operating in four geothermal fields: Cerro Prieto (720 MW), Los Azufres (188 MW), Los Humeros (40 MW) and Las Tres Vírgenes (10 MW). However, the running capacity is less than that, because of production decline mainly at Cerro Prieto geothermal field, one of the largest geothermal fields in the world. All of the geothermal fields and power plants are owned and operated by the governmental agency CFE (Comisión Federal de Electricidad). Electric uses of geothermal are planned, developed and operated by the Gerencia de Proyectos Geotermoeléctricos – the geothermal division of the CFE, (Flores-Armenta, 2012). In 2012, 221 production and 29 injection wells were operating in Mexico at the geothermal fields of Cerro Prieto, Los Azufres, Los Humeros and Las Tres Vírgenes. (Gerencia de Proyectos Geotermoeléctricos, GPG, 2012).

During the operation of a geothermal reservoir, stress changes occur which can be generated for several reasons; sudden release of energy in the ground, by the collapse of a geological structure, reactivation of geological structures, by exploitation of the geothermal resource and re-injection; these changes can be measured using the technique of microseismicity.

The use of geothermal microseismicity is significant since it is a powerful tool when combined with other subsurface measurements, resulting in an increase of the knowledge of the reservoir, useful for decisions making, when the exploitation strategy and the reservoir response is linked; in this way it can be observed that zones with high seismicity can be related to high permeability zones, those zones are very important in the development and profitability of the projects.

This article documents the use of this tool and it is illustrated with case studies of geothermal fields in Mexico.

2. UTILIZATION OF MICRO SEISMIC MONITORING

Monitoring of passive micro seismic activity among the geothermal fields in Mexico, aims to identify active faults, fractured or permeable zones, and the relationship that can be inferred with geothermal water injection and / or extraction of geothermal fluid in the subsurface, which may be related to the geothermal reservoir. These zones can manifest themselves due to the occurrence of very small seismic events, called microseisms, which originate due to the geothermal fluid movement or the reactivation of existing fault systems.

Seismic monitoring confirms the changes in the local stress and the presence of activity in areas where seismic activity had not been observed. Micro seismicity normally occurs in a place even before the operation of a geothermal field, but it might increases during the operation of the same due to numerous reasons.

Additionally the micro seismicity is a support tool for setting the objectives for production and injection new wells, joint to the resistivity and geology studies, as well as geoelectric gradients associated with structural systems matching the hypocentral location of seismicity. Also, having a comprehensive catalog of micro-earthquakes, it is possible to calculate the b-value, which is used to delineate indirectly the presence of magma beneath the reservoir (high b-values) or the lack of magma at the subsurface (small b-values).

Study cases for Los Azufres, Los Humeros and Las Tres Virgenes geothermal fields will be discussed as follow.

2.1 Los Azufres Geothermal Field

Los Azufres is the second geothermal field operating in Mexico. It is located in the central part of the country, 250 km away from Mexico City, and lies within the physiographic province of the Mexican Volcanic Belt in a pine-forest at 2,800 masl. The first power units were commissioned in 1982, and presently there are 14 power units in operation: one condensing of 50 MW, four condensing of 25 MW each, seven 5-MW back-pressure and two 1.5-MW binary cycles. The total installed capacity is 188 MW. (Flores-Armenta, 2012).

Three structural systems are identified in the whole field. The oldest of them is the NW-SE system, the NE-SW is intermediate in age, and the most recent is the E-W. Most of production wells are associated to this later and to its intersection with the others. (Pérez-Esquivias, 2001).

The seismic network in this area consists of five seismic stations which are distributed optimally in coverage to record as many earthquakes that occur on the field (Figure 1).

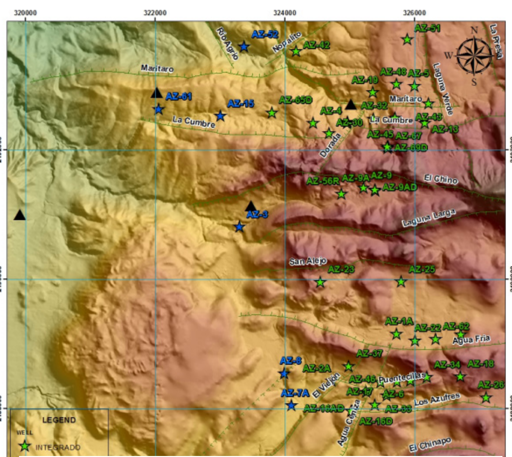


FIGURE 1: Distribution of the seismic network

These stations have digital seismographs, triaxial and broadband CMG-6TD Güralp, owned by the Universidad Nacional Autónoma de México (UNAM). The equipment continuously records 100 samples per second per channel, in a solid state memory with capacity of 2 GB. The equipment has GPS, for timing control.

To locate the seismic network detected, the Hypocenter program was used (Lienert, et al., 1986). The velocity model used in this study is presented below (Table 1):

TABLE 1: Velocity model

P Wave Velocity (km/seg).	Depth (km).
3.5	0.0
4.0	1.0
6.0	3.0
6.5	15.0

To illustrate the usefulness of the data obtained from the seismic monitoring, the period from November 2011 to October 2012 was selected. There were located 121 seisms of tectonic type with three or more seismic stations in the vicinity of the Azufres Geothermal Field. The seisms, which magnitudes vary between 0.3 and 1.7 degrees, are located primarily in the western sector of the seismic network. The depths of the hypocenters are generally less than 3 km (the average depth of the hypocenters at the geothermal reservoir is 2.4 km), although seisms a little further away from the reservoir have been detected, with depths of 11 km beneath the surface. Between the seismic activity reported, we observed two swarms of earthquakes in the vicinity of injection wells AZ-15 and AZ-61; on January. 14th with 16 seismic events, on May 25th with 15 seismic events; those seismic swarms, define an alignment or a tendency NW-SE and NS (Figure 2). While these possible fractured zones have not been mapped through the geological area surface, the seismic alignment NW-SE correlates well with a geoelectric gradient with the same direction, which indicates a possible major active structural system (Figure 3), since as mentioned earlier, it might represent a fractured area, with permeability and possible high temperature, so it is considered a potential area for new locations of wells.

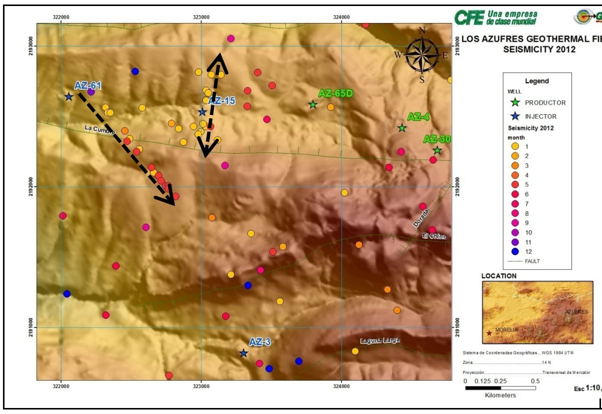


FIGURE 2: Los Azufres Geothermal Field Seismicity 2012

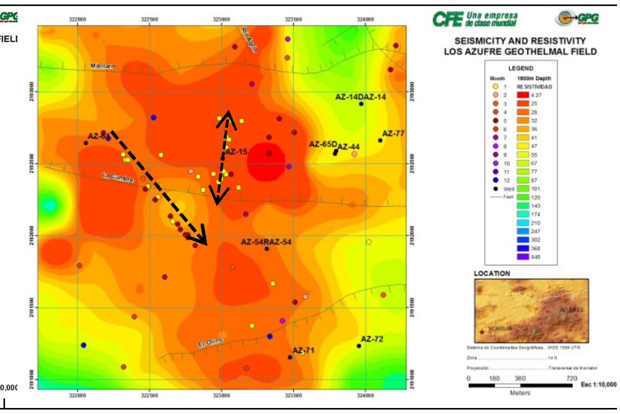


FIGURE 3: Los Azufres Geothermal Field Seismicity vs Electromagnetics

Another analysis of importance that begins to be used in this field, is the calculation of the B value, which is the value of the line's slope that best fits the linear part of the logarithm of the cumulative number of events and the magnitude into a region, according to Gutenberg and Richter relationships. High b-values are associated with the presence of magma, while the absence of high B-value, suggest a lack of magma, (C. Valdez-Gonzalez, 2012). Other factors that produce high b-values are the presence of hot fluids in geothermal systems or highly fractured systems, acquired by past eruptions. With this recorded seismicity at Los Azufres, the b-value calculation was performed and plotted in a three dimensions figure (Figure 4). This chart shows that there are high b-values in the South and Southwest location of the "El Chino" seismic station, and that at depth, the maximum b-value occurs approximately among 2 to 4 km below the surface. The high-B values calculated with this technique also corresponds to the higher temperature isotherms in Los Azufres, so this methodology is also useful to identify sites with higher temperature or heat ascent zones, to locate new production areas and could also identify the approximate location of the heat source of the system

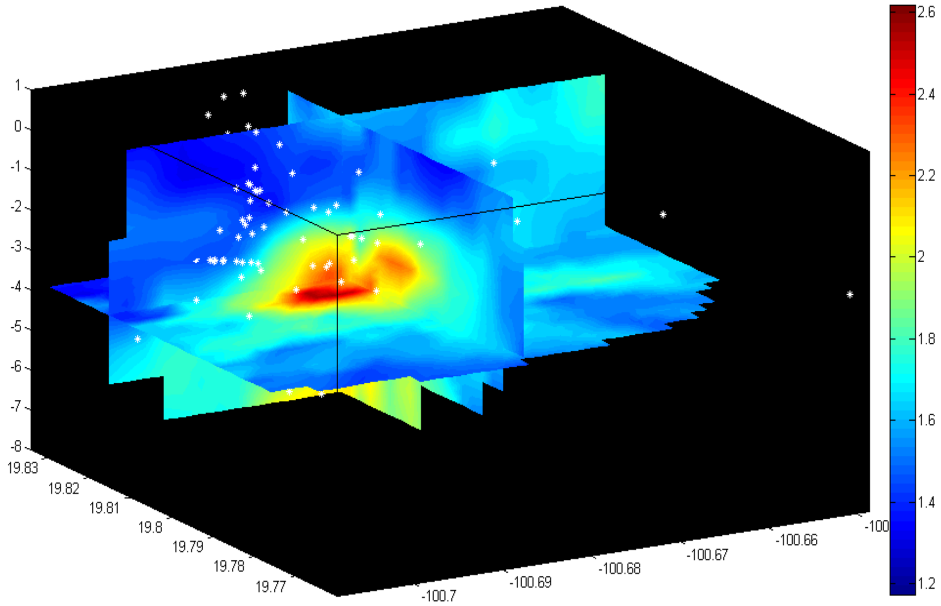


FIGURE 4: B value at Los Azufres Geothermal Field

An important part of the geothermal exploration activities, is the location of new geothermal wells, with the objective of increasing the production of steam, which means greater power generation. In this sense the micro seismic technique has shown to be of great support in locating new wells for production and injection if used in conjunction with detailed geological, gravity and electromagnetic studies. This is exemplified below with the location proposal of well AZ-77.

This well is located in the northern part of the geothermal field, with a target at depth of crossing the structural geological systems NW-SE 800 to 2000 m, NE-SW from 1100 to 1700 m, 1500 to EW 2000 m depth (La Cumbre Fault).

Figure 5 shows the NE 62 ° SW section, which shows that the seismicity occurring in the NW-SE geoelectric gradient with a fallen to the NE from 800 m and deeper, in the vicinity of the proposed well AZ-77; this gradient represents the structural system of La Cumbre fault and the seismicity indicates that it is an active fault.

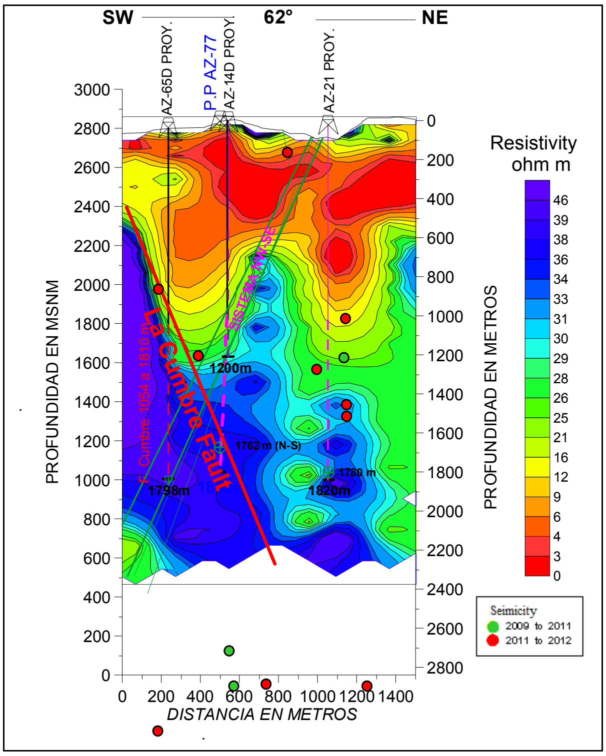


FIGURE 5: SW-NE Section Well AZ-77

The structures determined by the occurrence of spatial geoelectric gradients and seismic events recorded, corresponding to the SW part of the section as the Structural System "La Cumbre" which dips to the NE. These changes of gradient and the tendency that hypocenters show are associated to the present structure, being this the target for the production well AZ-77.

2.2 Los Humeros Geothermal Field

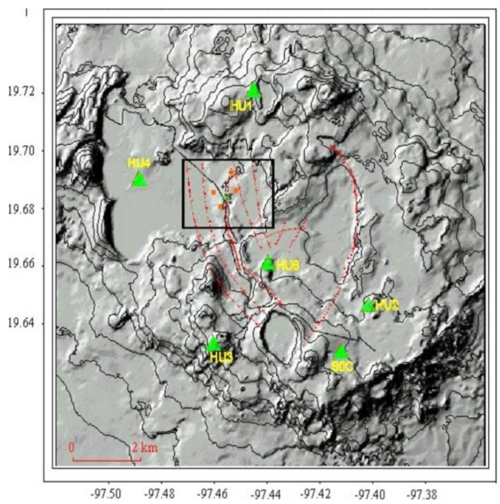
The geothermal field of Los Humeros-Puebla, is located in the eastern portion of Puebla, on the border with the state of Veracruz at 19.2 km northwest of the city of Perote, Veracruz, is part of the Transmexican Neovolcanic Axis. It should be mentioned that the complex superficial geology, product of the various geologic events that created the Caldera of Los Humeros, and the ones after its formation, resulted in some areas of geothermal interest with insufficient evidence surfacing in surface structures, except some exceptions. Microseismic monitoring, and lifting electromagnetic studies, are the support of indirect methods for the exploration stage, which helps to identify faults and fracture systems that lack of structural features visible on the surface. Furthermore, in the operational phase, they are used in the development of geothermal conceptual models and in the proposal of production and injection wells.

The Seismological Network of the geothermal field was installed in December 1997 and it is in operation to this day, being property of CFE. The main objective of the network is to monitor seismic geothermal reservoir, and to know the present seismic zones, which can identify the relationship that this activity present with the injection, and extraction of geothermal fluid, and the relationship with the presence of active structural geological systems (faults, fractures, etc.) and geothermal fluid conductors. From December 1997 to December 2004, the network was instrumented with high sensitivity equipment consisting of 6 remote stations (Figure 6) with three data channels each (components Z, NS and EW). These 18 data channels are transmitted to a central station via a relay station, for processing and recording, using the digital data transmission.

The six field telemetric stations consisted of:

- Three short-period seismometers Ranger SS-1 (1 second).
- A digital recorder Altus Kinemetrics K2, which is configured to shot STA / LTA, its event files are stored on its hard drive.
- A FreeWave Spread Spectrum Transceiver (DGR-115H).
- The house, tower and gate for protection.
- GPS Antenna Yagi TY-900.
- Solar panels, gel batteries and connector pins. From January 2008, to this date, a change of seismic instrumentation was made, on the six field stations which consist of:
- Three components X, Y, Z; oriented orthogonally.
- Broadband triaxial seismometer Analog, USB internal memory of 16 GB.
- Radio-Modem spread spectrum.
- GPS antenna.
- Solar panels, gel batteries and connector pins.

The change in the design of the seismic network was conducted to gain more control because migration of the recorded events was detected and also in order to continue recording the natural and local seismicity induced by the injection and exploitation of the geothermal field (Figures 6 and 7). In the geothermal field of Los Humeros the magnitudes of the local seismic events are between 1.1 to 2.9, with the presence of two tectonic events of magnitudes 4.2 and 3.6.



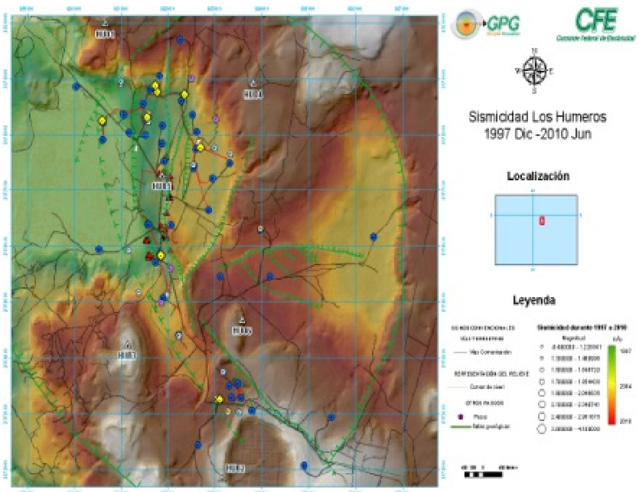
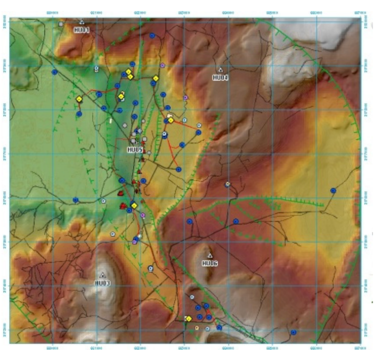
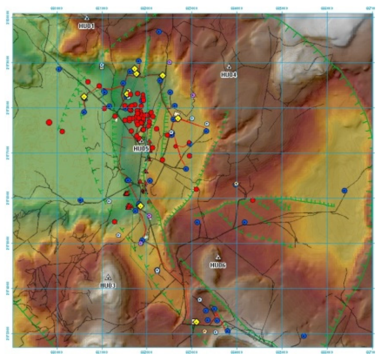


FIGURE 6: Design seismic network 1997 to 2004 FIGURE 7: Design seismic network 2005 to date

From December 1997 to January 1999, seismic activity was concentrated mainly in the northern part of the geothermal field; i.e. around H29D and H38 injection wells reaching depths of about 4 km (Figures 8 and 9), but from February 1999 the seismicity started to be detected towards the south zone of the field (Figure 10).





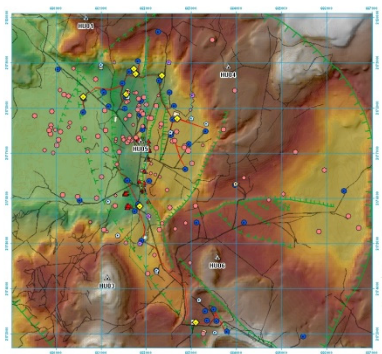


FIGURE 8: Activity December 1997 FIGURE 9: Activity year 1998 FIGURE 10: Activity year 1999

In general, these microseismics were distributed along the fault of Los Humeros, just south of this fault, an earthquake of moderate magnitude (Md = 3.6) and shallow depth (2 km) occured on January 21th, 2002.

The analysis of the information showed an activation of the northern part of Los Humeros fault, which finalized with the January earthquake. Soon after, a moderate and progressive increase in wellhead pressure and steam production was observed in some of the wells related to that geological structure. Figures 11 and 12 showed the normalized production of well H-09 versus the seismic activity, being notable a change in the normalized production slope, showing an improvement in wellhead conditions without any change in the orifice plate.

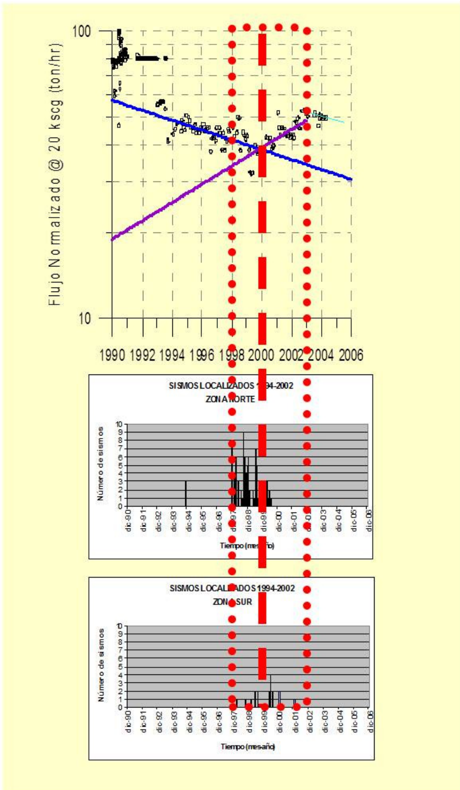


FIGURE 11: Normalized production of well H-09 versus Number of seismic events

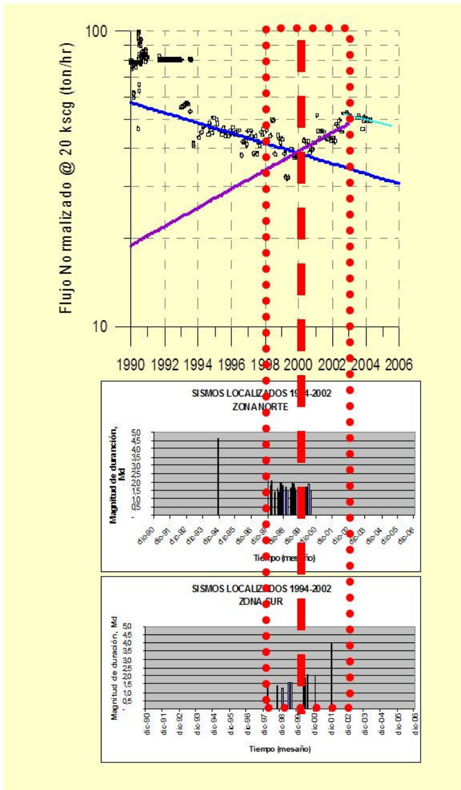


FIGURE 12: Normalized production of well H-09 versus Magnitude of the seismic events

Figure 13 shows the correlation of the present production in the geothermal field between 1990 and 2005, with respect to the number of seismic events recorded in the Northern and Southern part of the field, which highlights an increase in the normalized production after the seismic event of January 21th, 2002, this same correlation was performed in Figure 12, considering for this the magnitudes of all seismic events recorded in this period, with emphasis on the maximum magnitude of 3.6 registered on January 2002.

The monitoring of the registered seismic activity recorded from December 1997 to June 2010, has allowed to identify the presence of different sources of energy release which are:

- Seismicity induced by injection of geothermal water.
- Seismicity induced by extracting geothermal fluid.
- Seismicity by the presence of active geological faults, and fault reactivation.

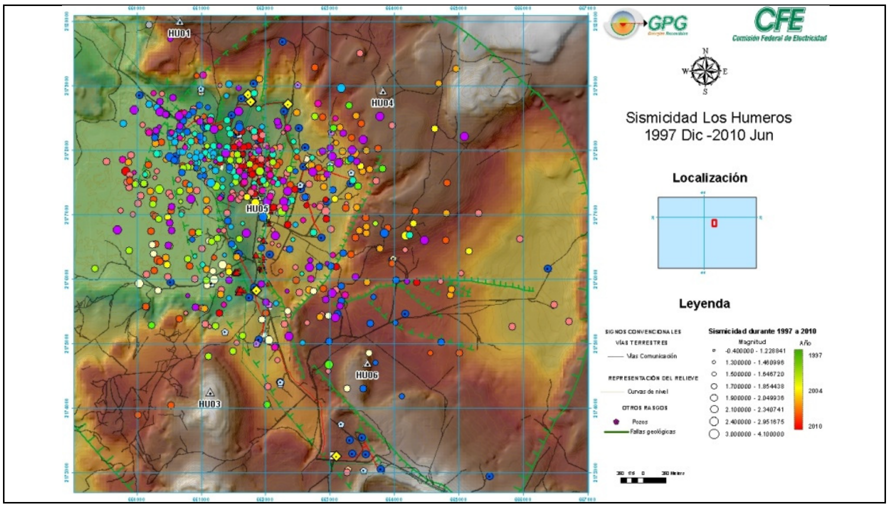


FIGURE 13: Seismic activity registered from the year 2000 to June 2010

Similar to what was presented to The Azufres, an important part of the geothermal exploration activities, is the location of new geothermal wells, and the case of Los Humeros is no exception. Following, it will be exemplified with the H-43 production well.

In 2007, a multidisciplinary work was conducted to locate a new production well (H-43), in the northern part of the geothermal field, with the target of crossing the Structural System "La Antigua" at depth.

Figure 14 shows the W-E section, where as part of the analysis, the resistivity profile was plotted and the hypocenters recorded the period from 1998 to 2008, which were identified between 1100 m and 4400 m depth in the vicinity of the proposed H-43 well. The geoelectric response identified three main resistive packages:

1. Unit U1 is presented which is the outermost layer with an average thickness of 200 m in the W section and a thickness of 100 m in part E. In general Unit 1 has a resistivity ranging from 63 to 100 Ohm-m corresponding to pumice material, basalt and andesite.
2. U2 Unit has thicknesses of approximately 500 m to 1000 m in Part E of this section, in general the U2 unit comes with a resistivity of 0-35 Ohm-m, corresponding to the compositional lithology tuff lithic, ignimbrite and andesite.
3. The U3 Unit presents greater thicknesses of 1200 m on the W and E of this section, in general the U3 Unit has a resistivity of 47-100 ohm-m, which materials are glassy tuff and hornblende andesites.

The structures determined by spatial occurrence of the geoelectric gradients and seismic events recorded, corresponded to the structural system "La Antigua" which dips to E. Derived from the presence of high deep seismic activity, it was decided to drill a vertical well reaching 2200 m depth, resulting in a production two times better than the average of the field.

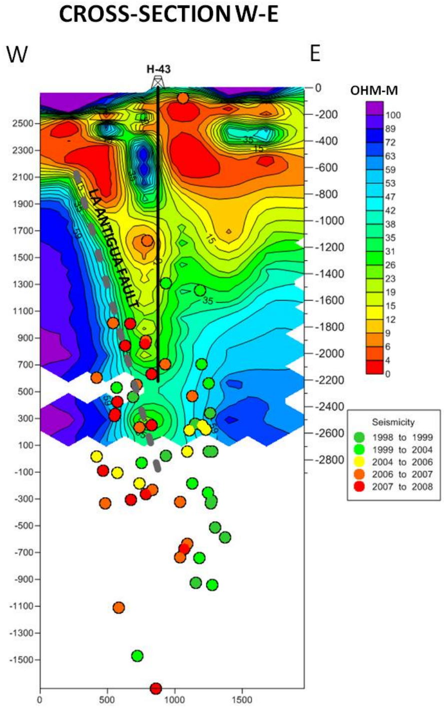


FIGURE 14: W-E Section Well H-43

2.3 Las Tres Vírgenes Geothermal Field

Las Tres Vírgenes is located in the middle of the Baja California peninsula, at the north of the state of Baja California Sur and inside the buffer zone of the El Vizcaíno Biosphere Reserve. Las Tres Vírgenes is inside a Quaternary volcanic complex composed of three N-S aligned volcanoes, from which the name of the field comes from. The geothermal fluids are hosted by intrusive rocks and the heat source of the system is related to the magma chamber of the La Virgen volcano, the youngest and most southern of the volcanic complex. There are only two condensing 5-MW power units in operation that were officially commissioned in 2002. (Flores-Armenta, 2012).

In this geothermal field there are identified four structural systems, two of them are the ones with the most geothermal importance. The first structural system has a direction NW-SE, it is one of the most important and it is represented by the faults "La Vírgen", "El Azufre", "Las Víboras", "El Volcán", "El Viejo (1)", "El Viejo (2)" and "El Partido". The second structural system in importance is the N-S; it is formed by the faults "El Colapso", "El Cimarrón" and another one yet unnamed. Both systems are active and are considered to move hydrothermal fluids with high temperature. The intersection of the faults "El Volcán" and "El Viejo (2)" with the N-S system are considered to allow much better permeability and therefore production. The third structural system has a NE-SW direction and is represented by the fault "La Puerta". At present, this fault is not active, since it does not show hydrothermal activity through fractures or faults. The fourth structural system has an E - W direction. It is the least studied, because it has little presence, thus, minor geothermal importance within the study area. It is possible that the E - W system, does not have much penetration (Gómez-López et al. 2010).

The study of seismicity in this geothermal field and surrounding areas began in 1992 with some interruptions until 2007. The earlier and recent studies (Macias, 1997) and (Lermo et al. 2009), consider this region as an area of high regional seismicity.

Until 2008 in the geothermal field of Las Tres Virgenes, BCS, seismological instrumentation consisted of five Kinemetrics K2 accelerographs autonomous, however these equipment's started to have problems in their different electronic cards due to the obsolesce of the equipment (more than 10 years).

As the year of 2008 it was decided to use for temporary monitoring, other seismographs new high dynamic range and higher capacity storage (one month), able to continuously keep records of the three components of motion (NS, EW and Z) with 100 samples per second.

The spatial distribution of the new seismic network, central station and relay station is shown in Figure 17, like the distribution of seismic stations can now be seen that the coverage seismic network is good for monitoring seismogenic areas of geothermal interest, and to have good locations of earthquakes with respect to the current coverage.

During the period April 2009 to November 2010, 1920 local earthquakes were identified, of which only 331 were able to estimate their hypocentral parameters, due to its small magnitude size, which in most cases can be identified only in the diagnostic station; for all of the others it is difficult to determine the arrival of body waves, since they can be confused with the natural noise of the station (Figure 15).

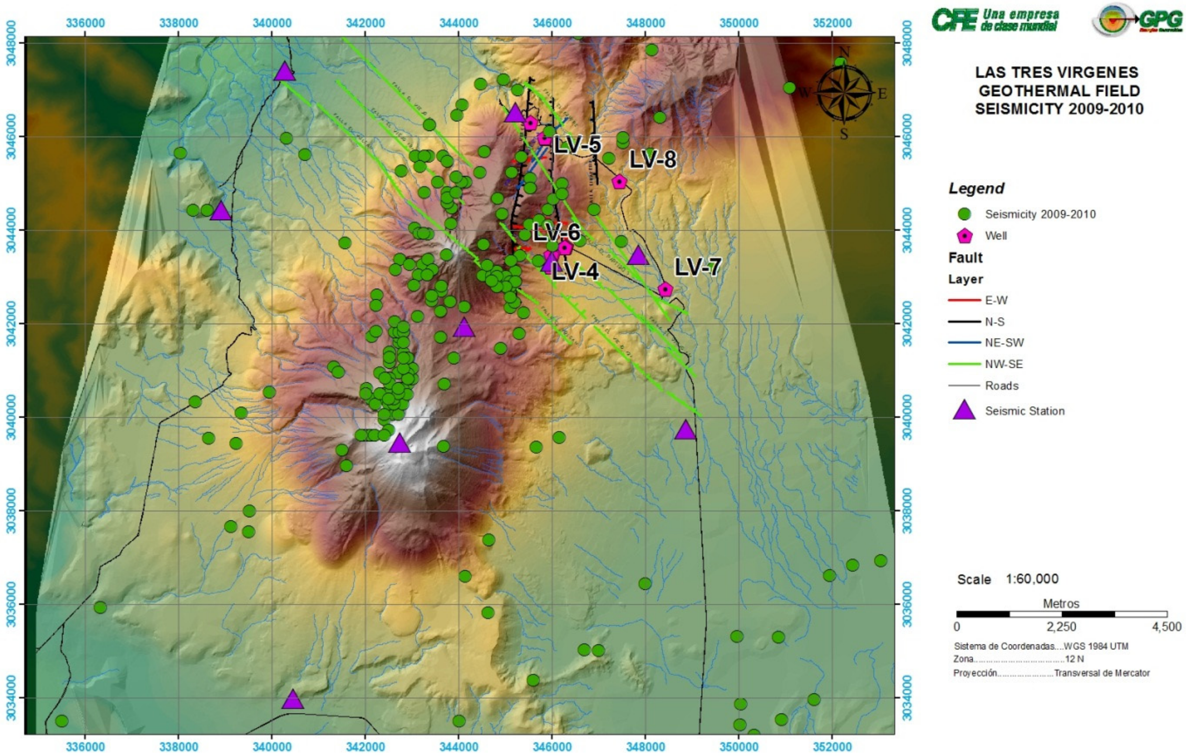


FIGURE 15: Las Tres Virgenes Geothermal Field Seismicity 2009-2010

It was interesting to note that while drilling the producer well LV-6 (from June 25th to December 18th, 2009); it was observed a sudden increase of local earthquakes, which also correlate with the acid job in the well on December of that year.

After this increased of seismic activity, further changes occur precisely when the production evaluation of the well started, beginning with a 3.5 inch orifice plate when the sudden aperture of the valve increased the number of local earthquakes which in this case, could count 32 earthquakes in just one hour, at 03:00 am (GMT hour) on March 9, 2009. This same behavior is repeated on June 15, when they changed from 3.5 to 4.0 inches. Subsequently, a raise in the local seismicity in the months of July, August and September, which can be associated with a change in the injection well LV-8, when going from 200 to 260 t/h. Given their maximum values on the early days of august, precisely when the largest earthquake of the period was detected (Mc = 3.2), this earthquake occurs on August 13 at 14:27, located near the injection well LV-5, at a depth of 3.1 km. (Figure 16).

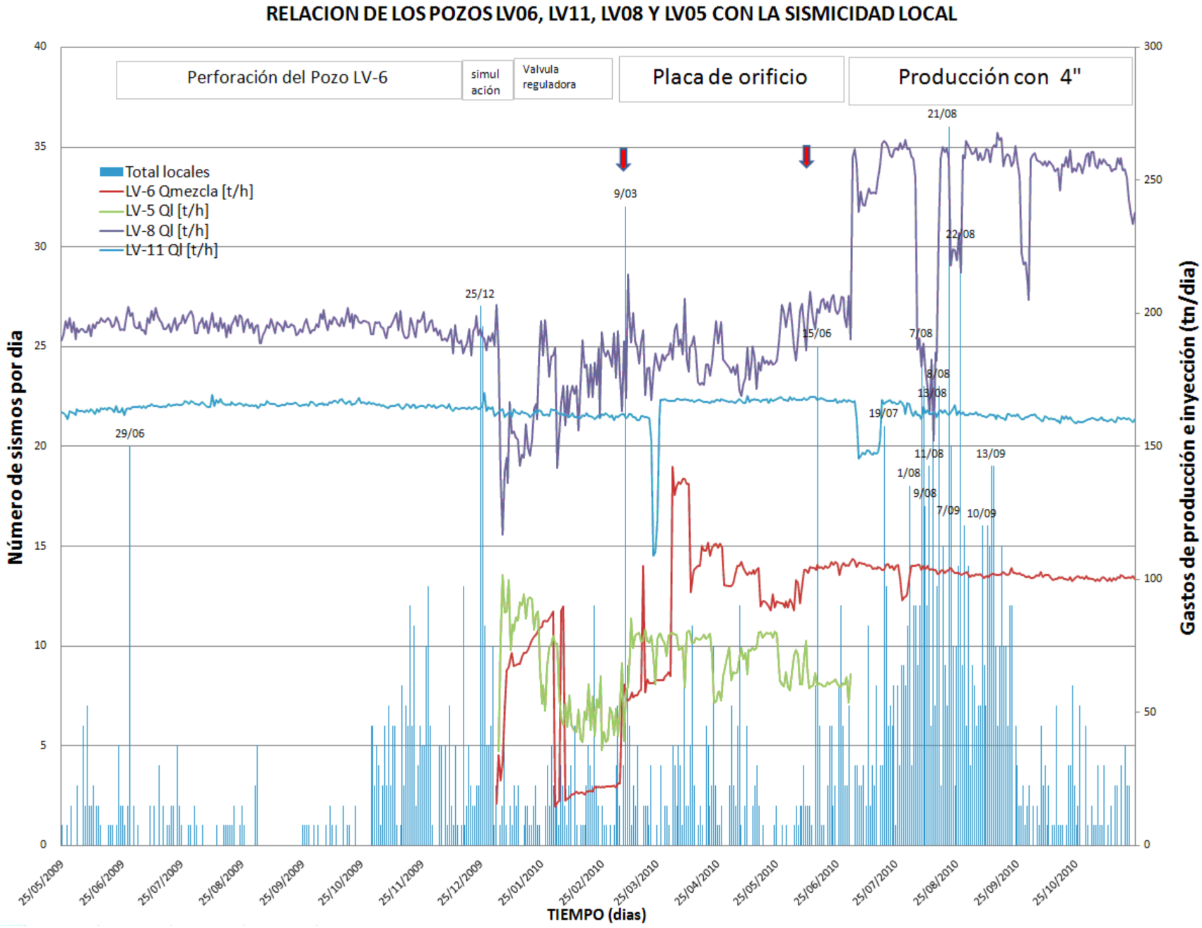


FIGURE 16: The graph shows the relationship during drilling, acidification and production of well LV-6, as well as the injection, versus local seismicity

Finally it should be noted that this seismicity is occurring in the Fault systems of “La Virgen”, “El Volcán” (La Cuesta) and the faults “El Viejo” 1 and 2, which represent the structural systems of most interest for the location of new wells.

On the other hand, the seismicity in this geothermal field allowed raising an interesting hypothesis during the update of the Conceptual geothermal model of Tres Vírgenes (Soto-Peredo, et. al, 2010 and 2012), in reference to the location of the magma chamber of this site.

Macías et al, in 2011 suggested the location of the magmatic system at depths between 7 and 9 km below the crater, after analyzing the composition of the edges of plagioclase and amphibole minerals.

By observing the spatial distribution of seismicity in the vicinity of the volcanic complex, it seems clear that there is a seismic gap below the 5500 mbsl, (Figure 17). In addition, the rounded form in that the events line up to the mentioned depth might suggest to be a laccolith with an extension of approximately 13 km in direction N37°E. This magmatic chamber of the volcanic complex of Tres Vírgenes would possibly be associated with the heat source of the geothermal system nowadays in exploitation.

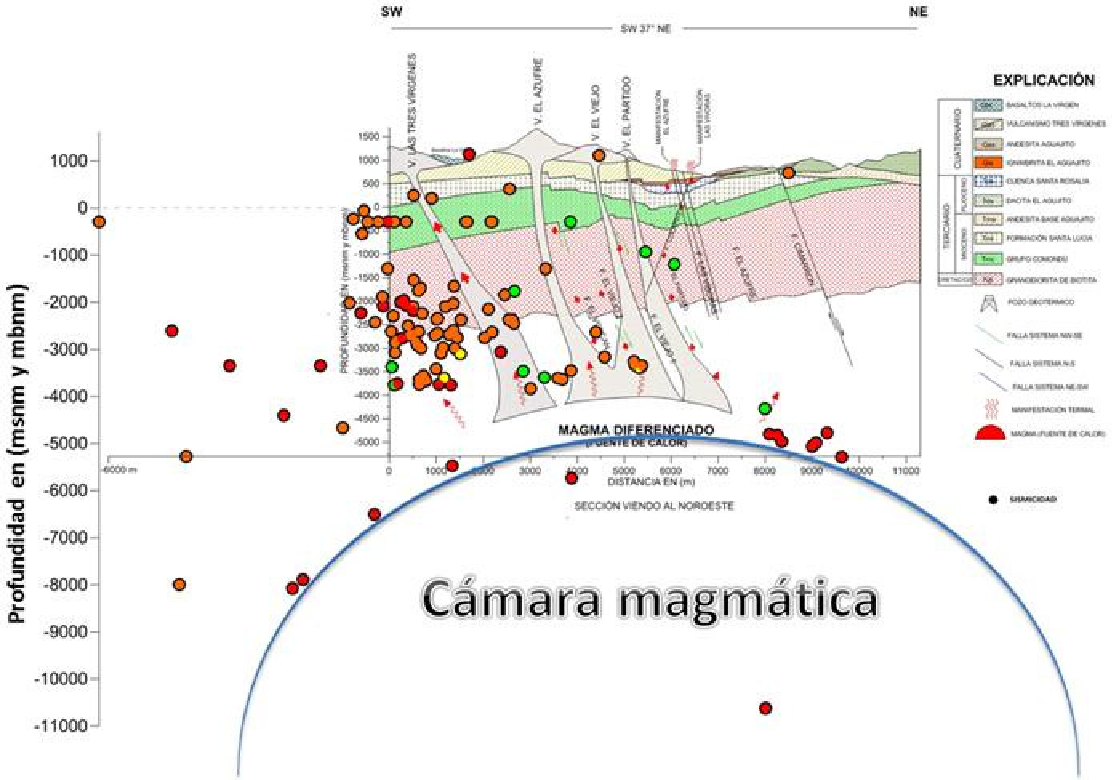


FIGURE 17: The section showing in color the original profile of 2010 as a spatial reference, the coloured circles are the hypocenters

3. CONCLUSIONS

The micro seismicity along with the electromagnetic method, are an important tools to identify fluid movement and to record subsurface activity of the geological faults. It provides information to support new production and injection wells, and especially in geothermal areas where no surface structural features are evident.

Micro seismicity catalogs can be exploited to determine the value of B, which may indicates us high temperature zones.

The energy release recorded in the seismic activity can be related to changes in production-injection strategies and also to the presence of active geological systems.

Changes in the micro seismic activity can also be measured while drilling, stimulation jobs and testing of producer wells.

The micro seismicity also reflects movements and breaks in the basement, identified as faults and fracture zones, which are favorable for geothermal fluid flow, as observed in seismic monitoring in the geothermal field of Los Humeros on the period from 1994 to 2005, where there were increases in production in several geothermal wells after an earthquake of 3.6 magnitude that reactivate the northern sector of the Los Humeros fault.

It is important to point out that the seismic activity within geothermal fields does not exceed the 3.5 magnitude, despite being in tectonically active areas, and there is no major event associated with the operation that could be considered a risk to population or infrastructure.

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LaGeo S.A. de C.V.

CONCEPTUAL MODELS FOR THE BERLIN GEOTHERMAL FIELD, CASE HISTORY

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ABSTRACT

The conceptual modelling is a useful tool in order to delineate and to define the main features of every geothermal system and reservoir thus must be updating as well as new data is being available. The main components for the conceptual model must include at least: heat source location, up flow and out flow areas, flow patterns into the system, the cap rock and basement formation as well as the reservoir formation, thermal conditions of the reservoirs if it is being possible. To achieve this, good correlation is needed between the information available including geological, geophysics, chemistry and well data. In this paper, there are presented several conceptual models constructed during more than 20 years of commercial operation of the Berlin geothermal field, El Salvador. Some uncertainties are being observed in all models due to the nature of volcanic hydrothermal geothermal systems. Additional studies must be developed in the near future.

1. INTRODUCTION

Conceptual modelling is the task where all the information gathered around a whole field is putting together in one drawing, the model integrates all data gathered among geological setting, geochemical, geophysical techniques and well data all of them to delineate the geothermal system, assess the resource capacity, and understand the reservoir chemistry, temperature and hydrological structure. This conduct with a high level of confidence to exploratory drilling and field delineation thus to reduce cost and risk. The conceptual model must provide the update understanding of geothermal reservoirs and systems.

The conceptual model is important for geothermal development in every field, among other uses, the conceptual models is essential for well targeting, well completion design and resource assessment, if the conceptual model is quite refined the resource risk must be reduced.

In this paper are presented several conceptual models developed at the Berlin Geothermal field in El Salvador which has been constructed since beginning of the commercial exploitation. The models were improved as new data was available i.e. geophysical survey, geological data and well drilling. Spite several models, at the moment some uncertainties has been identified due mainly to dynamic condition of the reservoir and constraints of the studies involved and also due to nature of the geothermal resource involved.

The conceptual model must delineate at least the following issues:

a) The heat source where the main convective and conductive heat flow is coming to the geothermal systems and reservoir. Caldera structures, active faulting systems, liquid/gas/isotopes geo thermometer from fumaroles, mud pools or thermal springs, and finally formation temperature could help to determine the location of heat source.
b) Permeable and productive layer where the reservoir is located. The flow pattern must be defined through resistivity anomalies (conductive layer overlaying resistive layer) MT/DC resistivity surveys is the standard methodologies, if is available, the seismicity mapping (passive or active) could contribute, the down hole pressure and temperature profiles with iso-contour mapping is also important to delineate the reservoir. The geological setting of main fault is also considered invaluable for this issue.
c) Due to the hydrothermal reservoirs are frequently confined or quasi confined, the cap rock and basement layers could be established mainly in the reservoir area.
d) The up flow and the possible out flow of the systems are also important part of the conceptual model.

2. THE BERLIN GEOTHERMAL FIELD.

The Berlin geothermal field is located 110 km towards to the East part of El Salvador where the Tecapa volcanic complex is located. In year 2000 the energy regulator Superintendencia General de Energia y Telecomunicaciones (SIGET) awarded the concession contract to LaGeo which enabled it to utilize the geothermal resource to produce electricity. Figure 1 shows the regional location of the field, the concession covers 40 km^2 with surrounding towns of the Berlin at the south, Alegría to the east and Mercedes Umaña to the North

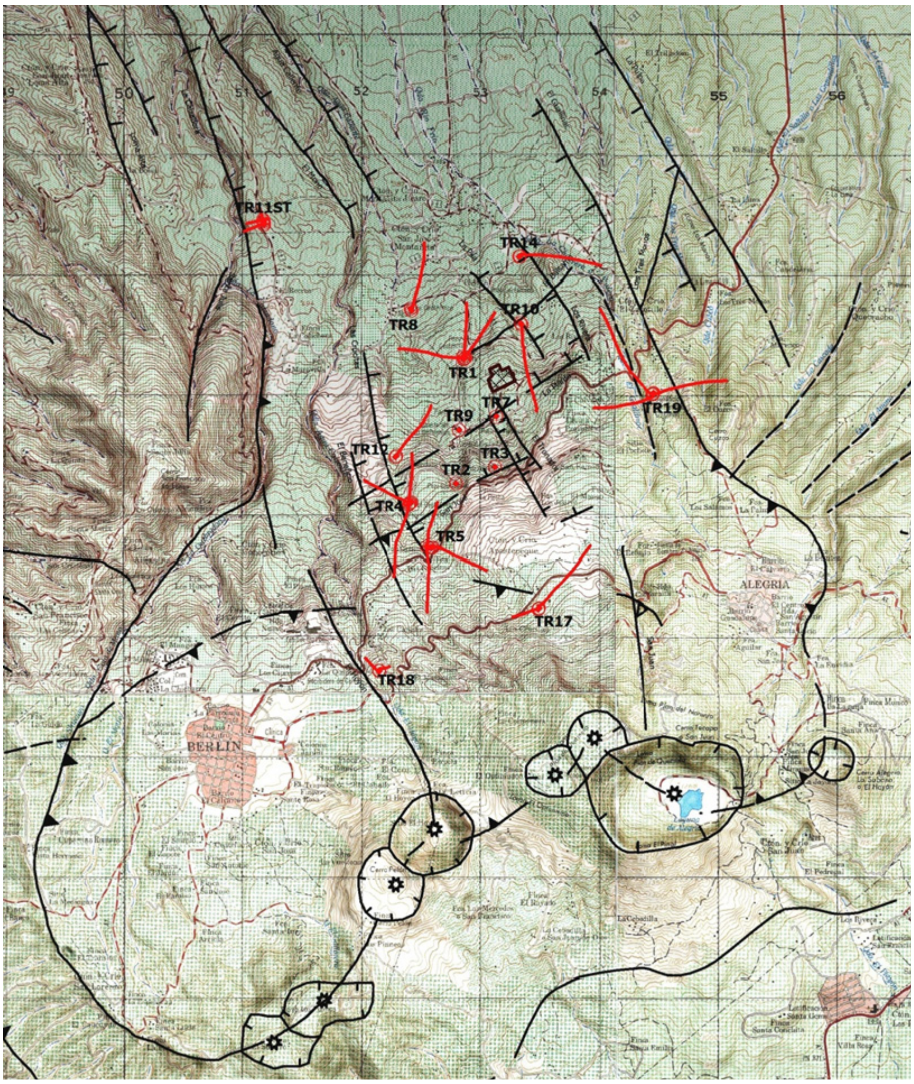

FIGURE 1: The location of the Berlin geothermal field

The field went to commercial operation (small scale) in 1992 with 2x5 MW back pressure units. Later on during 1999 went on line 2x28 MW condensing type units, during 2006 went on line 1x44 MW condensing type unit and finally in 2007 went on line the 9.2 MW binary bottoming unit to complete the 109.2 MW currently installed capacity. Figure 2 presents the well location into the field, the steam field is located to the southern part and the main injection area is located to the northern part of the steam field.

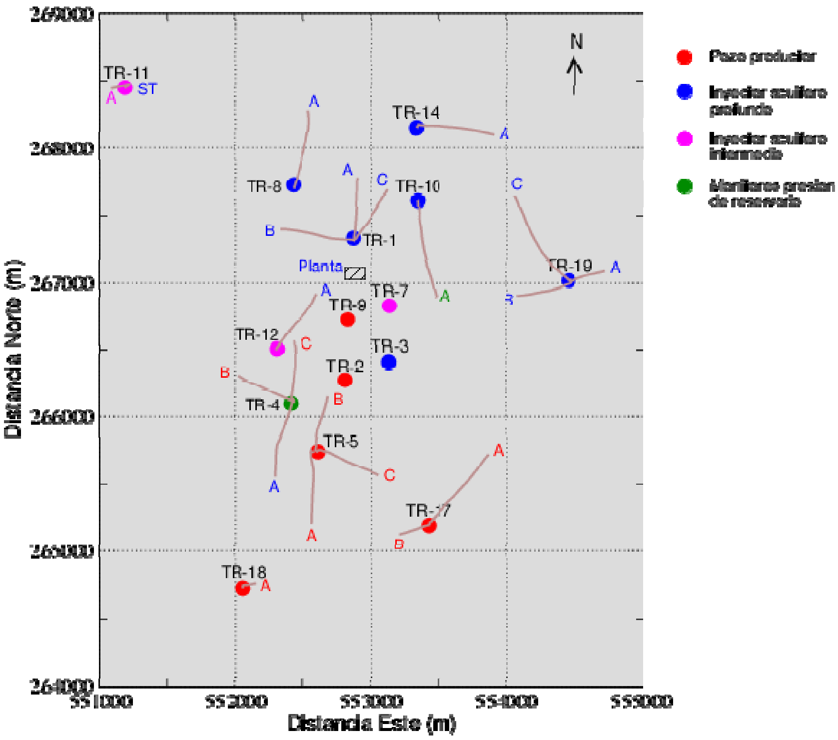

FIGURE 2: Wells location at the Berlin geothermal field

At present, 38 wells were drilling at the Berlin field, 14 of them are producers and 20 injectors (4 are abandoned). The total mass extracted which ranges 870 kg/s, the steam delivered to the power plant is approximately 220 kg/s and the injected brine is 650 kg/s which is partially injected using high pressure pumping system located al TR-1 site. The Figure 3 presents the production history of the field since year 2000 when the concession was granted the field and it is possible to observe when unit 3 went on line in late 2006.

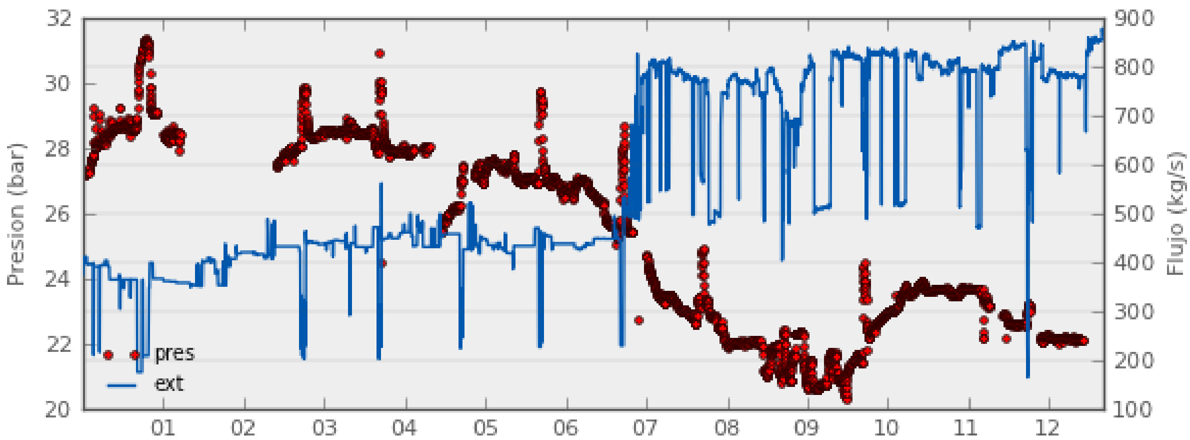

FIGURE 3: Production history of the Berlin field

2. CONCEPTUAL MODELS OF THE BERLIN FIELD

2.1 1996 conceptual model

This conceptual was developed in the early stage of the development in order to assess the feasibility for large scale exploitation. This model was constructed in 1996, and is show in the Figure 4. The results of the model delineate the following:

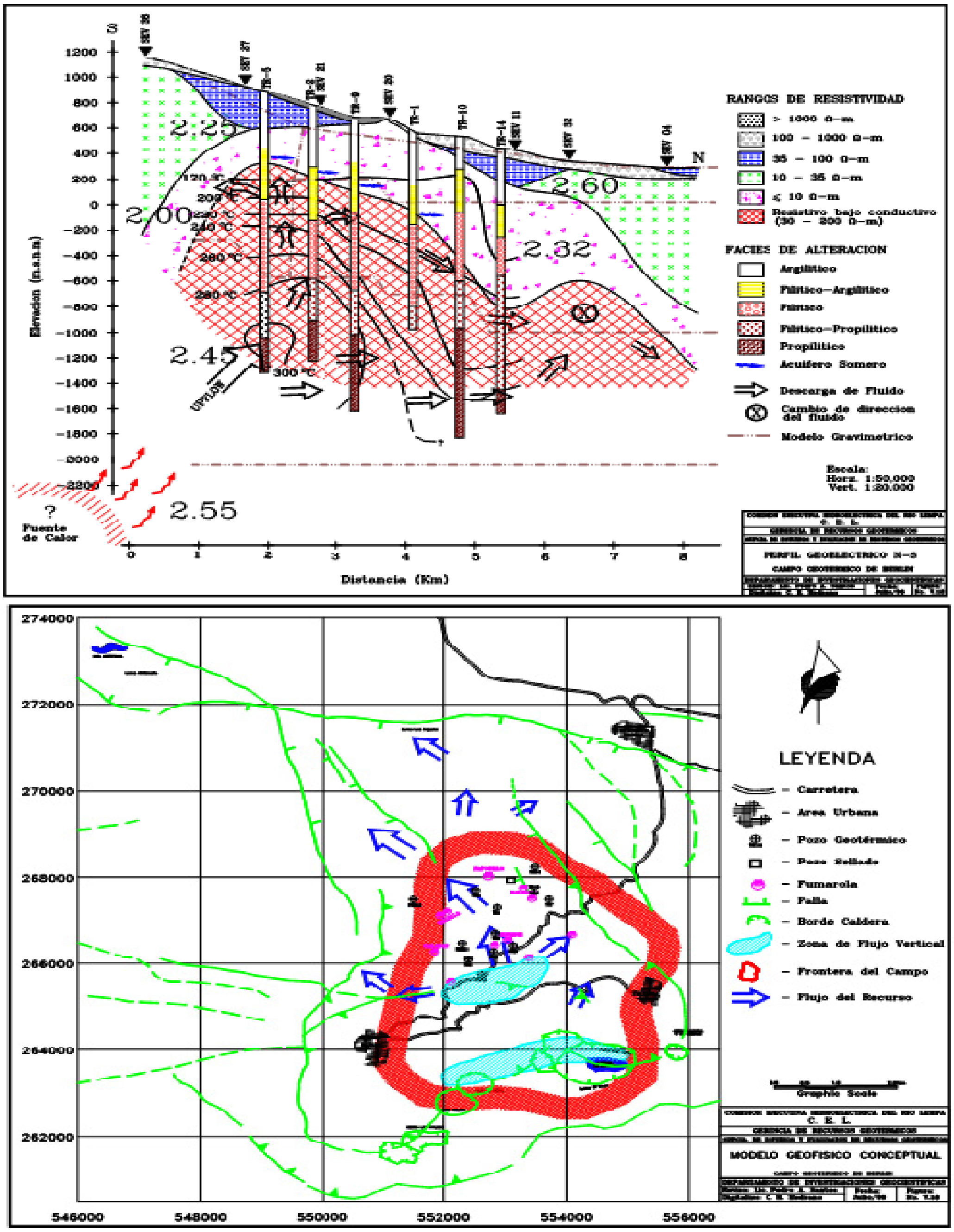

FIGURE 4: 1996 conceptual model for the Berlin field (CEL, 1996)

a) The up flow zone is located close to the production well pads TR4´s andTR-5´s which could be associated with the presence of a resistivity core and a positive gravity anomaly. A second up flow area was also proposed along the volcanic axis.

b) There are evidences of two thermal aquifers: an inter-mediate sea level with temperature around 150-200 °C which was identified by vertical electrical soundings and well drilling data, and the reservoir aquifer with temperature ranges 290-300 °C which is located below and separate for a cap rock.

c) The flow path is from the South to the North-West following the graven trend.

d) The reservoir is perhaps related to 30 Ω-m contours which are considered as deep resistive.

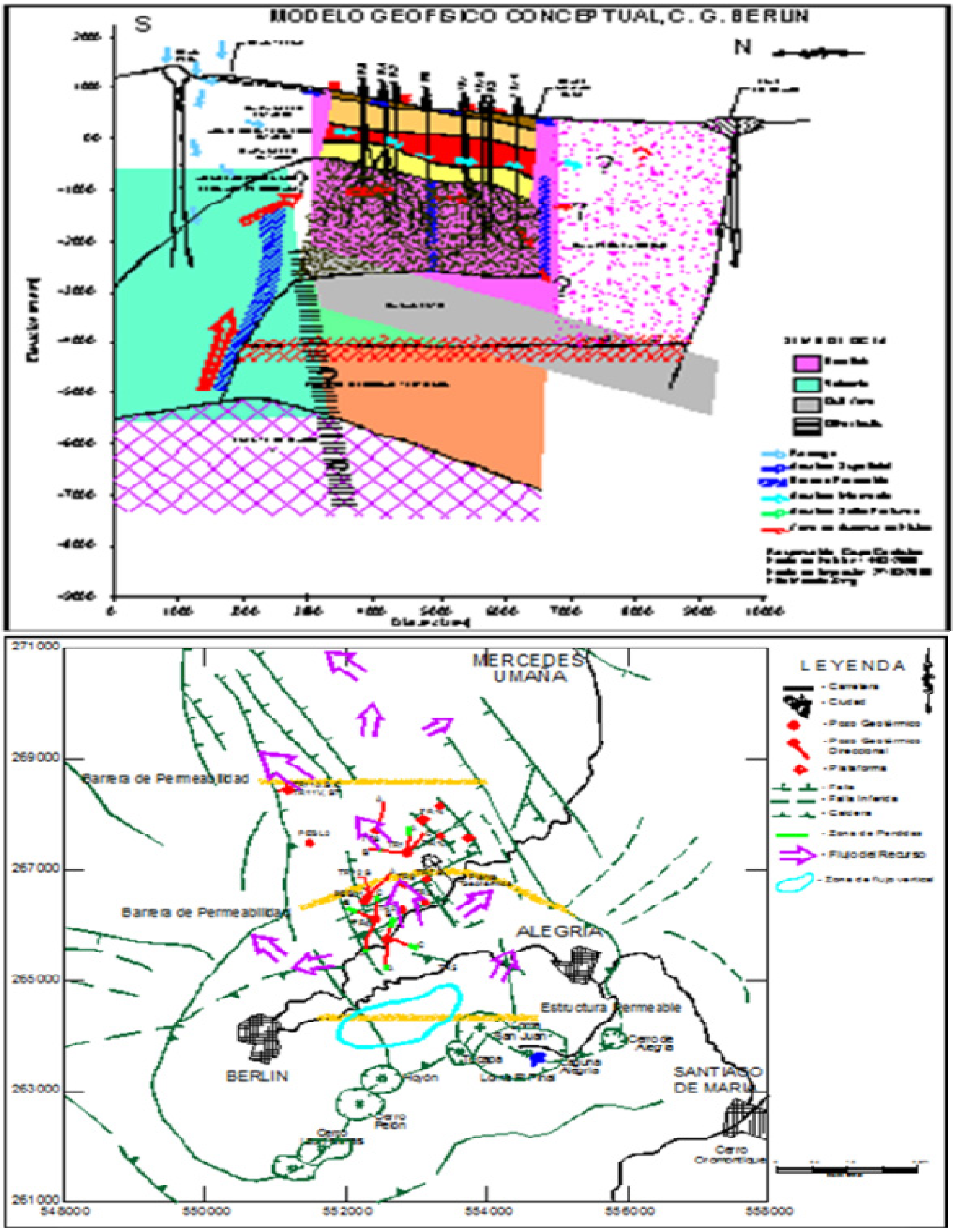

FIGURE 5: Year 2000 conceptual model for the Berlin field (GESAL, 2000a; 2000b)

2.2 Year 2000 conceptual model

In order to update the conceptual mode, new data was gathered during drilling of new wells, MT surveys were carried out by GENZL and 4 years passive seismicity monitoring, prior to starting the large scale exploitation. This model is presented in the Figure 5. Besides the main aspects detailed in previous model, some new additional results were observed:

a) At least three permeability barriers were under consideration and proposed in this new model.

b) The up flow is being associated along the volcanic axis which is supported by passive seismicity.

c) The almost 30-40 °C cooling down between the wells TR-1 and TR-9 was correlated with the Northern edge of the Berlin caldera which was the results of gravity surveys which represents perhaps the permeability limit between producer and injection wells.

Figure 6, on the other hand, shows the model proposed by GENZL (2000).

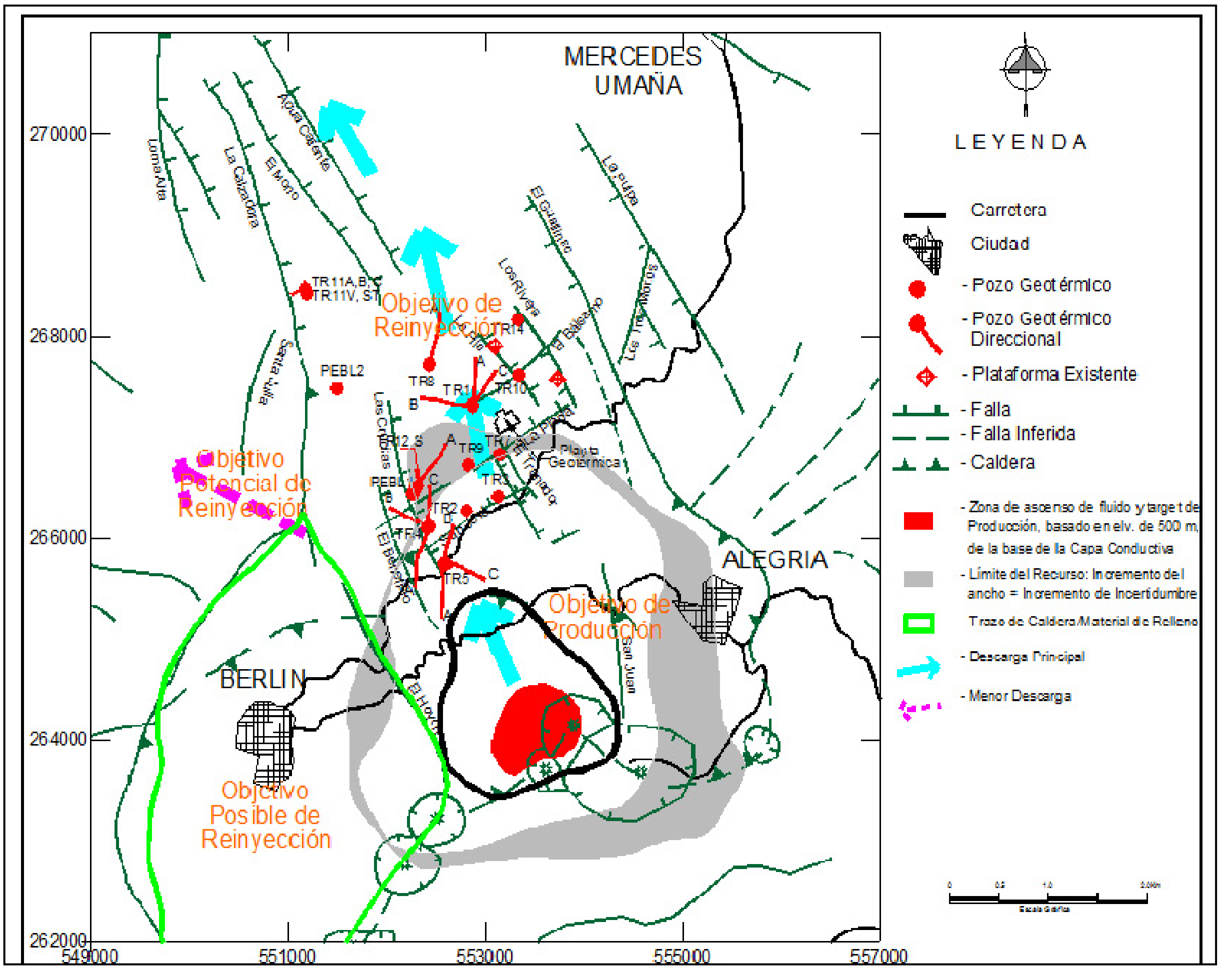

FIGURE 6: The Berlin conceptual model proposed by GENZL (2000)

2.3 2003 conceptual model

To assist in carrying out the feasibility study for Unit 4 an updated conceptual model was delivered in 2003, this model is shows in the Figure 7, besides previous results the new data indicate the follow:

a) The producer reservoir is characterized by the presence of a resistive deep with resistivity above 40 ohm-m in correspondence with the occurrence of prophylitic facie, whose formation temperature is in the range of 240-300°C.

b) A possible extension of the reservoir was suggested to the southeast of the production area.

c) A new conductive body was observed (DVC) which is related to western edge of the reservoir.

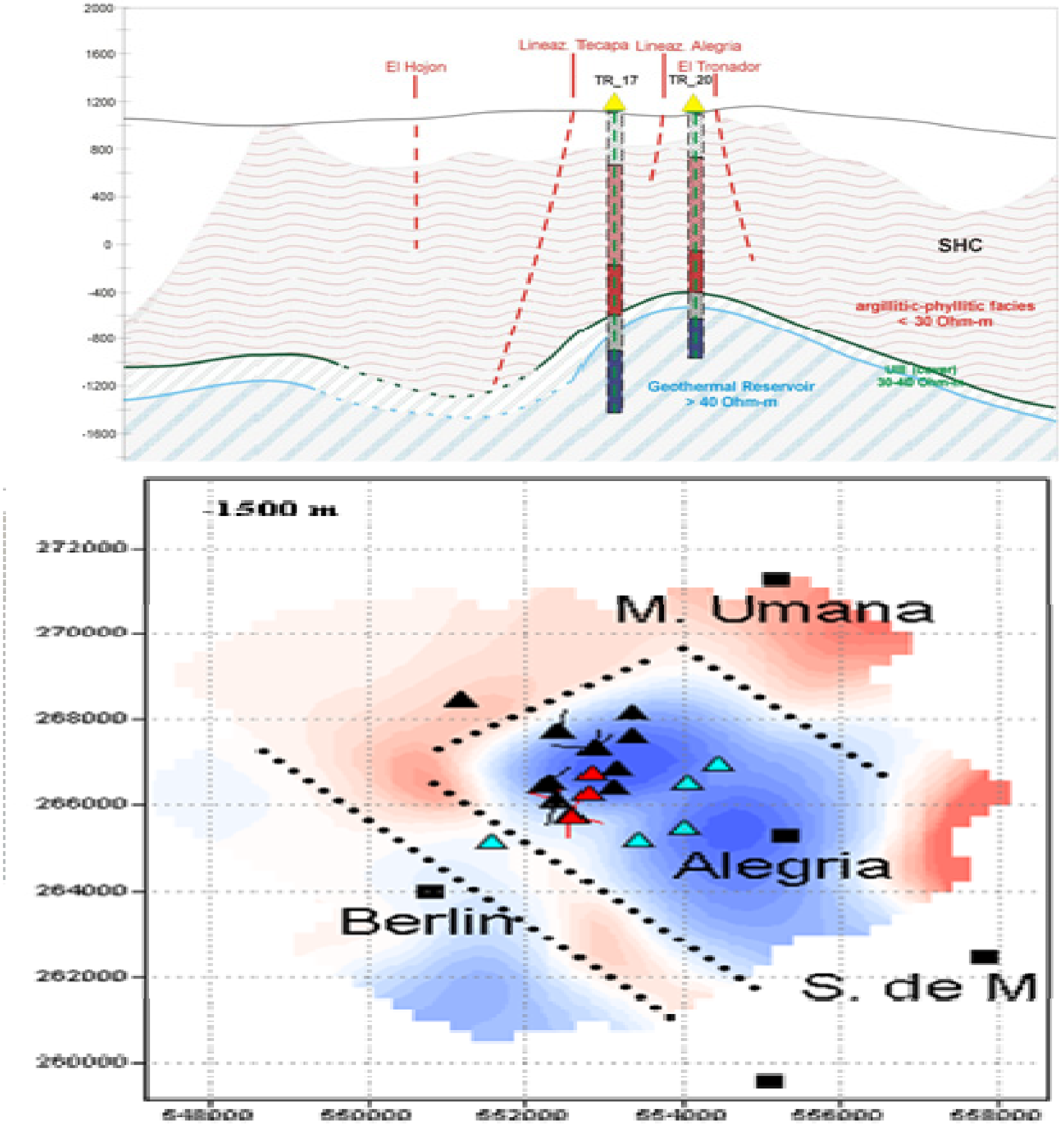

FIGURE 7: 2003 conceptual model of the Berlin field (LaGeo, 2008)

2.4 2008-2012 conceptual model

Several updated conceptual models have been developed by LaGeo, not shown in this paper. The following can be mentioned here:

a) Updated model with MT and CSAMT data in 2001 (West JEC, 2001).

b) Updated model with MT and TDEM surveys and 3D modelling, in 2005.

c) Finally, updated models from 2008-2012 which are the ones currently used. Figure 8 shows this model (LaGeo, 2008).

Despite the large quantity of available data there are still some features of the reservoir, which have not been defined or delineated, which must be evaluated in the future. The main ones are the following:

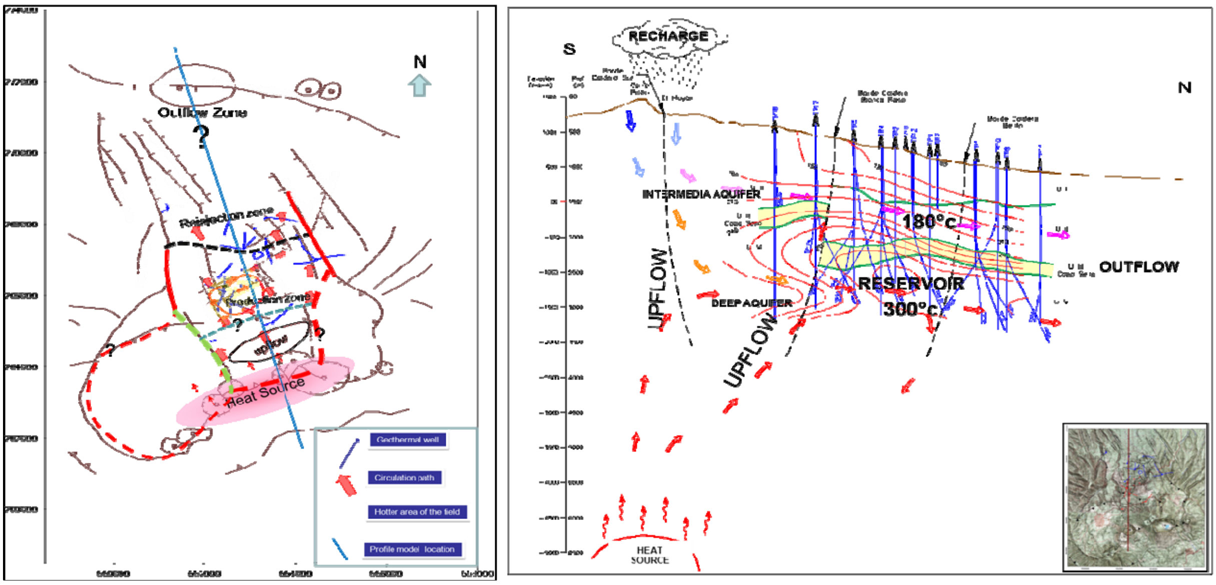

FIGURE 8: The 2008-2012 conceptual model of the Berlin field (LaGeo, 2008)

a) There are permeable connections between both aquifers observed in well TR-18

a) The temperature decline in the southern part wells is due to some out flow condition or perhaps down flow in the systems in that area.

b) The permeability difference between TR-9 and TR-1 is correlated to the caldera border or due to unknown condition.

c) It could be possible to intersect a 300°C reservoir in the southwest part of the actual bore field or possibly connect to the current aquifers being observed in other wells.

d) Where is the out flow of the systems? Is it correlated with some of the hot springs located to the North or are there other unknown flow paths which were not indicated in the surveys that have been undertaken.

3. CONCLUSIONS

1) The conceptual modelling is still an important tool to achieve a good understanding of the geothermal system on where the energy resource is located. The model is useful to delineate the reservoir and its conditions which is an important input for well targeting and resource assessment.

2) The conceptual model must include at least geological setting, geophysical data, chemistry of the fluids and well data. With this information the model must define heat source location, flow path into the reservoir and system, especially, the up flow and out flow, cap rock and basement, aquifers in the systems, thermal condition, etc.

3) Despite the number conceptual models having been developed and the large data available gathered during 20 years of commercial exploitation a completely “well known” systems is perhaps not a correct expression due to large uncertainties found in nature, especially associated with volcanic anisotropic systems.

4) A reliable conceptual model can be constructed with available data but must be updated when new additional data is becomes available.

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DEVELOPING A CONCEPTUAL MODEL OF A GEOTHERMAL SYSTEM

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ABSTRACT

Conceptual models are used to describe or illustrate essential features of geological situations and delineate the principal processes in the system, but conceptual models of geothermal systems are focused on data providing information about temperature, pressure and fluid flow towards, within and out of the system. Conceptual modelling of geothermal systems requires an integrated approach as geological, geochemical, geophysical data along with information from well testing and production have to be unified into a comprehensive model describing the physical features of the system. Conceptual models are an important tool throughout exploration, development and utilization of geothermal systems, where they are used both in field development planning and well siting as well as the basis for numerical modelling and reservoir assessment.

Conceptual models of geothermal systems are spatial representations of the physical features of the system, which have traditionally been presented by 2D cross sections. The development of geological modelling tools in the past 10-15 years have facilitated the integration of all geological, geophysical and geochemical data as well as seen the advancement of 3D visualization and interpretation of the models. These modelling tools can make the conceptual models more dynamic as they allow for more efficient and continuous data updates.

1. INTRODUCTION

Geothermal resources are distributed throughout the Earth's crust with the greatest energy concentration associated with hydrothermal systems in volcanic regions at crustal plate boundaries. Yet exploitable geothermal resources may be found in most countries, either as warm ground-water in sedimentary formations or in deep circulation systems in crystalline rocks. Shallow thermal energy suitable for ground-source heat-pump utilization is available world-wide and attempts are underway at developing enhanced geothermal systems (EGS) in places where limited permeability precludes natural hydrothermal activity. Geothermal systems and reservoirs are classified on the basis of different aspects, such as reservoir temperature or enthalpy, physical state, their nature and geological setting. Steingrímsson et al. (2013) and Axelsson (2008) review these classifications and the distribution of geothermal resources worldwide.

The understanding of the nature of hydrothermal systems started advancing during the 20th century. Increased utilization and greatly improved understanding went hand in hand with geothermal wells becoming the main instrument for geothermal development. This is because geothermal wells enable a drastic increase in the production from any given geothermal system, compared to its natural out-flow, as well as providing access deep into the systems, not otherwise possible, which enables a multitude of direct measurements of conditions at depth.

The key to the successful exploration, development (incl. drilling) and utilization of any type of geothermal system is a clear definition and understanding of the nature and characteristics of the system in question, based on all available information and data. This is best achieved through the development of a conceptual model of a geothermal system, which is the focus of this short course. Conceptual models are descriptive or qualitative models incorporating, and unifying, the essential physical features of the systems in question (Grant and Bixley, 2011). The cooperation of the different disciplines involved in geothermal research and development is of particular importance here, rather than each discipline developing their own models or ideas independently. Conceptual models are an important basis of field development plans, i.e. in selecting locations and targets of wells to be drilled (Axelsson *et al.*, 2013) and ultimately the foundation for all geothermal resource assessments, particularly volumetric assessments and geothermal reservoir modelling (Axelsson, 2013).

This paper provides a review of the step-by-step development of conceptual models of geothermal systems, how they develop in hand with the gradual exploration and development of the geothermal system. Other presentations go into comprehensive detail regarding the data that provide the basis for conceptual models, how they are developed and finally how they are used for siting the different types of wells and as the basis of resource assessments, including the development of models of geothermal systems.

2. CONCEPTUAL MODELS

The diverse information and data available on geothermal systems is increasingly being unified through the development of conceptual models of the respective systems. They play a key role in all phases of geothermal exploration and development, e.g. by providing a unified picture of the structure and nature of the system in question. Conceptual models are descriptive or qualitative models, not used for calculations. They are mainly based on geological information, both from surface mapping and analysis of subsurface data, remote sensing data, results of geophysical surveying, information on chemical and isotopic content of fluid in surface manifestations and reservoir fluid samples collected from wells, information on temperature- and pressure conditions based on analysis of available well-logging data as well as other reservoir engineering information. Comprehensive conceptual models of geothermal systems should incorporate the following as far as available information allows:

(1) Provide an estimate of the size of a system, more specifically information on areal extent, thickness and depth range as well as external boundaries (vertical)
(2) Explain the nature of the heat source(s) for a system
(3) Include information on the location and strength of the hot up-flow/recharge zones, including the likely origin of the fluid
(4) Describe the location and strength of colder recharge zones
(5) Define the general flow pattern in a system, both in the natural state and changes in the pattern induced by production
(6) Define the temperature and pressure conditions in a system (i.e. initial thermodynamic conditions through formation temperature and pressure models)
(7) Indicate locations of two-phase zones, as well as steam-dominated zones
(8) Describe locations of main permeable flow structures (faults, fractures, horizontal layers, etc.)
(9) Indicate the location of internal boundaries (vertical and/or horizontal) such as flow barriers
(10) Delineate the cap-rock of the system (horizontal boundaries)

(11) Describe division of system into subsystems, or separate reservoirs, if they exist

Not all geothermal conceptual models incorporate all of the items above, in fact only a few do so. How advanced a conceptual model is depends on the state of development of the system in question. In the early stages knowledge is limited and only information on a few of the items above will naturally be available. When development continues knowledge on the items above increases; first when substantial deep drilling has been conducted and later when large-scale utilization has been on-going for quite some time, with associated monitoring. Only then fairly comprehensive knowledge on the items listed has become available.

3. DEVELOPING 2D AND 3D CONCEPTUAL MODELS

Geothermal exploration and exploitation is a multidisciplinary science, starting with surface exploration followed by collection of drill-hole data and finally reservoir engineering modelling studies and utilization monitoring. Each discipline looks at the geothermal system from a certain viewpoint, having a tendency to define the geothermal system from that perspective. That is why developing a conceptual model is quite beneficial, as it unifies the different viewpoints. In order to create the most comprehensive geothermal conceptual model all the disciplines have to be incorporated, but essentially the focus is on geological structures, permeability, temperature and pressure conditions as well as fluid chemistry.

3.1 Data

When developing conceptual models the focus should be placed on the following data / information:

- Surface geological and structural maps and other related information. Aerial photos and other remote sensing data should also be considered, if available.
- Borehole information including location and design.
- Borehole geological data including lithology, alteration mineralogy and information on zones of circulation losses.
- Information on porosity of different formations, as far as available.
- Surface geophysical data including gravity data, magnetic data and resistivity data. Emphasis should be placed on available interpretations of such data.
- Seismic data, including information on regional seismicity, micro-earthquake data and seismic survey data (seldom available), as well as relevant interpretations.
- Information on temperature and pressure conditions in the geothermal system from well-logging data. Also initial temperature- and pressure-models,
- Information on feed-zone locations based on circulation losses, temperature and pressure logs, as well as spinner logs, if available.
- Pressure transient data, both from short-term well-tests and longer-term interference tests, along with available interpretation results.
- Available information on the chemical composition and gas content of reservoir fluid, including isotope data, e.g. based on samples from surface manifestations.
- Detailed well-by-well information on mass production history.
- Detailed well-by-well information on reinjection history.
- Monitoring data including information on reservoir pressure changes (preferably from monitoring wells) and reservoir temperature changes as well as changes in well-head pressure, well enthalpy, chemical content and gas content.
- Reinjection test data, tracer test data and reinjection monitoring data.
- Surface monitoring data such as geodetic measurements (e.g. surface subsidence data) and results of repeated micro-gravity surveying.
- Hydrogeological information on the whole geothermal region, including available hydrogeological models incorporating ideas on regional flow, recharge and boundaries.

- All relevant previous studies, in particular studies presenting conceptual models, resource assessments, modelling work and chemical studies.

3.2. 2D and 3D models

The relevant data and corresponding interpretation results, for the different disciplines involved in geothermal research and development, are described in various presentations at the present short course, but in the following the development of conceptual models in particular in 3D will be outlined.

Data compiled during surface exploration are often presented on maps and cross sections and in figure 1 is an example of an initial model of Þeistareykir geothermal area, where the area has been subdivided according to one type of data, in this case the gas composition of fumaroles.

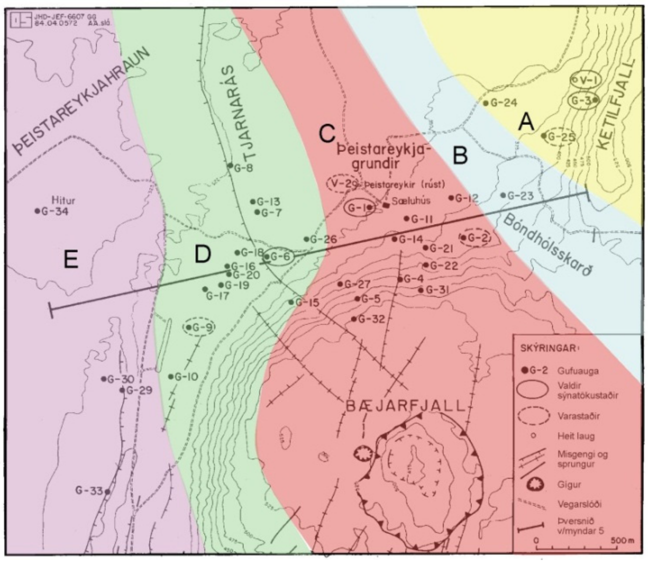

FIGURE 1: Zone division of Þeistareykir geothermal area based on gas geochemistry of fumaroles (Ármannsson *et al.*, 1986). Three of the areas appeared promising for drilling with estimated high reservoir temperatures (A, C, D), while area B and E appeared disturbed by cold, groundwater (B and E)

As exploration of the geothermal fields progresses with the commencement of drilling increasingly more data is obtained from the subsurface. For many years the main form of presentation of subsurface data and models have been through 2D cross sections despite the spatial relationship of the data. Figures 1 and 2 are examples of such models representing an initial simple model prior to exploration drilling of the Þeistareykir geothermal area based on gas geochemistry of fumaroles, while the model from 1977 of Krafla geothermal field, where arrows are highlighting the areas of up- and outflow in the geothermal reservoir, as well as outlining the geological and structural control of flow.

However, through computer software development it is now becoming more common to visualize geological data and models as digital 3D models.

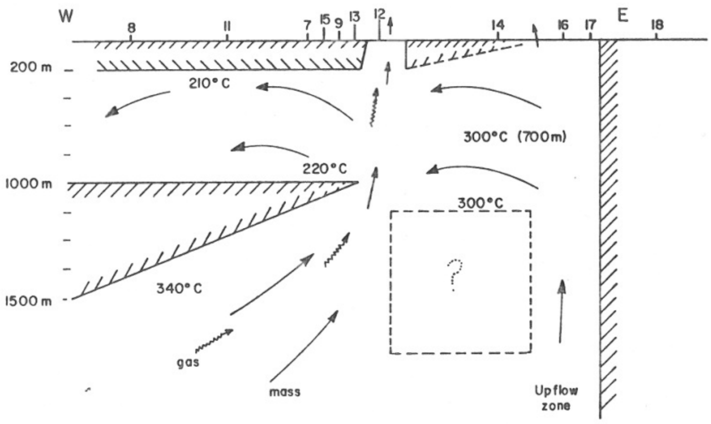

FIGURE 2: A conceptual models of the Krafla geothermal system in NE-Iceland from 1977, where arrows are highlighting the areas of up- and outflow in the geothermal reservoir, as well as outlining the geological and structural control of flow (Valgarður Stefánsson, 1981)

In recent years an increasing number of software programmes are becoming available for geological modelling and 3D visualization, typically originating from either the oil or mining industry, e.g. Petrel, Landmark, Leapfrog and RockWorks to name a few software programs representing different price ranges, capacities and degrees of user-friendliness.

The objective with conceptual modelling is manifold, but the models are primary used to outline a field development strategy, well targeting and siting as well as forming the foundation for reservoir modelling in representing "the static natural state model".

As listed above the 3D software programmes have to be able to integrate many different types of geological, geophysical and geochemical data. The resolution of the datasets is variable; for example resistivity surveys represent data with a large spatial coverage (10-30 km depth into the earth) at a low resolution, while well data in the form of geological and geophysical logs represent high resolution data with a low spatial coverage, but geological modelling is used to predict the inter-well or spatial variation of the geological, geophysical or geochemical variables that are used to characterise the geothermal reservoir, such as temperature, pressure, geology and resistivity to name a few.

The process of developing the 3D model is shown in Table 1, but it can be characterized by at least five steps; a) data preparation and quality control, b) data import and quality control, c) creating a surface and/or fault model (e.g. stratigraphic boundaries in geological model, d) creating 3D property model and e) model presentation in 2D and 3D.

TABLE 1: Flow diagram showing the work process for development of 3D models

<table>
<tr><th colspan="2">Pre-processing and preparation of data</th><th colspan="3">Create conceptual 3D model</th><th>Further use of conceptual 3D model</th></tr>
<tr><td>Drilling results
Well data</td><td rowspan="6">Data control and transfer to importable data format</td><td rowspan="6">Data import and further data controlling</td><td rowspan="6">3D fault and/or surface model</td><td rowspan="6">3D body model</td><td rowspan="2">Export data
(e.g. maps, cross sections, well siting)</td></tr>
<tr><td>Cross sections</td></tr>
<tr><td>Maps</td><td rowspan="2">Specific 3D models</td></tr>
<tr><td>Geophysical data</td></tr>
<tr><td>Other</td><td rowspan="2">Export 3D property model for further modelling (e.g. reservoir modelling)</td></tr>
<tr><td>Rock properties</td></tr>
</table>

After data has been imported into the software program, the first step is to make a surface model, which will be defining the data boundaries, e.g. strata boundaries, faults and aerial coverage of data, whether that is well locations or extent of surface exploration (Figure 3). In volcanic hosted geothermal fields permeability is strongly controlled by faults and fractures and therefore there is high emphasis on characterising the faults in the geological model through correlation of well data, seismic data and surface geology. Many geological models are so-called deterministic models, which fully acknowledge the data, thus the geological model is defined by the fault and strata boundaries in the model (Figure 4).

Once the boundaries of the model have been defined the next step is to create a 3D body (property) model, but this is a three-step process. The first step is to create a grid within the boundaries of the model. The second step is up-scaling, which is to average the data (e.g. well data) into the layers of the grid model, but in Figure 5 is an example comparing formation temperature log with up-scaled formation temperature in preparation of the temperature model. It is inherent that the resolution of the data decrease through the up-scaling, thus it is important to ensure that the up-scaled data maintains a statistically acceptable distribution in comparison with the input data so not to introduce errors into the model. The final step in creating a 3D body model, e.g. of temperature or resistivity (Figure 6), is to assign a property value to all cells in the grid of the 3D body model through the use of geo-statistical interpolation such as kriging.

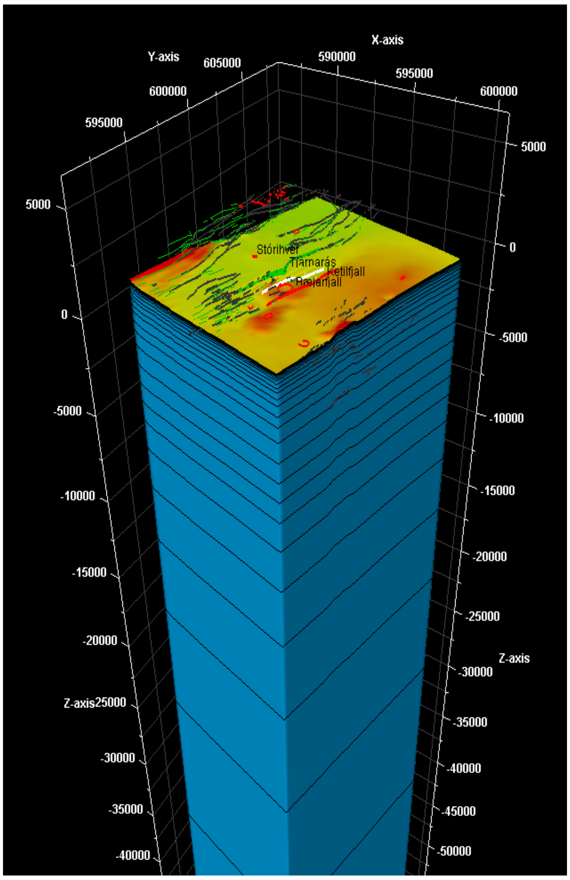

FIGURE 3: Surface model, where black horizontal line represent the horizons in the model, the first building blocks of the 3D body/property model

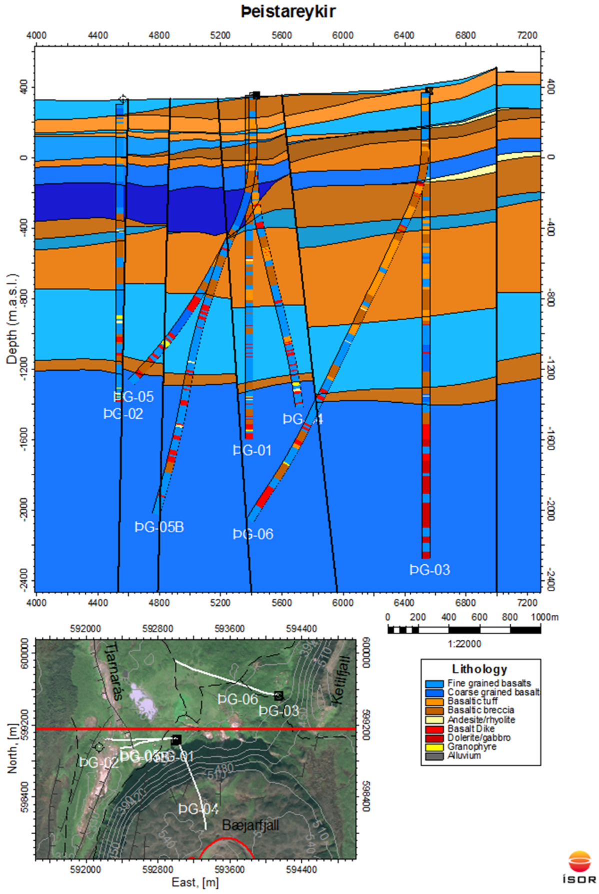

FIGURE 4: Geological model of Þeistareykir geothermal field

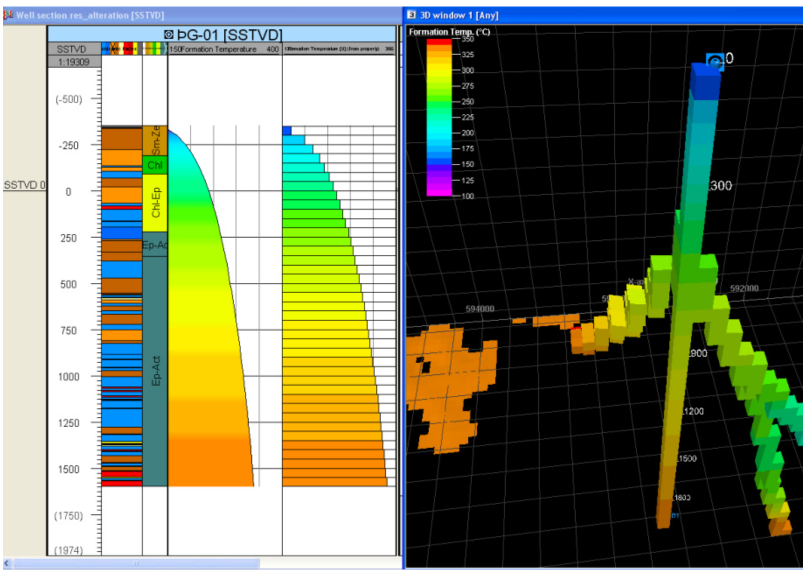

FIGURE 5: Left: well section window showing lithology and alteration log in comparison with formation temperature and formation temperature which has been up-scaled in preparation for the property model (3D body model). Right: Up-scaled formation temperature along well trajectory

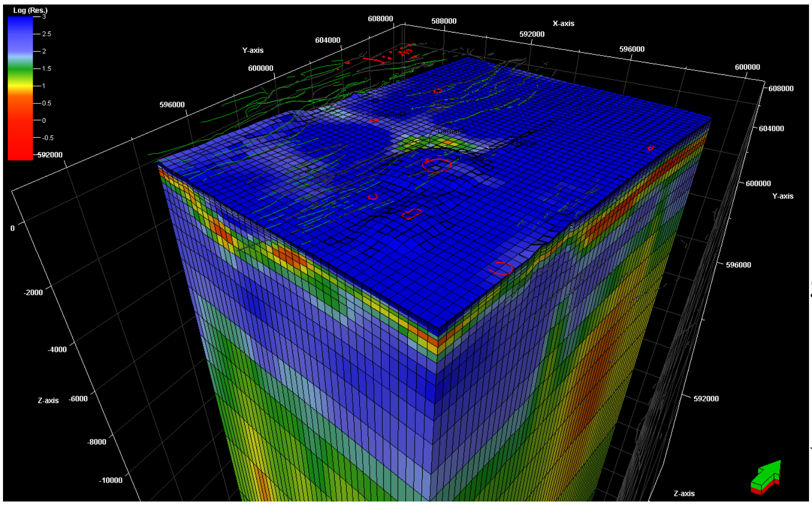

FIGURE 6: Property model or 3D body model of 3D inversed TEM-MT survey at Þeistareykir geothermal field (Karlsdóttir et al. 2012). Each block in the grid model is assigned a resistivity value through interpolation between up-scaled data points with geo-statistic methods such as kriging

3.3 Conceptual models – examples

Once the geological, geophysical and geochemical data have been assembled into the 2D and 3D model, a conceptual model can be developed through comparison of the different sets of data as they become available during the gradual development of the geothermal field.

The conceptual model aims at highlighting the distribution of temperature, pressure, permeability and fluid chemistry within the geothermal reservoir in order to delineate the direction of fluid flow and circulation (e.g. hot upflow and colder recharge) symbolized with arrows.

During the early stages of field exploration the conceptual model is commonly based on a comparison between geological, geochemical and geophysical surveys. The extent of geothermal manifestations and types are compared with resistivity surveys to estimate the aerial extent of the geothermal reservoir, while geothermometers through geochemical sampling of geothermal manifestations provide a first estimate of how high temperatures that are expected in the geothermal reservoir and where the outflow is centred.

As described by Cumming (2009) the shape of the low resistivity cap can be used to infer about potential upflow and outflow zones in the geothermal reservoir. However, in volcanic regions the resistivity model is commonly reflecting the highest degree of alteration attained with depth in the reservoir. Therefore it is important to compare the resistivity survey with other data, such as geothermal maps and geochemical surveys to confirm whether anomalies represent an active system of high temperature or if it is reflecting a system, which has cooled down.

When data becomes accessible from the subsurface through drilling of wells, interpretation about heat and fluid upflow and convection is depending to a higher degree on interpretation of temperature and pressure logs from the wells (Steingrímsson, 2013). However, in the early exploration drilling phase the wells are few and can be far apart. Data from wells have a low spatial resolution and therefore it continues to be important to compare the data from the wells with data from surface exploration, which have a high spatial resolution, such a resistivity surveys and geological maps, in order to verify whether the original conceptual model of the geothermal field is still valid or whether it has to be revised. In figure 7 is an example of the conceptual model of Þeistareykir geothermal field from 2008 after the first two exploration wells had been completed. A more detailed model of the field is already starting to emerge outlining a high temperature upflow zone within area C (Figure 4), while area D to the west is characterised by lower temperatures ~200°C due to mixing and cooling from cold groundwater along open fractures within the Þeistareykir fissure swarm. The new conceptual model for Þeistareykir geothermal field both changed the exploration strategy as well as the interpretation of data that constituted the foundation for the initial model of the field.

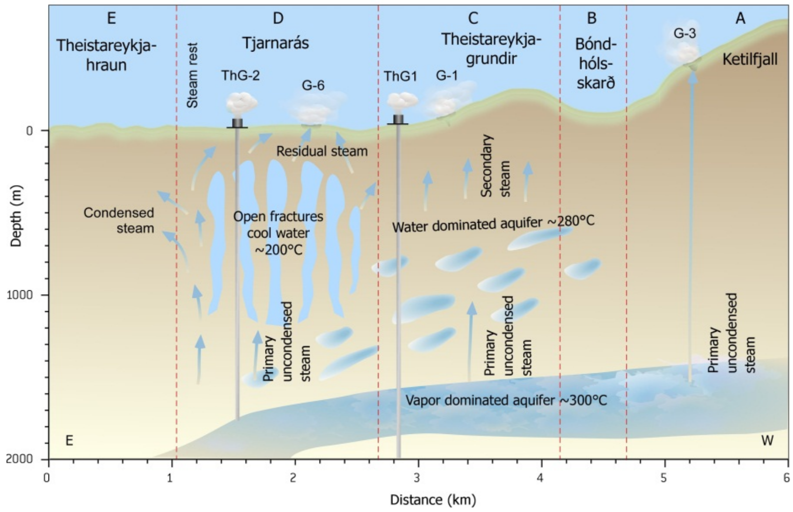

FIGURE 7: Conceptual model of Þeistareykir geothermal field after drilling the first three exploration wells (Guðmundsson *et al.*, 2008; Ármannsson, 2012)

As a geothermal field is being developed and numerous wells are being drilled the density of data from the subsurface increase. This inherently leads to that more emphasis is put on subsurface data, when the conceptual model is reviewed. In figure 8 is an example of a more recent 3D conceptual model of Krafla geothermal system, but at that time more than 40 wells had been drilled in the area. The model is showing a combination of surface and subsurface data delineating the temperature conditions and structural control of fluid flow in the system as well as the deep seated heat source as outlined by the low-resistivity anomaly, but arrows are used to highlight the inferred flow directions in the reservoir.

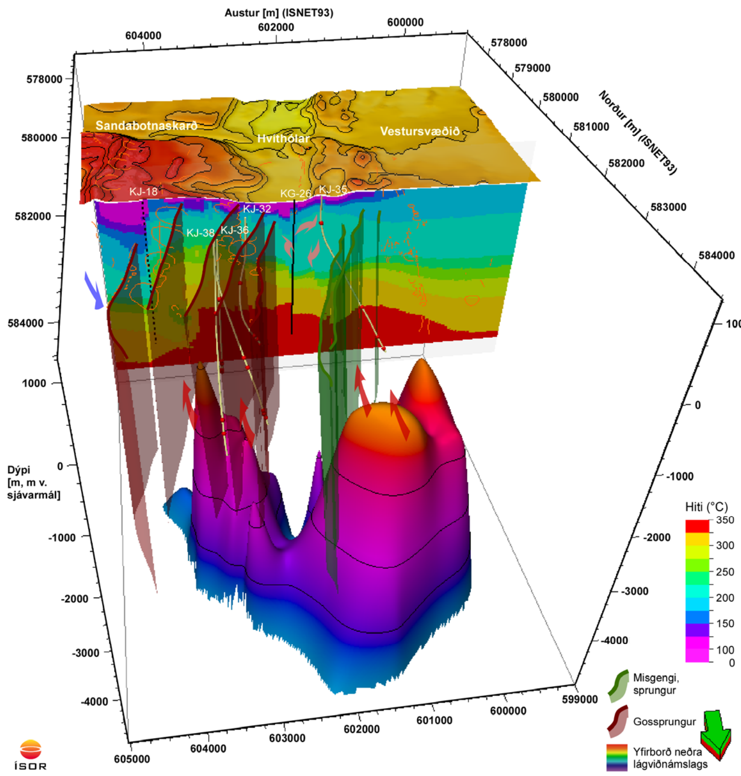

FIGURE 8: A 3-dimensional view of the current conceptual model of the Krafla geothermal system in NE-Iceland (Mortensen et al., 2009) showing a deep-seated low-resistivity anomaly reflecting a magma chamber, faults and eruption fissures as well as temperature conditions and inferred flow directions.

4. CONCLUSIONS

This paper has reviewed the step-by-step development of conceptual models of geothermal systems, how they develop in hand with the gradual exploration and development of the geothermal system. Conceptual models are used to illustrate the essential features of the geothermal systems, but geothermal systems are characterized through a multidisciplinary approach involving geological, geochemical, geophysical and hydrogeological data from both surface and subsurface exploration.

Hitherto data have mainly been integrated and presented in the form of 2D conceptual models. However, geological modelling tools have developed rapidly in the past decade and these software programmes are increasingly applied as a central tool in the development of geothermal fields. They facilitate spatial representation and visualization of the data in digital 3D models, but the multitude of data that are used to describe and define the geothermal system can be integrated and interpreted in one model. The geological modelling tools also allow for a more efficient and continuous model update as new data are obtained, but timely updates of conceptual models are critical for successful development planning, well siting and resource assessment of geothermal fields.

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UNITED NATIONS UNIVERSITY
GEOTHERMAL TRAINING PROGRAMME

LaGeo S.A. de C.V.

CONCEPTUAL MODEL AND RESOURCE ASSESSMENT FOR THE OLKARIA GEOTHERMAL SYSTEM, KENYA

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ABSTRACT

The first published conceptual model of the Olkaria geothermal system is 37 years old at present. It has been upgraded intermittently through time, as more information on the geothermal system has become available. The conceptual model was revised yet again during 2011 – 2012 on the basis of all available geological and geophysical information, temperature and pressure data, various reservoir testing and monitoring data as well as information on the chemical content of reservoir fluids. Most important are data from about 60 deep wells drilled in the area since 2007. The Olkaria geothermal resource can be split in two; a heavily explored part where extensive drilling has delineated the resource and long-term utilization experience exists, and a less explored part where drilling has been limited and mainly indirect indications of an exploitable resource exist. The conceptual model for the former part is quite accurately defined while the model for the latter part is very speculative. At least three deep magmatic heat sources are assumed below the heavily explored part of the system with hot water up-flows into the four main well-fields. The resources anticipated in the less explored part require exploration through comprehensive surveying and drilling. The electrical generation capacity of the heavily explored part of KenGen's concession area in Olkaria is estimated to be about 630 MW_e based on a volumetric resource assessment, lumped parameter pressure response modelling and detailed numerical modelling. This includes 150 MW_e already installed and 280 MW_e under construction. The results of the three different assessment methods are quite comparable, which adds confidence to the results. The electrical generation capacity of the less explored part is estimated to be about 300 MW_e based on a volumetric assessment, an estimate that needs to be confirmed through comprehensive exploration and drilling.

1. INTRODUCTION

The Olkaria geothermal resource is located in the Kenya Rift valley, about 120 km from Nairobi. Geothermal activity is widespread in the Kenyan rift and 14 major geothermal prospects have been identified (Figure 1). The Olkaria geothermal field is inside a major volcanic complex that has been cut by N-S trending normal rifting faults. It is characterized by numerous volcanic rhyolitic domes, some of which form a ring structure, which has been interpreted as indicating the presence of a buried volcanic caldera (Figure 2). Olkaria is surrounded by further geothermal prospects as shown in Figure 1.

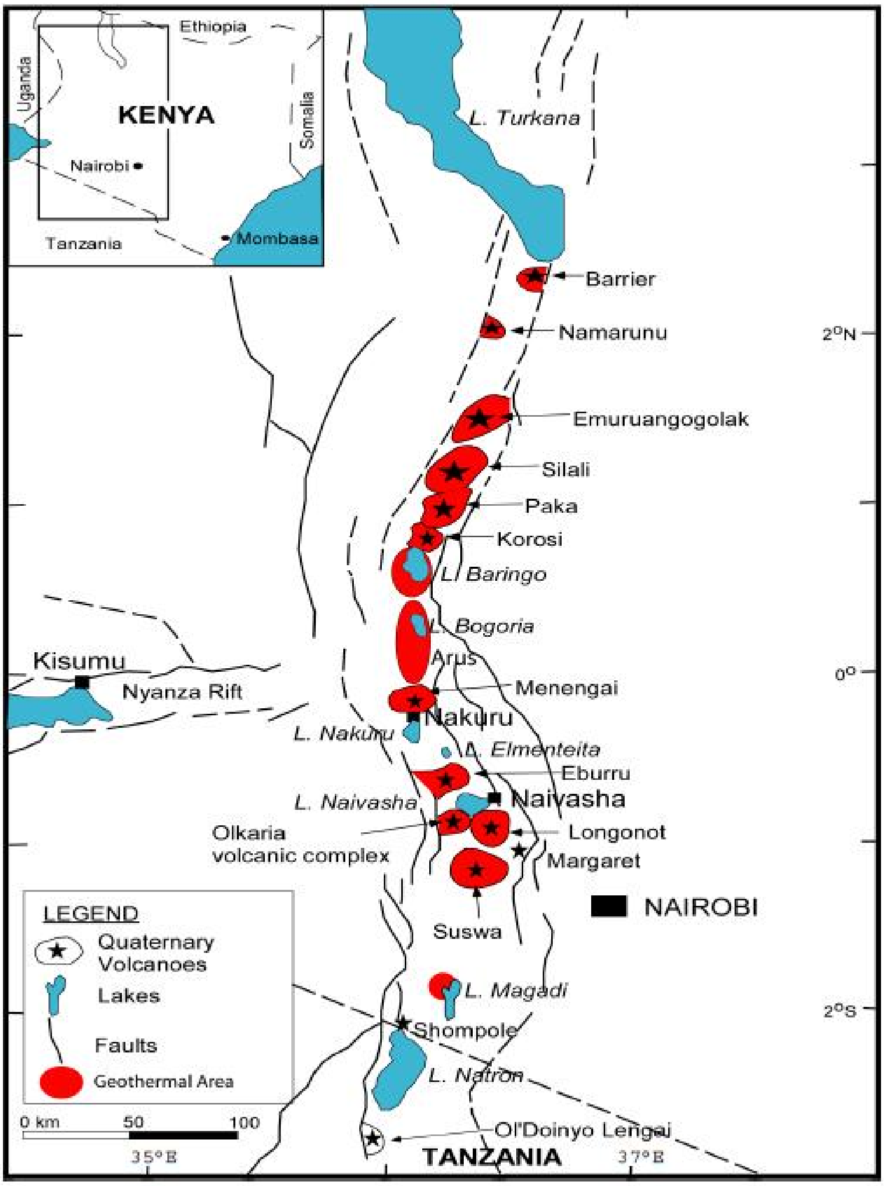

FIGURE 1: Map showing the location of the Greater Olkaria Geothermal Area within the Great Rift Valley of Kenya. Also shown are other volcanic and geothermal centres (Ofwona, 2010)

Exploration of the Olkaria geothermal resource started in 1956 with deep drilling commencing in 1973. A feasibility study in 1976 indicated that development of the geothermal resource was feasible and consequently a 30 MW_e power plant was constructed (Ouma, 2010). Three power plants are currently installed in the field and producing electricity; Olkaria I with 45 MW_e capacity, Olkaria II with 105 MW_e capacity and Olkaria III with 48 MW_e capacity. The first two are operated by KenGen while the third is operated by OrPower4 Inc. The Olkaria I power plant consists of 3 units commissioned between

1981 and 1985 while Olkaria II, which also has 3 units, was commissioned between 2003 and 2010. The Olkaria III power plant was commissioned in two phases between 2000 and 2009. In addition the geothermal resources of the NW part of the Olkaria area are utilized both for direct heat and small scale electricity generation by the Oserian flower farm. Finally KenGen has recently started operating a well-head unit of 5 MW_e capacity. The parts of the Olkaria geothermal field being utilized or under development have been subdivided into sectors that include Olkaria East (Olkaria I), Olkaria Northeast (Olkaria II), Olkaria West (Olkaria III) and Olkaria Domes (Olkaria IV).

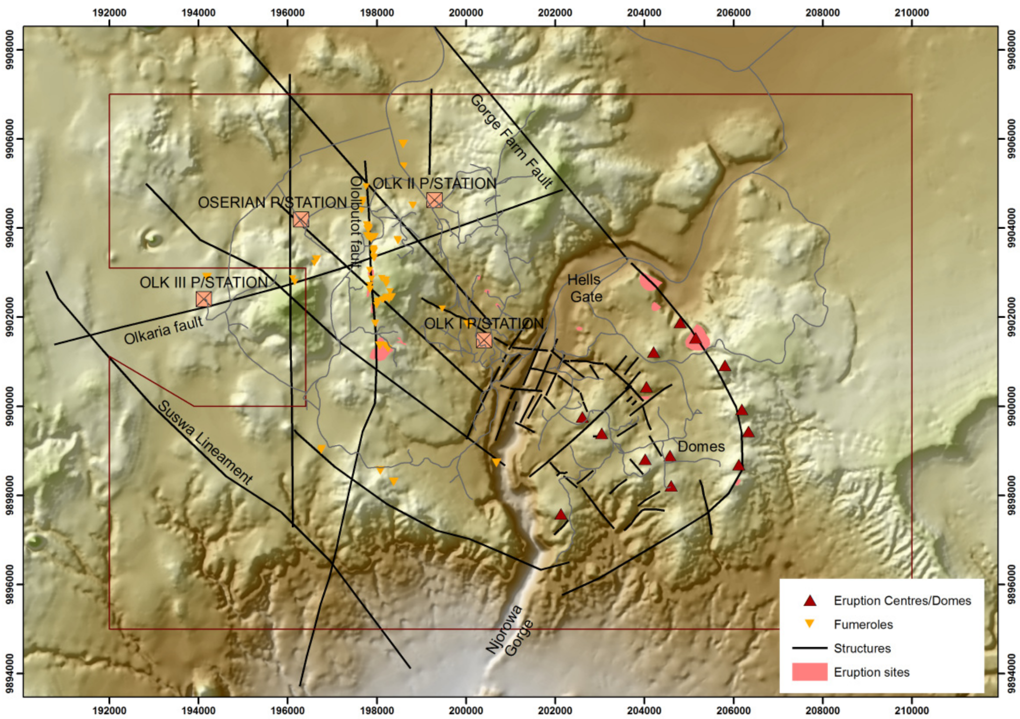

FIGURE 2: Map showing KenGen's geothermal concession area in the Olkaria volcanic complex, extending up to Lake Naivasha. The map also shows some of the main geological features of the area and the power plants in operation

KenGen's present estimate of the possible generating capacity of their 204 km^2 total concession area in Olkaria indicates that it may sustain as much as an additional 840 MW_e long-term generation (KenGen in-house data). Of these 280 MW_e have entered the implementation phase, a 140 MW_e expansion of Olkaria I and a 140 MW_e installation in Olkaria IV. As a result of intensive production drilling (60 wells) in progress since 2007 steam availability corresponding to as much as 440 MW_e (based on discharge testing of each well following heating-up) has been inferred in the Olkaria East and Olkaria Domes sectors (KenGen in-house data). Therefore a capacity of about 400 MW_e or moer still remains untapped, according to KenGen's estimates. Figure 3 shows the geothermal wells drilled to-date by KenGen.

The apparently large untapped resource was the motivation to carry out an optimization study for the Greater Olkaria Geothermal System in 2011 - 2012. The objectives of the study were to assess the energy production potential of geothermal resources within KenGen's 204 km^2 concession area in Olkaria, mainly through comprehensive reservoir modelling, assess the feasibility of continued and increased production, as well as to propose an optimized development plan for the area. This work was awarded to a consortium from Iceland composed of Mannvit hf, ÍSOR, Vatnaskil ehf and Verkís hf. The results of the optimization study have been presented in several in-house KenGen reports, while this paper summarizes the results of a revision of the conceptual model of the geothermal system and the results of production capacity estimates arrived at through three types of resource modelling. This paper is to a large extent based on Axelsson et al. (2013).

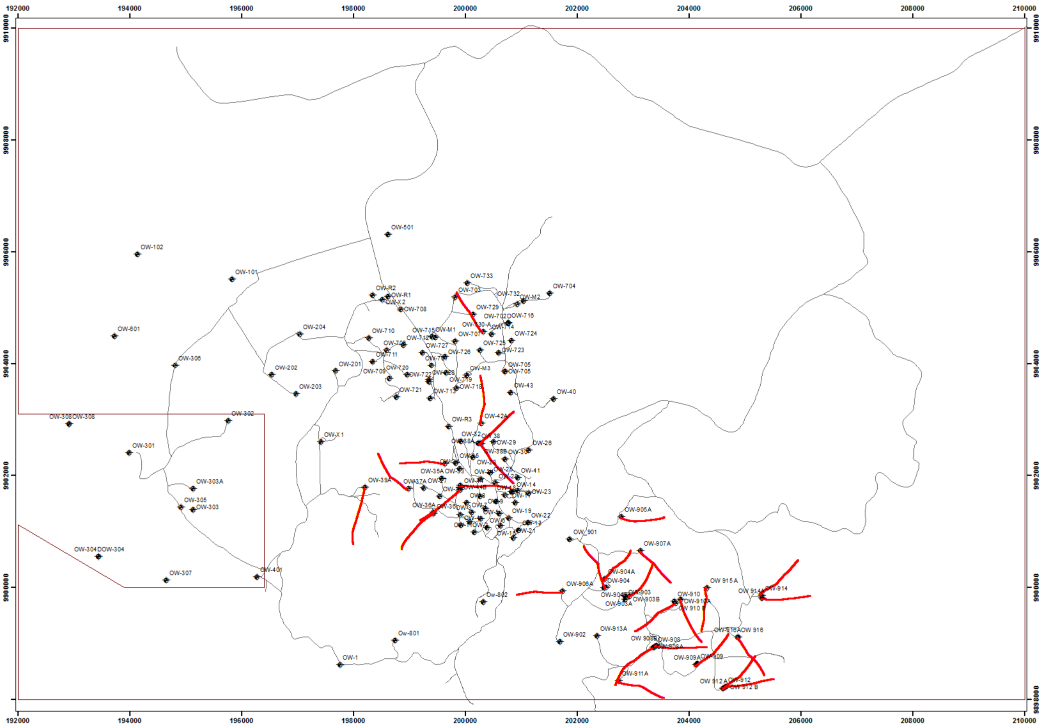

FIGURE 3: Map showing the location of wells in Olkaria drilled by KenGen up to middle 2012, horizontal trajectories of directionally drilled wells shown by red lines. The map covers KenGen's concession area, whilst OrePower4's concession can be seen on the left

The conceptual model of the Olkaria geothermal system has been constantly evolving during the last 4 decades, as reviewed below. The same applies to reservoir assessment and modelling.

2. UPDATED CONCEPTUAL MODEL

2.1 General

Reliable conceptual models of geothermal systems are the key to successful development of all geothermal resources and emphasis is increasingly being put on the development of such models, especially during geothermal exploration and development, as well as their revision during long-term utilization and resource management. Conceptual model revision is obviously vital during expansion of geothermal operations, as is on-going in Olkaria. Conceptual models are descriptive or qualitative models incorporating, and unifying, the essential physical features of the systems in question (Grant *et al.*, 1982).

Conceptual models are mainly based on analysis of geological and geophysical information, temperature and pressure data as well as information on the chemical content of reservoir fluids. Monitoring data reflecting reservoir changes during long-term exploitation, furthermore, aid in revising conceptual models once they become available. Conceptual models should explain the heat source for the reservoir in question and the location of recharge zones as well as the location of the main flow channels and the general flow patterns within the reservoir. A comprehensive conceptual model should, furthermore, provide an estimate of the size of the reservoir involved. Conceptual models are ultimately the foundation for all geothermal resource assessments, particularly volumetric assessments and geothermal reservoir modelling. In addition, conceptual models are an important basis of field development plans, i.e. in selecting locations and targets of wells to be drilled.

The conceptual model of the Olkaria geothermal system has, of course, evolved through time (more than 35 years) as more information has been accumulated through surface exploration, drilling, utilization and reservoir engineering work. The first published version of the conceptual model was presented by SWECO and Virkir (1976). It was very simple due to the limited drilling done at the time (see Figure 4). Later revisions saw the model expanding to cover more of the Olkaria area and include several zones of hot up-flow, first in the Northeast and West sectors and later in the East sector as well (see Ofwona, 2002). Ofwona (2002) presented an updated version of the conceptual model. According to his revised model the hydrothermal systems of western and eastern Olkaria are clearly separated by the low temperature zone of central Olkaria. He postulates two possible up-flow zones in Olkaria Northeast and one up-flow zone in Olkaria East, with a down-flow separating Olkaria Northeast and Olkaria East. Extensive boiling also occurs in the up-flow zones to form steam caps below the cap rock, according to this revision. Cold water recharge into the Olkaria geothermal system is assumed to occur from all directions in that model (see Figure 5).

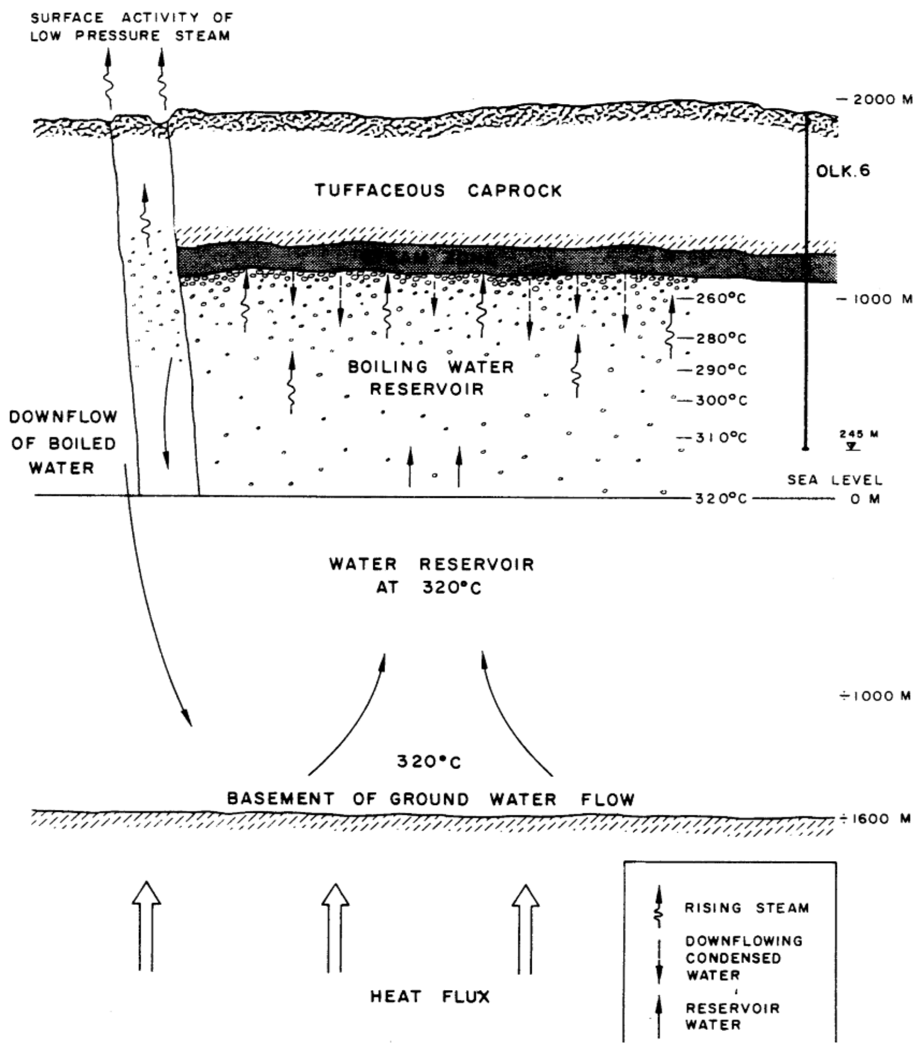

FIGURE 4: A pictorial rendition of an early conceptual model of the Olkaria East geothermal system (SWECO and Virkir, 1976)

The latest version of the Olkaria conceptual model, prior to the one presented here, is the one developed by West Japan Engineering Consultants Inc. and subcontractors from 2005 to 2009 (KenGen in-house report). This model is quite comprehensive and appears to be still mostly valid. Extensive new data have become available during the last 2–3 years, however, mostly through the intensive drilling program KenGen is conducting, prompting the update discussed in this paper.

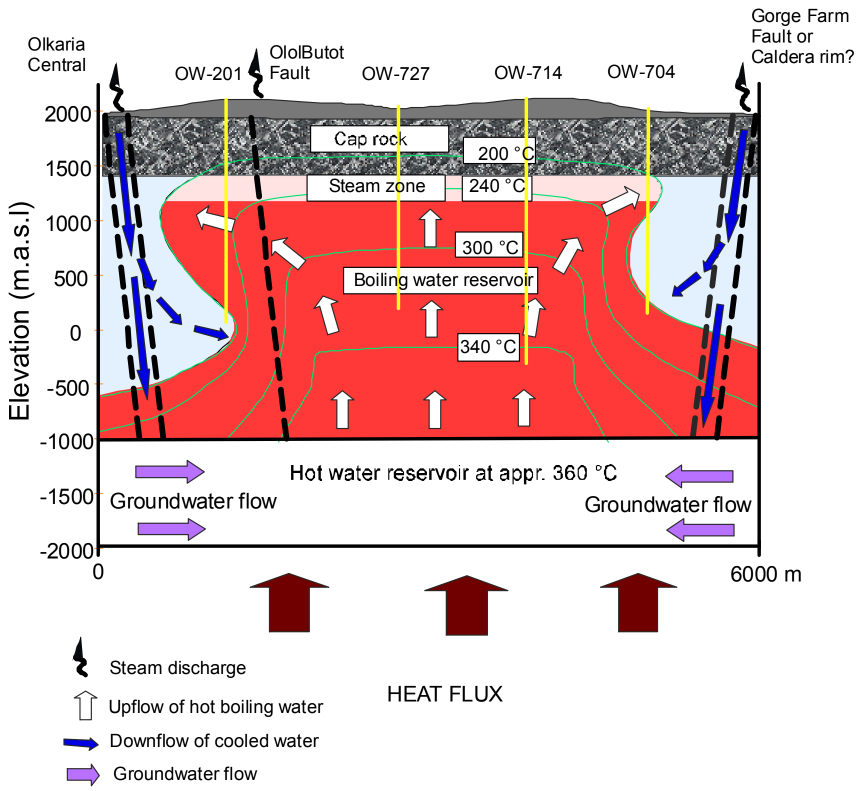

FIGURE 5: A revised conceptual model of the Olkaria East geothermal system from 2002 (Ofwona, 2002)

2.2 Geological data

The relevant geological data for the Greater Olkaria Geothermal System includes both information on surface geology and borehole geological data, which have been viewed by three-dimensional visualization software. These include both lithological and alteration analyses of drill cuttings from boreholes that have been drilled in the field.

The most important input from geological studies involves defining and understanding the permeability structure of a geothermal system. Permeability in the Olkaria system is fracture-dominated, which is e.g. evident from the high well-to-well variability in the depth to high-temperature alteration. Flow paths are controlled by predominantly N-S, NW-SE and NE-SW trending faults (see Figure 2). In addition to the main faults of the system the ring structures encircling the Domes field represent a possible inner and outer rim of the proposed Olkaria caldera. Both the inner and the outer ring structures connect to the Gorge Farm fault, located north and east of the main production area and possibly extending north to Lake Naivasha. Cold water is believed to flow into the Olkaria system through the N-S fault system along the Ololbutot fault, which also is associated with plentiful geothermal surface manifestations.

In spite of attempts to incorporate available data into a single model, the results are still rather inconclusive. This infers that the data resolution is insufficient in relation to the complexity of the geothermal system. Therefore, more detailed mapping of the geothermal system through the available boreholes is needed, especially the correlation between permeability and known geological structures. This lack of refined structural control of the geothermal system makes borehole siting more challenging. The method adopted by KenGen has been of a cautious nature where the well-fields have in general been expanded both by short distance step-out wells from areas of good productivity, as well as through drilling into deeper and hotter parts of the system. This approach has turned out to be sensible as can e.g. been seen by the success of the KenGen drilling program in recent years.

2.3 Geophysical data

Subsurface resistivity data (EM data including TEM and MT) and micro-seismic monitoring data are considered the most important geophysical data in the case of Olkaria. Good quality data of the former type are only available for limited parts of the Olkaria area, in particular the Domes sector, while such data are almost entirely lacking in other parts of the area. Further EM data collection is planned by KenGen. Most significantly the available resistivity data support the hypothesis that exploitable geothermal resources extend much further to the east and southeast in the Domes sector than previously assumed, as supported by other types of data (see below).

Micro-seismic data collected in the Olkaria area from 1996 to 1998 have provided highly valuable data for the conceptual model of the Olkaria geothermal system. This includes both location of the seismic events as well as information on S-wave attenuation derived from the data, which has been interpreted as reflecting volumes of partially molten material (Figure 6). The largest of these volumes are found below the Olkaria Domes, Northeast and West production fields, with other smaller attenuating bodies possibly indicating further undiscovered geothermal resources.

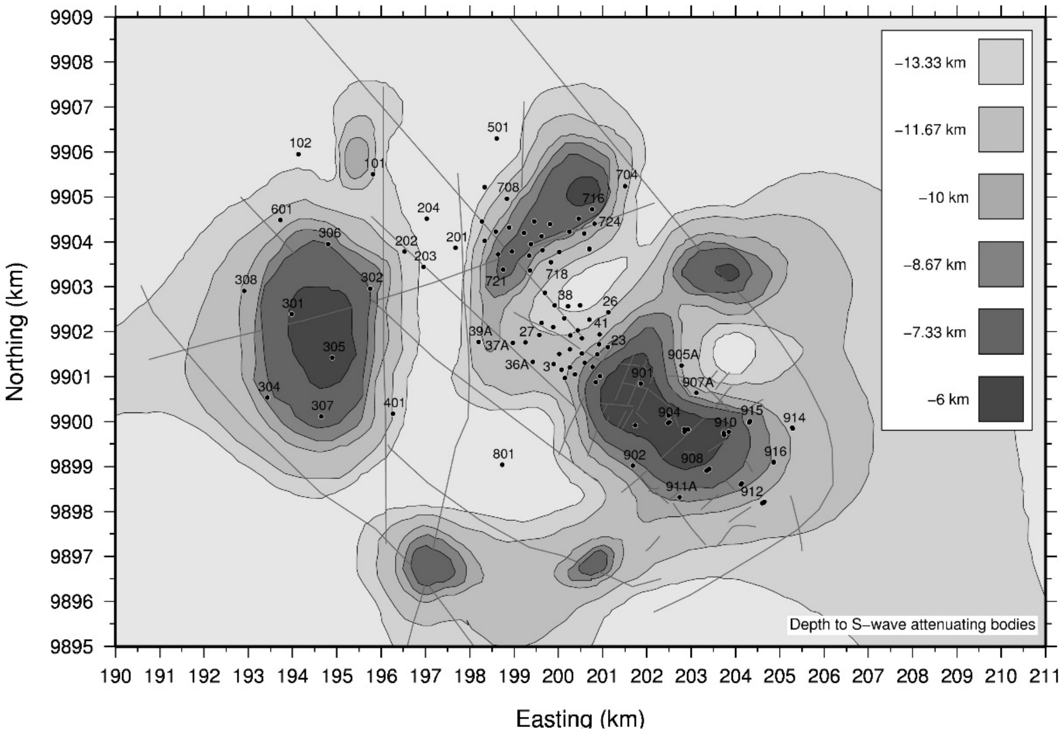

FIGURE 6: Contour map of the depth to the top of attenuating bodies beneath the Olkaria geothermal field along with structural features in the area and location of drilled wells. Based on in-house KenGen reports and Simiyu (2000)

2.4 Reservoir and chemistry data

The temperature and pressure model for the geothermal system, which has been set up during the Optimization Study, is at the core of the conceptual model development and resource assessments discussed here. It also provides an essential basis for the field development for Olkaria. The model is based on so-called formation temperature and initial pressure profiles for all KenGen boreholes in Olkaria. The updated formation temperature and initial pressure model of the Greater Olkaria Geothermal System has provided a significantly clearer picture of the Domes area than has been available up to now. It should be mentioned that some profiles are still uncertain because of insufficient temperature and pressure data for certain wells.

The temperature and pressure model of the Olkaria geothermal system was constantly revised and updated during the course of the study presented here, providing an essential basis for the development of the volumetric assessment and numerical reservoir model (see later). Thus new data were constantly incorporated. A glimpse into the revised temperature and pressure model is presented in figures 7 – 11, whilst a more complete view was not possible here.

Other data-sets that aid in revising the conceptual model as well as in establishing the field development plan for Olkaria include the variation in injectivity, estimated transmissivity and well output (mass flow, enthalpy and estimated electrical generation capacity). These have been presented in various project reports (KenGen in-house reports). The great capacity of some wells in the Domes sector is, in particular, noteworthy.

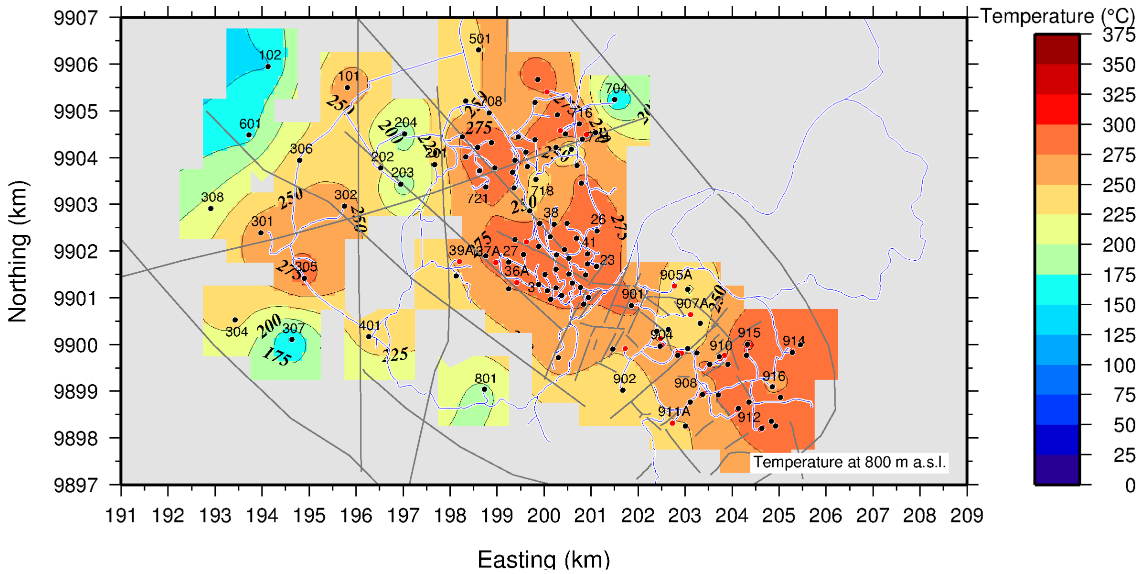

FIGURE 7: Horizontal view of the temperature distribution at 800 m a.s.l. (~1200 m depth) in the revised temperature model of the Greater Olkaria Geothermal System

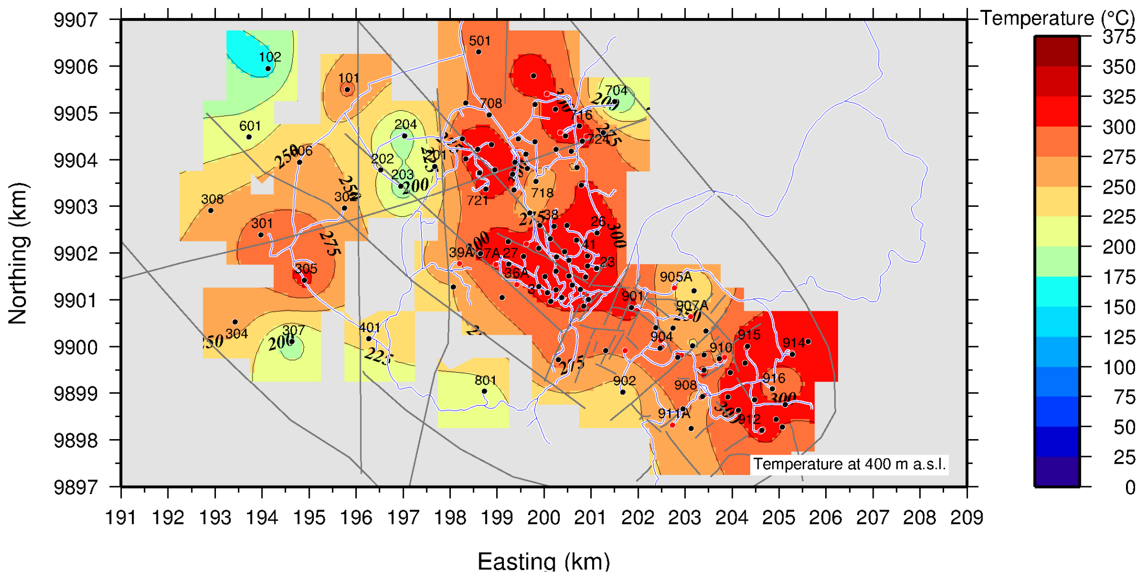

FIGURE 8: Horizontal view of the temperature distribution at 400 m a.s.l. (~1600 m depth) in the revised temperature model of the Greater Olkaria Geothermal System

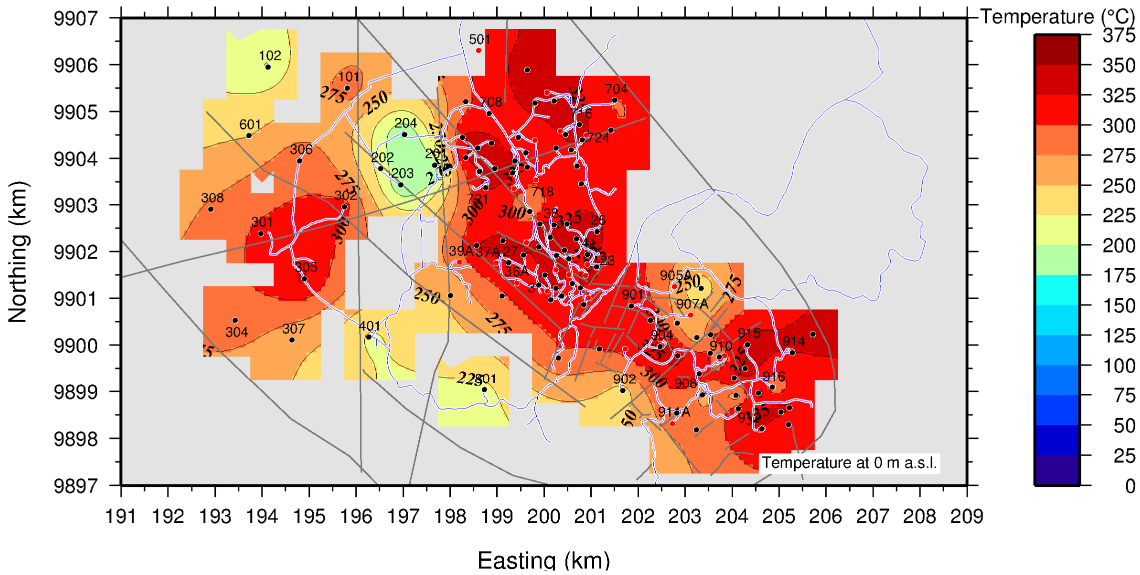

FIGURE 9: Horizontal view of the temperature distribution at 0 m a.s.l. (~2000 m depth) in the revised temperature model of the Greater Olkaria Geothermal System

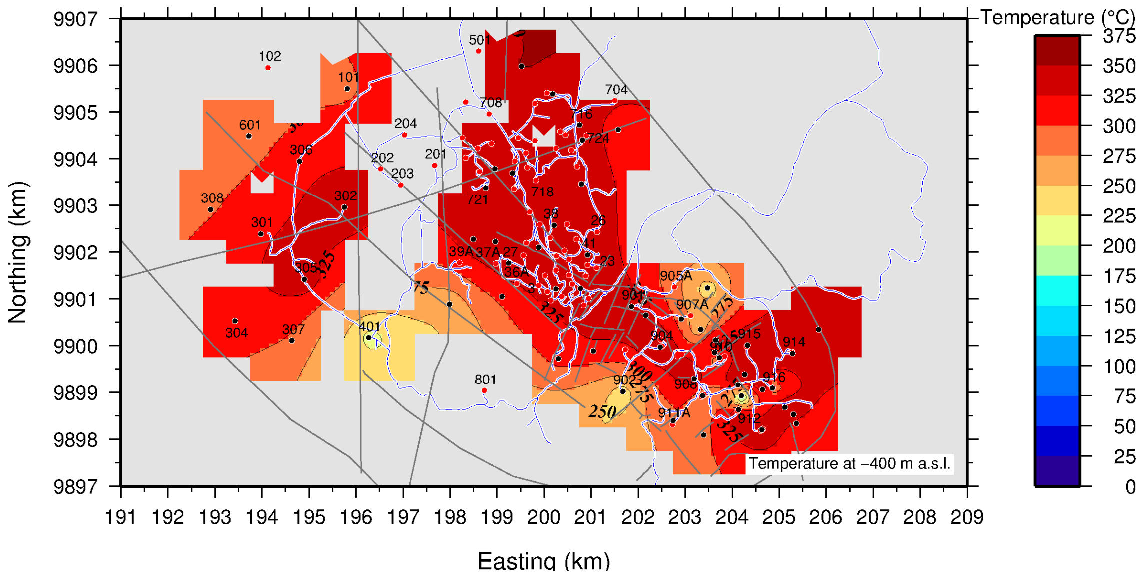

FIGURE 10: Horizontal view of the temperature distribution at -400 m a.s.l. (~2400 m depth) in the revised temperature model of the Greater Olkaria Geothermal System

Additionally to the above information, data on the chemical and gas content of fluid from geothermal surface manifestations and fluid samples from geothermal wells provide important information. The following main results should be emphasized. Firstly, that the chemical content of fluids from the Domes sector support the possibility of an hot up-flow in the southeast part of the Domes as well as supporting the contention that the resources there extend further to the east and southeast (see Figure 12). Secondly, that surface manifestations are widespread in all parts of Olkaria, except the northeast quadrant of the region. Samples from these indicate source temperatures from 240°C to more than 300°C in different parts of the area.

2.5 Revised conceptual model

The revision of the conceptual model for the Greater Olkaria Geothermal System has emphasised (a) interpretation of data not available during development of previous conceptual models, (b) development of a new temperature and pressure model for the system as well as (c) presentation of principal aspects of the conceptual model by a three-dimensional visualization software.

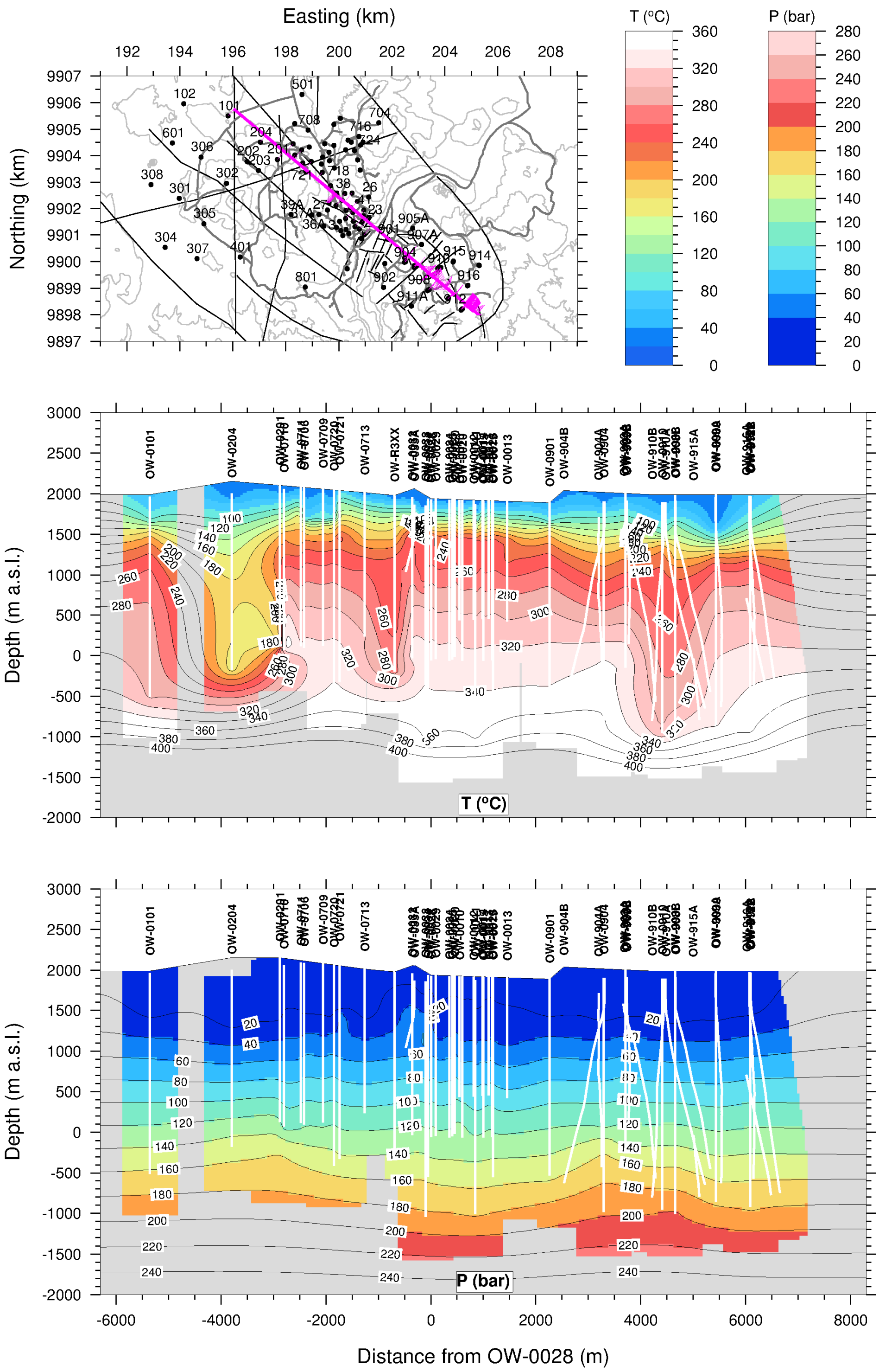

FIGURE 11: A view of the temperature and pressure distribution in a NW-SE cross-section through the Olkaria Geothermal System

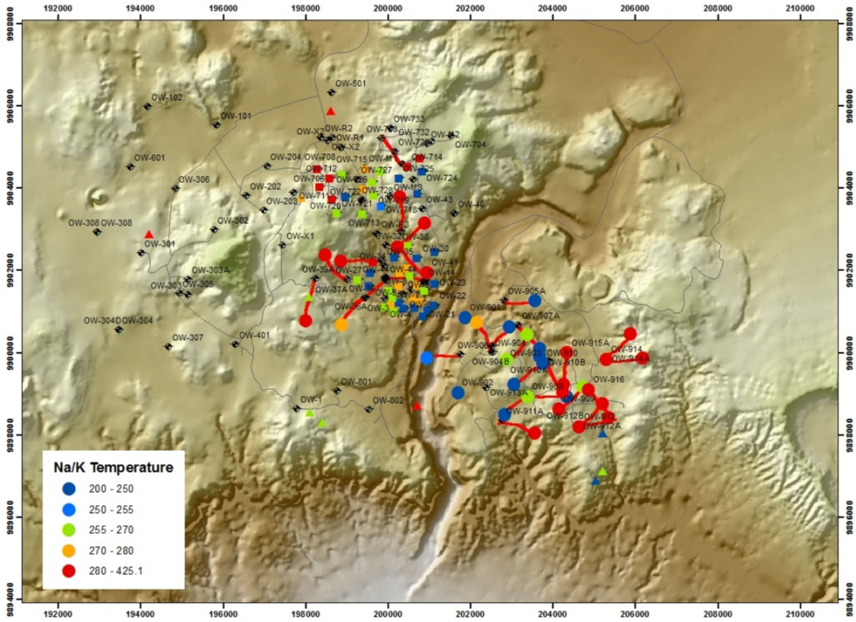

FIGURE 12: Na/K temperatures of Olkaria production wells (based on KenGen in-house chemical data). Larger symbols represent data for recently drilled wells

The main aspects of this most recent revision of the conceptual model are the following:

(1) The Olkaria geothermal resources can be split in two based on the level of knowledge on their nature and characteristics, i.e. the part which has been heavily explored, in particular through extensive deep drilling, and the part that has been drastically less explored. The conceptual model for the former part is understandably much better defined and includes much more detail. The conceptual model for the latter part is less detailed and considerably more speculative.
(2) The heat source of the geothermal system is assumed to be a deep-seated magma chamber or chambers. Three main intrusions are believed to extend up from the magma chamber(s) to shallower depths of 6 – 8 km. These heat source bodies (possibly partially molten) are proposed to lie beneath Olkaria Hill (Olkaria West), in the northeast beneath the Gorge Farm volcanic centre, and in the Domes area.
(3) Four major geothermal up-flow zones are identified from the temperature and pressure model related to these heat sources. Firstly an up-flow zone feeding the West field seems to be associated with the Olkaria Hill heat source body. Secondly two up-flow zones, one feeding the Northeast field and another feeding the East field and the northwest corner of the Domes, are probably both associated with the heat source body beneath the Gorge Farm volcanic centre. Finally an up-flow zone appears to be associated with the ring structures in the southeast corner of the Domes field, related to the heat source proposed beneath the area. The existence of these up-flow zones is supported by Cl^- concentration data and Na/K temperature estimates as well as resistivity data.
(4) Permeability of the Olkaria system is mainly controlled by predominantly NW-SE and NE-SW tending faults as well as the proposed ring structure and intersections of such structures. Colder water flows into the system through the N-S fault system along the Ololbutot fault and possibly into the Domes area from the northeast. The Ololbutot fault presents a flow barrier between the eastern and western halves of Olkaria. Generally, the origin of Olkaria fluids appears to be 50% or more as deep Rift Valley water, with some variability between sectors.
(5) The Olkaria geothermal resource extends further to the southeast in Olkaria Domes than previously assumed. In fact, on-going step-out drilling has not detected the limit, or boundary, of the resource in this region of the Olkaria field. This is supported by temperature and pressure data, well characteristic and output data, fluid chemistry data as well as geophysical data.

(6) Some exploitable resources are expected in the south central and southwest parts of Olkaria, as indicated by limited geophysical data and surface manifestations. The same applies to the northwest part of Olkaria, even though somewhat lower reservoir temperatures may be expected there. Limited resources are anticipated in the far northeast sector of the concession area apart from a limited region to the east and northeast of the East and Northeast production areas, due to limited indications in available resistivity and micro-seismicity data.

3. CAPACITY ESTIMATES

3.1 Overview

The capacity assessments of KenGen's concession in the Greater Olkaria Geothermal Area are based on a division of the area in two, a division which has already been mentioned. In addition a third part/category is introduced here involving the peripheral zone around the heavily explored part. The division is as follows:

(A) The ***heavily explored part*** of KenGen's Olkaria concession area, mainly the Northeast, East and Domes sectors where the existence of an exploitable resource has been confirmed by drilling (Figure 3) and long-term utilization (Olkaria I and II). Linked with the heavily explored part is a third part/category involving the ***peripheral zone*** around the heavily explored part, because of strong indications (lack of well-defined limits) that the present well-fields may be expanded considerably (see Figure 13).

(B) The ***less explored parts*** of KenGen's concession area, where drilling has been much more limited and mostly indirect indications of an exploitable resource exist (further surface exploration also needed). The possible capacity of this part can only be estimated approximately and the realization of its generation capacity will depend entirely on the outcome of the exploration proposed and consequent exploration drilling.

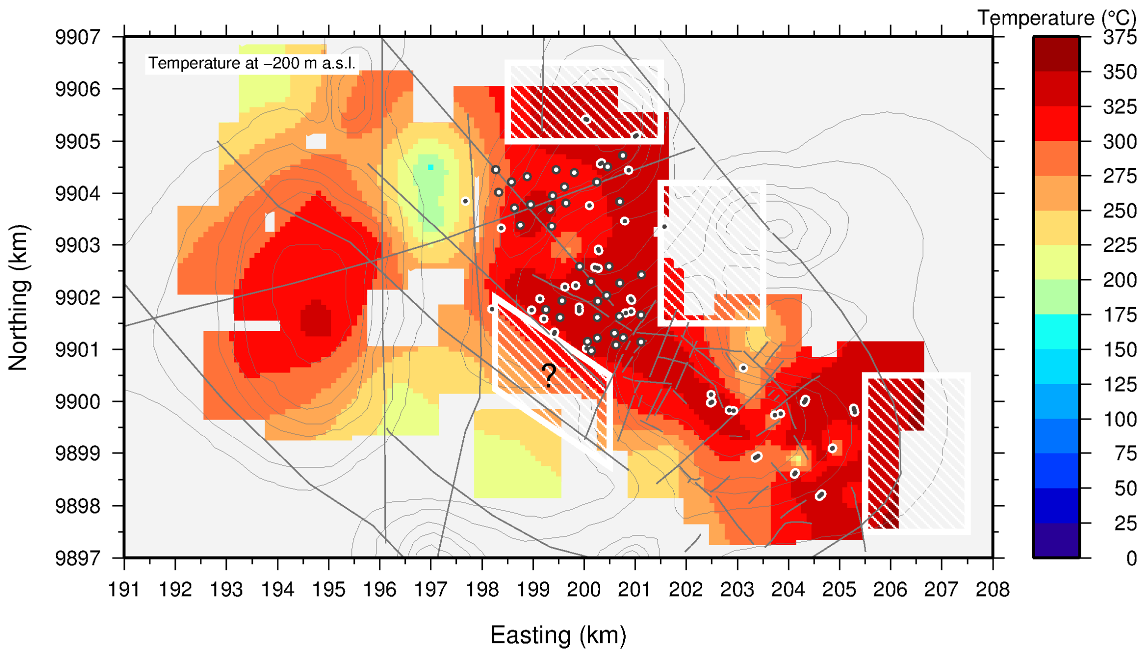

FIGURE 13: Horizontal view of the temperature distribution at 0 m a.s.l. in the temperature model of the Olkaria geothermal system (see Figure 9) along with areas at the edges of the present well-fields, where indications of a boundary haven't been found (white stripes), and expansions of the present well-fields may be possible, termed the **peripheral zone**

The production capacity estimates for the Olkaria geothermal system are based on the results of three types of reservoir assessment and modelling; (i) volumetric capacity assessments for both the heavily explored and less explored parts, (ii) lumped parameter modelling of the pressure response of Olkaria East and Northeast, and (iii) the predictions of the detailed numerical model for the heavily explored part (including the peripheral zone).

3.2 Volumetric assessment

The volumetric method is the main static modelling method used in assessing geothermal resource capacity. The volumetric assessment method is based on estimating the total thermal energy stored in a volume of rock (referred to some base temperature). Subsequently a recovery factor is incorporated, indicating how much of the thermal energy may be technically recovered. The recovery factor is, however, the parameter in the volumetric method, which is most difficult to estimate. The main drawback of the volumetric method is the fact that the dynamic response of a reservoir to production is not considered. This method is often used for first stage assessment, when data are limited, and was more commonly used in the past (Muffler and Cataldi, 1978). It is increasingly being used, however, through application of the Monte Carlo method, which enables the incorporation of overall uncertainty in the results. The volumetric method is e.g. described by Sarmiento et al. (2013) and its application to the Olkaria system by Axelsson et al. (2013).

The main parameters used in the volumetric assessment for Olkaria are presented in Table 1, along with their ranges as used in the Monte Carlo calculations. The resulting probability distributions for the heavily explored part are not presented here (see Axelsson et al., 2013), but they are summarized in Table 2.

TABLE 1: Values and ranges of the principal parameters assumed in the volumetric assessment of the Olkaria geothermal system, employing the Monte Carlo method

Parameter	Heavily explored part	Less explored part
Surface area	40-45 km^2	50-100 km^2
Thickness	2000-2500 m	1000-2500 m
Resource temperature		
% of boiling curve	75-100	-
average	-	200-300°C
Rejection temperature	30°C	30°C
Recovery factor	0.10-0.20	0.05-0.15
Generation efficiency (thermal-electrical)	0.11-0.15	0.08-0.14
Utilization time	50 yrs.	50 yrs.

According to Table 2 the electrical generating capacity of the ***heavily explored part*** of Olkaria may be expected to be above 520 MW$_e$. The volumetric assessment further indicates that the electrical generating capacity of the ***less explored parts*** of Olkaria may be expected to be above 400 MW$_e$. These are the southeast extension of the Domes area, where available data indicate that the resource extends still

TABLE 2: Summarized results of a volumetric resource assessment for the Greater Olkaria Geothermal System in MW$_e$. Numbers refer to estimated generation capacity for 50 years

Monte Carlo results	Heavily explored part	Less explored part
90% confidence interval	450 – 910	320 – 1000
Mean value	670	630
90% limit from cumulative distribution	**520**	**400**

further than drilled so far, as well as the central south and southwest parts of Olkaria, the northwest part of the overall system and a region to the east and northeast of the East and Northeast production sectors. This needs to be confirmed, however, through comprehensive surface exploration and exploration drilling.

Setting these results in the context of a geothermal reporting code (i.e. Australian Geothermal Code Committee, 2008) the generating capacity of the heavily explored part of Olkaria can be classified as a *proven reserve* while the generating capacity of the less explored part should be classified as an *inferred resource.*

3.3 Lumped parameter modelling

Axelsson (1989) presents an efficient method of lumped parameter modelling of pressure response data from geothermal systems and Axelsson *et al.* (2005) present examples of long pressure response histories of several geothermal systems distributed throughout the world, examples which demonstrate its accuracy and reliability. Lumped parameter modelling is also presented at the current workshop by Axelsson (2013).

The fundamental data required for lumped parameter modelling, as outlined above, are production (mass extraction) data and information on reservoir pressure changes resulting from the production. Figures 14 and 15 present the most recent compilation (from early 2012) of such data, for the Olkaria East and Northeast production sectors, respectively.

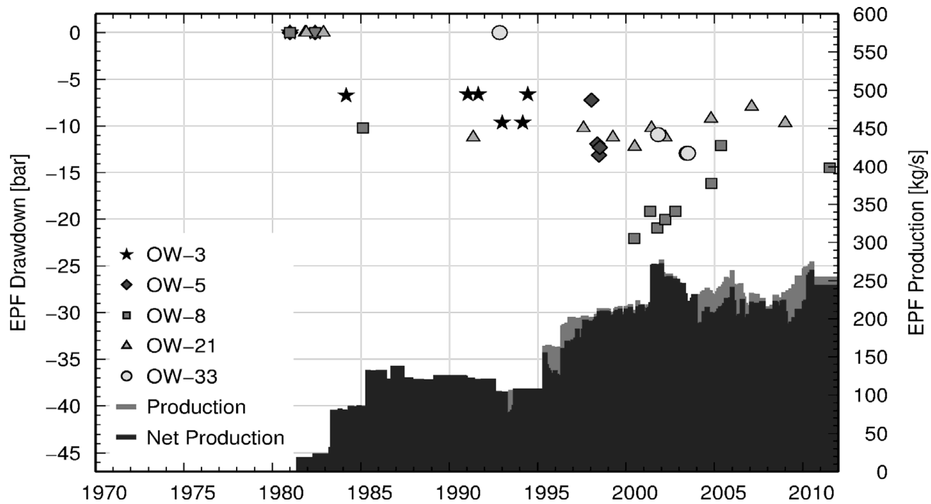

FIGURE 14: Production and pressure response history of the Olkaria East production sector. The pressure draw-down is based on pressure measured at ~650 m a.s.l. and estimated initial pressure conditions for each well (KenGen in-house data)

Figures 16 and 17 show the simulated pressure changes in the two active Olkaria production sectors along with 50-year predictions for two future prediction scenarios. The two scenarios assume that the combined electrical generation of the Olkaria Northeast, Olkaria East and Olkaria Domes sectors corresponded to 520 MW_e (in agreement with the lower bound of the results in Table 2) divided evenly between the three sectors (~170 MW_e each). Based on the average steam-water ratio of Northeast and East production wells (~60% steam by mass) an average mass extraction of 540 kg/s will be needed to sustain this generation, in each of the sectors. The two scenarios were consequently set up as follows:

I) Average production 540 kg/s with 200 kg/s average brine reinjection, for each sector. Net mass extraction is thus 340 kg/s.
II) Average production 540 kg/s, for each sector, with no reinjection.

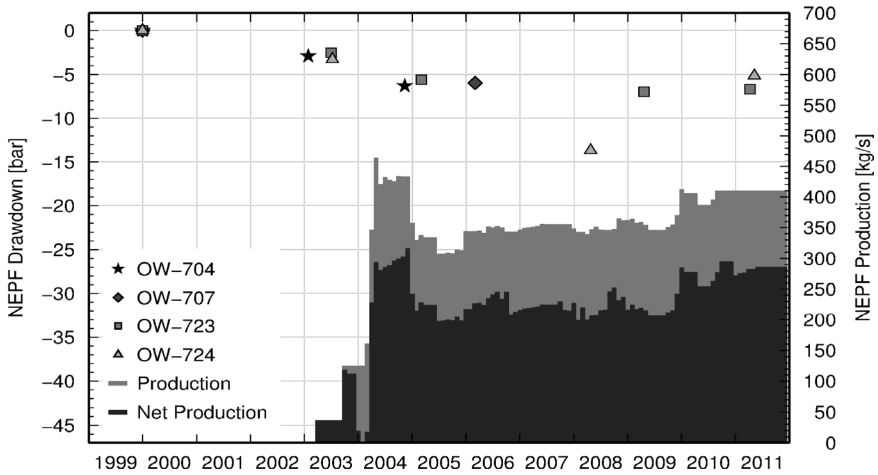

FIGURE 15: Production and pressure response history of the Olkaria Northeast production sector. The pressure draw-down is based on pressure measured at ~1100 m a.s.l. and estimated initial pressure conditions for each well (KenGen in-house data)

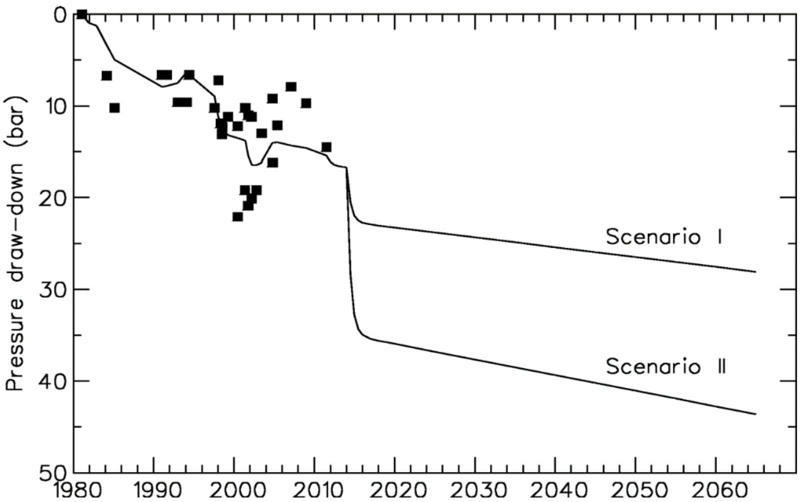

FIGURE 16: Reservoir pressure predictions for the Olkaria East sector calculated by a lumped parameter model for two future production scenarios (see text). Filled squares represent observed data

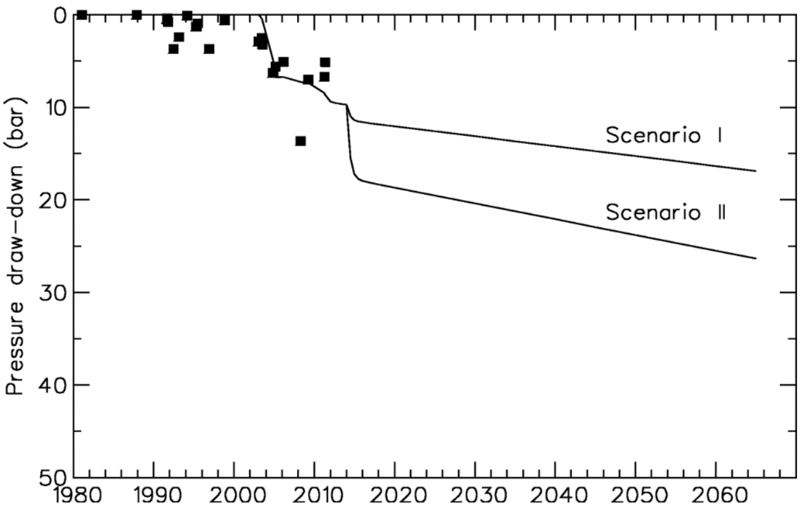

FIGURE 17: Reservoir pressure predictions for the Olkaria Northeast sector calculated by a lumped parameter model for two future production scenarios (see text). Filled squares represent observed data

The main results of the lumped parameter modelling for the Olkaria geothermal system are:

(1) The properties of the lumped parameter models indicate that the whole hydrological system, encompassing the Olkaria geothermal system, is quite large, providing recharge to the geothermal system. The average permeability-thickness of the geothermal system is estimated to be about 10 and 19 Darcy-m, for the East and Northeast sectors respectively, according to the models, which can be considered as close to normal compared with values for other productive geothermal systems.

(2) The predictions for the two scenarios show that the pressure decline for the scenario with reinjection should be manageable. The pressure decline predicted for the scenario without reinjection is quite large, however, especially for the East sector, indicating that such a scenario is not realistic. The short pressure decline history of the Northeast sector indicates that long-term pressure decline there should be somewhat less than the decline in the East sector, at comparable net production.

(3) The principal result of the lumped parameter modelling is, therefore, that brine reinjection, and available steam condensate injection, will be essential if KenGen's future plans of greatly increased electrical generation are to materialize (see later). Otherwise reservoir pressure decline may be expected to be too great. Reinjection will also help minimize pressure interference between production sectors.

(4) It should be noted that the available pressure response data are quite scattered, which adds uncertainty to the pressure response modelling. The length of the Olkaria production history (31 years), on the other hand, enhances the reliability of the model predictions.

3.4 Detailed numerical model

Several numerical modelling studies were carried out for Olkaria from 1980 to 1993. In fact the earliest of these can be considered among the pioneering numerical modelling studies of the geothermal industry. These studies were predominantly carried out by scientists at Lawrence Berkeley National Laboratory in California, chiefly the late Gudmundur Bödvarsson. The first model was a very simple small, two-dimensional, vertical model. The models rapidly became more complex with advancing knowledge on the geothermal system, advances in numerical modelling techniques and rapidly improving computer capabilities.

These modelling studies are described in various internal KenGen reports as well as international publications (Bödvarsson *et al.*, 1987a, 1987b and 1990). Ofwona (2002) also reviews the first two decades of modelling. The first detailed three-dimensional, well-by-well numerical model was set up in 1984, calibrated on basis of the production history of the field up to that time. The final modelling phase lead by Bödvarsson lasted from 1987 to 1993. In this phase the entire Olkaria geothermal system, as known at the time, was modelled. In 1993 the model was revised and calibrated further and used to assess the generating capacity of Olkaria Northeast (Bödvarsson, 1993).

Later Ofwona (2002) updated the 1987 – 1993 model on basis of both new well data and an additional decade of monitoring data. This work was expanded further in 2008. Finally, West Japan Engineering Consultants Inc. and subcontractors set up, from 2005 to 2009, the most detailed numerical model developed up to that time for Olkaria. It was based on their revised conceptual model, covering about half of the KenGen concession area (KenGen in-house reports).

A detailed numerical reservoir model of the Greater Olkaria Geothermal System was set up as part of the project presented here, being by far the largest and most comprehensive model of the system developed so far. It covers the whole KenGen concession area, and beyond. It uses the TOUGH2/iTOUGH2 software for calculating the model conditions and output. The model grid covers 720 km^2 with a total thickness of 3600 m. It is composed of 15 layers and nearly 37,000 elements. The model is calibrated to fit an extremely large dataset of formation temperature and initial pressure for the great number of wells drilled so far. In addition the model fits measured enthalpy of well fluids and pressure drawdown in wells throughout the production period. The model, and its calibration, are described in full detail in KenGen in-house reports.

The model has been used to forecast the response of the geothermal system to six production scenarios, ranging from continuing current production up to an expansion to about 580 MW_e for 30 years. This ultimate scenario assumes 190 MW_e capacity in the East and Northeast production fields, in addition to the 45 MW_e in operation in Olkaria I and 105 MW_e in operation in Olkaria II, as well as 240 MW_e capacity in Olkaria Domes. The results indicate that the system can sustain this, although for the full 580 MW_e scenario the drawdown in the production layers, especially in the Domes field, becomes large over an extensive area. It is however, clear that at present the exploration efforts have not yet delineated the limits of the geothermal system in several areas, most notably to the southeast of the Domes field and north of the Northeast production field. It should also be noted that the results of the numerical modelling for the Domes are not as well constrained as for the two production fields with production histories, even though a great number of wells has already been drilled there.

3.5 Summarized results

Table 3 summarizes the generation capacity estimates for the Greater Olkaria Geothermal System that have emerged as part of the study presented here. These are the results of the volumetric capacity assessment and lumped parameter modelling performed as part of the study as well as the predictions of the detailed numerical model, all of which are discussed above.

The following are the main premises of the numbers presented in the table:

- The range presented as the outcome of the volumetric assessment is based on the 90% limit from the cumulative distribution on one hand (the lower value) and the mean value of the probability distribution on the other hand (the higher value).
- Only the 90% cumulative limit for the less explored part is presented because of the great uncertainty associated with that estimate.
- The volumetric assessment results are based on a 50 year utilization period, e.g. to take into account past utilization and a prolonged development period for the whole region. A shorter period would necessitate applying a smaller recovery factor.
- The capacity estimate based on the lumped parameter modelling assumes a reservoir pressure decline less than 30 bar with full reinjection of separated brine. Thus the capacity of the Northeast sector is estimated to be about 50% greater than that of the East sector.
- In addition the generation capacity of the Domes is assumed to approximately equal to the average of the capacities of the East and Northeast production fields estimated through the lumped parameter modelling.
- The predictions of the numerical model, which only involve the heavily explored part of Olkaria (where data for calibration purposes are available), indicate a generation capacity of about 185, 155 and 240 MW_e for the East, Northeast and Domes production sectors, respectively.

The results for the heavily explored part of Olkaria, deduced by the different assessment methods (Table 3), are quite comparable, which adds confidence to the results. The outcome of the numerical model is e.g. in the middle of the range for the results of the volumetric assessment. In addition the numerical model results are fully comparable with the results of the lumped parameter model predictions. Therefore a combined generation capacity estimate of 630 MW_e for the heavily explored and peripheral parts of KenGen's concession area in Olkaria is assumed, as well as the estimate of 300 MW_e for the less explored parts. This is based on the 580 MW_e capacity estimate of the numerical model and the lower limit of the capacity estimate for the peripheral zone, 50 MW_e. The estimate includes the 430 MW_e already utilized and under implementation.

TABLE 3: Electrical generation capacity estimates for the Greater Olkaria Geothermal System obtained during the present Optimization Study. See text for various relevant premises of the estimates

Area/sector	Assessment method	Generation capacity (MW_e)	Classification[1)]	Comments
Heavily explored Part	Volumetric method	520 – 670	Proven reserve	Includes plants in operation w. 150 MW_e capacity
	Lumped modelling	~600[2)]		
	Numerical model	580		
Peripheral zone	Volumetric method	50 – 150	Probable reserve	
Less explored Parts	Volumetric method	>300	Inferred resource	***To be confirmed by surface exploration and exploration/ appraisal drilling***
Total		870 – 1120		

1) Australian Geothermal Code Committee (2008)
2) Assuming a generation capacity for the Domes approximately equalling the average of the capacites of the East and Northeast production fields estimated through lumped parameter modelling

KenGen estimates that steam corresponding to approximately 440 MW_e has become available in the Olkaria East and Olkaria Domes sectors, as of the middle of 2012, through production wells drilled during the intense drilling activity in progress since 2007, as already mentioned. This may be interpreted as indicating that only about 40 MW_e more are needed to reach the 630 MW_e capacity of the heavily explored and peripheral parts of Olkaria, referred to above. The situation is not so simple, however; of course one needs to keep in mind that these results are based on individual testing of new wells for a relatively short period. It is prudent to assume that the production capacity of individual wells will decline once all the wells needed for a given generation unit are put on-line simultaneously, e.g. due to reservoir pressure decline and pressure interference.

3.6 Field development plan and reinjection

The optimization study for KenGen's concession area in the Olkaria geothermal field also included proposing a field development plan for the possible expansion of electricity generation in the field. The quantitative basis for the plan is of course the most reliable and recent estimates of the generation capacity of the geothermal system (see above) whereas drilling targets are founded on the most recent conceptual model, reviewed above. The development plan proposed is based on the division of the KenGen concession area in the two parts on the basis of knowledge on the underlying resources, already mentioned.

The development plan for the heavily explored part is based on a generation capacity estimate of about 630 MW_e for 30 years as well as the revised conceptual model of the geothermal system, with particular emphasis on permeable structures, exploitable temperature and indications of heat sources. It is estimated that about 86 production, reinjection and make-up wells are needed to attain the estimated 630 MW_e capacity, in addition to existing stand-by wells already drilled. They are assumed to be capable of yielding about 390 MW_e in the long-term (based on KenGen in-house data). New production wells may be drilled as in-fill wells, mainly in the Domes but also in the Northeast sector and as step-out wells in the peripheral zone.

The development plan for the less explored part involves a proposal for comprehensive surface exploration (e.g. complete TEM/MT-resistivity surveying) and further research before development for generation begins. The development plan proposal includes about 16 new exploration/appraisal wells in this part as well as approximately 10 pressure monitoring wells throughout the whole area.

Reinjection of all separated brine, as well as a substantial part of the steam utilized for electricity generation after condensation, is foreseen as crucial in the future development of the Olkaria geothermal resource, mainly for the purposes of mass balance preservation and reservoir pressure maintenance, but also for environmental reasons. Predicting the overall effect of different long-term reinjection scenarios with the numerical model of the Olkaria geothermal system turned out to be quite uncertain and poorly constrained because of lack of data to calibrate reinjection sectors away from the current production zones, as well as their connections to the production sectors.

Some of the main issues that need to be resolved in order to optimize future reinjection in Olkaria are (i) how much of the mass extracted should be reinjected, or actually how much steam condensate (since all brine is expected to be reinjected), (ii) where the reinjection should be located, (iii) at what depth should the reinjection be focussed, (iv) what is the benefit of increased reinjection in terms of fewer make-up wells needed and (v) how detrimental is the lower injection temperature associated with condensate injection? The numerical model can only partly resolve these issues.

A certain very clear result can be seen, however, through reinjection scenario modelling of the heavily explored part of Olkaria. This is the fact that the benefit of reinjection beyond that of separated brine is quite limited and that the need for make-up wells does not decrease with increased reinjection. This appears to be a result of the nature of the heavily explored parts of the geothermal system as simulated by the model, which causes the increased mass discharge from production wells due to increased reinjection to be counteracted by reduced enthalpy, because of how close reservoir conditions are to boiling. The reinjection modelling furthermore indicates that deep (~2000 m) reinjection is more advisable, as a general rule, and confirms the contention that the temperature of reinjected fluid is not an issue as such. The latter is because the rate of the so-called cold-front propagation from a reinjection well to near-by production wells is not dependent on the temperature, but rather on the properties of flow-paths connecting the wells and the rates of reinjection and production.

It is likely that reinjection in Olkaria will need to be in line with the general idea of reinjecting on the margins of the most productive parts of the geothermal system rather than in-between production wells, because of the expected scale of the reinjection and associated cooling risk. As reinjection will increase in coming years the opportunity should be used to conduct comprehensive reinjection research. This research should include a comprehensive program of tracer testing, with associated analysis and modelling. A long-term reinjection plan for Olkaria must also be seen as dynamic and flexible.

4. CONCLUSIONS AND RECOMMENDATIONS

The conceptual model of the Greater Olkaria Geothermal System, which originally dates back to the middle 1970's, has been revised based on all available geological and geophysical information, temperature and pressure data, various reservoir testing and monitoring data as well as information on the chemical content of reservoir fluids. Most important are data from about 60 deep wells drilled in the area since 2007. Consequently the electricity generation capacity of the geothermal system was assessed on the premises that the resource should be split in two parts; a heavily explored part where extensive drilling has delineated the resource and long-term utilization experience exists and a less explored part where drilling has been limited and mainly indirect indications on an exploitable resource exist. The generation capacity estimates for Olkaria are based on the results of three reservoir assessment methods; (i) volumetric capacity assessments for both the heavily explored and less explored parts, (ii) lumped parameter modelling of the pressure response of Olkaria East and Northeast, and (iii) the predictions of detailed numerical model for the heavily explored part. The numerical model is by far the largest and most comprehensive model developed for the system so far. The results obtained through applying the different assessment methods for the heavily explored part of Olkaria are quite comparable, which adds confidence to the results.

Various recommendations have been put forward as part of the optimization study this paper is based on. These will not all be repeated here, but the following should be emphasised:

(1) This study has revealed the great importance of a comprehensive monitoring program for geothermal systems being utilized, in particular production and pressure decline monitoring. Monitoring of other aspects, such as chemical content and flowing enthalpy, is of course also of great importance. The considerable scatter in available reservoir pressure monitoring data, for both production sectors, reveals the need for a more focussed reservoir pressure monitoring program for Olkaria, which can e.g. be improved through both selection of appropriate monitoring wells distributed throughout the Olkaria area and through a sufficient monitoring frequency.
(2) The pressure response of the East production sector indicates substantial recharge to the geothermal system. Repeated micro-gravity monitoring provides an efficient way of quantifying the mass balance in geothermal systems, i.e. the balance between mass extraction, reinjection and natural recharge. Such monitoring has to some extent been conducted in Olkaria.
(3) A great increase in electrical generation by KenGen in Olkaria is expected within the next few years, with an associated drastic increase in mass extraction. Carefully monitoring the eventual effect of this increase provides the most important information on which to base further expansion of generation in Olkaria. Realizing future expansion in appropriately sized steps provides a continuous opportunity for such monitoring.
(4) The numerical model, which has now been developed for the Olkaria Geothermal System, can become an indispensable management tools during long-term utilization. The same applies to the lumped parameter models, which can easily be upgraded as more pressure monitoring data become available.
(5) The experience in Olkaria III, where 100% reinjection is applied, should be used to help planning future reinjection in KenGen's concession area in Olkaria.

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GEOTHERMAL TRAINING PROGRAMME

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THE MIRAVALLES GEOTHERMAL SYSTEM, COSTA RICA

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ABSTRACT

The Miravalles Geothermal Field is a high-temperature liquid-dominated reservoir with temperatures reaching 230-255ºC, and is the first of two exploited geothermal fields in Costa Rica. The geothermal energy is an important part of the electrical supply in the country and has been producing since 1994, accounting for about 8% of Costa Rica's total electrical production to date and is an important part of it. The installed capacity of Miravalles has reached 163 MW. 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 almost twenty years exploitation period has evolved notably due to massive production and injection in some sectors of the field, and different actions and strategies have been successfully implemented for sustaining the steam supply to the power plants and for reservoir management.

1. INTRODUCTION

The Miravalles Geothermal Field was the first geothermal reservoir under exploitation in Costa Rica (Figure 1). A mission of Experts of the United Nations who visit the country in 1963-64 agreed on the interest in studying the slopes of Miravalles and Rincón de la Vieja volcanoes, both of them located in the north part of the country and which showed high possibilities for the geothermal resource exploitation. In 1974 the Instituto Costarricense de Electricidad (ICE) began a general study of the mentioned area. Deep drilling started in 1978, when a high-temperature reservoir was discovered and more exploratory studies continue until 1985 (Corrales, 1985). A feasibility study for the first unit recommended the installation of a 55 MW power plant (CE and ELC, 1986), but later studies increased the possible installed capacity. Subsequent drilling stages completed the steam necessary to feed three flash plants commissioned in 1994, 1998 and 2000, and one binary plant in 2004, totalling an installed capacity of 163 MW. Three 5 MWe wellhead units have also produced for different periods, and one of them is still in use.

2. GEOLOGICAL SETTING

The Miravalles Geothermal Field is a typical high-temperature liquid-dominated reservoir, located in the northwest part of Costa Rica (Figure 2). Drilling of the first deep exploratory wells dated from 1978-1980, but it is not until 1992 that was begun the extensive drilling with exploitation purposes.

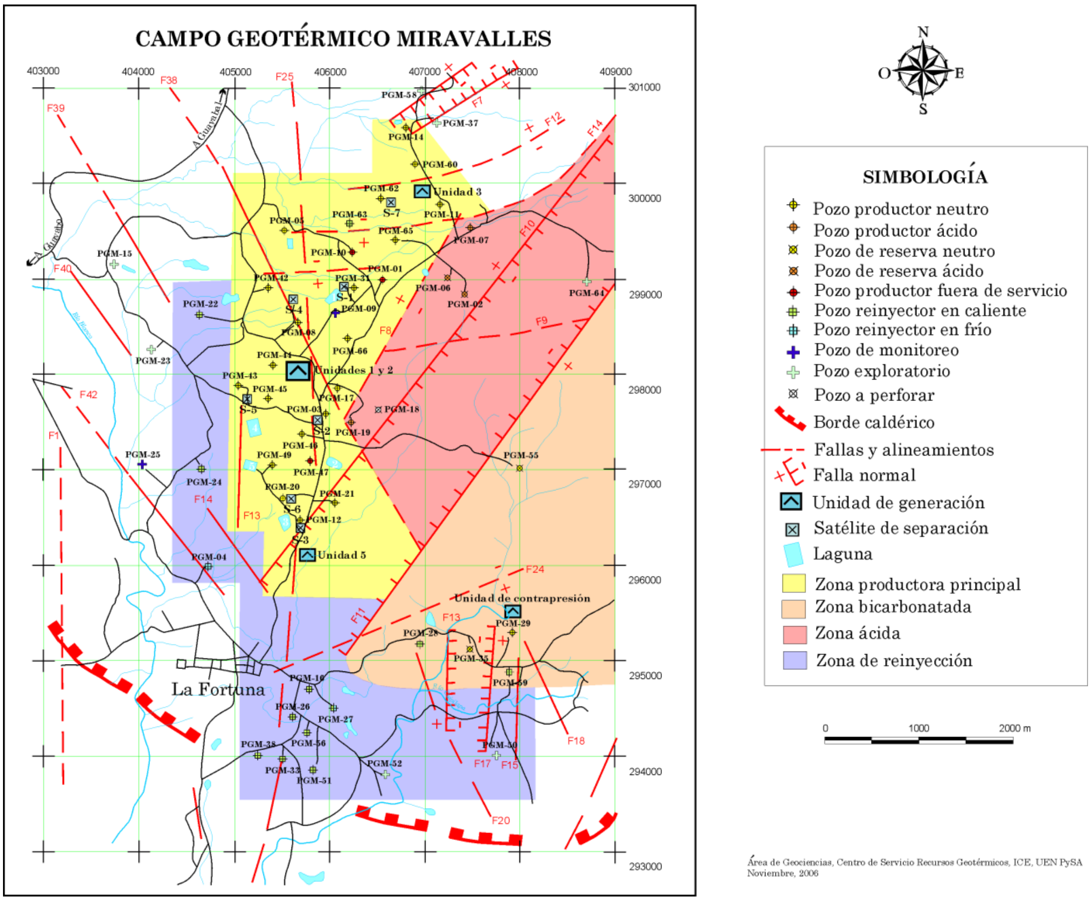


FIGURE 1: The Miravalles Geothermal Field

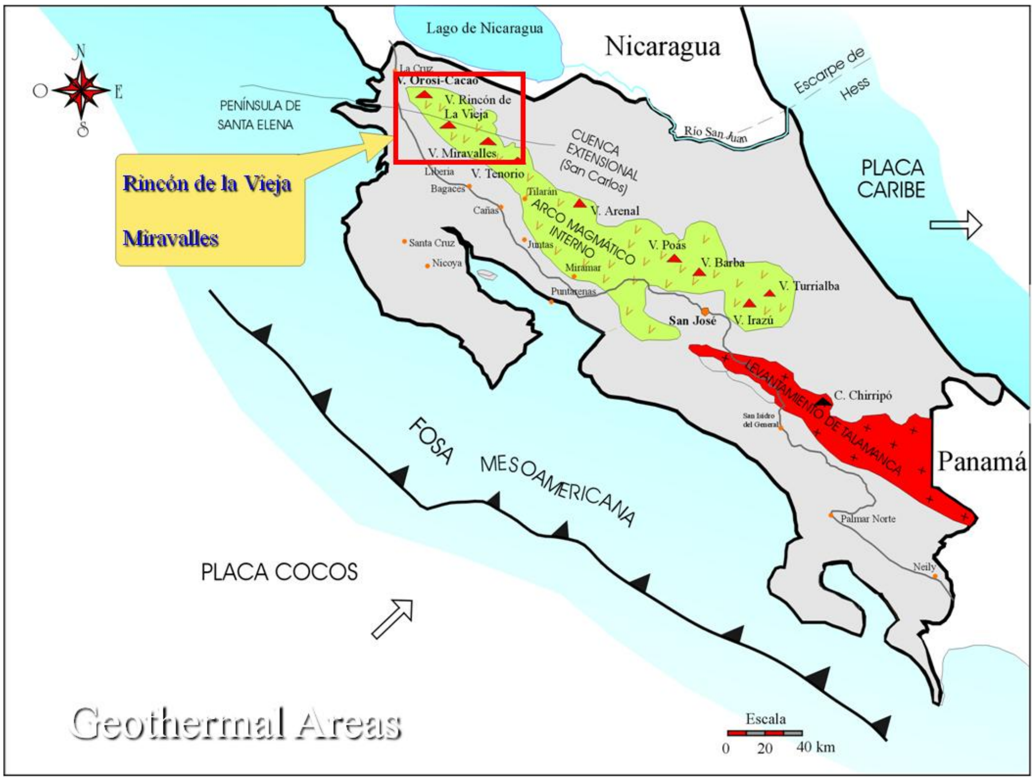


FIGURE 2: Costa Rica and the Miravalles Geothermal Field Location

The field is confined to a caldera-type collapse structure of 15 km diameter. It was formed about 600 000 years ago with the eruption and deposition of pyroclastic flows. A caldera collapse of over 1000 m has been estimated (ICE and ELC, 1986).

Associated with, or soon after, the caldera formation was a subvertical fracture striking in a NS, to NWW-SSE direction toward the east of the caldera, giving rise to a graben which extends southward beyond the caldera margin (graben La Fortuna).

In a second cycle, volcanic activity was concentrated in the east-giving rise to the andesitic complex of Cabro Muco-la Giganta, followed by the emissions of the Paleo Miravalles. Both are located on a system of faults and fractures trending SW-NE.

In the last 50 000 years, the Miravalles andesitic stratovolcano (2028 m.a.s.l.) was formed. This third cycle culminates with an explosive-effusive activity associated with lava flows and thin pumice deposits which occurred in the Santa Rosa area about 7 000 year ago. During this period, the N-S tectonic regime was reactivated producing a system with an E-W trending fault (ICE and ELC, 1986).

2.1 Stratigraphic sequence

The rock sequence within and around the Guayabo Caldera, as well as that described in the deep wells includes a series of stratigraphic units related to processes that occurred before, during and after the formation of the aforementioned structure (Figure 3). In the wells drilled, the majority of these rocks show strong hydrothermal alteration, which makes it difficult, in some cases, to recognize the original textures (this section as described in Vega et al., 2005).

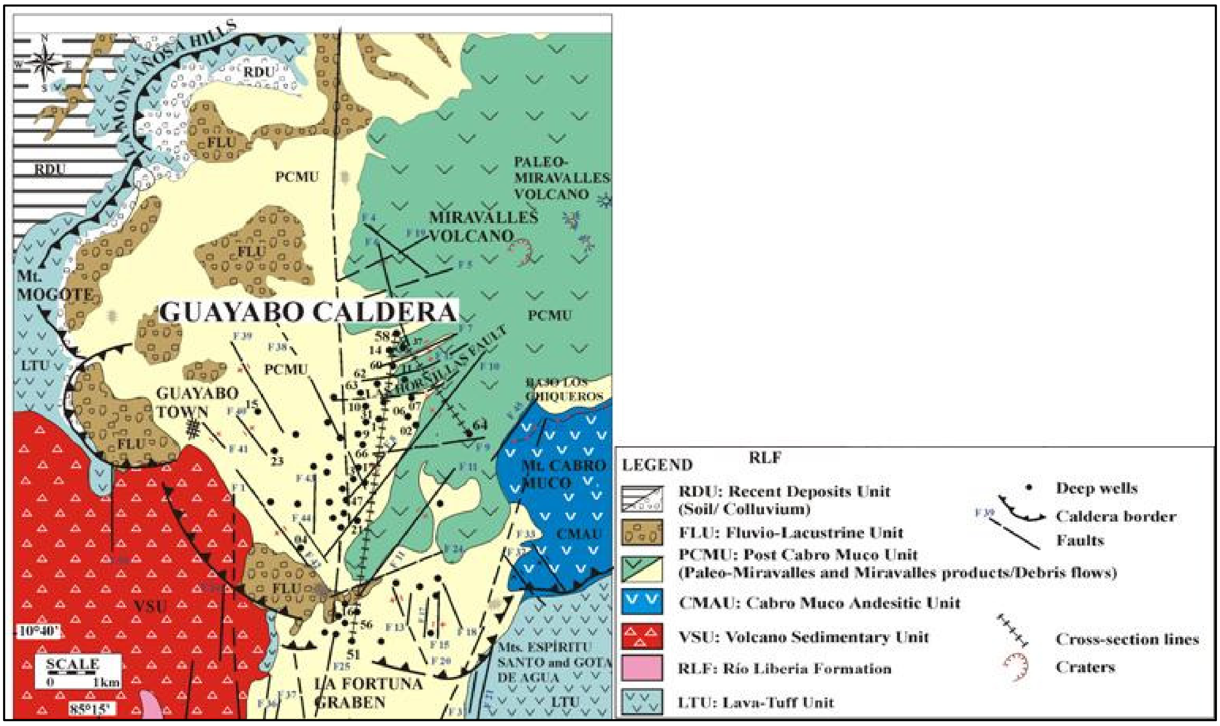


FIGURE 3: Geologic Map of the Guayabo Caldera

2.1.1 Deep lava unit (DLU)

It is composed of a lava flow sequence originated from emission centres possibly related to a paleo-volcanic arc. These rocks are predominantly andesitic and are observed only in the bottom section of well PGM-15, between 2500 and 3022 meters depth. It is interpreted as the local basement rock, and could be associated with Tertiary rocks.

2.1.2 Ignimbrite unit (IU)

It is composed of pyroclastic deposits and sporadic lava flows associated with paleo-volcanic calderas. The pyroclasts consist of tuff and ignimbrite sequences, with scarce andesitic lava intercalations. This Formation has been drilled in the wells of the northern and central sectors, reaching a maximum thickness of 1087 m, in well PGM-15. These materials could be correlated with pyroclastic sequences of the Bagaces Formation, which crop out various km south of the caldera border. It has been dated from 8 to 1.6 Ma (Gillot et al, 1994), indicating a wide period of deposition.

2.1.3 Lava -tuff unit (LTU)

This unit is composed of lavas and sporadic pyroclastic deposits. It is inferred that these materials correspond with the activity of a paleo-volcanic complex, known as Guayabo Volcano (ICE and ELC, 1983), which was emplaced over the products of the Ignimbrite Unit. The lavas are predominantly andesitic, with occasional intercalations of tuff, ignimbrite and epiclastic levels.

In the wells, a thickening of this unit is observed towards the southern and western sectors of the field, reaching thicknesses between 260 and 1190 m. This sequence has been dated at 2.3± 0.1 Ma (ICE, 1976). Based on this age, it is associated with the Bagaces Formation.

2.1.4 Río Liberia formation (RLF)

It is composed of a pumitic pyroclastic sequence that includes at least four flows, which are differentiated by variations in lithic content, crystals, and the level of consolidation. All of these flows are characterized by the presence of biotite, in varying amounts. These pyroclastic flows form a regional ignimbrite mesa, with thicknesses of up to 60 m. It is considered that at the time of deposition there was a topographic high at the present-day Guayabo Caldera (possibly the Guayabo Volcano), which is why these rocks have not been found within the caldera. This Formation ranges from 1.29 ± 0.03 and 1.83 ± 0.03 Ma (Gillot et al., 1994).

2.1.5 Volcano sedimentary unit (VSU)

This unit includes pumitic pyroclastic flows, tuffs, epiclastic deposits and lacustrine deposits, as well as occasional andesite and basaltic andesite levels. It is widely distributed in the drilled wells, with thicknesses ranging from 255 to 1050 m. This unit represents the products emitted during the formation process and filling of the Guayabo Caldera.

The Volcano Sedimentary Unit is correlated by Vega et al, 2005 with the Guayabo Pyroclastic Formation (defined by Chiesa et al., 1992), which has been dated from 1.456 ± 0.036 Ma to 0.6 ± 0.011 Ma (Alvarado et al., 1992) and consists of a series of pyroclastic flows that crop out southwest of the caldera, partially covering and extending beyond its border for various kilometres.

2.1.6 Dome-flow unit (DFU)

It is series of rocks that were emplaced in the form of a dome-flow, whose distribution is limited to the northern part of the field. This unit developed during the final phases of the Volcano Sedimentary Unit, taking advantage of the distensive E-W structural system. Texturally, it is characterized by its low porphyritic index, where sparse plagioclase phenocrysts and mafic minerals, replaced by chlorite, are observed embedded in an intensely silicified matrix. Due to these characteristics, a dacitic composition is inferred for these rocks.

2.1.7 Cabro Muco andesitic unit (CMAU)

It includes mainly andesites and basaltic-andesites, as well as sporadic lithic tuff levels. These rocks are the product of activity from the Cabro Muco-La Giganta volcanic complex. This volcanic edifice rose in the south-eastern sector of the caldera, after the emplacement of the Dome-Flow Unit. It has been affected by collapses associated with volcanic explosions, erosion and tectonism. It has been reported in the majority of the wells with thicknesses between 50 and 1000 m. Radiometric dating indicates ages from 0.4±0.1 Ma (Alvarado et al., 1992).

2.1.8 Post Cabro Muco unit (PCMU)

This unit is composed of lavas and pyroclasts, from the Paleo-Miravalles and Miravalles volcanoes, as well as debris flows from these and other volcanic centres. A thickness of 25 to 156 m has been observed for this unit.

2.1.8.1 Lavas and pyroclasts from the Paleo-Miravalles and Miravalles volcanoes

These consist mainly of andesites and basaltic-andesites with sporadic pyroclastic deposits. They are volcanic products posterior to the formation of the Cabro Muco-La Giganta volcanic edifice. This complex is located in the eastern sector of the field.

Paleo-Miravalles is considered as the second-most oldest post-caldera edifice, estimated at less than 200,000 ybp (ICE and ELC, 1983); followed by the current Miravalles volcano whose activity could have initiated around 50,000 ybp (ICE, 1976). The youngest rocks are pumitic pyroclastic flows with limited extension.

2.1.8.2 Debris flow

This consists mainly of debris avalanches, lahars, and lacustrine deposits. They correspond in part with the activity of the Miravalles volcano as well as volcanic collapse events in the Bajo Los Chiqueros area and probably extending towards the Espiritu Santo Mountain.

These rocks were deposited in different stages, where dates from the lower sections indicate ages greater than 40,000 ybp (ICE, 1976) and the upper levels show ages near 9000 ybp (Alvarado et al., in press).

2.1.9 Fluvio-lacustrine unit (FLU)

This unit consists of clay, silt and fine sand intercalations that grade to andesitic alluvial deposits, which are found distributed in various localities within the caldera. These materials evidence a period of quiescence, where laminar flows and low volcanic activity dominated. The total thickness of these deposits is not known, however in outcrop they are up to 3 m.

2.1.10 Recent deposits unit (RDU)

This unit includes thick soil levels and colluvium formed by lava fragments from the border of the caldera, cropping out towards the northwest sector.

2.2 Volcano-tectonic structures

The Guayabo Caldera and the Miravalles and Paleo-Miravalles volcanic edifices comprise the most noticeable volcano-tectonic structures in the region. This caldera consists in a marked semi-circular crescent-shaped 14 km diameter depression built up in various stages of volcanism and caldera collapse. Its NE and E extremities are masked by post-calderic materials from the aforementioned volcanoes, whose craters are aligned along a NE-SW strike, associated with deep fractures. The northern and southern borders of the caldera are truncated by the N-S distensive structural system that provoked downthrowing of the caldera border in the area of the La Fortuna graben. There is not a clear panorama with respect to the tectonic forces that have affected the region, however, taking into consideration the stresses caused by interaction between the Cocos and Caribbean Plates, as well as field evidence, it is inferred that the N-S and NE-SW structural systems, identified in the Miravalles area, present recent activity.

Four structural systems have been defined. Chronologically, these systems (from oldest to youngest) correspond with the directions: NW-SE, N-S, NE-SW and E-W, all contributing significantly to the permeability of the geothermal system.

The N-S fault system, to which the La Fortuna graben is associated, existed prior to the caldera formation and was later reactivated (Chiesa et al., 1992), thus offsetting it and hence favouring the lateral discharge of reservoir fluids.

In the northern part of the field a series of horsts and grabens, associated to the E-W structural system, which is considered to be the most recent, has been defined. It has surficial expressions such as thermal anomaly and hydrothermal alteration lineations, which is why some of these faults are considered to be active (Vega et al., 2010).

2.3 Alteration mineralogy

The Miravalles Geothermal Field is comprised of a high enthalpy reservoir where the water-rock interaction has developed a pattern of hydrothermal alteration, which has been separated into the smectite (Sm), transition (I/Sm), and Illite (I) zones (Figure 4).

The smectite zone (< 165°C) corresponds to the most surficial part of the field (upper level of the cap rock) and is characterized by the presence of clays from the smectite group along with iron oxides/hydroxides and the appearance of subordinate pyrite, calcite, chlorite, zeolites, and some forms of silica (tridimite, cristobalite and quartz). Alunite and kaolinite can be present locally, particularly in areas affected by acidic fluids.

The transition zone is defined by the appearance of the mixed layered clay illite/smectite, in which the percentage of illite increases with depth. It corresponds with a range of temperatures between 140 and 220°C (Vega, 2000; Sánchez & Vallejos, 2000) and its base is localized near the top of the reservoir. In this level, there is a clear increase in the amount of calcite, quartz and chlorite minerals; as well as the first appearances of other mineral species such as adularia, leucoxene/titanite, epidote (particularly incipient type I, based on the classification given in Reyes 1990, 2000), anhydrite, pennine, zeolites, wairakite and the mixing of chlorite and smectite layers.

The illite zone is associated particularly to reservoir levels with temperatures of at least 220° C. It is characterized by the presence of illite, higher percentages of epidote (types I, II and III according to the classification given in Reyes 1990, 2000) and well-crystallized chlorite minerals. Also, quartz, wairakite, adularia, pyrite, and the mixing of chlorite and smectite layers can be observed. In some cases, prehnite, garnet, and some sulfides have been identified (Milodowski et al., 1989), in association to the highest temperatures registered at the Miravalles Geothermal Field.

Epidote is used as a high temperature indicator; illite on the other hand, due to its rapid response to temperature changes, represents current thermal conditions.

In general, the first stable appearance of these minerals corresponds well with the 220°C isotherm although this behaviour is affected by local thermal anomalies generated by fluid circulation along permeable structures (NE-SW and E-W), that disturb this condition.

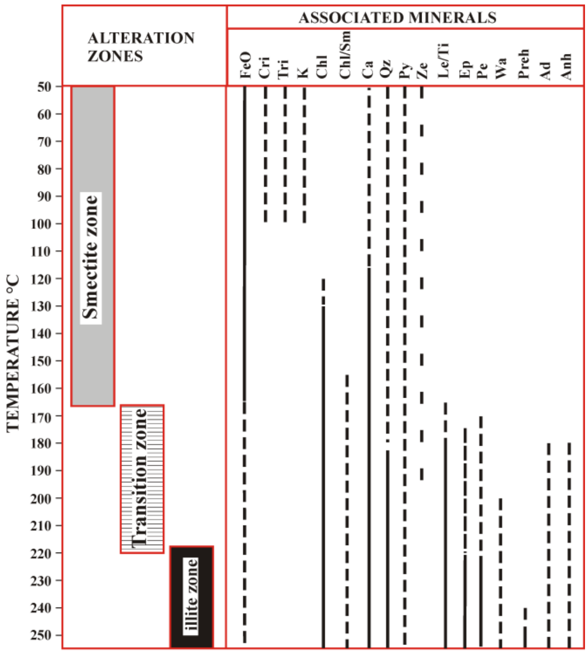


FIGURE 4: Clay alteration zones and associated mineralogy. FeO: Iron oxides/hydroxides, Cri: Cristobalite, Tri: Tridimite, K: Kaolinite, Chl: Chlorite, Chl/Sm: Mixed layered clay Chlorite Smectite, Ca: Calcite, Qz: Quartz, Py: Pyrite, Ze: Zeolites, Le/Ti: Leucoxene/Titanite, Ep: Epidote, Pe: Pennine, Wa: Wairakite, Preh: Prehnite, Ad: Adularia, Anh: Anhydrite

3. GEOCHEMISTRY

3.1 Water chemistry.

Most of the hot and cold springs on the Miravalles Geothermal Field are bicarbonate waters, with lesser sulfate waters and minor chloride waters. Most of the chloride waters discharge from the deep wells and only one chloride spring was found, located in Salitral de Bagaces in the south part of the area under study, about 19.5 km from the summit of the Miravalles Volcano and 170 m.a.s.l. It is characterized by high TDS and conductivity, with a temperature of 59.5 °C and the presence of travertine around it. The sulfate waters occur mostly in the area between Guayabal, Los Llanos and Sitio Las Mesas. The water coming from Sitio Las Mesas and Sitio Miravalles is drained by the Herrumbre Creek whose pH is close to 4. Another two zones far away from this area where this type of water emerge are: Las Azufreras, which is characterized by native sulphur deposits near the spring with H2S and stunted vegetation presence in a 50 m diameter area. The other zone is Las Hornillas, where the fumarolic activity is associated with a fracture zone and is characterized by mud pools and small steam vents, sulphur deposit etc.

The main reservoir fluids have a sodium-chloride composition with TDS of 5300 ppm, a pH of 5.7 and a silica content of 430 ppm. The main aquifer is characterized by a 230-255 ºC lateral flow (yellow zone in Figure 1). A shallow steam dominated aquifer is located in the north-eastern part of the field, and it is formed by the evaporation of fluid from the main aquifer that moves along fractures (Vallejos, 1996). Another important sector shows an acid aquifer in the north-eastern sector of the field (magenta zone in Figure 1), where a sodium-chloride acidic aquifer with pH values between 2.3 and 3.2 is present. A highly bicarbonate east-southeast zone (beige zone, not actually under exploitation excepting for well PGM-29) is also present. From the geochemical point of view this sector shows some differences relative to the main and acid reservoirs. The main differences are high bicarbonates content and the Na/K relationship, which shows a significant difference between geothermometer results and measured temperatures. Similar differences can be seen in calcium and magnesium content. The fluids in this sector have a high tendency to form calcium carbonate deposition as well as high NCG content in the steam (Sánchez et al 2010).

Over the years the chloride content in the waters have been increasing, thus indicating that reinjection waters are arriving to some sectors of the field; the most significant of these increases are related with wells to the south and western sectors of the field which are the main injection zones of the field (blue zone in Figure 1).

3.2 Calcite deposition

The Miravalles reservoir fluids have a silica content of 430 ppm and show a tendency of carbonate scaling in the wells, which ranges from strong to severe depending on the area and kind of aquifer present and causing that the wells would be obstructed in periods that range from several days to several months without a correcting inhibition process. This treatment have helped in maintaining a permanent fluid production, thus saving money in lost production and costs due to cleaning of wells by using drill rigs. The system used for the scaling inhibition has been used since the start of exploitation at Miravalles and has shown to be totally reliable.

3.3 Acidic aquifer

The Miravalles reservoir fluids typically have a neutral composition, but five of the wells drilled produce acid fluids. These wells were drilled in the north-eastern sector of the field (magenta-colored area in Figure 1), where a sodium-chloride acidic aquifer with pH values between 2.3 and 3.2 is present. This corrosive character would cause irreparable damages to the well casings and surface equipment, which would force discarding them after a few weeks of production.

Studies started in 1994, aimed to neutralized the acid fluids and commercially exploit such wells. The experience gained due to continuous experimentation allowed the commission of several acid wells. At this moment, this zone is an important supplier of fluids for production (Sanchez et al, 2005).

3.4 Non condensable gas

At the beginning of intensive field production the non condensable gas content (NCG) was low, in the range of 0.6 to 0.9% weight/weight (w/w) of steam. The NCG is composed mainly of CO2 which is between 97 to 99% w/w, with relatively high content of nitrogen of about 1.4 to 2 % w/w, and the content of hydrogen sulfide is less than 1% w/w (ICE and ELC, 1986). However, over the years an increasing trend in the non-condensable gases present in the steam has been observed. In the present days it is 0.2 to 2.4% (w/w) in the main aquifer, from 0.9 to 1.75% w/w acid in the aquifer and approximately 3 to 18% w/w in the bicarbonate aquifer (Sánchez et al, 2010).

4. TERMOHYDRAULIC CHARACTERIZATION

4.1 Temperature and pressure

The formation temperature and the initial reservoir pressure before exploitation indicate that the geothermal fluid flow primarily follows a NE-SW direction with change to the N-S direction in the central part of the field. A fluid flow appears to come from the vicinity of wells PGM-10 and PGM-11, where the highest temperatures and pressures in the field are observed. The temperature and pressure descend gradually to the south, from a maximum of around 250 °C near well PGM-11 to around 220-230 °C in wells PGM-26 and PGM-16 The reservoir is clearly bounded to the west due to the low temperatures and pressures observed there (wells PGM-04, 15 and 22). To the east the temperature and pressure remain not completely identified due to lack of data in that part (Figure 5). There was a gradual pressure decrease of about 3-4 bar from the north to the south parts of the field (from wells PGM-11 to

PGM-26). Near wells PGM-28 and PGM-29 the undisturbed reservoir pressure was considered to be about 70-71 bar at -500 m.a.s.l. Those values were similar to the ones observed at the central part of the field; this can be considered an indication of another deep recharge zone coming from the NE or E to the field.

Temperatures and pressures around the field have changed over the years; this is a direct influence of the continuous exploitation for around 19 years.

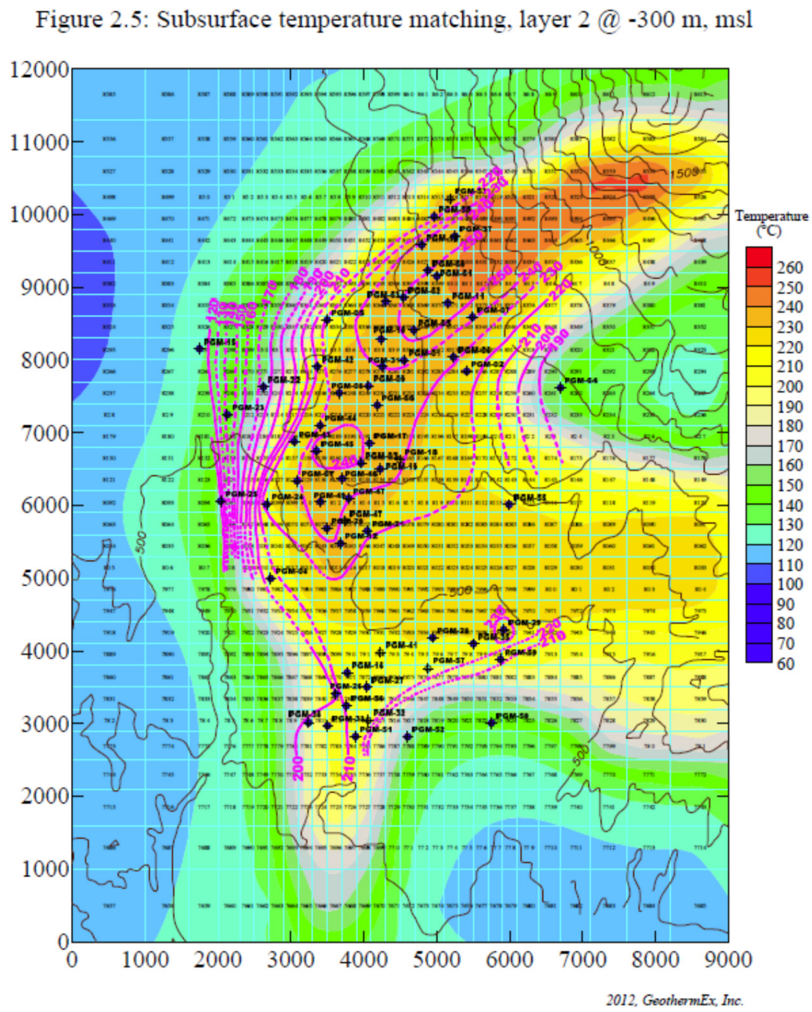


FIGURE 5: Temperature Contour Map at -300 m.a.s.l. (measured and modelled)

4.2 Permeability and porosity

The permeability in the reservoir is mainly secondary, as a result of widespread fracturing of brittle rocks due to its lithology or to hydrothermal alteration. The permeability increases from the north to the meridian part of the field, going from 60 D.m. in the north, 80 D.m. in the centre to 230 D.m. in the south. Considering a reservoir thickness of 1000-1200 m the average permeability is about 50-100 mD. The formation permeability is concentrated in very limited thick zones well defined. These zones may be highly fractured or single fractures with high permeability in a diffused less permeability medium.

More than one permeable zone is usually found in the Miravalles wells, and it is normal that spontaneous flow occurs between them. It is normally to find the first permeable zone between -100 to -300 m.a.s.l. (ICE and ELC, 1995), and the majority of the permeable zones found in the central part of the reservoir were around -198 to -1034 m a.s.l. (Castro, 1999). To characterize the productivity potential of the wells previously to production tests the injectivity index is determined, because this has been proven as a reliable way for assessing the productivity or injection performance of the wells in Miravalles (Acuña, 1994). There are a wide range of indexes, as low as 0-1 (l/s)/bar and as high as over 15 (l/s)/bar (accuracy of the measurement limits the measurement range).

During the drilling of PGM-44 a deep permeable zone was found at -1404 m a.s.l. and the well became a 4 MWe productor. After that, another deep zone was found in well PGM-46 (-1470 m a.s.l.). Prior that PGM -24 (-1314 to -1384 m a.s.l.) and PGM-25 (-1619 m a.s.l.) crossed also deep permeable zones but for different reasons there were not considered an important issue. These results showed the existence of a deep aquifer related with the main aquifer of Miravalles (yellow zone in Figure 6) in the zone around -1400 to -1600 m a.s.l.

The porosity is about 9.8%, with a standard deviation of 4.9% in the measurements. It is observed the higher values of porosity in the Volcano Sedimentary Unit, and the lower values are for the Andesite Lavas Unit and the Ignimbritic Unit (ICE and ELC, 1995). For numerical modelling purposes, the porosity is set to about 5.0 because higher values have proven not to be good for matching in recent numerical models of the field.

5. CONCEPTUAL MODEL

The conceptual model of the Miravalles Geothermal Field is shown in Figure 6. 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. The magmatic source is related with the extinct Miravalles Volcano.

- 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 showing a 250-260 °C temperature. 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 (Figure 7).

A closed boundary is clearly observed in the western part of the field, as the temperature decreases rapidly in that part, as does the pressure. The reservoir is open to the north (inflow) and south (outflow). The reservoir continues to the east, but the extension cannot be estimated clearly because there are very few wells in that region.

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 and ELC, 1995). These areas may increase as the reservoir is investigated further.

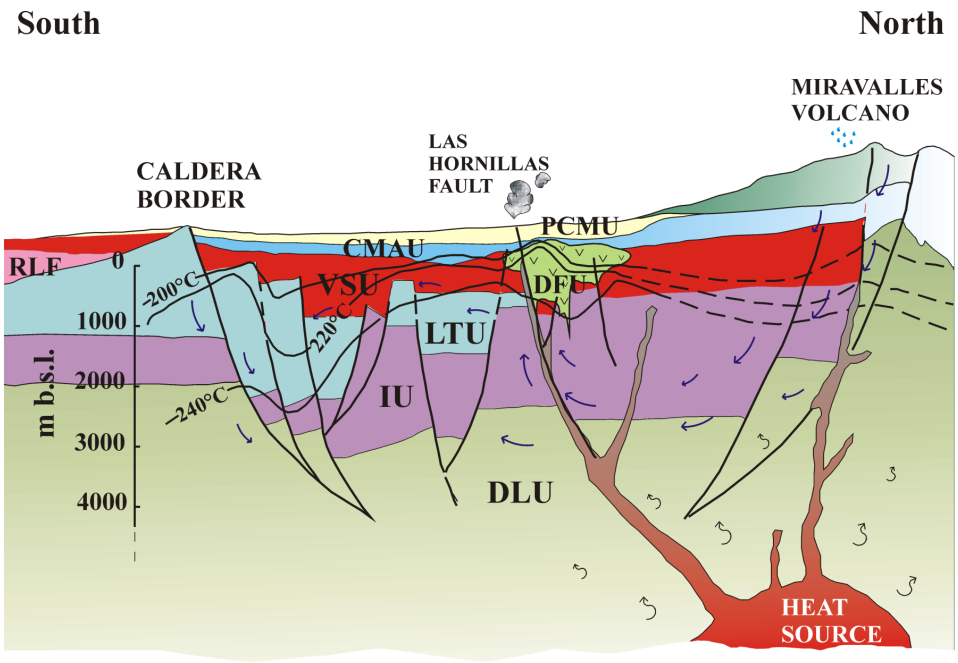


FIGURE 6: Conceptual Model of the Miravalles Geothermal Field

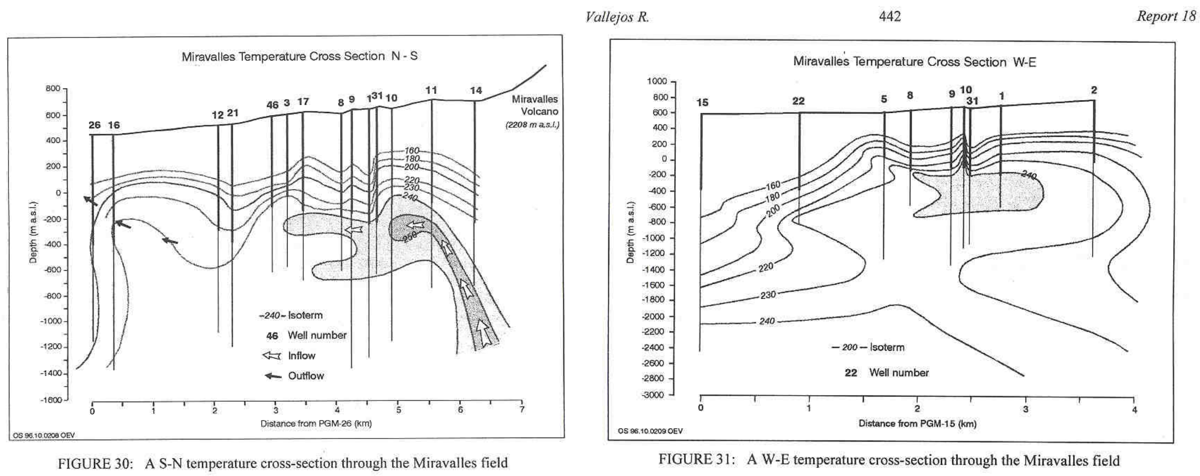


FIGURE 7: Temperature Cross Sections through the Miravalles Geothermal Field

6. NUMERICAL MODELLING

Numerical model is an important part of an assessment of a geothermal field, as a tool for helping in the decision making process during the operation of the reservoir. Two different models are used to simulate the Miravalles field data, a lumped parameter model using LUMPFIT and a three-dimensional model using TOUGH2, the latter being the most developed, accurate and used.

6.1 Lumped model

Lumped parameter modelling is a simple method where the reservoir is modelled in different parts, each of them having some distinct hydrological properties. Those properties are lumped together, simplifying the reservoir characteristics into a few dependent variables (Axelsson and Arason, 1992). The method visualizes the reservoir as a network of separate tanks and resistors, each of them representing different parts of the reservoir (tanks) and permeabilities (resistors). This network can be open or closed to a constant pressure boundary (Axelsson, 1989). An automated, least squares inversion program, LUMPFIT, is available for solving the parameters that define the lumped models that would fit the observed pressure and production history of the reservoir (Arason and Björnsson, 1994).

Lumped parameter modelling is a valuable alternative to the complex process of numerical modelling of a geothermal field. In spite of limited capacity, this modelling process can give an idea of the possible evolution of a geothermal field under different, easily envisioned production scenarios.

A development of a lumped parameter model of the Miravalles Geothermal Field was made in 2004 (Vallejos, 2005). This approach was made considering the wells PGM-09, PGM-14, PGM-29 and PGM-52. These wells had pressure monitoring units in different times of the field exploitation, being that only well PGM-09 had a pressure drawdown recorded during almost all the Miravalles Field exploitation history to that date (from October 1993 to April 2004). A second lumped parameter model was made three years later (Vallejos, 2010). Simulations were carried out in wells PGM-09, PGM-25, PGM-35 and PGM-55. Since PGM-09 has the most complete pressure drawdown history (about 14 years from October 1993 to September 2007), its corresponding model provides more confidence than the rest of the models.

For comparison purposes, the forecasted pressure behaviour of the previous model for well PGM-09 was compared against the corresponding new model. Also, it was tried to compare the possible evolution of the models by using the forecasted pressure behaviour of well PGM29 (made in 2004) against the forecasted pressure behaviour of well PGM-35. This was considered because these wells belong to the same area and are less than 500 m from each other.

In the case of PGM-09, the previous model was rerun with the updated mass extraction data and a new estimation for future steam production in order to compare the models under similar conditions; the results are shown in Figure 8.

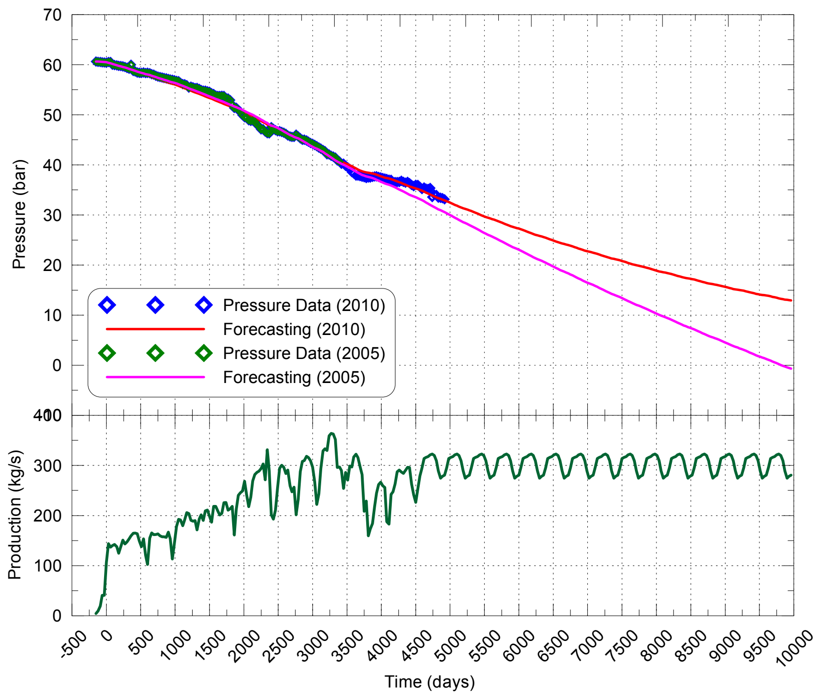


FIGURE 8: Matching and Prediction of the Future Reservoir Pressure (PGM-09) – Steamflow Rate: Comparison between Previous and Updated Lumped Parameters Model

As can be seen from Figure 10, the forecasted pressure behaviour with the newer model shows that the mass extraction is impacting the reservoir pressure less than in the previous model. This can be explained for a possible combination of reasons: 1) the reservoir has evolved and actually is developing a bigger steam cap in the northern zone of the field which appears to be extending to other zones of the reservoir; this means that more steam available allows the extraction of less mass thus reducing the pressure drop; 2) after the year 2004 the reduction in the mass extraction of the field has been reinforced, taking advantage of the annual maintenance of the different power plants at Miravalles; it has been tried to extend the time the power plants generate electricity at an amount below their installed capacity; 3) the reinjection scheme was improved, trying to divert as much water to the western zone as possible. This appears to have reduced the pressure drawdown in the wells located at the central part of the field (including PGM-09).

6.2 Three-dimension numerical model

The numerical modelling method consists of simulating the reservoir as a number of subvolumes, each of them having determined hydrological, thermodynamic and chemical properties. Those properties are set according to the measured data observed during the reservoir assessment, and change throughout the reservoir exploitation. In such a condition, simplifying the reservoir characteristics does not make sense, as the purpose of the numerical modelling is to have a reservoir model as close to reality as possible. The modelling is made using not only the data available, but also analytical and empirical equations that represent the real behaviour of the different components of the mass, rock, etc. The simulation is run in high velocity computers because of the high number of variables involved. The program TOUGH2 is one of those numerical models. The basis of TOUGH2 is the same as normally applied in geothermal reservoir simulators. The mass- and energy-balance equations are applied to the develop model and a solution for a selected period of time run is obtained (Pruess, 1991).

Different numerical models of the Miravalles reservoir have been developed over the years, for forecasting the future behaviour of the field according to the data collected.

In 1991 the Lawrence Berkeley Laboratory and ICE developed a preliminary natural-state and exploitation numerical models of Miravalles, based on the present conceptual model (Haukwa et al, 1992). The TOUGH2 code was used for the 62-block model (Figure 9).

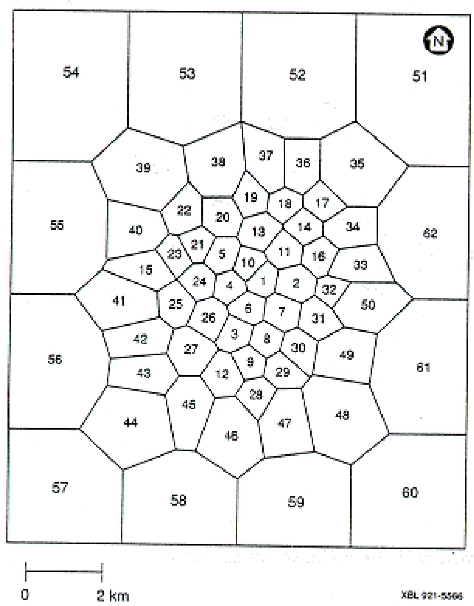


FIGURE 9: Lawrence Berkeley Laboratory/ICE Numerical Model (1991)

ELC Electroconsult and ICE developed another numerical model in 1995 (Figure 10), based in one used for the first feasibility studies done in 1985 and 1988 (made by using the GEMMA code). Natural state and exploitation models were created based on the information gathered by ICE during the exploration and the first eight months of massive reservoir exploitation. TOUGH2 was also used for this 146-block model (ICE and ELC, 1995).

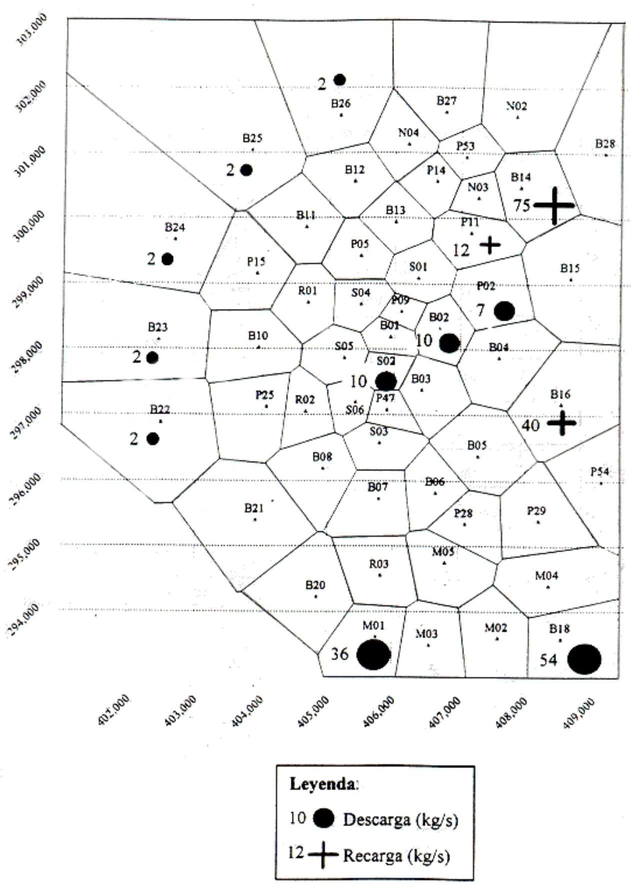
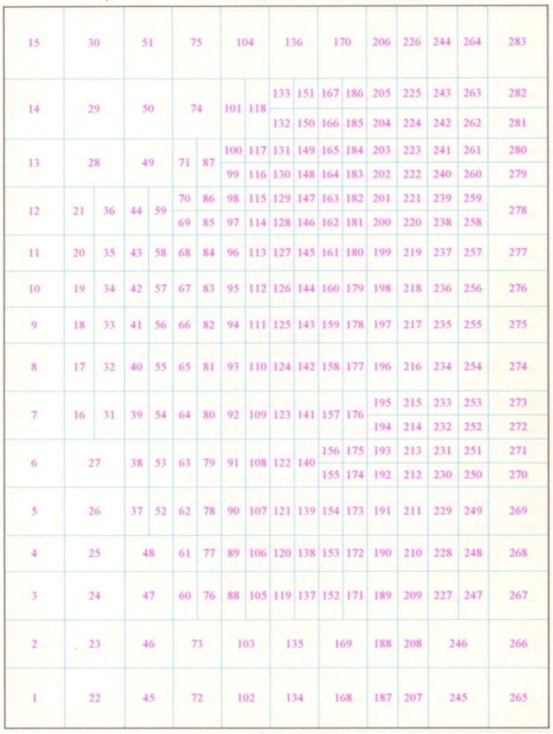


FIGURE 10: ELC Electroconsult/ICE Numerical Model (1995)

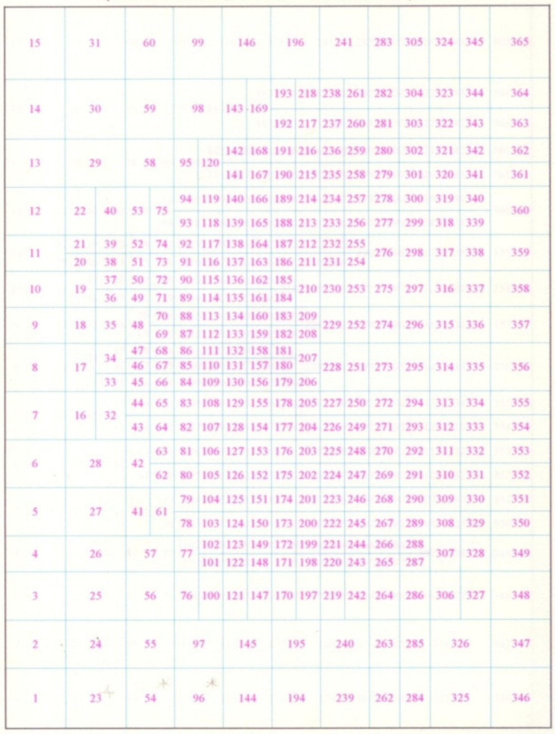
In 1998 GeothermEx, Inc. developed a TOUGH2 1953-block numerical model, this time including the data from three years of continuous field exploitation. The model comprises and area of 12 km long N-S and 9 km long E-W, extending from +100 to –1500 m m.a.s.l (1600 m total thickness) and divided into six layers of non-uniform thickness and a couple of different grid layer arrangements(layers 1, 5, 6 and layers 2, 3, 4), totalling 1953 grid blocks (Figure 11). The numerical model history matching and forecasting runs under different production and injection schemes were accomplished in that study (Pham et al, 2000). This model was updated by GeothermEx, Inc. in early 2001. The grid blocks were refined and increased to 5110 (Figure 12), and a double porosity and two-waters options were used. This code was used for matching the chloride returns observed in the fluids. Also, the model took into account the new information gathered from July 1997 to March 2001 (GeothermEx, Inc., 2002). In 2012, a third actualization of the same model was made. This time the model was extended to -1900 m.a.s.l in order to model the deep zone found in some of the deepened wells. The layers were increased from six to ten and all the layers were unified to only one design; some of them were thickened in the most permeable depths in order to get a better match in the actual enthalpy changes observed. As the layers were increased also the grid was refined; the number of base blocks were then increased to 9570 (Figure 13). After the double-porosity method is applied, this number is doubled bringing the total number of gridblocks in the model to 19,140 (GeothermEx, 2012).

Figure 3.3: Gridblocks layout in the updated model - layer 1 (from +100 m, msl to -200 m, msl)



1997, GeothermEx, Inc.

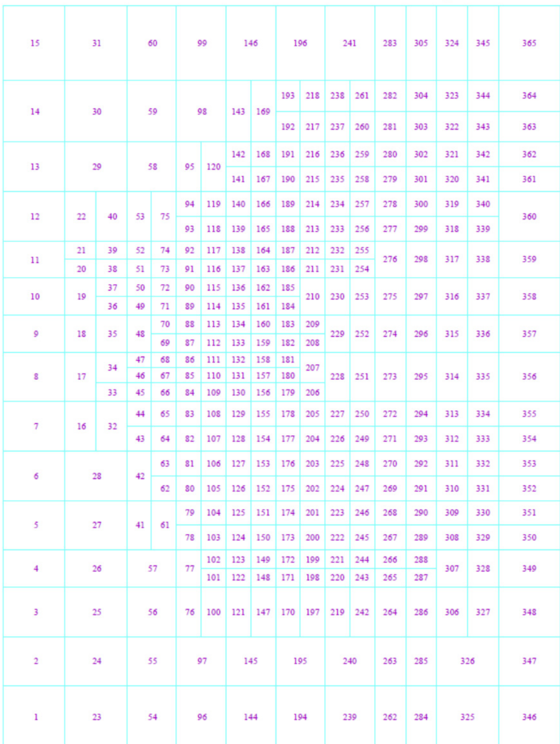
Figure 3.4: Gridblocks layout in the updated model - layer 2 (from -200 m, msl to -400 m, msl)



1997, GeothermEx, Inc.

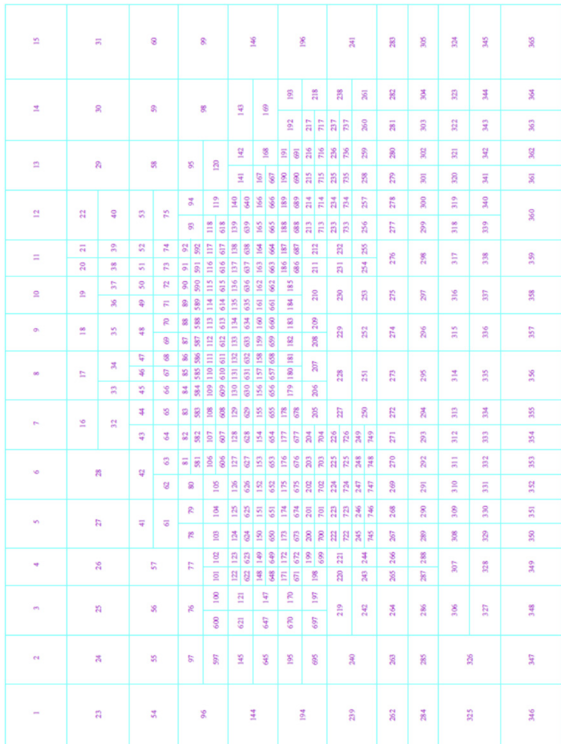
FIGURE 11: GeothermEx/ICE Numerical Model (1998)

Figure 2.3: Gridblocks arrangement at layer 1 @ -50 m, msl



2001, GeothermEx, Inc.

Figure 2.4: Gridblocks arrangement at layer 2 @ -300 m, msl



2001, GeothermEx, Inc.

FIGURE 12: GeothermEx/ICE Numerical Model (2002)

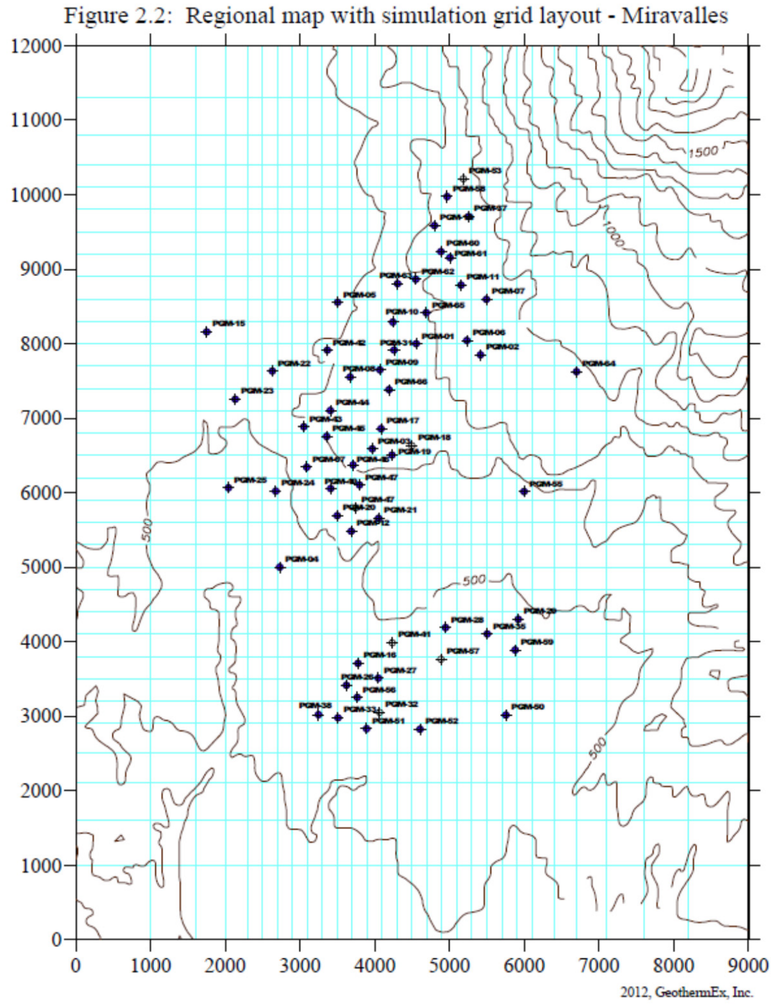


FIGURE 13: GeothermEx/ICE Numerical Model (2012)

The current model has been used for evaluating different possible exploitation scenarios which have been proposed, i.e. injecting waste brine into the north-central zone of the field, producing from the deep zone of Miravalles, etc.

The actual situation of the Miravalles reservoir is very complex and the amount of data collected over the years has become very large (geoscientific and production data). This situation joined with some technical deficiencies in the TOUGH2 program that is currently used by the ICE make it very difficult and laborious to effectively predict reservoir performance of the Miravalles field. ICE is actually taking steps to migrate the TOUGH2 simulation software to a more effective simulation program, where it can be more effectively evaluate reservoir behaviour of Miravalles and other fields in the future. The actual plans are to migrate from TOUGH2 to TETRAD platform and continue using the latter in the following years.

7. PRODUCTION HISTORY

The Miravalles Complex comprises five power units in three different power houses (Figure 14), seven separations stations, the pipeline networking, 53 wells (production, injection and observation) and a series of artificial ponds aimed for cold injection, maintenance operations and emergencies. A simple scheme of the pipeline network, wells, power plants and other facilities is shown in Figure 15.

FIGURE 14: Power Plants at Miravalles

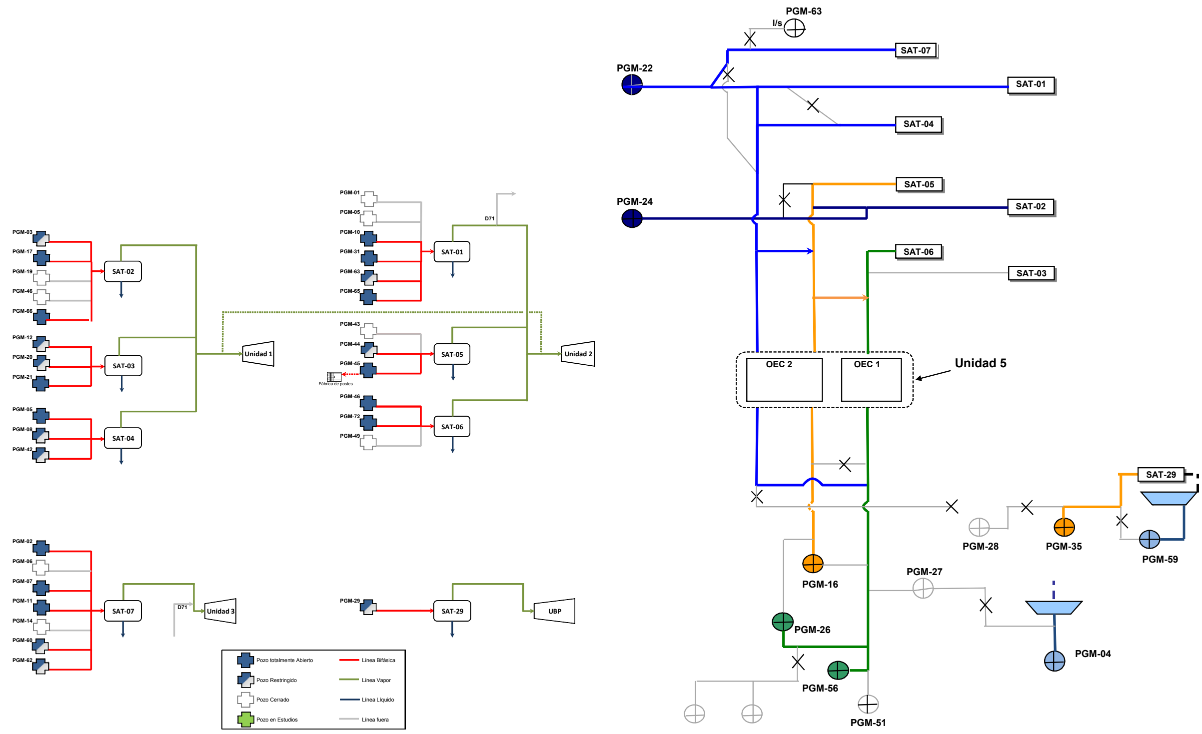


FIGURE 15: Power Plants, Wells, Separation Stations and Pipeline Networking at Miravalles

In Miravalles is also located the main facilities of the Centro de Servicios Recursos Geotérmicos (CSRG), which is the ICE´s department charge of the exploration, evaluation and exploitation of the geothermal resources in the country.

Table 1 shows the commissioning sequence of the different power plants installed in Miravalles. All the actual operative units are owned by ICE.

TABLE 1: Generation at the Miravalles Geothermal Field

Unit	*Operator*	**Power Output (MW)**	*Operation Time*	
			Start	*End*
Unit 1	ICE	55	03/1994	---
Wellhead 1	ICE	5	11/1994	---
Wellhead 2	CFE	5	09/1996	08/1998
Wellhead 3	CFE	5	04/1997	01/1999
Unit 2	ICE	55	08/1998	---
Unit 3	Geo	29	03/2000	---
Unit 5	ICE	19	12/2003	---

7.1 Mass production

The total mass extraction and injection rates in Miravalles are shown in Figure 16. Around 1500.6 kg/s of total mass are extracted from the reservoir, and 345.8 kg/s are steam used for generation (as of 13/02/2013; Nietzen, personal communication). All the waste water is injected back to the reservoir.

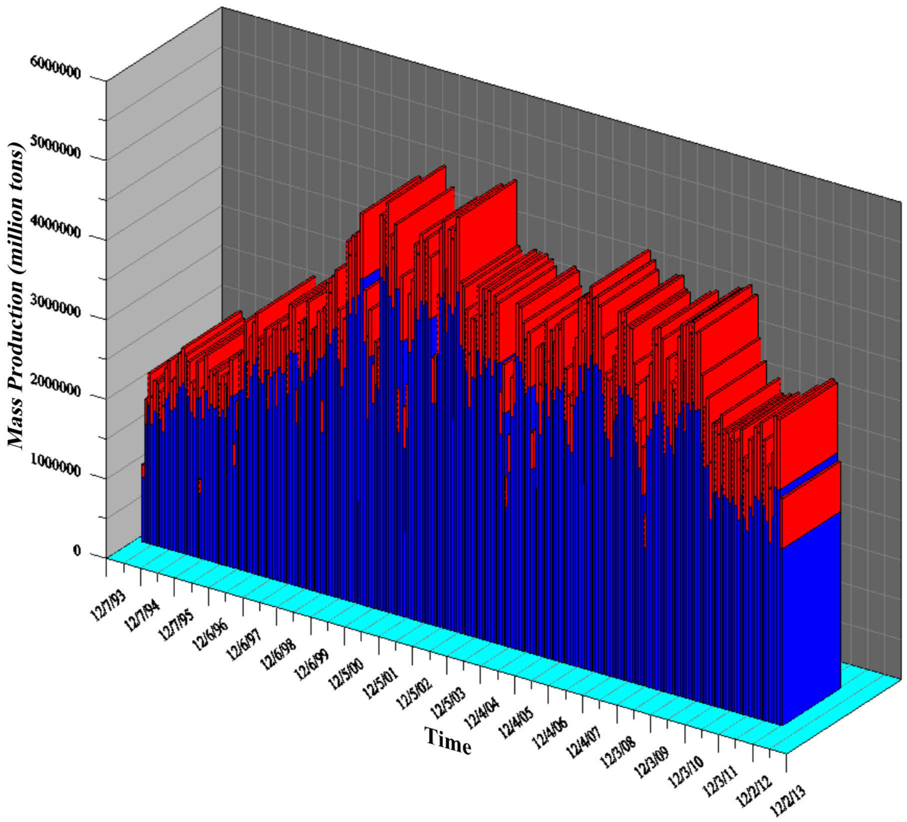


FIGURE 16: Mass Production and Injection at the Miravalles Field

The annual maintenance of the different power plants is historically scheduled during the second half of every year; this explains the observed decrease in the mass production over this period of time.

7.2 Mass injection

Injection has been an important factor of the Miravalles operation. Injection rates account for around 83% of the total mass extracted from the field. Injection into the different sectors at the Miravalles Field is shown in Table 2 as a percentage of the total injected mass into the field (Vallejos et al, 2005).

The injection of waste brine has been made in "hot" conditions that is around 165 °C, and a small proportion in "cold" conditions (less than 60 °C). "Cold" injection is located in well PGM-04, which is located to the southwest of the field. The "Hot" conditions changed when the Unit 5 came online since it recovers some of the heat of the waste brine, lowering its temperature to 136 °C. A big part of the total waste brine will pass through Unit 5 and then be injected into the southern injection zone. The western injection zone will continue receiving brine at around 165 °C.

Percentages on Table 2 are average of the injections rates over the periods considered; for example, injection in any given month can change for various reasons: a special need for producing more electricity with the binary plant, maintenance operations in one or more injector wells, etc. Sometimes the injection in a month at the southern injectors can be as high as 80% or as low as 50%, thus varying the percentages in the other wells.

TABLE 2: Injection into the Miravalles Field Zones

Start	End	South	PGM-22	PGM-24	PGM-04	PGM-63
1994	1998	30%	30%	30%	10%	---
1998	2000	65%	13%	13%	9%	---
2000	2002	73%	9%	9%	9%	---
2002	2003	63%	11%	17%	9%	---
2003	2006	65%	14%	15%	5%	small
2007	2012	65.4%	14%	13.6%	5.8%	1.2%

7.3 Electrical production

The electrical generation of the Miravalles Complex is shown in Table 3 (ARESEP, 2011) and Figure 17. The main power plants have been working at high plant load factors (90% under normal operation conditions), due to their excellent performance, maintenance and the good behaviour the reservoir has showed along these years of exploitation.

7.4 Importance of the geothermal energy in Costa Rica

The installed capacity of Miravalles and Pailas fields accounts for about 8,2% of the country's total installed capacity; however, it represents around 13,2% of the country's total generation (ARESEP, 2012). Since the geothermal plants produce constantly throughout the year round, they are used as a base for the country's electrical generation, because of the variation in the hydro electrical plants production due to the seasonal variations of the Costa Rica's weather (Figure 18).

The importance of geothermal energy in Costa Rica is increasing. In 2001, geothermal represented the 8.6% of Costa Rica's total electrical production and accounted for 14.2% of the country's total generation. By 2011, the installed capacity was essentially the same (8.2%) but the generation was 13.2% of the total supplied by the National Electrical Grid or SEN (in Spanish). SEN includes all the electrical generation companies of Costa Rica (public and privates), and the total installed capacity of the country reaches 2650 MW (Table 4) and generated 9748 GWh in 2011 (ARESEP, 2012).

TABLE 3: Electrical Generation of the Miravalles Power Plants (March 1994 – December 2011)

1994-2011 (GWh)													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Set**	**Oct**	**Nov**	**Dec**	**Total**
1994	0,0	0,0	7,0	31,9	37,1	33,6	39,2	39,7	33,8	37,2	40,5	41,7	341,8
1995	39,4	41,7	43,4	45,3	45,2	44,0	43,8	41,1	38,6	46,2	8,4	31,0	468,2
1996	47,5	42,1	45,7	45,0	43,9	40,8	45,4	43,5	45,5	48,5	26,5	35,6	510,0
1997	47,7	43,0	50,9	46,0	47,5	51,2	52,5	43,7	46,0	43,0	23,7	49,2	544,4
1998	51,1	45,5	51,8	49,3	46,4	44,6	49,3	52,6	36,8	58,9	48,0	57,7	591,9
1999	64,2	59,4	65,3	69,6	74,0	46,9	66,6	75,0	72,8	78,7	74,1	57,2	803,9
2000	66,9	72,2	82,4	94,2	94,6	93,7	100,7	102,2	79,1	59,3	67,0	64,1	976,5
2001	63,2	60,7	101,0	94,8	99,5	98,2	95,2	96,5	58,8	99,4	57,0	62,0	986,3
2002	91,4	90,7	103,3	99,8	103,6	100,0	102,2	98,9	73,4	67,7	87,5	102,5	1121,0
2003	105,2	91,7	105,8	104,3	104,9	97,0	99,8	97,9	83,3	71,8	90,1	92,4	1144,2
2004	115,7	106,6	118,7	112,2	116,2	105,3	112,4	107,6	77,7	94,4	62,9	75,9	1205,6
2005	91,0	96,2	106,5	110,2	110,0	103,9	107,2	68,5	63,1	96,5	89,2	105,3	1147,7
2006	114,8	99,1	110,8	107,5	112,1	106,7	105,1	88,6	86,5	83,1	100,7	99,9	1214,9
2007	109,2	104,0	112,2	105,9	112,3	109,6	112,2	103,8	94,4	87,3	87,9	90,3	1229,1
2008	105,6	104,8	114,3	109,9	113,3	107,9	110,0	97,2	89,0	68,3	64,1	46,4	1130,8
2009	89,0	101,8	112,5	105,8	111,7	105,3	91,5	99,0	88,7	86,8	92,8	101,1	1185,8
2010	107,7	98,8	110,0	107,6	110,1	104,9	107,9	88,9	79,1	90,7	77,3	93,2	1176,1
2011	91,2	90,0	100,8	98,8	99,9	95,2	99,5	96,2	87,0	98,0	87,4	84,9	1129,0

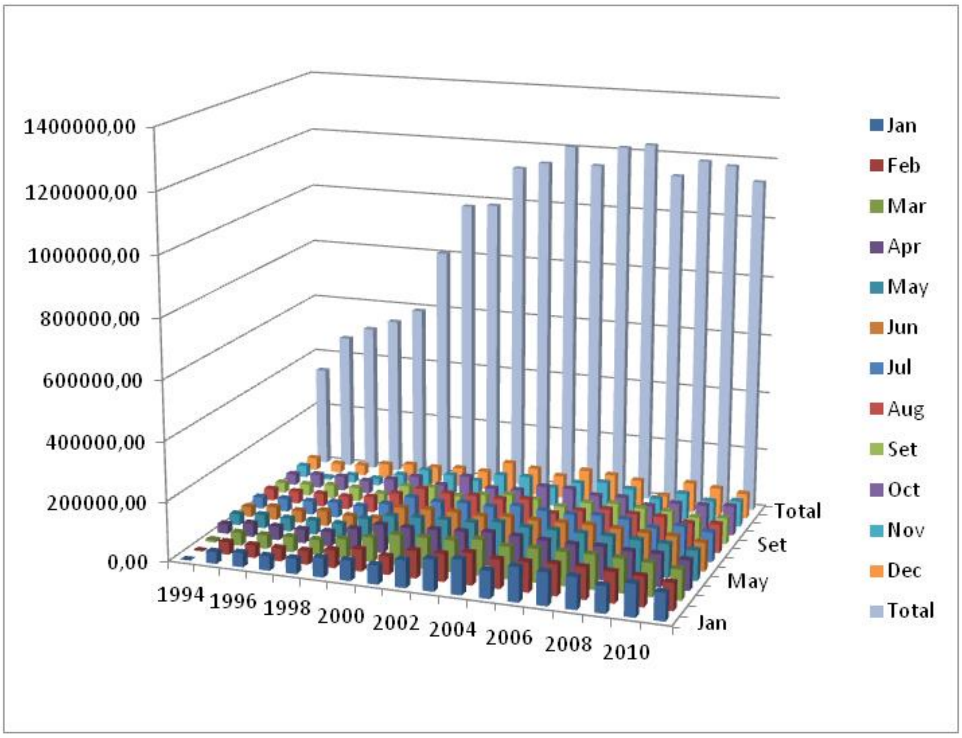


FIGURE 17: Electrical Generation of the Miravalles Power Plants (March 1994 – December 2011)

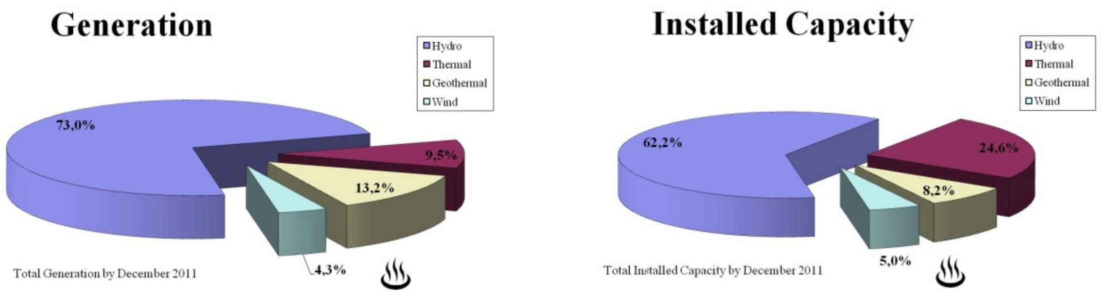


FIGURE 18: Costa Rica Installed Capacity and Generation – year 2011

TABLE 4: Costa Rica Installed Electrical Capacity and Generation

Type	Installed Capacity (MW & %) Generation (%)				
	2007	**2008**	**2009**	**2010**	**2011**
Hydro	1494.0 (69.3) (75.2)	1511.5 (63.9) (78.3)	1532.3 (63.5) (78.4)	1532.3 (58.6) (76.4)	1647.6 (62.2) (73.0)
Thermal	432.4 (20.1) (2.7)	624.4 (26.4) (3.5)	624.4 (25.9) (3.1)	826.8 (31.6) (1.0)	652.6 (24.6) (3.7)
Geothermal	163.7 (7.6) (13.8)	163.7 (6.9) (12.1)	163.7 (6.8) (12.8)	163.7 (6.3) (12.4)	217.5 (8.2) (13.2)
Wind	66.0 (3.1) (2.7)	66.0 (2.8) (2.1)	91.2 (3.8) (3.4)	91.2 (3.5) (3.8)	132.8 (5.0) (4.3)
Total	2156.0 (100.0) (100.0)	2365.5 (100.0) (100.0)	2411.6 (100.0) (100.0)	2614.0 (100.0) (100.0)	2650.4 (100.0) (100.0)

8. MIRAVALLES RESERVOIR EVOLUTION

The observed evolution of the Miravalles Field during the 19 years of production can be divided in four different stages:

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 centre 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 observed.

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 separation station 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, and its effect on the pressure of the reservoir has proven to be effective. Even though, the effect of this action is less than expected because the quantity of reinjected water sent to the west has not been the desired.

Figures 19, 20 and 21 show the variation of some parameters in selected wells of Miravalles, specially the changes observed in some central wells of the field. Figure 22 show the generalized pressure drop observed all around the field since 1994. Most of the wells show a drop in the wellhead pressure; that condition is causing problems when the wells have to be put online. Some of them are actually operating very near to the separation station pressure, so any disturbance in the power plant can cause that the well shut off.

Figure 21 clearly shows the effect of the reinjection in some of the wells of the central part of the field; especially those located near wells PGM-22 and PGM-24. The chlorides increase and the noncondensable gas content drops in these wells. However, there are wells that increase in the noncondensable gas content; some because of the steam cap formation as mentioned earlier in this section, others because of its own nature. The overall effect over the power plants is a higher noncondensable gas content that surpasses the capacity of the actual extraction system. These are then forced to work with ejector and compressor, consuming energy and steam in the process.

Numerical modelling done in 2002 to forecast future reservoir behaviour showed that, under the then 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 were partly completed as was mention before, but changes in the production rates of wells connected to separation station 1 have made it impossible to achieve the original rate of the fluid injection into well PGM-22 (Moya and Yock, 2004).

The operation of Unit V has been 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 and GeothermEx, Inc., 2012). The most recent modelling studies warn about the expected reduction in production of the binary plant due to the enthalpy rise observed under the nominal operation conditions of the field (GeothermEx, Inc., 2012). Monitoring of the field has been carried out in order to avoid future problems that might occur if lowering the temperature of the reinjection waters (from 165 to 136 ºC) impacts the reservoir more than predicted by the numerical modelling. 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 detected nor quantified.

The modelling runs in 2002 clearly indicated 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 centre of the field. This was achieved by the end of 2006, and since then the back pressure unit has been producing to its maximum capacity and well PGM-29 has been very stable in their productive and thermo hydraulic parameters.

The most recent numerical model, developed in March 2012, forecasts the sustainability of the exploitation of the Miravalles reservoir under the conditions described below:

UNIT I: generating up to 55 MW.
UNIT II: generating up to 55 MW.
UNIT III: generating up to 27.5 MW.
UNIT V: generating up to 14 MW (injection temperature 136 °C.)
Wellhead unit: installed in well PGM-29 (generating up to 5 MW).

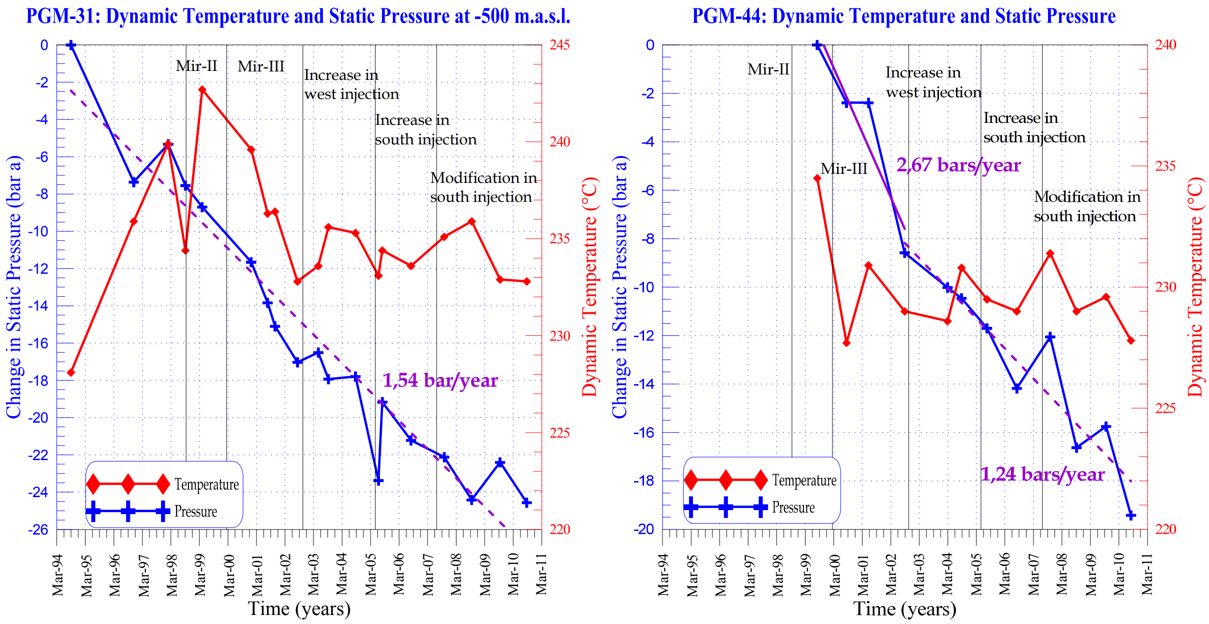


FIGURE 19: Temperature and Pressure Drop in Some Miravalles Central Zone Wells

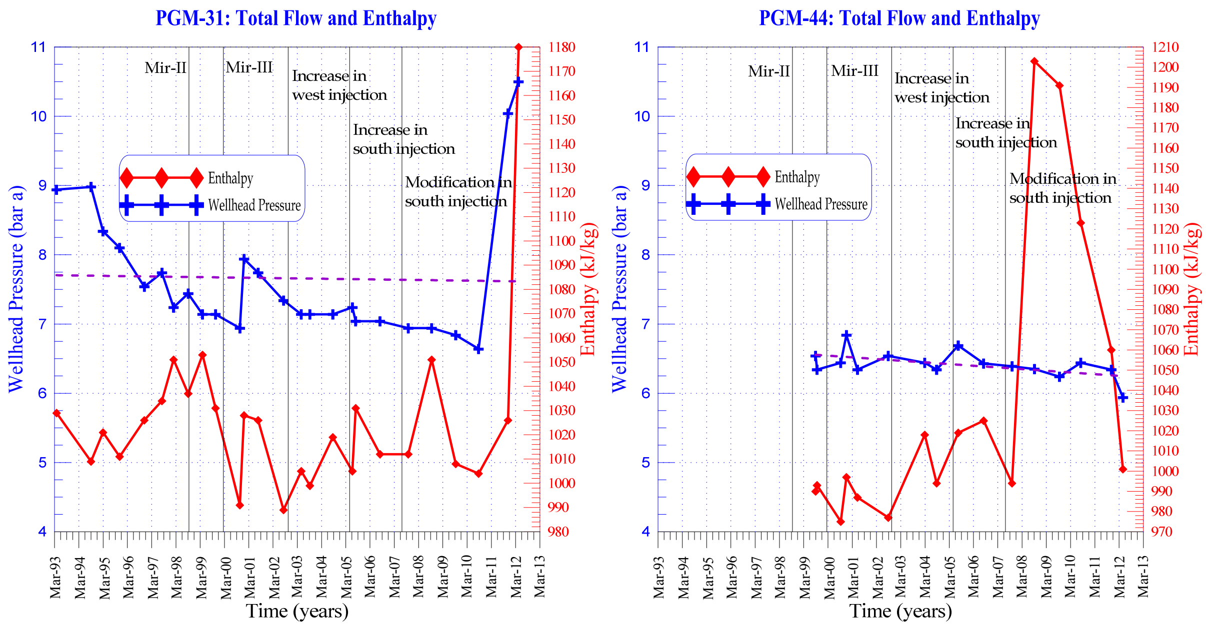


FIGURE 20: Wellhead Pressure and Enthalpy in Some Miravalles Central Zone Wells

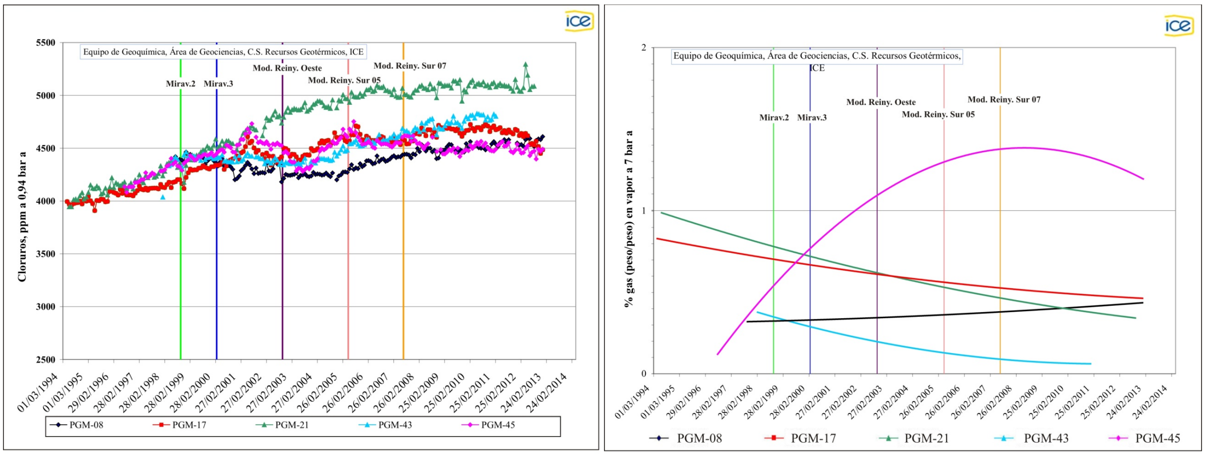


FIGURE 21: Chlorides and Non Condensable Gas Content in Some Miravalles Central Zone Wells

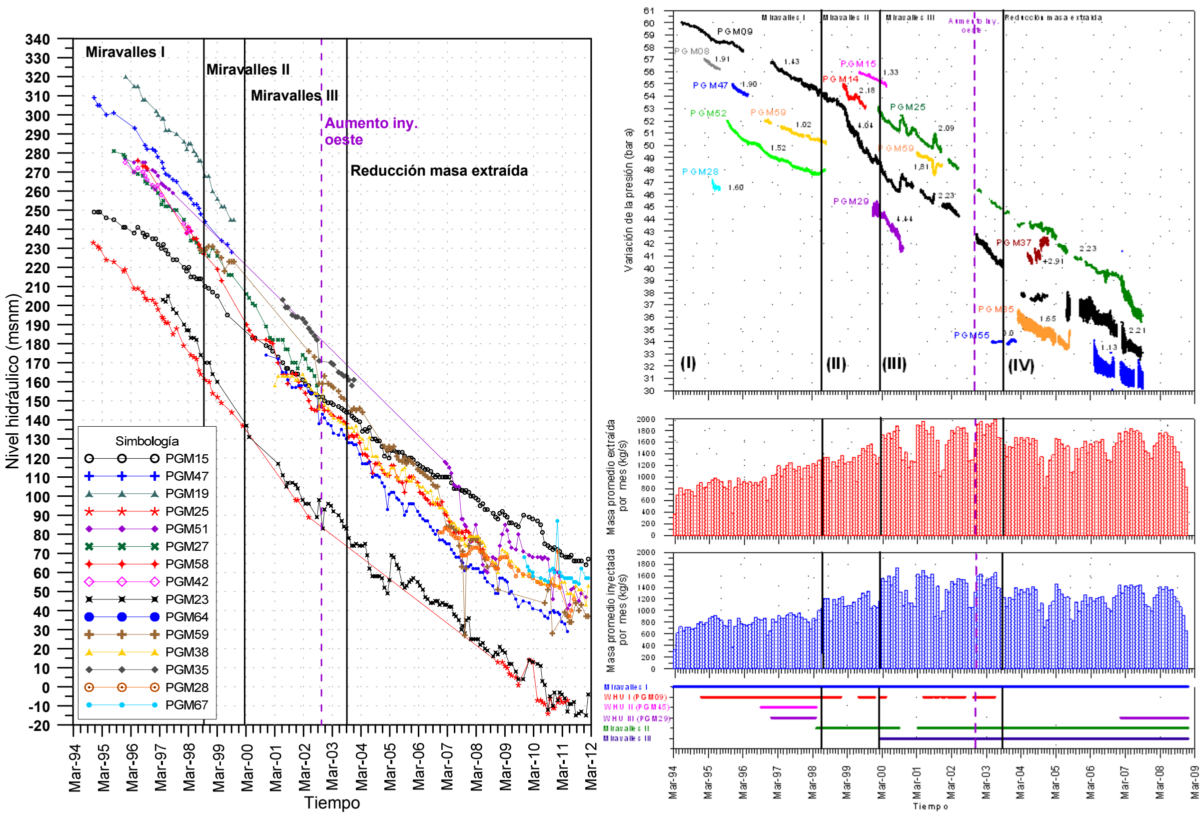


FIGURE 22: Pressure Drop at the Miravalles Field (hydraulic levels and monitoring probes)

The main conclusions of this study were the following (GeothermEx, 20120):

- Wells in the field will continue to cease producing due to high pressure drop in the reservoir under the present conditions of exploitation (Figure 22).

- Modelling results and measured data suggest the increase in the injection rate since 2003 has had a positive impact on the pressure decline rate observed in the reservoir. Pressure decline rate measured in the field has an average decline rate of 1.7-2.0 bar/yr prior to the shift of injection to the western injection wells. After the injection rate was increased in the two western injectors (PGM-22 and PGM-24), the reservoir pressure decline rate has averaged about 1.4 bar/yr (Figure 22).

- Injection into the southern wells has provided little pressure support to the production wells. Measured chloride and pressure decline data have shown that the fluid injected into the southern wells has quickly moved out of the reservoir and has not come back to the production area in any significant amount.

- Expect reduced production from the binary unit (unit 5) as the enthalpy in the reservoir is expected to continue to increase (Figure 23).

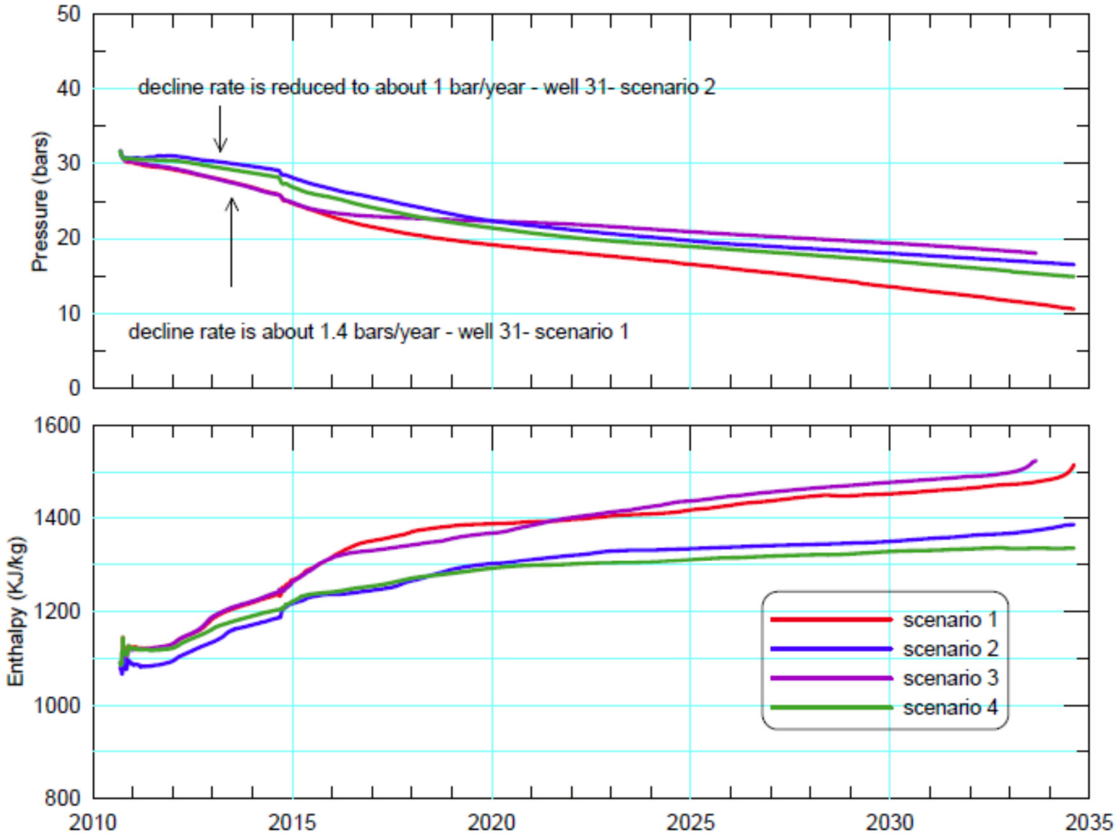


Figure 23: Forecast of Pressure an Enthalpy under different Production Scenarios at Miravalles (2012)

Currently, the northern zone of the field is the most strongly affected by the continuous exploitation of the reservoir. Specific actions are and 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. Reduction in the extraction rates during certain periods of the year is done during the rainy season of every year, taking advantage of the peak in production of the hydro power plants. In this period of the year, the main power plants produce 45 MWe each and the binary plant produces about 12 MWe. Among the actions considered is the injection of controlled quantities of water (at 165 ºC) into the northern part of the field. Some former production wells are being prepared in order to become injectors and inject some quantities of water in the near future.

9. FINAL REMARKS

The Miravalles Geothermal Field has completed almost nineteen years of successful exploitation, and the continuous exploration and development that has increased its installed capacity from 55 to 163 MWe.

The installed capacity of geothermal energy accounts for more than 8% of the country's installed capacity, and produces more than 13% of the country's total generation. The Miravalles Complex itself supplies the 11,5% of the total generation of the country. This position must give the sustainability of the Miravalles reservoir an important subject under the energetic planning strategy of ICE.

ICE have implemented different actions focused on sustaining the steam supply to the power plants and also on reservoir management. So far, these actions have been successful in sustaining the production of the field to the actual levels when required by the National Electrical Grid but the Miravalles reservoir faces an actual evolution that has forced to reduce the production in certain times of the year. The reservoir must be carefully monitored in order to avoid a future decline in production and electrical generation.

The actual knowledge of the reservoir and the evolutions trend observed has headed to conclude that the Miravalles field has actually reached its maximum extraction rates. There are still more zones under exploration (east zone, acid aquifer) which can help (and actually does) to solve the production decline observed in the main aquifer, and in a future to evaluate an expansion of the field if it is proven that these other zones are independent and not following the same declining rates of the main aquifer.

In the near future the actions to be taken for ICE in order to stabilize the field production and reach the maximum field productive levels are the following:

- - It should be drilled a limited number of wells in the northern area to supplement the steam rate going to Unit III.

- - An infield injection testing program using wells PGM-01 and PGM-10 should be conduct. The test must be done gradually to avoid watering out nearby production wells (start injecting at a low rate and gradually increase the rate if no adverse impacts are seen). The infield injection should provide more pressure support to production wells and help stabilizing the trend of the produced non-condensable gasses. A test injecting into well PGM-63 started in July 2005, injecting 40 l/s and monitoring the nearby producer wells (water chemistry and occasional temperature and pressure surveys). Further increments in the injection regime (up to 80 kg/s) showed no impact in temperature nor thermal and hydraulic parameters, as the pressure and chlorides parameters in the nearby wells. The test lasted up to August 2006 (Vallejos, 2005(2); González and Sánchez, 2006).

- The noncondensable extraction system at the main power plants (Unit 1 and 2) is actually being upgraded. The capacity will increase in the near future from 1,0 to 2,5% in order to reduce the use of compressors and ejectors(less energy consumption and less steam consumption that can be used in the energy conversion process).

- - The injection fluid from the south should be gradually shifted to the middle and to the west (as much as it is operationally feasible). Unit 5 can continue partial production if a pipeline is built from unit 5 to injection well PGM-24.

- - Wells in the east-south-eastern area of the field should be drilled. This is an unexplored area, and if steam is successfully proven in this area, the produced steam could be sent to Units I and II. Wells could be deviated from PGM-55 or drilled from new pads. The east-southeast zone comprises the wells PGM-28, 29, 59, 55 and 35. From geochemical point of view this sector shows some differences regarding the main and acid reservoirs. The main differences are in the high bicarbonates content and their Na/K relationship, which shows an important difference between the geothermometers and the measured temperatures. Similar differences can be seen in the values of calcium and magnesium. For their characteristics, these fluids present a high tendency to form calcium carbonate deposition and a high non condensable gases content in the steam. The first point has been treated successfully with the correct inhibitor dosage, but the later presents a big restriction in the face of the current non condensable gas extraction capacities Units 1 and 2. This problem has partially been solved since the non condensable gas extraction system of these units is being improved from the actual 1% to 2.5%. Actual and future studies are now oriented to define the dimensions of this aquifer, the stable productive characteristics of their wells and the correct way to handle the high noncondensable gas content (Sánchez et al, 2005 and Cumming et al, 2005). Future drilling in this zone is not intended to increase but to give support to the current production of Miravalles (163 MW)

- - The well deepening program should be continued to investigate further the benefits of tapping fluids from the deep zone in the reservoir. Wells PGM-44, PGM -24, PGM-45and PGM-25 (-1619 m a.s.l.) crossed deep permeable zones but for different reasons there were not considered an important issue at the beginning of exploration in Miravalles. The results in those wells and further analysis showed the existence of a deep aquifer related with the main aquifer of Miravalles (yellow zone in Figure 1) in the zone around -1400 to -1600 m a.s.l. (Sánchez et al, 2010).

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GEOTHERMAL TRAINING PROGRAMME

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GEOTHERMAL DRILLING TARGETS AND WELL SITING

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ABSTRACT

Increased geothermal utilization and improved understanding of geothermal systems during the last century coincided with geothermal wells becoming the main instruments of geothermal development. They enable a drastic increase in geothermal energy production, compared to natural out-flow, and provide access deep into the systems, not otherwise possible. The key to the successful drilling of any type of geothermal well (temperature gradient, exploration, production, step-out, make-up, reinjection, monitoring and unconventional wells) is correct siting and design of the well based on a clear definition and understanding of the drilling target aimed for, founded on all information available at any given time. This is best achieved through a comprehensive and up-to-date conceptual model, which is a qualitative models incorporating, and unifying, the essential physical features of a geothermal system. The principal geothermal drilling targets are in fact structures of adequate permeability and sufficiently high temperature to yield productive wells. Temperature conditions may be indirectly inferred from resistivity surveying, natural seismicity and concentration of chemical components or measured directly through wells. The permeability structure of a geothermal system is usually quite complex and usually not well defined until a certain number of wells have been drilled into a geothermal system. Once this structure becomes well known and clearly defined drilling success usually improves. The siting of the first well in a geothermal field depends mostly on surface exploration but once the first wells have been drilled subsurface data come into play, increasing the knowledge on a geothermal system. Most important are feed-zone, temperature-logging and well-test data.

1. INTRODUCTION

Geothermal resources are distributed throughout the Earth's crust with the greatest energy concentration associated with hydrothermal systems in volcanic regions at crustal plate boundaries. Yet exploitable geothermal resources may be found in most countries, either as warm ground-water in sedimentary formations or in deep circulation systems in crystalline rocks. Shallow thermal energy suitable for ground-source heat-pump utilization is available world-wide and attempts are underway at developing enhanced geothermal systems (EGS) in places where limited permeability precludes natural hydrothermal activity. Geothermal springs have been used for bathing, washing and cooking for thousands of years in a number of countries world-wide, e.g. China, Japan and the remnants of the Roman Empire (Cataldi et al., 1999). Yet commercial utilisation of geothermal resources for energy production only started in the early 1900's. Electricity production was initiated in Larderello, Italy, in 1904 and operation of the largest geothermal district heating system in the world in Reykjavik, Iceland, started in 1930. Extensive geothermal heating of greenhouses also started in Hungary in the 1930's. Since this time, utilisation of geothermal resources has increased steadily.

The understanding of the nature of hydrothermal systems didn't really start advancing until their large-scale utilization started during the 20th century. Some studies and development of ideas had of course been on-going during the preceding centuries, but various misconceptions were prevailing (Cataldi et al., 1999). In Iceland, where highly variable geothermal resources are abundant and easily accessible, a breakthrough in the understanding of the nature of geothermal activity occurred during the middle of the 19th century, a breakthrough which was, however, beyond the scientific community at the time (Björnsson, 2005). Increased utilization and greatly improved understanding went hand in hand with geothermal wells (or boreholes/drillholes) becoming the main instrument for geothermal development. This is because geothermal wells enable a drastic increase in the production from any given geothermal system, compared to its natural out-flow, as well as providing access deep into the systems, not otherwise possible, which enables a multitude of direct measurements of conditions at depth.

The technology of geothermal well drilling is mostly derived from the petroleum industry, as well as from the ground-water and mineral industries. The technology has been adapted to different conditions, however, mostly in terms of geology, temperature, pressure and chemistry of the fluid involved. Because of the limited size of the geothermal industry, compared with e.g. the petroleum industry, advancement of the geothermal drilling technology has been relatively slow. Geothermal wells play a variable role, however, both during development of geothermal resources as well as during their utilization. The main roles are: (a) exploration wells, (b) production wells, (c) reinjection wells and (d) monitoring wells.

The key to the successful drilling of any type of geothermal well is correct siting and design of the well based on a clear definition and understanding of the drilling target aimed for. This paper discusses targeting and siting of the different types of geothermal wells with particular emphasis on how all available information and data should be used for this purpose. The cooperation of the different disciplines involved in geothermal research and development is of particular importance here. The paper starts out by reviewing briefly the types and classification of geothermal resources as well as discussing conceptual models of geothermal systems, which play a key role in targeting and siting geothermal wells. Subsequently the paper discusses the different types of geothermal wells along with different aspects of their targeting and siting. The paper is concluded by general conclusions and recommendations.

2. GEOTHERMAL SYSTEMS

2.1 Types and classification of geothermal systems

Geothermal systems and reservoirs are classified on the basis of different aspects, such as reservoir temperature or enthalpy, physical state, their nature and geological setting. Axelsson (2008a) and Saemundsson et al. (2009) summarize the classifications based on the first three aspects, i.e. as high-temperature (> 200°C) or low-temperature (< 150°C) systems, high-enthalpy (> 800 kJ/kg) or low-enthalpy (< 800 kJ/kg), or liquid-dominated, two-phase or vapour-dominated systems.

Geothermal systems may also be classified based on their nature and geological setting (Figure 1) as follows:

A. *Volcanic systems* are in one way or another associated with volcanic activity. The heat sources for such systems are hot intrusions or magma. They are most often situated inside, or close to, volcanic complexes such as calderas and/or spreading centres. Permeable fractures and fault zones mostly control the flow of water in volcanic systems.

B. In *convective fracture controlled systems* the heat source is the hot crust at depth in tectonically active areas, with above average heat-flow. Here the geothermal water has circulated to considerable depth (> 1 km), through mostly vertical fractures, to extract the heat from the rocks.
C. *Sedimentary systems* are found in many of the major sedimentary basins of the world. These systems owe their existence to the occurrence of permeable sedimentary layers at great depths (> 1 km) and above average geothermal gradients (> 30ºC/km). These systems are conductive in nature rather than convective, even though fractures and faults play a role in some cases. Some convective systems (B) may, however, be embedded in sedimentary rocks.
D. *Geo-pressured systems* are sedimentary systems analogous to geo-pressured oil and gas reservoirs where fluid caught in stratigraphic traps may have pressures close to lithostatic values. Such systems are generally fairly deep; hence, they are categorised as geothermal.
E. *Hot dry rock (HDR) or enhanced (engineered) geothermal systems (EGS)* consist of volumes of rock that have been heated to useful temperatures by volcanism or abnormally high heat flow, but have low permeability or are virtually impermeable. Therefore, they cannot be exploited in a conventional way. However, experiments have been conducted in a number of locations to use hydro-fracturing to try to create artificial reservoirs in such systems, or to enhance already existent fracture networks. Such systems will mostly be used through production/reinjection doublets.
F. *Shallow resources* refer to the thermal energy stored near the surface of the Earth's crust. Recent developments in the application of ground source heat pumps have opened up a new dimension in utilizing these resources.

Saemundsson et al. (2009) discuss the geological setting of geothermal systems in more detail and present a further subdivision principally based on tectonic setting, volcanic association and geological formations. Numerous volcanic geothermal systems (A) are found for example in The Pacific Ring of Fire, in countries like New Zealand, The Philippines, Japan and in Central America. Geothermal systems of the convective type (B) exist outside the volcanic zone in Iceland, in the SW United States and in SE China, to name a few countries. Sedimentary geothermal systems (C) are for example found in France, Central Eastern Europe and throughout China. Typical examples of geo-pressured systems (D) are found in the Northern Gulf of Mexico Basin in the U.S.A. The Fenton Hill project in New Mexico in The United States and the Soultz project in NE-France are well known HDR and EGS projects (E) while shallow resources (F) can be found all over the globe. The type of geothermal system involved of course affects the design and siting of geothermal wells to be drilled into the system.

There are definite differences between geothermal systems and their ground-water and petroleum counterparts, which are worth mentioning since they also affect the siting and design of geothermal wells. Geothermal reservoirs in volcanic (A) and convective (B) systems are in most cases embedded in fractured rocks, while ground water and petroleum reservoirs are usually found in porous sedimentary rocks. In addition geothermal reservoirs are most often of great vertical extent (from a few hundred meters to a few kilometres) in contrast to ground water and petroleum reservoirs, which have limited vertical extent, but may be quite extensive horizontally. Many geothermal systems are also uncapped and the hot fluid may be directly connected to cooler surrounding systems. Finally it should be mentioned that heat transport as well as mass transport is important in geothermal systems in contrast to ground water and petroleum cases, where only mass flow needs to be considered. Heat extraction, rather than simply fluid extraction, is in fact at the core of geothermal utilization. Moreover, two-phase conditions often prevail in high-temperature geothermal systems.

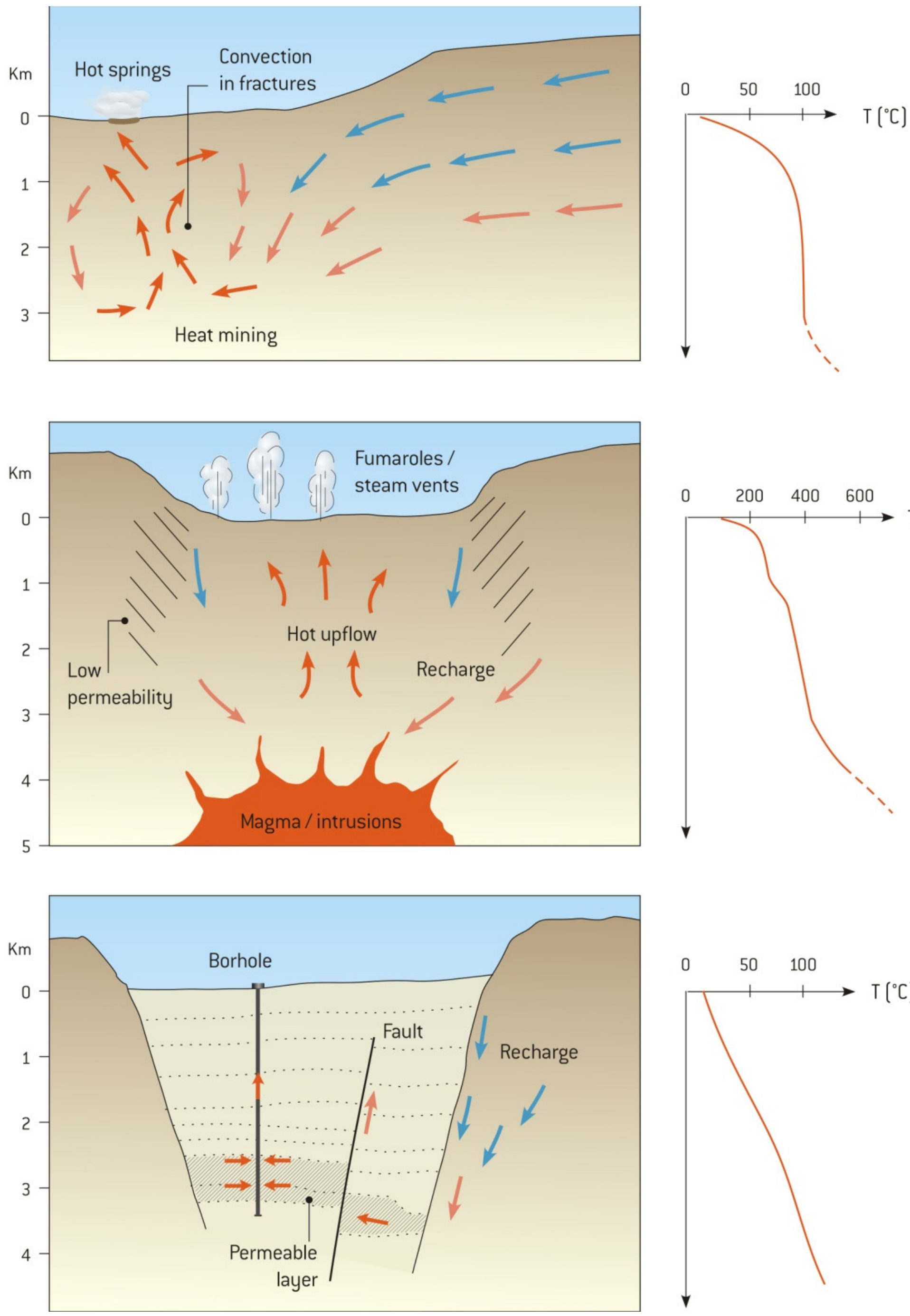

FIGURE 1: Schematic figures of the three main types of geothermal systems; a convective fracture controlled system (B) at the top, a volcanic system (A) in the middle and a sedimentary system (C) at the bottom (Axelsson, 2008a)

2.2 Conceptual models of geothermal systems

The basis of defining drilling targets and well locations is good understanding of the structure and nature of a geothermal system based on all information available at any given time. This information is increasingly being unified through the development of so-called conceptual models, which play a key role in all phases of geothermal exploration and development. This approach has obvious benefits beyond an approach where each discipline develops their own ideas independent from other disciplines. Conceptual models are descriptive or qualitative models incorporating, and unifying, the essential physical features of geothermal systems, which have been revealed through analysis of all available exploration, drilling and testing data (Grant and Bixley, 2011). Conceptual models are mainly based on geological information, both from surface mapping and analysis of subsurface data, remote sensing data, results of geophysical surveying, information on chemical and isotopic content of fluid in surface manifestations and reservoir fluid samples collected from wells, information on temperature- and pressure conditions based on analysis of available well-logging data as well as other reservoir engineering information. Comprehensive conceptual models of geothermal systems should incorporate the following as far as available information allows:

(1) Provide an estimate of the size of a system
(2) Explain the heat source(s) for a system
(3) Include information on the location of the hot up-flow zones
(4) Describe the location of colder recharge zones
(5) Define the general flow pattern in a system
(6) Indicate location of two-phase zones, as well as steam-dominated zones
(7) Describe location of the main permeable flow structures (faults, fractures, horizontal layers, etc.)
(8) Indicate the location of flow barriers
(9) Define the cap-rock of the system
(10) Describe division of system into subsystems, or separate reservoirs, if they exist

Not all geothermal conceptual models incorporate all of the items above, in fact only a few do so. How advanced a conceptual model is depends on the state of development of the system in question. In the early stages knowledge is limited and only information on a few of the items above will naturally be available. When development continues knowledge on the items above increases, but it's really only when large-scale utilization has been on-going for quite some time, with associated monitoring, that fairly comprehensive knowledge on the items listed has become available.

Two examples of visualizations of geothermal conceptual models are presented in Figures 2 and 3. Other examples are available in the geothermal literature, such as a number of examples presented by Grant and Bixley (2011), the conceptual model for the Ahuachapan geothermal system in El Salvador presented by Monterrosa and Montalvo (2010) and the conceptual model for the Hengill geothermal system presented by Franzson et al. (2005).

3. GEOTHERMAL WELLS

3.1 General

Wells or boreholes are vital components in both geothermal research and utilization, since they provide essential access for both energy extraction and information collection, as already mentioned. Deep geothermal drilling didn't really commence on a large scale until the middle of the 20th century even though some geothermal drilling had already started a century before that. Deep (150–200 m) geothermal drilling started in Larderello, Italy, in 1856 (Grant and Bixley, 2011) and the first deep (~970m) geothermal well in Hungary was drilled in Budapest from 1868 to 1878 (Szanyi and Kovács, 2010).

The design, drilling and construction of geothermal wells are discussed in other lectures at this short course. Sarmiento (2007) discusses drilling practises in The Philippines in particular, where extensive experience has accumulated during the countries extensive geothermal development. Typically the upper parts of a geothermal well are closed off by a series of casings; to stabilize the well, to close off non-geothermal hydrological systems and for safety reasons. The deeper parts of the well are either fully open or cased with a so-called liner, which is not cemented in place but perforated in selected intervals, to allow fluid (water and/or steam) to flow from the reservoir into the well. The most significant difference between geothermal and petroleum wells are the following:

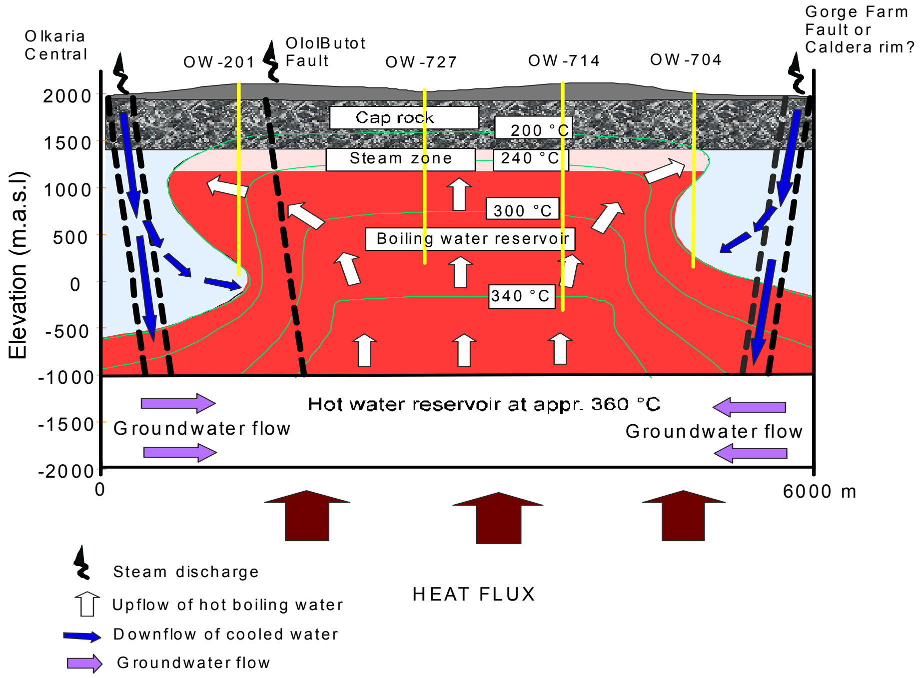

FIGURE 2: A view of the 2002 conceptual model of the Olkaria East geothermal system (Ofwona, 2002)

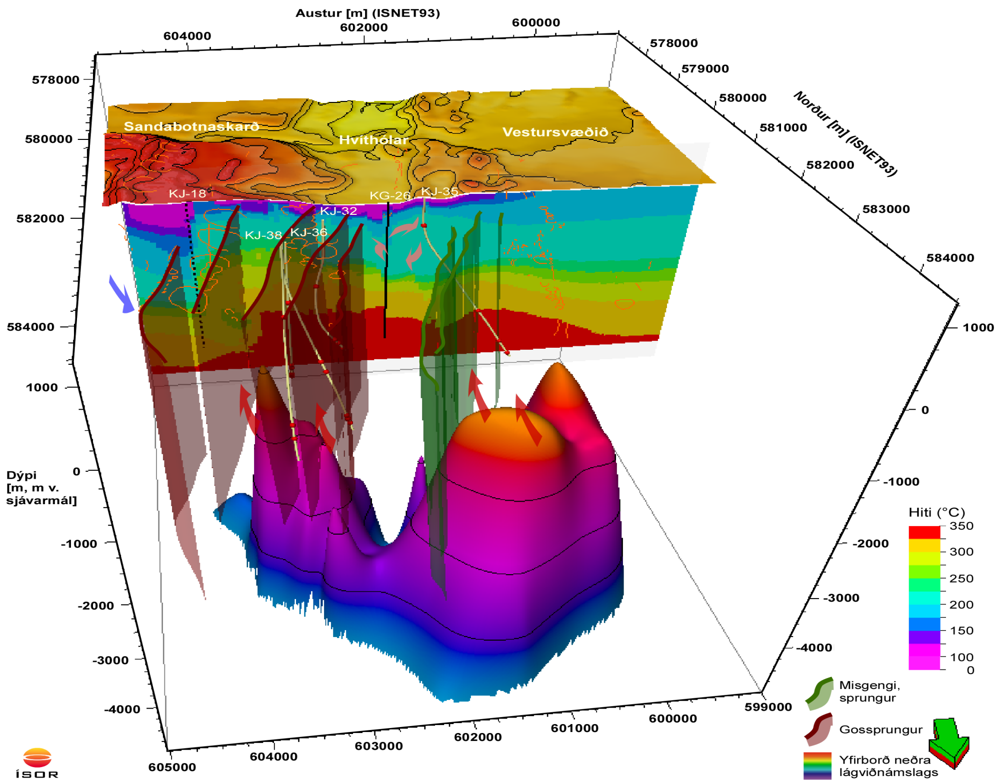

FIGURE 3: A 3-dimensional view of the current conceptual model of the Krafla geothermal system in NE-Iceland (Mortensen et al., 2009) showing a deep-seated low-resistivity anomaly reflecting a magma chamber, faults and eruption fissures as well as temperature conditions and inferred flow directions

(i) Geothermal wells are most often drilled in hard, igneous rocks, which are more difficult to drill than the sedimentary environment of petroleum wells.
(ii) The open production sections of geothermal wells are quite long in comparison with those of petroleum wells, ranging from a few hundred metres to more than 2 km.
(iii) Yet geothermal wells usually have some discrete in-flow sections (feed-zones, see below).
(iv) Geothermal wells often encounter high temperatures and pressures, sometimes associated with blow-out danger due to explosive boiling.
(v) Water is commonly used as drilling fluid for open sections in contrast with drilling mud most commonly used in petroleum wells to avoid clogging any feed-zones (also reduced pollution danger).
(vi) The drilling of successful geothermal wells often involves large, or even total, circulation losses.
(vii) Geothermal production wells are generally of larger diameter (up to a few tens of cm's) than petroleum wells, because of greater flow-rates involved.

Grant and Bixley (2011) discuss some of these in more detail.

A geothermal well is connected to the geothermal reservoir through feed-zones of the open section or intervals. The feed-zones are either particular open fractures or permeable aquifer layers. In volcanic rocks the feed-zones are often fractures or permeable layers such as interbeds (layers in-between different rock formations) while in sedimentary systems the feed-zones are most commonly associated with a series of thin aquifer layers or thicker permeable formations. Yet fractures can also play a role in sedimentary systems. In some instances a well is connected to a reservoir through a single feed-zone while in other cases several feed-zones may exist in the open section, but often one of these is the dominant one.

Geothermal wells can be classified as either:

(a) liquid-phase low-temperature wells, which produce liquid water at well-head (pressure may be higher than atmospheric, however),
(b) two-phase high-temperature wells where the flow from the feed-zone(s) is liquid or two-phase and the wells produce either a two-phase mixture or dry-steam or
(c) dry-steam high-temperature wells where the flow from the feed-zone(s) to the well-head is steam-dominated.

In the liquid-phase and dry-steam wells the inflow is single phase liquid water or steam, respectively, while two-phase wells can be furthermore classified as either liquid or two-phase inflow wells. In multi feed-zone two-phase wells one feed-zone can even be single-phase while another one is two-phase.

In general the productivity of geothermal wells is a complex function of:

(1) well-bore parameters such as diameter, friction factors, feed-zone depth and more,
(2) feed-zone temperature and enthalpy,
(3) feed-zone pressure, which depends directly on reservoir pressure and reservoir permeability,
(4) well-head pressure or depth to water level during production and
(5) temperature conditions around the well.

Most of these parameters can be assumed approximately constant for reservoirs under production, except for the reservoir pressure (3), which varies with time and the overall mass-extraction from the reservoir. The feed-zone temperature and enthalpy may also vary with time in some cases, albeit usually more slowly than reservoir pressure.

Finally it should be mentioned that geothermal wells are often stimulated following drilling (Thórhallsson, 2012a), either to recover permeability reduced by the drilling operation itself, to enhance lower than expected near-well permeability or to open up connections to permeable structures not directly intersected by the well in question. Axelsson and Thórhallsson (2009) review the main methods of geothermal well stimulation with emphasis on methods applied successfully in Iceland. The methods most commonly used involve applying high-pressure water injection, sometimes through open-hole packers, or intermittent cold water injection with the purpose of thermal shocking. Stimulation operations commonly last a few days while in some instances stimulation operations have been conducted for some months. The stimulation operations often result in well productivity (or injectivity) being improved by a factor of 2-3. Geothermal wells stimulation is discussed further in other lectures at this short course.

3.2 Types of geothermal wells

The different types of geothermal wells are listed and described briefly below:

(1) **Temperature gradient wells** are generally both slim and quite shallow, most often only around 50 m in depth, even though in some instances they may reach a few hundred metres depth. Their main purpose is to study shallow temperature conditions (temperature gradient) and estimate heat flow. In contrast with other geothermal wells temperature gradient drilling can in fact be classified as a surface exploration tool. Saemundsson (2010) discusses the use of such wells in geothermal exploration and presents example. Their use has been particularly effective in the exploration for fracture controlled low-temperature geothermal resources in Iceland, especially hidden systems (Axelsson et al., 2005).

(2) **Exploration wells** are deeper wells intended to extend into the geothermal system being explored, i.e. to reach a specific target. Their main purpose is to study temperature conditions, permeability and chemical conditions of the target. Exploration wells are either so-called slim wells with diameter < 15 cm (Thórhallsson, 2012b), which are drilled for the sole purpose of exploring conditions at the target depth, or exploration wells designed as production wells (full diameter wells). The former can be used to estimate the capacity of production wells later drilled to reach the same target(s) (Garg and Combs, 1997; Combs and Garg, 2000). The latter can later be converted to production wells, however, if successful. Slim wells are of course considerably less expensive than full diameter wells and they can be considered more appropriate when the risk involved is relatively large.

(3) **Production wells** are wells drilled with the sole purpose of enabling production of geothermal energy (as hot liquid, two-phase mixture or steam) from a specific target, or a geothermal reservoir. Their design is of paramount importance, e.g. the casing program applied. Production wells are either designed for spontaneous discharge through boiling (high-temperature reservoirs) or for the application of down-hole pumps (lower temperature reservoirs).

(4) **Step-out wells** are either exploration or production wells drilled to investigate the extent, of a geothermal reservoir already confirmed. A step-out well either approaches the edge, or boundary, of a reservoir or is drilled beyond it. A number of step-out wells in different directions may be required if a given reservoir is extensive in area.

(5) **Make-up wells** are production wells drilled inside an already confirmed reservoir, which is being utilized for energy production, to make up for production wells which are either lost through damage of some kind (collapse, scaling, etc.) or to make up for declining capacity of wells.

(6) **Reinjection wells** are used to return energy-depleted fluid back into the geothermal system in question or even to inject water of a different origin as supplemental recharge. The location of reinjection wells is variable as reinjection can either be applied inside a production reservoir, on its periphery, above or below it or outside the main production field, depending on conditions and the purpose of the reinjection (Axelsson, 2012).

(7) **Monitoring wells** are used to monitor changes in geothermal systems, mainly after utilization starts, mostly pressure and temperature changes. These are in most cases already existing wells, such as exploration wells or abandoned production wells. Active production wells are sometimes used for monitoring purposes (chemical content, temperature and pressure).

Carefully designed and comprehnsive monitoring is the key to successful management of geothermal resources during utilization (Axelsson, 2008b). Monitoring wells are also used to monitor transport of chemicals, such as during tracer tests.

(8) **Unconventional wells** are either wells of unconventional design or wells drilled into parts of geothermal systems generally not used for energy production. Good examples are the wells of the Iceland deep drilling program (IDDP, see e.g. Fridleifsson et al., 2010). The aim of the program is to drill down to 4–5 km depth in high-temperature volcanic systems, where supercritical fluid conditions are expected. The first IDDP well was, furthermore, drilled into magma at ~2 km depth, i.e. conditions which surely are unconventional.

The different types of wells play a role during different stages of geothermal development as can e.g. be seen in Figure 4, which shows an example of a geothermal development project plan. The plan includes a subdivision of well categories, beyond the one listed above, which will not be discussed here. Steingrímsson et al. (2005) and Björnsson et al. (2012) provide further information on overall plans for geothermal development in Iceland. Another example worth mentioning is the geothermal development program of the Philippines (Dolor, 2005). In addition Stefánsson (1992) analyses the success of geothermal development, which depends to a great extent on the success of drilling.

4. WELL SITING AND TARGETTING

The key to the successful drilling of any type of geothermal well is correct siting and design of the well based on a clear definition and understanding of the drilling target aimed for, as already stated. This is best achieved through a comprehensive and up-to-date conceptual model. In addition data from different sources play different roles for different types of wells. This can be seen from Table 1, which lists most of the different research methods relevant for defining geothermal drilling targets.

Discussing all these research methods is beyond the scope of the present paper, but instead the reader is referred to numerous papers in the general geothermal literature, and in particular papers presented at a number of short courses given by the United Nations University Geothermal Training Programme (available at http://www.unugtp.is/page/workshops-and-short-courses). A good review of the methods applied in geothermal well targeting during the exploration stage is e.g. given by Santos (2011).

The methods classified as primary in the table are methods which are used in most geothermal development programs worldwide, while the ones classified as secondary are methods only applied in some cases. Yet some of the latter methods are quite valuable when applicable. A case in point is e.g. passive seismic analysis; including event location (depth distribution), focal mechanism and S-wave attenuation analysis, which may add greatly to the understanding of the deeper parts of geothermal systems, in particular those of volcanic systems.

The principal geothermal drilling targets are in fact structures, or volumes, of adequate permeability and sufficiently high temperature to yield adequately productive wells. The nature of the permeability depends on the type of geothermal system involved, being controlled by the geology involved (formations, faults/fractures, etc.) and in-situ stress conditions reflected by the nature of local seismic activity. Temperature conditions may be indirectly inferred from resistivity surveying and concentration of chemical components or measured directly through wells. The permeability structure of a geothermal system is usually quite complex and usually not well defined until a certain number of wells have been drilled into a geothermal system. Once this structure becomes well known and clearly defined drilling success usually peaks. Figure 5 shows a schematic figure of the geological structures most often controlling permeability in Icelandic geothermal systems as well as how their relative importance changes with depth. It should be pointed out that experience has shown that the best permeability is often found at the intersection of two or more such geological structures.

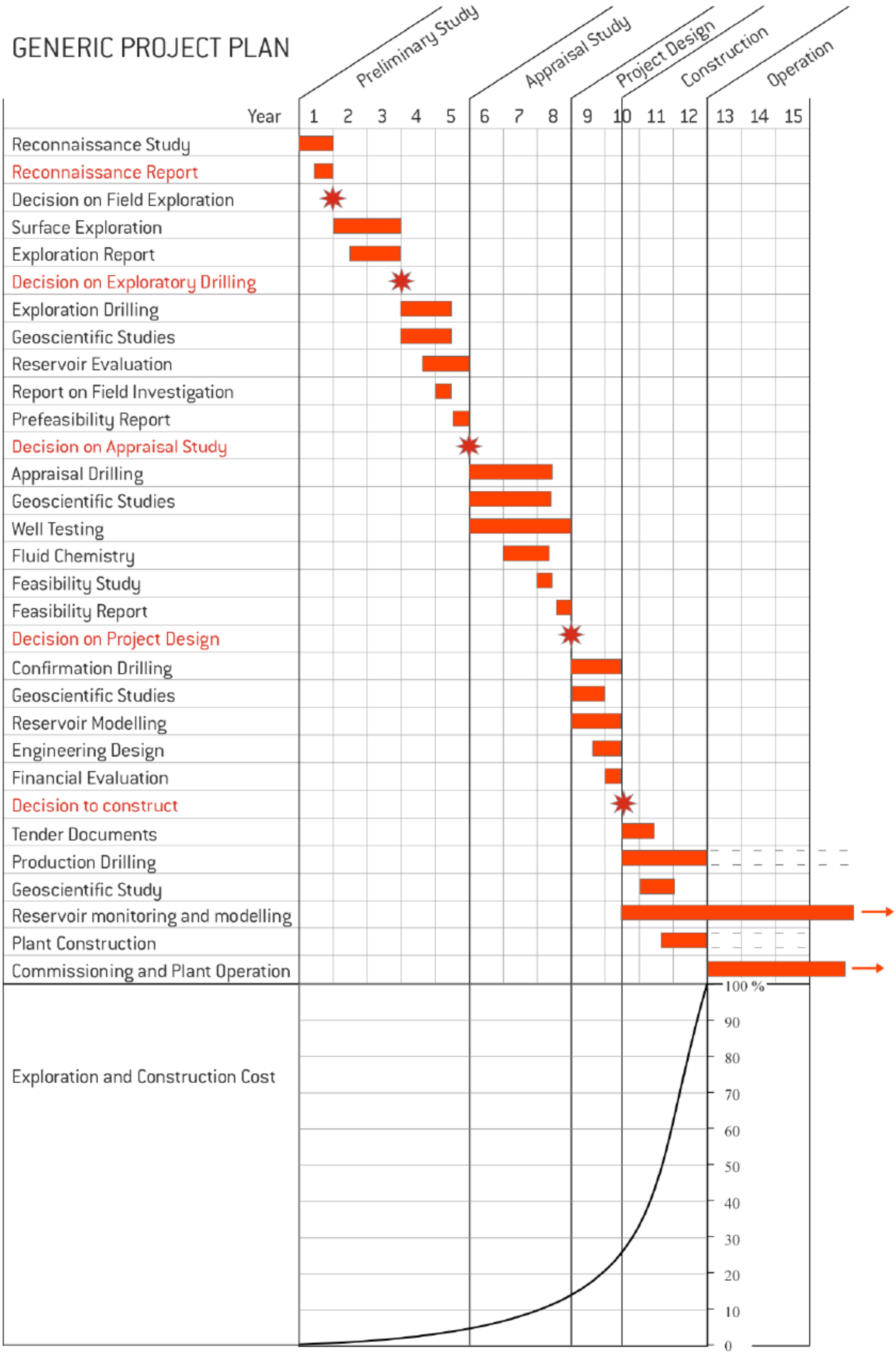

FIGURE 4: Generic project plan for phases of geothermal development proposed in Iceland in 1982 (Steingrímsson et al., 2005)

TABLE 1: Table indicating the contribution of different types of geothermal research to targeting of different types of geothermal wells. The symbol **P** indicates a primary research method most often applied while **S** indicates a secondary method, which is not applied in all cases

Research	Exploration wells	Production wells	Make-up and step-out wells	Reinjection wells
Geological mapping	**P**	**P**	**P**	**P**
Mapping of faults/fractures	**P**	**P**	**P**	**P**
Surface manifestation mapping	**P**	**P**	**P**	
Ground temperature surveying	**S**	**S**	**S**	
Chemical-content/isotope surveying	**P**	**P**	**P**	
Aerial photos and satellite imagery	**S**	**S**	**S**	**S**
Remote sensing (e.g. infrared)	**S**	**S**	**S**	
Hydrogeological studies	**S**	**S**	**S**	**S**
Temperature gradient wells	**S**	**S**	**S**	**P**
Magnetic mapping	**S**	**S**	**S**	**S**
Gravity mapping	**S**	**S**	**S**	**S**
Resistivity surveying	**P**	**P**	**P**	**P**
Seismic studies	**S**	**S**	**S**	**S**
Borehole lithology		**P**	**P**	**P**
Feed-zone inventory		**P**	**P**	**P**
Temperature/pressure logging		**P**	**P**	**P**
Borehole fracture imaging		**S**	**S**	**S**
Well testing		**P**	**P**	**P**
Discharge testing		**P**	**P**	
Temperature/pressure monitoring		**P**	**P**	
Chemical monitoring		**P**	**P**	
Gravity monitoring		**S**	**S**	**S**
Micro-seismic monitoring		**S**	**S**	**S**
Tracer testing				**P**
Reservoir modelling		**S**	**P**	**P**

The table above demonstrates that the siting of the first wells in a geothermal field, i.e. the exploration wells, depends mostly on surface exploration data, with geological (e.g. faults/fractures) and geophysical (e.g. resistivity) data being most important. Formation temperature is e.g. unknown at such an early stage. Once the first wells have been drilled subsurface data come into play, increasing drastically the knowledge on and understanding of a geothermal system. Most important are lithological and feed-zone data, temperature-logging data and well-test data. Some of the logging and reservoir engineering data collection in geothermal wells is described in a separate paper at this short course. Thus target definition for production wells and other wells relies more and more on subsurface data as development progresses (Table 1).

Once the drilling of a geothermal well has been completed the results, or data collected from the well, should be compared with the interpretation of surface exploration data, i.e. what was expected. Based on this comparison the conceptual model of the geothermal system should be updated, to ensure that the next well siting will be based on the most up-to-date information and understanding.

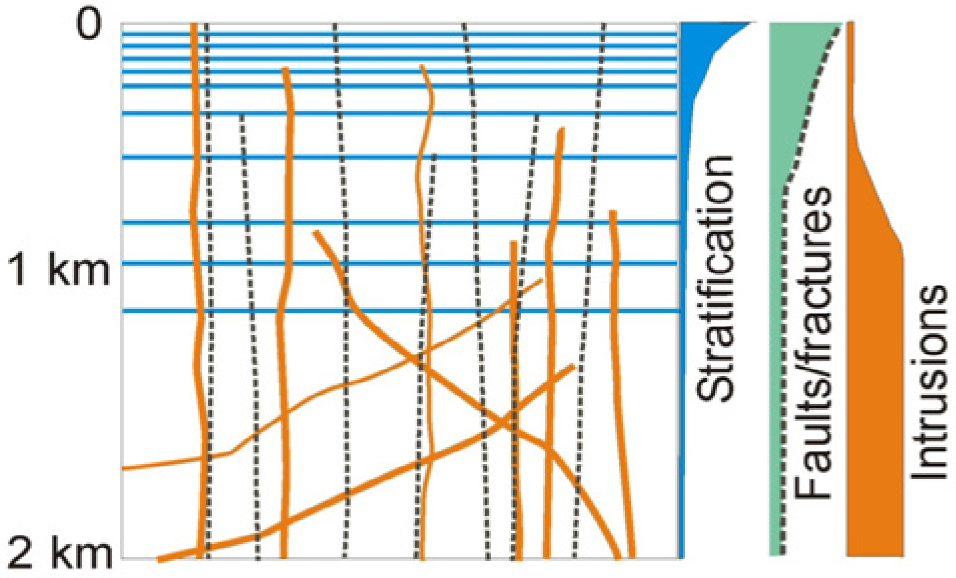

FIGURE 5: A schematic figure showing how the importance of permeability associated with different geological structures varies typically with depth in volcanic geothermal systems in Iceland. The best permeability is often found at the intersection of two such structures

Figure 6 shows an example of how both surface exploration data and well data are used to define the drilling target for a step-out well at Þeistareykir geothermal field in NE-Iceland, but the resistivity model is based on a 3D inversion of the TEM-MT survey, while the temperature and alteration model is projected from well data.

Figure 7 shows another example of how multiple data sets from surface and subsurface exploration are combined and compared with 3D visualization. These models are forming the foundation for the conceptual model of the field and for well siting. This figure is highlighting data, which are providing information about the extent of the geothermal reservoir and distribution of temperature and permeability.

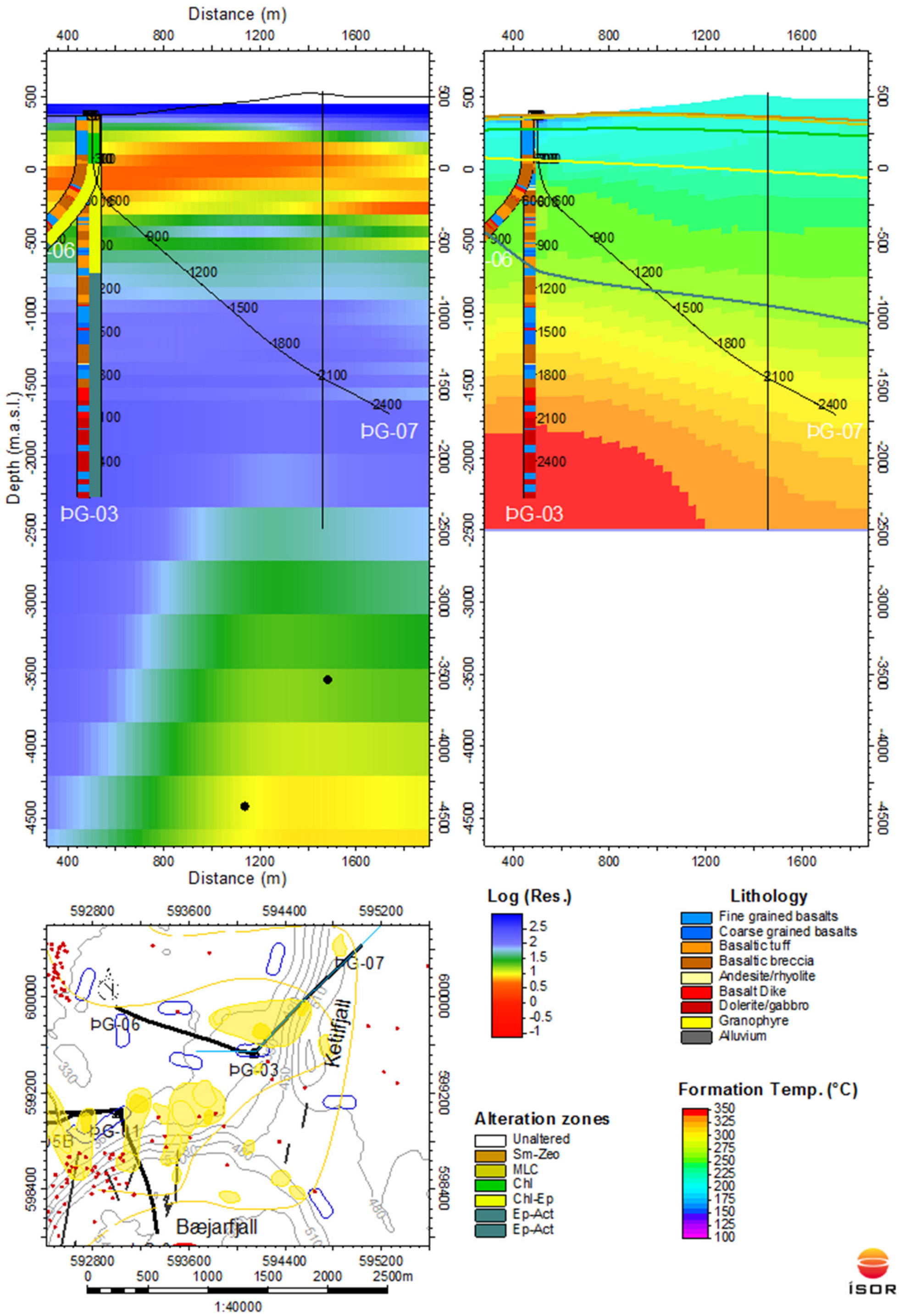

FIGURE 6: Example of projected target visualization for a step-out well at Þeistareykir geothermal field in NE-Iceland. Well trajectory is compared with 3D resistivity model (left) and to the right is comparison with temperature and alteration model. The black vertical line defines the Ketilfjall fissure, which the well is projected to intersect at ~2100 m depth. Lithology is plotted along well trajectory of well ÞG-03. The uncertainty of the temperature model is high at more than 1000 m from previously drilled wells (ÞG-03)

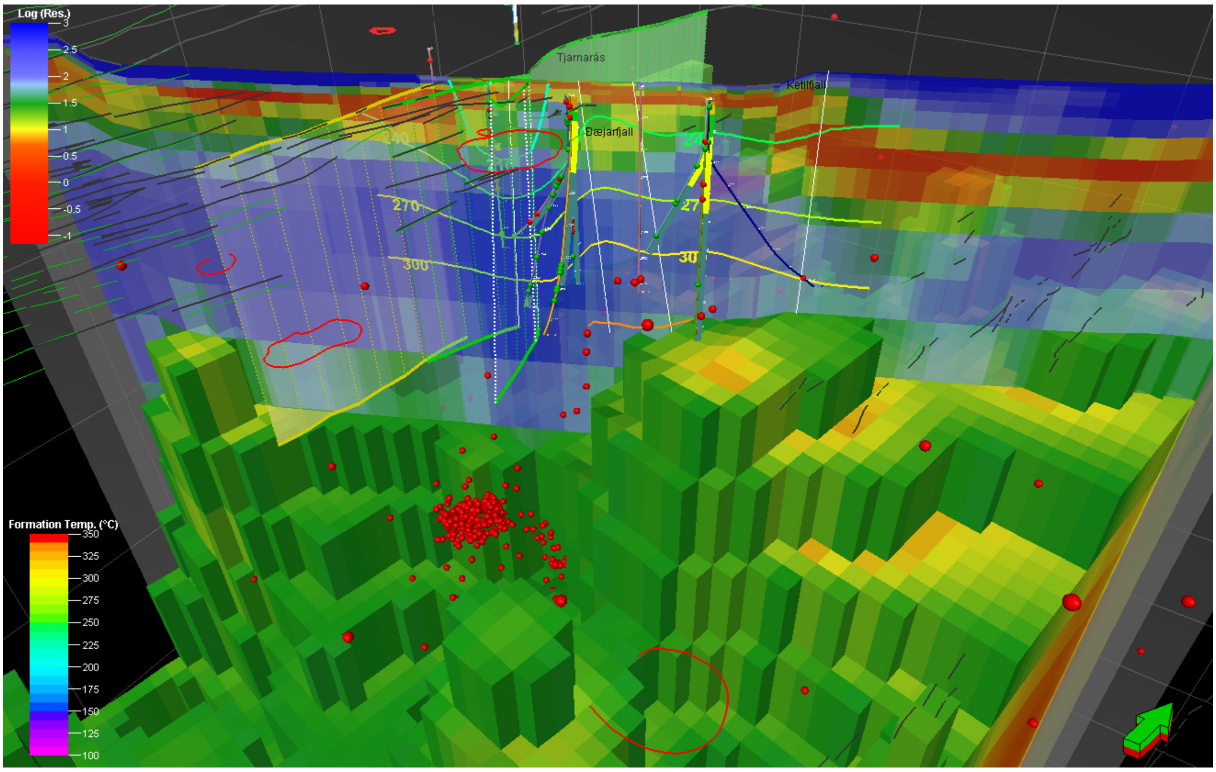

FIGURE 7: 3D visualization of Þeistareykir geothermal field combining data of resistivity, temperature, seismicity and alteration. Yellow-green 3D block model in the lower part of the figure is showing the structure if the deep conductive layer based on TEM-MT survey. On the NE-SW cross section is also projected the resistivity model, where yellow-red colours are highlighting the conductive cap above the geothermal reservoir, while the temperature model is projected as isotherm lines on the cross section. Alteration zoning is plotted along the well trajectories (green – chlorite zone; yellow: chlorite-epidote zone; blue-green: epidote-actinolite zone). The 240°C isotherm and the top of the chl-ep zone correlated with the lower part of the low resistive cap of the geothermal reservoir. Red dots indicate earthquake locations covering the time interval from 1993-2011. The Tjarnarás fault plane is marked with a light-green plane in the upper part of the figure. North arrow is in the lower right corner

In the past geothermal wells were mostly vertical and the same usually also applies to the first wells (exploration wells) in fields where development is just starting. Recently directional wells (Thórhallsson, 2012c) have become dominant in many geothermal fields in the world. The principal benefits (environmental and economic) are that fewer drill-pads and less surface piping are needed. Directional drilling also enables reaching drilling targets that are not easily accessible by vertical wells. There have been claims that directional wells are more productive in certain geological situations, in particular when near vertical fractures/faults are dominant. This has not been substantiated, however.

It should be noted that the success rate for geothermal drilling is dependent on the geothermal system involved. This is because of their individual nature and the fact that some systems are not as easily understood as others. The drilling success rate also depends on the speed of development of a given project. If the speed is too high the necessary knowledge doesn't accumulate rapidly enough (because of insufficient time for research and conceptual model updating) and the drilling is more risky.

Finally it should be mentioned that targets for reinjection wells are not fully comparable to the targets of production wells. This applies in particular to temperature conditions as reinjection is not always applied directly in the hottest parts of a geothermal reservoir or system (Axelsson, 2012). In fact reinjection sectors selected are quite variable from one area to another, as already mentioned, with the reinjection targets therefore being quite different. Sufficient permeability is, of course, also a necessary requirement for successful reinjection wells and therefore all the research methods applied to evaluate permeability are also required for reinjection wells (Table 1). A research method particular to reinjection studies is tracer testing, which is used to study connections between reinjection and production wells and to estimate the danger of production well cooling because of reinjection (for more details see Axelsson, 2012).

5. CONCLUSIONS AND RECOMMENDATIONS

This paper has discussed targeting and siting of the different types of geothermal wells with particular emphasis on how all available information and data should be used for this purpose. This is best achieved through a comprehensive and up-to-date conceptual model of the geothermal system in question. Cooperation of the different disciplines involved in geothermal research and development is of particular importance here. This approach has obvious benefits beyond an approach where each discipline develops their own ideas independent from other disciplines. The principal geothermal drilling targets are structures, or volumes, of adequate permeability and sufficiently high temperature to yield productive wells.

The nature of the permeability depends on the type of geothermal system involved, the geology of the system (formations, faults/fractures, etc.) and in-situ stress conditions. In the early stages of development knowledge on which to base well siting is limited but when development continues (with drilling) the necessary knowledge increases. Yet it's really only when large-scale utilization has been on-going for quite some time, with associated monitoring, that fairly comprehensive knowledge and understanding on the nature and structure of a system has been achieved.

The research methods applied in defining geothermal targets have been classified as primary or secondary depending on whether they are used in most geothermal development programs worldwide or only in some cases. Yet some of the methods currently classified as secondary are quite valuable when pertinent, and may add significantly to information needed for geothermal well targeting. This applies e.g. to passive seismic analysis; including event location (depth distribution), focal mechanism and S-wave attenuation analysis, which may add greatly to the understanding of the deeper parts of geothermal systems, in particular those volcanic in nature.

The principal benefits (environmental and economic) of directional drilling, compared to vertical drilling, are that fewer drill-pads and less surface piping are needed. Directional drilling also enables reaching drilling targets that are not easily accessible by vertical wells. It should be noted that, in addition to drastic differences between individual systems, drilling success also depends on the speed of development of a given project. If the speed is too high the necessary knowledge doesn't accumulate rapidly enough (because of insufficient time for research and conceptual model updating) and the drilling becomes more risky.

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LaGeo S.A. de C.V.

VOLUMETRIC RESOURCE ASSESSMENT

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ABSTRACT

Geothermal resource assessment is the estimation of the amount of thermal energy that can be extracted from a geothermal reservoir and used economically for a period of time, usually several decades. Various methods have been developed for this purpose. At early stages of geothermal development, when available data are limited, relatively simple methods are used in assessing the reservoirs. But as more information are gathered on the reservoir parameters and experience is gained in producing energy from the reservoir, sophisticated numerical computer models are used to simulate the geothermal reservoir in the natural state and the response to utilization which eventually will determine the generating potential of the reservoir.

The main focus in this paper is on the volumetric method (stored heat calculations) and the key elements that constitute a thorough evaluation of a geothermal resource. Calculation of the geothermal energy reserves based on the range of values of the various reservoir parameters can be carried out using Monte Carlo simulation. It applies a probabilistic method of evaluating reserves or resources that captures uncertainty. Given the complexity and heterogeneity of the geological formations of most geothermal reservoirs, this method is preferred as opposed to the usual deterministic approach which assumes a single value for each parameter to represent the whole reservoir. Instead of assigning a "fixed" value to a reservoir parameter, numbers within the range of the distribution model are randomly selected and drawn for each cycle of calculation over a thousand iterations.

1. INTRODUCTION

Geothermal resource evaluation (*resource assessment*) is a process of evaluating surface discharge and downhole data, and integrating it with other geoscientific information obtained from geological, geophysical and geochemical measurements. The main focus of geothermal resource evaluation or resource assessment is to confirm that there exists a geothermal resource that could be exploited at a certain capacity for a certain period with well defined fluid characteristics and resource management strategies to ensure production sustainability over a long term period. Resource evaluation serves as a mechanism to verify if the project may be carried out from a technical standpoint by 1) defining the technical characteristics, selecting the best conditions after a technical and economical comparison of various development alternatives and 2) in choosing the type of plant and equipment design that would define their functional characteristics, their cost and implementation schedule and 3) assessing costs and benefits, economic and financial comparisons out of various alternatives as part of an overall project technical and financial feasibility studies.

An assessment of geothermal resources can be made during the reconnaissance and exploratory stage prior to well drilling; typically dealing with the extent and characteristics of the thermal surface discharges and manifestations, geophysical boundary anomaly, and the geological setting and subsurface temperatures inferred from geothermometers. The main feature of this evaluation is the presentation of a conceptual or exploration model that pinpoints the possible heat source and host of the geothermal reservoir. The results of this study serve as the basis for drilling shallow and deep exploratory wells to confirm the existence of a resource.

A discovery well drilled during the exploratory stage provides the basis for refining the preliminary conceptual model. By incorporating the results of drilling and well measurements and testing, reserves estimation needed in establishing the size of the reservoir and numerical modelling used in forecasting the future performance of the field can be conducted. Moreover, when planning to expand the capacity of an operating field, a resource assessment will describe the overall production history to show if additional reserves may be available to supply steam to the power plant.

This paper discusses the main elements of a geothermal resource assessment typically applied at early stages of geothermal development in the Philippines and Iceland. This mainly involves the volumetric method (stored heat calculations) with Monte Carlo simulation technique, which is named after the city of Monte Carlo in Monaco, where the primary attractions are casinos that play games of chance like roulette wheels, slot machines, dice, cards and others. It is a technique that uses a random number generator to produce and extract an uncertain variable within a distribution model for calculation in a given formula or correlation. Monte Carlo simulation became popular with the advent and power of computers; because the simulations are too tedious to do repeatedly.

The numerical simulation modelling is the preferred technique to determine the generating potential of the geothermal reservoir, when the exploration reaches the feasibility stage and through later developments and operation of the geothermal reservoir. The numerical reservoir modelling will be discussed in another paper at this short course.

2. THE GEOTHERMAL RESOURCE

2.1 Location

With a portfolio of various geothermal prospects, investors consider the location of a geothermal prospect as a primary factor in their project selection. Projects for exploration and development are ranked by looking first at the various risks associated with the resource characteristics or quality of fluids, size, geological risks or hazards and location with respect to the load centre or market. Given the same resource risks and characteristics, prospects that are close to the load centres and transmission grid are more likely to be chosen by investors for exploration and development. It also favours a project if the government prioritizes the development of infrastructures in the area where the resource is located. Prospects located in national parks and requiring special legislations before permits are issued for development are more likely to be at the end of the wish list of investors.

2.2 Stage 1 Surface Exploration Program

A geothermal surface exploration program is usually implemented in three phases starting from (1) a due diligence work which is carried out by thoroughly reviewing available information related to previous investigations of hot springs, fumaroles, silica mounds, solfataras and alteration zones as well as air-photo analyses and remote sensing studies, (2) field reconnaissance surveys including primarily the acquisition of geology and geochemistry data with a glimpse of what is expected on the environmental aspects of the area and 3) detailed exploration surveys consisting of geological mapping, geochemical sampling and geophysical measurements that can be used to delineate a potential geothermal reservoir and assist in the designation of possible exploration drilling targets (Richter et al., 2010).

In the Philippines, due diligence work is carried out through the regional identification of a prospect by identifying regional targets based on the association of most high temperature geothermal fields in the Philippines with the Philippine Fault; an active, left-lateral, strike slip fault dotted with Pliocene-Quaternary volcanoes, that forms a discontinuous belt from Northern Luzon to Mindanao. The Philippines has about 71 known surface thermal manifestations associated with decadent volcanism (Alcaraz et al., 1976). These are distributed in 25 volcanic centres as hot spouts, mud pools, clear boiling pools, geysers, and hot or warm altered grounds.

The results of a due diligence study rank the various geothermal prospects that have shown potential for exploration and development by carefully looking into the intensity and significance of the different thermal manifestations observed in the area. Immensely hot and widespread occurrences of thermal manifestations indicate a greater potential for a high temperature and large size reservoir. Acidic fluids are less preferred than the more benign fluids in view of the constraints imposed on handling the corrosion effects on casings and pipelines as well as the associated reservoir management problems during exploitation. The ranking of the field based on such geologic and geochemical parameters are then produced for selection and prioritization in each of the company's future project portfolios. This technique resulted in achieving a very high success ratio in the Philippines, by being able to discover high temperatures fields with exception of some areas that are lacking in permeability and those that have exhibited acid and magmatic fluids.

The field reconnaissance surveys will confirm what has been reported and seen from the areal photos and satellite images. Geologists and geochemists collect both rock and fluid samples, map out major surface manifestations, and then document all the observations that are significant to all the thermal areas for further investigations. The report should show the probable areal boundaries by which the detailed geological, geochemical and geophysical surveys will be conducted. It is on the basis of the results of the reconnaissance surveys that a budget is prepared to cover the expected cost of the detailed exploration surveys.

Following the identification of a more potentially resourceful area, detailed surface geological mapping, geochemical sampling and geophysical measurements are conducted. The results of the multi-disciplinary works are then integrated to draw out a hydrological model of the system, where the postulated upflow and outflow areas are described.

Previously the Philippines and Iceland have been very successful in using resistivity measurements (Schlumberger and later TEM) in discovering some of the operating geothermal fields in the countries today. But it can't be denied that more exploratory wells had to be drilled subsequently than today before the main sweet spots in those fields were identified. Recent application of Magnetotellurics (MT), which are found to have been able to predict more precisely the more drillable productive sections of the reservoir in Iceland and many other geothermal countries of the world, still have to make its mark in the Philippines, given the complex geological setting of the remaining areas that are being offered for concessions. Previously 1d interpretation of the data was carried out but with increased computer capacities joint three dimensional interpretation of TEM and MT data is routinely carried revealing more details in the resistivity structure of the geothermal reservoir than is possible with one dimensional interpretation.

With the construction of a conceptual or exploration model of the field from the results of the detailed surface exploration techniques, a pre-feasibility report is also prepared which similarly touches on preliminary cost estimation, financial analyses, market studies and environmental impact review.

2.3 Stage 2 Exploration Drilling Program

In view of the large drilling cost (of 3-5 million dollars per well) and the associated risk in hitting a good production well, it is at this stage when the need for a well-defined financial risk management strategy and instruments becomes extremely important. In the oil and gas industry, farm-in agreements are usually resorted to where additional investors or consortiums partners are invited to share in the cost of drilling. Financial institutions and other companies are willing to advance the cost of drilling in favour of a carbon trade mechanism.

The local geothermal industry in the Philippines and Iceland apply similar development strategy. The Philippines has explored 22 distinct high temperature resources, to an advanced stage and the exploration in Iceland includes detailed surface exploration and drilling of some 10 geothermal areas. Their development history has a general trend. Upon the integration of the multi-disciplinary exploration data from geology, geochemistry and geophysics for a selected area, a preliminary conceptual model is proposed. Drilling of 2-3 deep exploration wells ensues to validate the hydrological model and to confirm the existence of a geothermal system. Potential targets are identified within the closure of a resistivity or electrical sounding anomaly based on their chances of striking the upflow zones, penetrating permeable structures at depths. The first well is usually targeted towards the main upflow zone, where the chance of drilling a discovery well is high. The other two wells are drilled to probe for the lateral extension of the area; usually to block a well field equivalent to at least 5 km^2, sufficient enough for committing to a 50-100 MW generation potential. Once the existence of a geothermal system is confirmed after preliminary drilling, a resource assessment follows to determine the resource power potential. If the quality of the fluids is such that it could be used for commercial production, a volumetric estimate of the reserves is used for initially committing the size of the power station. The development of Mindanao I in the Philippines typified this approach where the results of the first two exploratory wells were used as a basis for building the 2 x 52 MW power station (Figure 1).

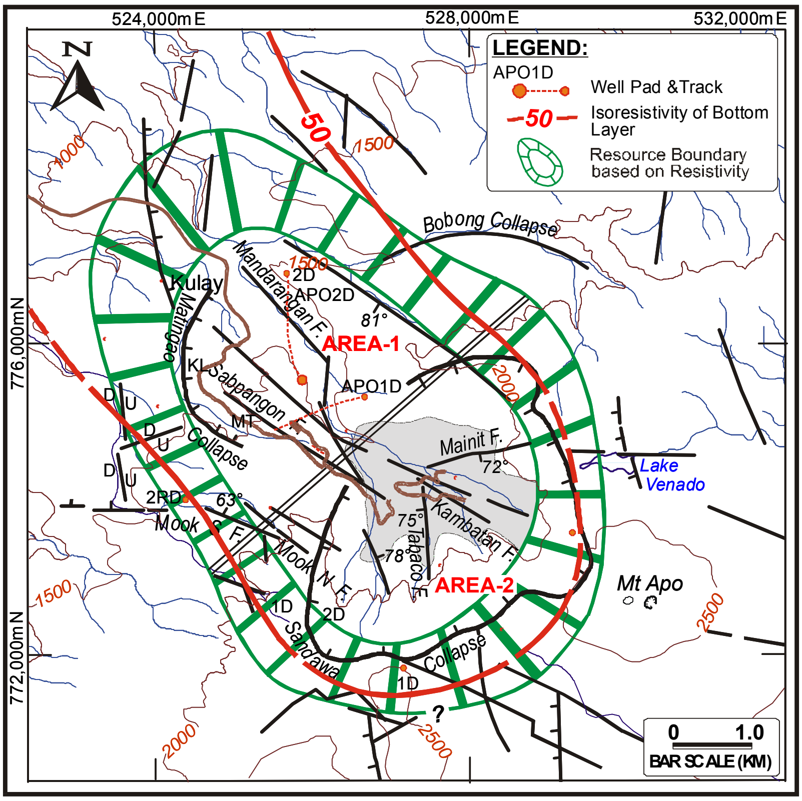

FIGURE 1: Exploratory well location map showing provisional resource boundary for Mindanao geothermal field. (Modified from Delfin et al, 1992)

Targeting the first well is the most difficult decision to make in a new project as its results may affect the final outcome of the project, especially if the results are not encouraging. If this happens, the decision to pursue drilling of the second well hinges fully on whether additional targets differed significantly and/or is entirely different on the first target. The third well is usually drilled only after the second well gives promise or provides a new perspective on the understanding of the prospect. Otherwise, it is cancelled.

2.4 Geology of the Exploration Wells

The subsurface geologic data indicates the equilibrium temperatures of minerals penetrated by the well from the top of the reservoir down to the bottom of the well. Obvious from the results are the alteration minerals commonly found in geothermal systems associated with a high temperature resource. Typical of these minerals are the elite, smectite and epidote. When these temperatures are compared with measured downhole temperatures, the relationship of the alteration minerals with respect to the equilibrium state and maturity of the system is established. If the alteration minerals indicate temperatures much higher than measured temperatures, a relict geothermal system or waning geothermal resource exists. Cooling of the fluids might have also taken place. Mineral assemblages like alunite are usually associated with acidic fluids and therefore their detection during drilling gives warning that the zone by which it was detected may have to be isolated. Other clay minerals are used during drilling to predict temperatures at depth like those of kaolinite, smectite and illite to be in the range of temperatures < 230°C; smectite, illite and quartz with fewer amounts of calcite and chlorite to be in the range of temperature >230°C; epidote, albite, calcite and anhydrite to indicate moderate temperatures of 200-300°C and potassic minerals near hot fluids to be indicative of >300°C of magmatic and high salinity fluids.

3. THERMAL ENERGY CALCULATION

The volumetric method refers to the calculation of thermal energy in- the rock and the fluid which could be extracted based on specified reservoir volume, reservoir temperature, and reference or final temperature. This method is patterned from the work applied by the USGS to the Assessment of Geothermal Resources of the United States (Muffler, 1978). In their work, the final or reference temperature is based on the ambient temperature, following the exhaust pressures of the turbines (for electrical generation). Many, however, choose a reference temperature equivalent to the minimum or abandonment temperature of the geothermal fluids for the intended utilization of the geothermal reservoir. For space heating the abandonment temperature is typically 30-40°C but for electricity generation the reference temperature is usually ~180°C (the separation temperature) for conventional power plants but as low as 130°C for binary plants. . It is important to keep in mind, however, that the efficiency used for the particular energy generation process be based on the same reference temperature, whatever reference temperature is selected.

The equation used in calculating the thermal energy for a liquid dominated reservoir is as follows:

$$Q_T = Q_r + Q_w \tag{1}$$

where

$$Q_r = A \cdot h \cdot [\rho_r \cdot C_r \cdot (1 - \emptyset) \cdot (T_i - T_f)] \tag{2}$$

and

$$Q_w = A \cdot h \cdot [\rho_w \cdot C_w \cdot \emptyset \cdot (T_i - T_f)] \tag{3}$$

The question to be raised is: What if the reservoir has a two-phase zone existing at the top of the liquid zone? Theoretically, it is prudent to calculate the heat component of both the liquid and the two-phase or steam dominated zone of the reservoir. However, a comparison made by Sanyal and Sarmiento (2007) indicates that if merely water were to be produced from the reservoir, only 3.9 percent is contained in the fluids; whereas, if merely steam were to be produced from the reservoir, only 9.6 percent is contained in the fluids. If both water and steam were produced from the reservoir, the heat content in the fluids is somewhere between 3.9 and 9.6 percent. Conclusively, all the fluids are in the rock and it doesn't matter whether one distinguishes the stored heat in water and steam independently.

This approach is illustrated by the following set of equations to separately account for the liquid and steam components in the reservoir:

$$Q_T = Q_r + Q_s + Q_w \tag{4}$$

where

$$Q_r = A \cdot h \cdot [\rho_r \cdot C_r \cdot (1 - \emptyset) \cdot (T_i - T_f)] \tag{2}$$

$$Q_s = A \cdot h \cdot [\rho_{si} \cdot \emptyset \cdot (1 - S_w) \cdot (H_{si} - H_{wf})] \tag{5}$$

$$Q_w = A \cdot h \cdot [\rho_{wi} \cdot \emptyset \cdot S_w \cdot (H_{wi} - H_{wf})] \tag{6}$$

and the parameters are as follows:

Q_T = Total thermal energy (kJ/kg);
Q_r = Heat in rock (kJ/kg);
Q_s = Heat in steam (kJ/kg);
Q_w = Heat in water (kJ/kg);
A = Area of the reservoir (m^2);
h = Average thickness of the reservoir (m);
Cr = Specific heat of rock at reservoir condition (kJ/kg°K);
C_l = Specific heat of liquid at reservoir condition (kJ/kg°K);
C_s = Specific heat of steam at reservoir condition (kJ/kg°K).
Ø = Porosity;
T_i = Average temperature of the reservoir (°C);
T_f = Final or abandonment temperature (°C);
S_w = Water saturation;
ρ_{si} = Steam density at reservoir temperature (kg/m^3);
ρ_{wi} = Water density at reservoir temperature (kg/m^3);
H_{si}, H_{wi} = steam and water enthalpies at reservoir temperature (kJ/kg); and
H_{wf} = Final water enthalpy at abandonment temperature (kJ/kg).

4. POWER PLANT SIZING

The above calculations only provide for the total thermal energy in place in the reservoir. To size the power plant that could be supported by the resource, the following equation is further introduced.

$$P = \frac{(Q_T \cdot R_f \cdot C_e)}{P_f \cdot t} \tag{7}$$

where P = Power potential (MW_e);
R_f = Recovery factor;
C_e = Conversion efficiency;
P_f = Plant factor; and
t = Time in years (economic life):

4.1 Recovery factor

Recovery factor refers to the fraction of the stored heat in the reservoir that could be extracted to the surface. It is dependent on the fraction of the reservoir that is considered permeable and on the efficiency by which heat could be swept from these permeable channels.

4.2 Conversion efficiency

The conversion efficiency takes into account the conversion of the recoverable thermal energy into electricity. More accurately the conversion can be estimated in two stages, first the conversion of the thermal energy into mechanical energy and later the conversion of the mechanical energy into electrical energy. This is not considered necessary, in view of all the uncertainties involved in the volumetric assessment method, so applying a single thermal-mechanical-electrical efficiency is considered sufficiently accurate.

4.3 Economic life

The economic life of the project is the period it takes the whole investment to be recovered within its target internal rate of return. This is usually 25-30 years.

4.4 Plant factor

The plant factor refers to the plant availability throughout the year taking into consideration the period when the plant is scheduled for maintenance, or whether the plant is operated as a base-load or peaking plant. The good performance of many geothermal plants around the world places the availability factor to be from 90-97%.

5. GUIDELINES FOR THE DETERMINATION OF RESERVOIR PARAMETERS

Recent developments in the geothermal industry require the establishment of guidelines on how reserves estimation is to be approached and reported in corporate annual reporting or financial statements. Sanyal and Sarmiento (2005) had proposed three categories for booking of reserves: proven, probable and possible; which are more appropriately estimated by volumetric methods. The reserves could be expressed in kW-h and/or barrels of fuel oil equivalent (BFOE). Conversion into MW unit should only be done when sizing up a power station for a period of time. Recently, Clothworthy et al. (2006), proposed to develop an agreed methodology for defining the reserves in order to increase market confidence in the industry and deter developers and consultants from quoting any figures they choose. The same categories of reserves are indicated except that the word inferred was used instead of the possible reserves. Lawless et al. (2010) is similarly proposing guidelines on methodologies and other consideration when preparing reserves estimation in response to the requirement of investment companies, especially, those listed in the stock exchanges.

5.1 Definitions

The need for an industry standard is now imminent following the above developments, to create consistency in declaring the estimated reserves for a given project. Sanyal and Sarmiento (2005) uses the result of Monte Carlo simulation to determine the proven, probable and possible or inferred reserves based on the resulting percentiles obtained from the cumulative frequency or the probability density function. The percentile value indicates the value of probability that the quantities of reserves to be recovered will actually equal or exceed. The above and all other definitions in this paper conform with SPE (2001), where the *proven* reserves will have a P90 (90 percentile) probability, P50 for the *proven*

+ *probable* reserves and P10 for the *proven* + *probable* + *possible* reserves. The histogram of geothermal reserves calculated by Monte Carlo simulation is often highly skewed; hence, the *proven* + *probable* is better represented by the *most likely* or the *mode* instead of the P50.

5.2 Resource

Resource is the energy which can be extracted economically and legally at some specified time in the future (less than a hundred years).

5.3 Reserves

Reserves are defined as quantities of thermal energy that are anticipated to be recovered from known reservoirs from a given date forward. A reserve is the part of the resources, which can be extracted economically and legally at present and that is known and characterized by drilling or by geochemical, geophysical and geological evidence (Muffler and Cataldi, 1978; Dickson and Fanelli, 2002).

5.4 Proven

Proven reserves are quantities of heat that can be estimated with reasonable certainty based on geoscientific and engineering data to be commercially recoverable from the present to the future, from known reservoirs under current economic conditions and operating methods and government regulation. The definition by Clotworthy et al (2006) and Lawless et al. (2010) give more specific descriptions, stating that a proven reserve is the portion of the resource sampled by wells that demonstrate reservoir conditions and substantial deliverability of fluids from the reservoir.

5.5 Probable

Probable reserves are unproven reserves which are most likely recoverable, but are less reliably defined than the proven reserves but with sufficient indicators of reservoir temperatures from nearby wells or from geothermometers on natural surface discharges to characterize resource temperature and chemistry.

5.6 Possible

Possible reserves have slighter chance of recovery than the probable reserves but have sound basis from surface exploration, such as springs, fumaroles, resistivity anomalies, etc., to declare that a reservoir may exist. Clotworthy et al. (2006) adopted the *inferred* resources from what could cover possible reserves based on McKelvey box as adopted by SPE (2001). Based on their graphic illustration, the probable reserve encompasses what could be categorized as only possible reserves in the Philippines (Figure 2). From *probable* to *possible* there is an increasing geoscientific and economic uncertainty whereas *inferred* connotes further geoscientific uncertainty only.

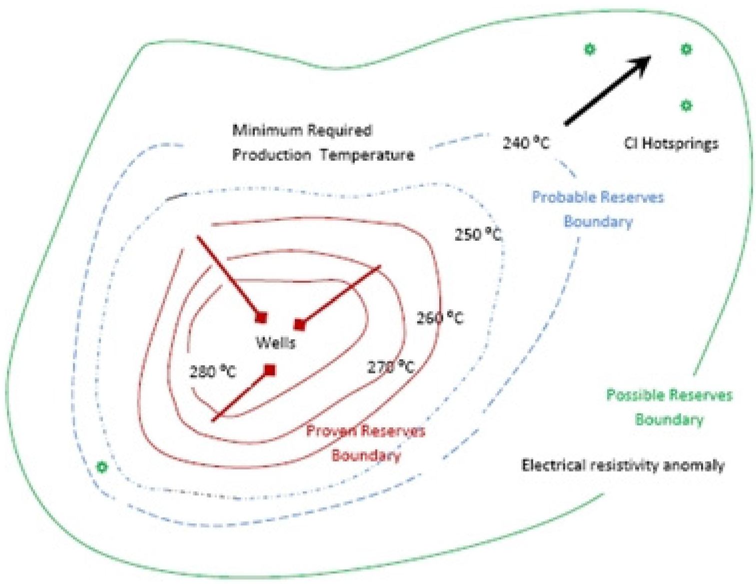

FIGURE 2: Illustration of the boundaries used in differentiating the three categories of reserves

The following guidelines or set of criteria are followed in the resource assessment and reserves estimation in the Philippines.

6. UNCERTAINTY DISTRIBUTION

The accuracy of the methods used in geothermal reserves estimation depends on the type, amount, and quality of geoscientific and engineering data, which are also dependent on the stage of development and maturity of a given field. Generally, the accuracy increases as the field is drilled with more wells and more production data become available. Volumetric estimation is most commonly applied during the early stage of field development to justify drilling and commitment for a specified power plant size. This method is better applied during the early stage than numerical modelling which requires significant number of wells and production history to be considered reliable. To be used for companies' annual reporting and to enhance corporate assets for valuation, booking of geothermal reserves could be performed during the maturity of the field (Sanyal and Sarmiento, 2005). However, because of the limited data and uncertainty on the assumptions on reservoir parameters, some degree of cautiousness and conservatism are also inputted. This approach which takes into account the risk factor in the decision making can be quantified with reasonable approximation using Monte Carlo Simulation.

Unlike a *deterministic* approach, where a single value representing a best guess value is used, the *probabilisti*c method of calculation is considered to account for the uncertainty on many variables in geothermal reserves estimation. As seen from Table 1, a range of possible reserves estimates could be obtained depending on the assumptions included in the calculation. In general, the proven reserves refer to the minimum, the probable reserves as the most likely or intermediate, and the possible or inferred reserves as the maximum. The Monte Carlo simulation performs the calculation and determines the estimate based frequency distribution of the random variables, which are dependent on the number of times a value is extracted from the uncertainty models of the input parameters.

The area and the thickness of the reservoir are usually assigned the triangular distribution because these parameters are obtained directly from drilling and well measurements. There is a good approximation of the resource area based on the temperature contours and electrical resistivity measurements; while drilling depths and indication of permeability and temperature are directly measured from the well. The deepest wells in Iceland are drilled to 3 km depth and even though the best permeability is found at 1 to 2 km depth good permeability has been encounter down to 2.5 km. There has been good evidence from wells currently drilled that permeability still exists at depths below 3,400 meters in the Philippines, (Golla et al, 2006) and down to 4000 meters in Larderello (Capetti and Cepatelli, 2005; Capetti, 2006) which could justify an addition of 500 meters beyond currently drilling depth range of 2500-3000 meters. The successful drilling in Tanawon located at the southernmost edge of Bacman proves a point that geothermal resource may really extend within or beyond the fence delineated by a geophysical anomaly, i.e., Schlumberger resistivity anomaly. The distribution model for these two parameters could be skewed appropriately depending on one's knowledge of the area.

Earlier volumetric estimation in the Philippines defined the lateral and vertical resource boundaries on the basis of the ability of many wells to flow unaided at minimum required temperature of 260°C. However, recent findings from the country's maturing geothermal fields indicate that this minimum temperature limit could be lowered to 240°C. Wells were recently observed to sustain commercial flow rate at this temperature, after the field had been produced sufficiently to cause boiling and expansion of two-phase zones in the reservoir. In New Zealand, wells are drilled to intersect temperatures of 180°C at shallower levels of the reservoir as the fluid has the ability to flow to the surface (Lawless, 2007b).

The porosity is usually assigned a log normal distribution following the observations of Cronquist (2001) quoting Arps and Roberts (1958) and Kaufmann (1963) giving that, in a given geologic setting, a log normal distribution is a reasonable approximation to the frequency distribution of field size, i.e., to the ultimate recoveries of oil or gas and other geological or engineering parameters like porosity, permeability, irreducible water saturation and net pay thickness. The mean and the standard deviation are however needed to be defined. All other parameters like fluid densities and specific heat are dependent on temperatures (Table 2).

The correlation between the recovery factor and porosity is shown in Figure 3, while the conversion efficiency and reservoir temperature correlation is shown in Figure 4.

TABLE 1: Guidelines followed in determining the various parameters for reserves estimation

Parameter	Proven	Probable	Possible/Inferred
Area	Defined by drilled wells with at least 500 meters beyond the drainage of the outermost wells bounded by an extrapolated production temperature of 240°C. Enclosed by good permeability and demonstrated commercial production from wells. Acidic blocks excluded until demonstrability for utilization is achieved.	Defined by wells with temperature contours that would extrapolate to 240°C to the edge of the field. Acidic or reinjection blocks earlier delineated could be included. Areas currently inaccessible because of limited rig capacity and restriction imposed within the boundaries of national parks. Areas with wells which could be enhanced by stimulation like acidizing and hydro-fracturing, by work-over of wells, other treatments or procedures which have been proven to be successful in the future. Areas with extensive surface manifestations where geothermometers indicate consistent or constant? temperatures >250°C.	Areas include those not yet drilled but enclosed by geophysical measurements like Schlumberger/TEM electrical resistivity and magneto-telluric surveys. Defined by areas with thermal surface manifestations, outflow zones, high postulated temperatures based on geothermometers
Thickness	Depth between the 180°C and the maximum drillable depth of the rig that has demonstrated commercial production. Maximum depth should have at least 240°C to warrant commercial output of the well.	Defined by demonstrated productivity in nearby areas or adjacent wells. Depth beyond the deepest well drilled in the area +500 meters provided projected temperatures reached at least 240°C at the bottom	Defined by demonstrated productivity in nearby areas or adjacent wells
Reservoir Temperature	Taken from direct measurement in production wells, supplemented by enthalpy and chemical geothermometers. Reservoir temperature should be at least 240°C to allow the well to self discharge	Extrapolated from temperature gradients and temperature distribution across the field or results of geothermometers using water, steam and gas from hot springs and fumaroles	Results of geothermometers using water, steam and gas from hot springs and fumaroles. Resistivity anomaly where high resistivity anomaly is seen blow conductive cap, indicating chlorite-epidote alteration at depth.
Base Temperature	Similar to the abandonment temperature, usually @ 180°C or at ambient temperature		

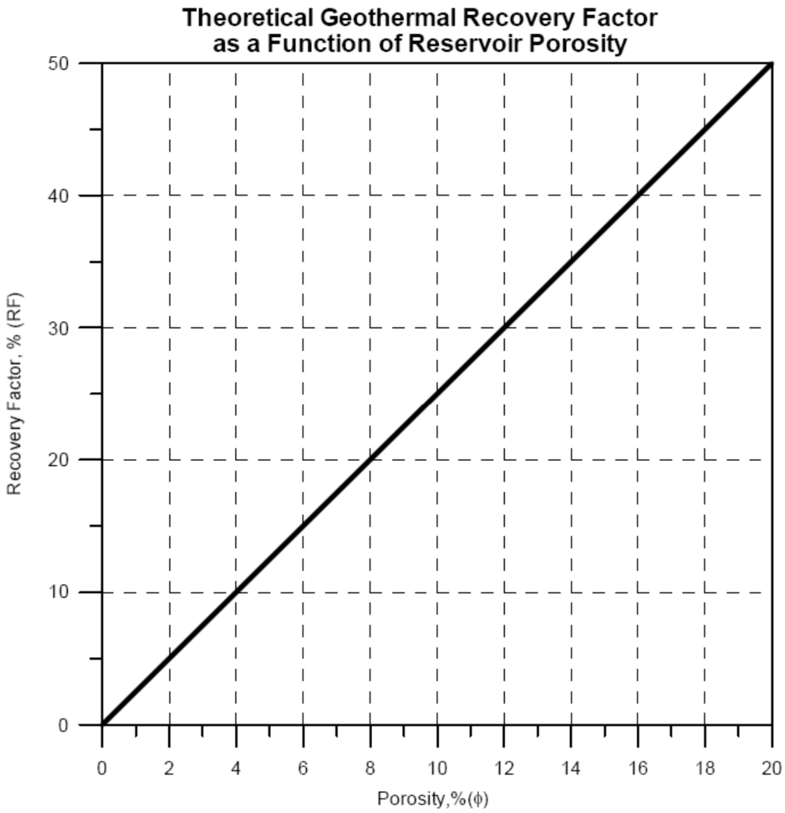

FIGURE 3: Correlation between recovery factor and porosity (After Muffler, 1978)

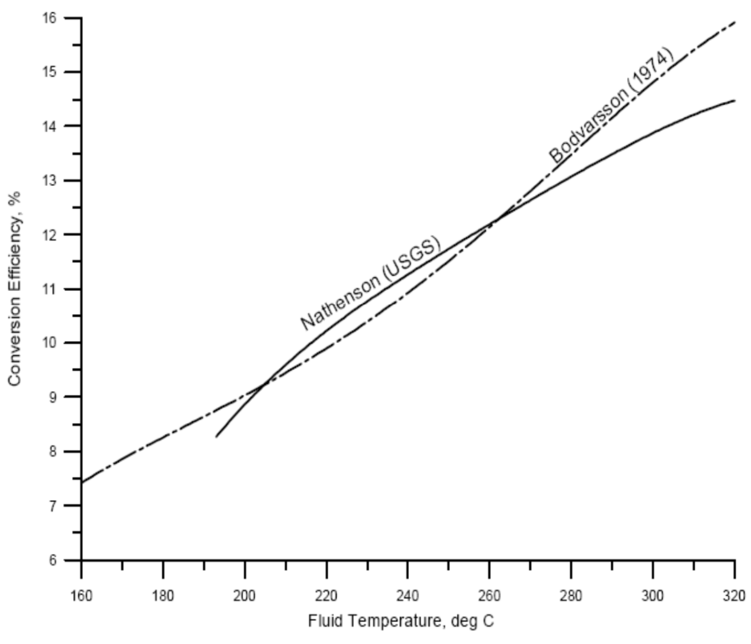

FIGURE 4: Correlation between thermal conversion efficiency and reservoir temperatures (From Nathenson, 1975 and Bodvarsson, 1974)

It has been practice to slice the reservoir into several layers to capture the variation in temperature, porosity, permeability and productivity. This full representation of the various properties of the entire field does not make the whole process more precise than when treating it as a single block in a Monte Carlo simulation, and is not necessary because all of the values in a given range for every parameter are inputted in the calculation.

7. THE MONTE CARLO SIMULATION SOFTWARE

The reserves estimation is done using commercial software that provides for a probabilistic approach of calculating uncertainty in the occurrence of events or unknown variables. The most common commercial software are Crystal Ball (2007) and @Risk which are used in assessing risks in investment, pharmaceuticals, petroleum reserves and mining evaluation. Monte Carlo simulation can also be programmed using an Excel or Lotus spreadsheet but the use of commercial software allow the user to take advantage of all the features required in a statistical analyses as follows:

- Graphs of input parameters and output, frequency, cumulative frequency, linear plot etc.;
- Statistics: minimum, mean, median, mode, maximum, standard deviation and others;
- Sensitivity test.

To obtain a good representation of the distribution sampling is done through 1000 iterations with continuous calculation.

7.1 The input cells

The Monte Carlo Simulation program is embedded in MS Excel spreadsheet and, like other programs, various cells that have links to the main output or target reserves need to be filled-up. A typical worksheet for volumetric reserves estimation is shown in Table 2.

TABLE 2: Typical worksheet and input parameters for Monte Carlo Simulation

VOLUMETRIC STORED HEAT RESERVE ESTIMATES								
Hengill Geothermal Field								
INPUT VARIABLES (USER DEFINED/DERIVED)	UNITS	MOST LIKELY	MIN	MAX	MEAN	SD	PROBABILITY DISTRIBUTION	
Liquid phase volume								
AREA	km^2	100	80	120			107.5	triang
THICKNESS (liquid zone+500n	m	1500	1000	2000			1451.0	triang
ROCK DENSITY	kg/m^3	3000	3000	3000			3000.0	triang
POROSITY					0.1	0.02	0.1	lognorm
RECOVERY FACTOR		0.230703591					0.2	=f(por)
ROCK SPECIFIC HEAT	kj/kg °C	0.85	0.85	0.9			0.9	triang
TEMPERATURE	°C	280	240	320			283.8	triang
FLUID DENSITY	kg/m^3	748.67					748.7	=f(temp)
CONVERSION EFFICIENCY		0.13	0.127	0.141			0.1	=f(temp), tri
FLUID SPECIFIC HEAT	kj/kg °C	5.34					5.3	=f(temp)
PLANT LIFE	years	50					50.0	single value
LOAD FACTOR		0.95	0.9	1.0			0.9	triang
REJECTION TEMPERATURE	°C	180					180.0	single value
OUTPUT VARIABLE								
POWER CAPACITY								
	MWe (liquid)	886.6						
	MWe (total)	886.6						

7.2 Output

To obtain the required output, the user has to specify the targeted input and output to print and plot. In reserves estimation, the most important output of the program is related to the frequency plot of the thermal energy or its equivalent power plant size capacity.

The thermal energy or the plant capacity is usually plotted using the relative frequency histogram and the cumulative frequency distribution. The relative frequency of a value or a group of numbers (intervals or bins) is calculated as a fraction or percentage of the total number of data points (the sum of the frequencies). The relative frequencies of all the numbers or bins are then plotted, as in Figure 5, to show the relative frequency distribution.

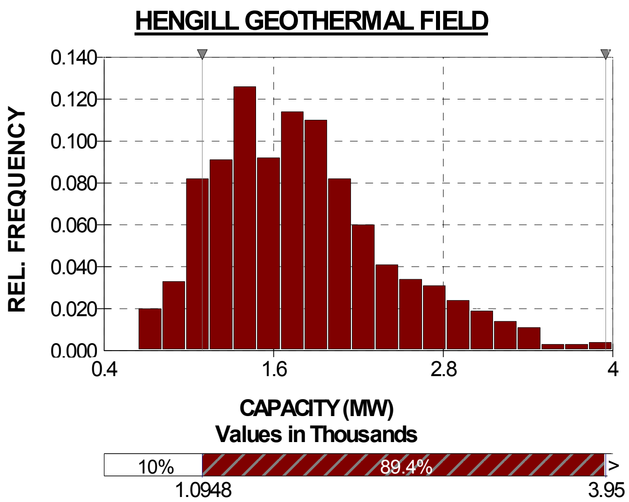

FIGURE 5: Relative frequency plot of the volumetric reserves estimation of the Hengill field (after Sarmiento and Bjornsson, 2007)

On the other hand, the cumulative frequency distribution is similar to a probability density function. It is plotted by cumulating the frequency or adding incrementally the relative frequency of each number or bins. Figure 6 is plotted by cumulating the frequency distribution from maximum value of the random variable to the minimum random variable. The vertical axis is then interpreted as representing the cumulative frequencies greater than or equal to given values of the random variable. The same plot could be represented in a reverse order, from minimum to maximum, but the vertical axis would then be interpreted as the cumulative frequency equal or less than the given values of the random variable. The cumulative frequency greater than or equal to the maximum value is always 1 and the cumulative frequency greater than or equal the minimum value is always 0. In Figure 6, the probability that the output is greater than or equal to 1,095 MW is 90 percent (*Proven* reserves); the probability that the capacity is greater than or equal to 1,660 MW is 55 percent (*Proven + Probable* Reserves, Mode or Most Likely); and the probability that the output is greater than or equal to 2720 MW is 10 percent (*Proven + Probable + Possible* or Maximum Reserves). These results imply that the field could initially support a 1,095 MW power plant for 25 years; possible expansion to 1660 MW will be subject to further delineation drilling and availability of field performance data. The risk that the field could not sustain 1,095 MW is equal to or less than 10 percent.

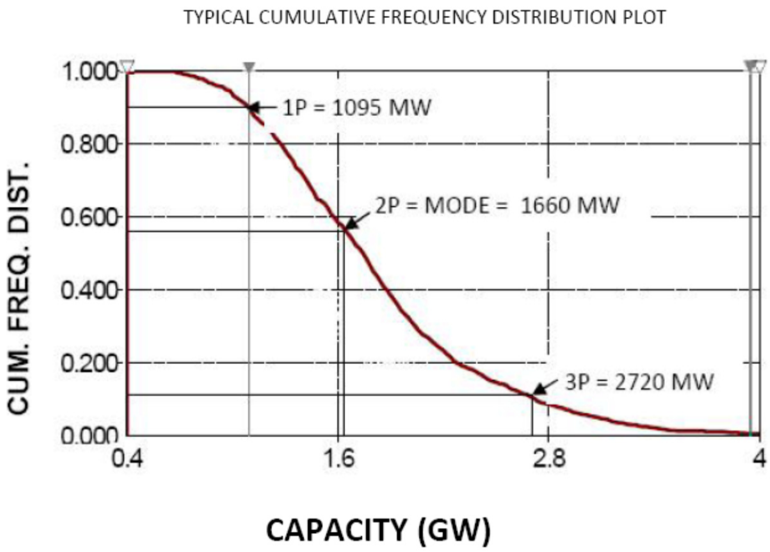

FIGURE 6: Illustration of a typical cumulative frequency plot of the volumetric reserves estimation.

8. CONCLUSION

Geothermal resource assessment is the estimation of the amount of thermal energy that can be extracted from a geothermal reservoir and used economically for a period of time, usually several decades. The key elements vital to the successful evaluation of a geothermal resource consist of a thorough review of the exploration results, well discharge tests and application of the appropriate reserves estimation and numerical simulation techniques. The size and the quality of the reservoir fluids define the various options to be followed in planning for full commercial development of the field. The well chemistry takes special emphasis on scaling potential, acidity, high salinity and gas content of the reservoir.

Several methods have been developed for resource assessment. The methods used vary according to the availability of data on the reservoir, its inner structure, the natural state and reservoir response to utilization. Different methods are therefore applied at different stages of the development. At early stages of geothermal development when available data are limited relatively simple methods are used assessing the reservoirs but as the more information is gain on the reservoir parameters and experienced is gain in producing energy from the reservoir sophisticated numerical computer models are used to simulated the geothermal reservoir in the natural state and the response to utilization which eventually will determine its generating potential of the reservoir.

The preferred method in reservoir assessment in the early phases of geothermal development is the volumetric method. The volumetric method refers to the calculation of thermal energy in- the rock and the fluid which could be extracted based on specified reservoir volume, reservoir temperature, and reference or final temperature. Through the aid of a computer program using Monte Carlo simulation, a probabilistic approach of estimating geothermal reserves becomes less demanding. Some guidelines in the selection of the various reservoir parameters are needed to have consistency in the estimation. By this method, the risks associated with overestimating the size of a geothermal field could be quantified. Moreover, future expansion in the field could be planned in advance while drilling gets underway to confirm the available reserves.

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UNITED NATIONS UNIVERSITY
GEOTHERMAL TRAINING PROGRAMME

LaGeo S.A. de C.V.

DYNAMIC MODELLING OF GEOTHERMAL SYSTEMS

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ABSTRACT

The energy production capacity of hydrothermal systems is predominantly controlled by the reservoir pressure decline caused by the hot water production, which is in turn determined by the size of a geothermal reservoir, its permeability, reservoir storage capacity, water recharge and geological structure. More generally the capacity of all geothermal systems is also controlled by their energy content, dictated by their size and temperature conditions (enthalpy if two-phase). Hydrothermal systems can in most cases be classified as either closed, with limited or no recharge, or open, where recharge equilibrates with the mass extraction in the long run. Modelling plays a key role in understanding the nature of geothermal systems and is the most powerful tool for predicting their response to future production. Predictions are used to estimate their production capacity. Reliable models are also an indispensable part of successful geothermal resource management during utilization. In addition to the volumetric assessment method (static modelling) different methods of dynamic modelling are the main techniques used for geothermal reservoir modelling and resource assessment. The dynamic modelling methods apply simple analytical models, lumped parameter models or detailed numerical models to simulate the nature and production response of geothermal systems as well as to calculate future predictions. The modelling method applied should be determined by the purpose of a study and the data available for calibrating a model, as the time and cost involved are highly variable. All reliable models of geothermal systems, whether static or dynamic, should be based on an accurate conceptual model of the corresponding system. The results of geothermal system modelling may, moreover, lead to changes in their respective conceptual models.

1. INTRODUCTION

Geothermal resources are distributed throughout the Earth's crust with the greatest energy concentration associated with hydrothermal systems in volcanic regions at crustal plate boundaries. Yet exploitable geothermal resources may be found in most countries, either as warm ground-water in sedimentary formations or in deep circulation systems in crystalline rocks. Shallow thermal energy suitable for ground-source heat-pump utilization is available world-wide and attempts are underway at developing enhanced geothermal systems (EGS) in places where limited permeability precludes natural hydrothermal activity. Saemundsson et al. (2009) discuss the classification and geological setting of geothermal systems in considerable detail.

The potential of the Earth's geothermal resources is enormous when compared to its use today and to the future energy needs of mankind. Stefánsson (2005) estimated the technically feasible electrical generation potential of identified geothermal resources to be 240 GW_e (1 GW = 10^9 W), which are likely to be only a small fraction of unidentified resources. He also indicated the most likely direct use potential of lower temperature resources (< 150°C) to be 140 EJ/yr (1 EJ = 10^{18} J). The Earth's ultimate geothermal potential is, however, impossible to estimate accurately at the present stage of knowledge and technology. Even though geothermal energy utilization has been growing rapidly in recent years, it is still miniscule compared with the Earth's potential. Bertani (2010) estimated the worldwide installed geothermal electricity generation capacity to have been about 10.7 GW_e in 2010 and Lund et al. (2010) estimated the direct geothermal utilization in 2009 to have amounted to 438 PJ/yr (1 PJ = 10^{15} J).

The successful exploration, development and utilization of a geothermal resource rely on efficient collaboration between various scientific disciplines as well as engineering during all stages. During the exploration stage of a geothermal resource research focuses on analysis of surface exploration data; mainly geological, geophysical and geochemical data, while this emphasis shifts to reservoir physics research during development and utilization. Geothermal reservoir physics, commonly also called geothermal reservoir engineering, is the scientific discipline that deals with mass and energy transfer in geothermal systems and geothermal wells. It attempts to understand and quantify this flow along with accompanying changes in reservoir conditions, in particular those caused by exploitation. The purpose of geothermal reservoir physics is, in fact, twofold; to obtain information on the nature, reservoir properties and physical conditions in a geothermal system and to use this information to predict the response of reservoirs and wells to exploitation. Based on the latter the energy production capacity of a geothermal resource can be assessed, which actually can be termed the fundamental issue of geothermal reservoir physics. Geothermal reservoir physics is e.g. discussed in more detail by Bödvarsson and Witherspoon (1989), Grant and Bixley (2011) and Axelsson (2012).

Diverse types of model calculations are the principal tools of geothermal reservoir physics, and as such play a key role in overall geothermal research. Modelling is used to analyse various types of reservoir engineering data, such as pressure transient data (Axelsson, 2013), with the purpose of providing estimates of different reservoir properties (e.g. permeability). Once reservoir properties and physical conditions have been estimated, subsequent models are used to simulate the conditions and changes in the geothermal system in question, both during the pre-exploitation stage (natural state) and during utilization (production state). Modelling thus plays a key role in understanding the nature of geothermal systems as well as being the most powerful tool for predicting their response to future production. Reliable models are also an indispensable part of successful geothermal resource management during utilization, since response predictions can e.g. aid in foreseeing the outcome different management actions (Axelsson, 2008b).

The modelling methods used in geothermal development can be classified as either static or dynamic methods. The volumetric assessment method, discussed by Sarmiento et al. (2013) at this Short Course, is the principal static modelling method. It is used to estimate the static energy content of a geothermal system and its possible utilization (extraction). Yet the different methods of dynamic modelling are the main techniques used for geothermal reservoir modelling and resource assessment. The dynamic modelling methods apply simple analytical models, lumped parameter models or detailed numerical models to simulate the nature and production response of geothermal systems as well as to calculate future predictions. Modelling of geothermal systems, in particular detailed numerical modelling, is e.g. discussed by Bödvarsson et al. (1986), O'Sullivan et al. (2001) and Pruess (2002).

Models of geothermal systems are calibrated by various reservoir physics data, e.g. well test and monitoring data. In addition they should be based on other relevant geo-scientific data, generally more indirectly. All reliable models of geothermal systems, whether static or dynamic, should thus be based on an accurate conceptual model of the corresponding system, which is the subject of this Short Course. The results of geothermal system modelling may, moreover, provide input into the development, or revision, of conceptual models geothermal systems, or lead to changes therein, e.g. if the modelling indicates discrepancies between what appears to be physically acceptable and the conceptual model.

This paper starts out by discussing the factors which control the nature and energy production capacity of geothermal systems. The main emphasis is, however, on reviewing the different methods of dynamic modelling of geothermal systems, including their strengths and weaknesses along with data requirements. The paper is concluded by general conclusions and recommendations.

2. NATURE AND PRODUCTION CAPACITY OF GEOTHERMAL SYSTEMS

The long-term response and hence production capacity of geothermal systems is mainly controlled by (1) their size and energy content, (2) permeability structure, (3) boundary conditions (i.e. significance of natural and production induced recharge) and (4) reinjection management. Their energy production potential, in particular in the case of hydrothermal systems, is predominantly determined by pressure decline due to production. This is because there are technical limits to how great a pressure decline in a well is allowable; because of pump depth or spontaneous discharge through boiling, for example. The production potential is also determined by the available energy content of the system, i.e. by its size and the temperature or enthalpy of the extracted mass. The pressure decline is determined by the rate of production, on one hand, and the nature and characteristics of the geothermal system, on the other hand.

Natural geothermal reservoirs can often be classified as either ***open*** or ***closed***, with drastically different long-term behaviour, depending on their boundary conditions (see also Figure1):

(A) Pressure declines continuously with time, at constant production, in systems that are ***closed*** or with small recharge (relative to the production). In such systems the production potential is limited by lack of water rather than lack of thermal energy. Such systems are ideal for reinjection, which provides man-made recharge. Examples are many sedimentary geothermal systems, systems in areas with limited tectonic activity or systems sealed off from surrounding hydrological systems by chemical precipitation.

(B) Pressure stabilizes in ***open*** systems because recharge eventually equilibrates with the mass extraction. The recharge may be both hot deep recharge and colder shallow recharge. The latter will eventually cause reservoir temperature to decline and production wells to cool down. In such systems the production potential is limited by the reservoir energy content (temperature and size) as the energy stored in the reservoir rocks will heat up the colder recharge as long as it is available/accessible.

The situation is somewhat different for ***EGS-systems*** and sedimentary systems utilized through production-reinjection ***doublets*** (well-pairs) and heat-exchangers with 100% reinjection. Then the production potential is predominantly controlled by the energy content of the systems involved. But permeability, and therefore pressure variations, is also of controlling significance in such situations. This is because it controls the pressure response of the wells and how much flow can be achieved and maintained, for example through the doublets involved (it's customary to talk about intra-well impedance for EGS-systems, based on the electrical analogy). In sedimentary systems the permeability is natural but in EGS-systems the permeability is to a large degree man-made, or at least enhanced.

Water or steam extraction from a geothermal reservoir causes, in all cases, some decline in reservoir pressure, as already discussed. The only exception is when production from a reservoir is less than its natural recharge and discharge. Consequently, the pressure decline manifests itself in further changes, which for natural geothermal systems may be summarised in a somewhat simplified manner as follows:

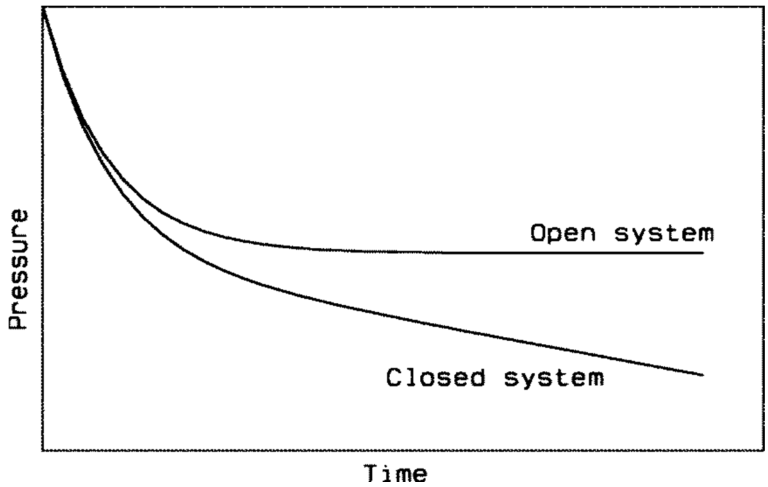

FIGURE 1: Schematic comparison of pressure decline in open (with recharge) or closed (with limited or no recharge) geothermal systems at a constant rate of production (from Axelsson, 2008a)

A. Direct changes caused by **lowered reservoir pressure**, such as changes in surface activity, decreasing well discharge, lowered water level in wells, increased boiling in high-enthalpy reservoirs and changes in non-condensable gas concentration.
B. Indirect changes caused by **increased recharge** to the reservoir, such as changes in chemical composition of the reservoir fluid, changes in scaling/corrosion potential, changes in reservoir temperature conditions (observed through temperature profiles of wells) and changes in temperature/enthalpy of reservoir fluid.
C. **Surface subsidence**, which may result in damage to surface installations

Axelsson (2008a) presents examples of production and response histories of several geothermal systems worldwide, both high- and low-enthalpy systems, of quite contrasting nature. Some exhibit a drastic pressure draw-down for limited production while others experience very limited draw-down for substantial mass extraction. A few examples of reservoir cooling due to long-term production are also presented, even though they are relatively rare. Such histories are extremely valuable for the calibration of models of geothermal systems. A number of long and well documented utilization and response case histories are, in particular, available, many spanning more than 30 years, which are extremely valuable for studying the nature of geothermal systems, e.g. their renewability (Axelsson, 2011). This reflects the importance of comprehensive and careful monitoring of the response of geothermal systems to energy extraction (Monterrosa and Axelsson, 2013), both for conceptual and reservoir model development.

3. GEOTHERMAL RESERVOIR MODELLING

3.1 General

Various methods have been used the last several decades to assess geothermal resources during both exploration and exploitation phases of development. These range from methods used to estimate resource temperature and size to complex numerical modelling aimed at predicting the production response of systems and estimating their production potential. Being able to assess a given resource during different stages of its development, as accurately as possible, is essential for its successful development. The main methods used are:

(a) Deep temperature estimates (based on chemical content of surface manifestations).
(b) Surface thermal flux.
(c) Volumetric methods (adapted from mineral exploration and oil industry).
(d) Decline curve analysis (adapted from oil/gas industry).

(e) Simple mathematical modelling (often analytical).
(f) Lumped parameter modelling.
(g) Detailed numerical modelling of natural state and/or exploitation state (often called distributed parameter models).

The first two methods are not modelling methods per se, but are the methods that can be used for resource assessment prior to extensive geophysical surveying and drilling. The remaining methods in the list can all be considered modelling methods, which play an essential role in geothermal resource development and management. These range from basic volumetric resource assessment (c) and simple analytical modelling (e) of the results of a short well test to detailed numerical modelling (g) of a complex geothermal system, simulating an intricate pattern of changes resulting from long-term production. In the early days of geothermal reservoir studies decline curve analysis (d) proved to be an efficient method to predict the future output of individual high-temperature wells (Bödvarsson and Witherspoon, 1989), but today other modelling methods are usually applied. Decline curve analysis is particularly applicable to wells in dry-steam reservoirs.

The purpose of geothermal modelling is firstly to obtain information on the conditions in a geothermal system as well as on the nature and properties of the system. This leads to proper understanding of its nature and successful development of the resource. Secondly, the purpose of modelling is to predict the response of the reservoir to future production and estimate the production potential of the system as well as to estimate the outcome of different management actions.

The diverse information, which is the foundation for all reservoir-modelling, needs to be continuously gathered throughout the exploration and exploitation history of a geothermal reservoir. Information on reservoir properties is obtained by disturbing the state of the reservoir (fluid-flow, pressure) and by observing the resulting response, and is done through well and reservoir testing and data collection (Axelsson, 2013). Different methods of testing geothermal reservoirs are available (Axelsson and Steingrímsson, 2012), but it should be emphasised that the data collected does not give the reservoir properties directly. Instead, the data are interpreted, or analysed, on the basis of appropriate models yielding estimates of reservoir properties. It is important to keep in mind that the resulting values are ***model-dependent,*** i.e. different models give different estimates. It is also very important to keep in mind that the longer, and more extensive the tests are, the more information is obtained on the system in question. Therefore, the most important data on a geothermal reservoir is obtained through careful monitoring during long-term exploitation (Monterrosa and Axelsson, 2013), which can be looked upon as prolonged and extensive reservoir testing.

The modelling methods may be classified as either ***static modelling methods*** or ***dynamic modelling methods***, with the volumetric method (c) being the main static method. Both involve development of some kind of a mathematical model that ***simulates*** some, or most, of the data available on the system involved. The volumetric method is based on estimating the total heat stored in a volume of rock and how much of that can be efficiently recovered (Sarmiento et al., 2013). The dynamic modelling methods ((d) – (g) in the list above) are based on modelling the dynamic conditions and behaviour (production response) of geothermal systems. These are the main subject of the present paper.

The volumetric method, which is discussed in a separate presentation at the present short course (Sarmiento et al., 2013) is the main static modelling method, as already stated. It is often used for first stage assessment, when data are limited, and was more commonly used in the past (Muffler and Cataldi, 1978; Rybach and Muffler, 1981), but is still the main assessment method in some countries. It is increasingly being used, however, through application of the Monte Carlo method (Sarmiento et al., 2013; see also Sarmiento and Björnsson, 2007). This method enables the incorporation of overall uncertainty in the results. The main drawback of the volumetric method is the fact that the dynamic response of a reservoir to production is not considered, such as the pressure response and the effect of fluid recharge. Reservoirs with the same heat content may have different permeabilities and recharge and, hence, very different production potentials.

The main dynamic modelling methods applied to geothermal systems are simple mathematical (analytical) modelling methods (e), lumped parameter methods (f) and detailed numerical modelling (g), as listed above. The initial phase of such model development should be based on a good conceptual model of the geothermal system in question (Bödvarsson et al., 1986; Pruess, 2002), which is a qualitative or descriptive model incorporating all the essential features of a geothermal system revealed by analysis of all available data, as described in detail at the present short course. The next step is the development of a quantitative natural state model, which should simulate the physical state of a geothermal system prior to production. Finally, an exploitation model is developed to simulate changes in the physical state of a system during long-term production, and to calculate predictions as well as for other management purposes. Numerous examples are available on the successful role of modelling in geothermal resource management (Axelsson and Gunnlaugsson, 2000; O'Sullivan et al., 2001).

In simple models, such as simple analytical models and lumped parameter models, the real structure and spatially variable properties of a geothermal system are greatly simplified so that analytical mathematical equations, describing the response of the model to energy production may be derived. These models, in fact, often only simulate one aspect of a geothermal system's response. In such models the natural state is, furthermore, simply given by the initial conditions assumed. Detailed and complex numerical models, on the other hand, can accurately simulate most aspects of a geothermal system's structure, conditions and response to production. Simple modelling takes relatively little time and only requires limited data on a geothermal system and its response, whereas numerical modelling takes a long time and requires powerful computers as well as comprehensive and detailed data on the system in question. The complexity of a model should be determined by the purpose of a study, the data available and its relative cost. In fact, simple modelling, such as lumped parameter modelling, is often a cost-effective and timesaving alternative. It may be applied in situations when available data are limited, when funds are restricted, or as parts of more comprehensive studies, such as to validate results of numerical modelling studies.

3.2 Simple modelling

Simple mathematical models wherein the real structure and spatially variable properties of geothermal systems are greatly simplified, so that analytical mathematical equations describing their response may be derived, have been used extensively in geothermal reservoir engineering. Many examples are e.g. given by Grant and Bixeley (2011). Many of these simple models have been inherited from ground-water science or even adopted from theoretical heat conduction treatises (because the pressure diffusion and heat conduction equations have exactly the same mathematical form). A good example of the former is the well-known Theis model, a sketch of which is presented in Figure 4, along with sketches of a few variants of the basic model. The Theis model comprises a model of a very extensive horizontal, permeable layer of constant thickness, confined at the top and bottom, with two-dimensional, horizontal flow towards a producing well extending through the layer. Geothermal well-test data are often analysed on basis of the Theis model, and its variants, by fitting the pressure response of the model(s) to observed pressure response data. Consequently the parameters of the model provide an estimate of the parameters of the reservoir being tested. Figure 5 shows the calculated responses of the Theis model and its variants (Figure 2), on a semi-logarithmic plot.

Simple modelling has been used extensively to study and manage the low-temperature geothermal systems utilised in Iceland, in particular to model their long-term response to production (Axelsson and Gunnlaugsson, 2000). Lumped parameter modelling of water level and pressure change data, has been the principal tool for this purpose (Axelsson et al., 2005). Lumped models can simulate such data very accurately, even very long data sets (several decades). Lumped parameter modelling will be discussed in more detail below. It plainly illustrates the general methodology of geothermal modelling.

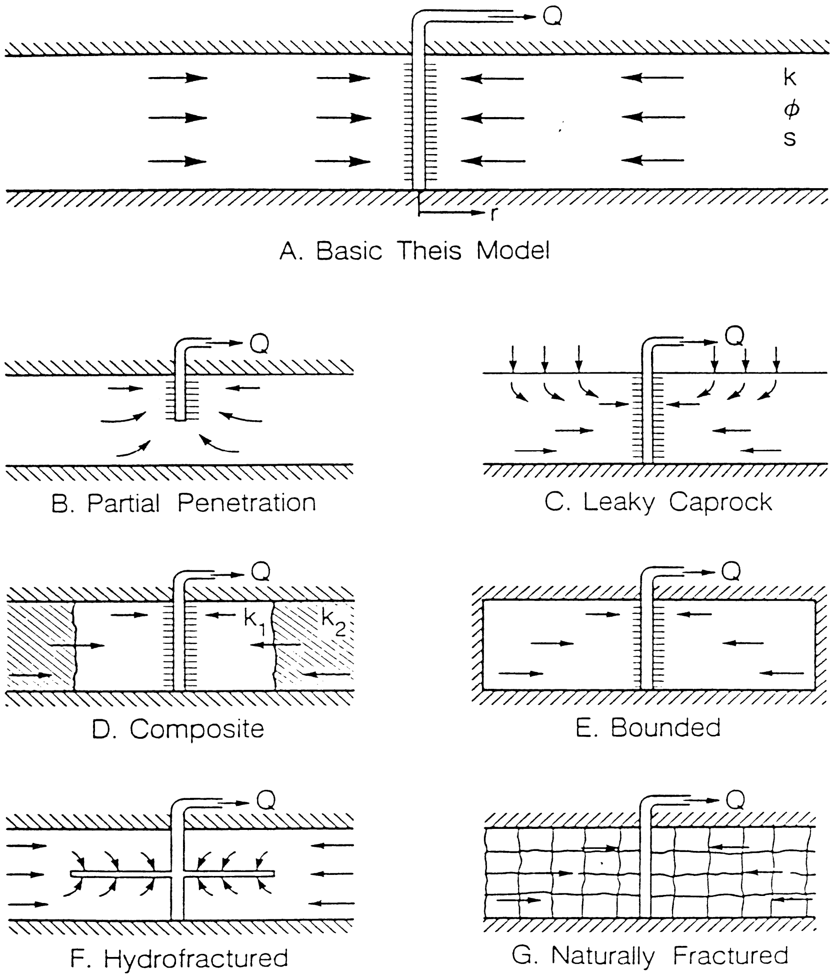

FIGURE 2: A sketch of the basic Theis-model (top) used to analyse pressure transient well-test data along with several variants of the basic model (Bödvarsson and Whiterspoon, 1989)

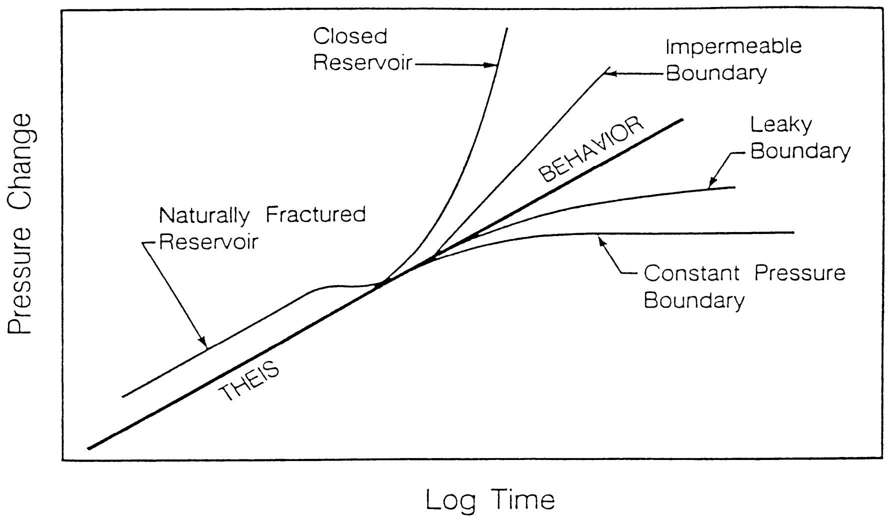

FIGURE 3: Responses of the models in Figure2 plotted on a semi-logarithmic plot (linear pressure change vs. logarithmic time) demonstrating the linear behaviour, which is the basis of the semi-logarithmic analysis method (Bödvarsson and Whiterspoon, 1989)

Axelsson (1989) presents an efficient method of lumped parameter modelling of pressure response data from geothermal systems and other underground hydrological systems. Pressure changes are in fact the primary production induced changes in geothermal systems, as already emphasised. The method tackles the simulation as an inverse problem and can simulate such data very accurately, if the data quality is sufficient. It automatically fits the analytical response functions of the lumped models to observed data by using a non-linear iterative least-squares technique for estimating the model parameters. Today, lumped models have been developed by this method for more than 20 low-temperature and 3 high-temperature geothermal systems in Iceland, as well as geothermal systems in China, Turkey, Eastern Europe, Central America and The Philippines, as examples (Axelsson et al., 2005). It may be mentioned that this method has been employed and revised by e.g. Sarak et al. (2005) and Onur et al. (2008) have broadened the method to incorporate temperature changes as well as pressure changes.

The theoretical basis of this automatic method of lumped parameter modelling, and relevant equtions, are presented by Axelsson (1989), with a general lumped model consisting of a few tanks and flow resistors (Figure 4). The tanks simulate the storage capacity of different parts of a geothermal system and the pressure in the tanks simulates the pressure in corresponding parts of the system. Figure 5 shows the type of lumped parameter model most commonly used. The first tank of the model in the figure can be looked upon as simulating the innermost (production) part of the geothermal reservoir, and the second and third tanks simulate the outer parts of the system. The third tank is connected by a resistor to a constant pressure source, which supplies recharge to the geothermal system. The model in Figure 5 is, therefore, open. Without the connection to the constant pressure source the model would be closed. An open model may be considered optimistic, since equilibrium between production and recharge is eventually reached during long-term production, causing the pressure draw-down to stabilize. In contrast, a closed lumped model may be considered pessimistic, since no recharge is allowed for such a model and the water level declines steadily with time, during long-term production. In addition, the model presented in Figure 5 is composed of three tanks; in many instances models with only two tanks have been used.

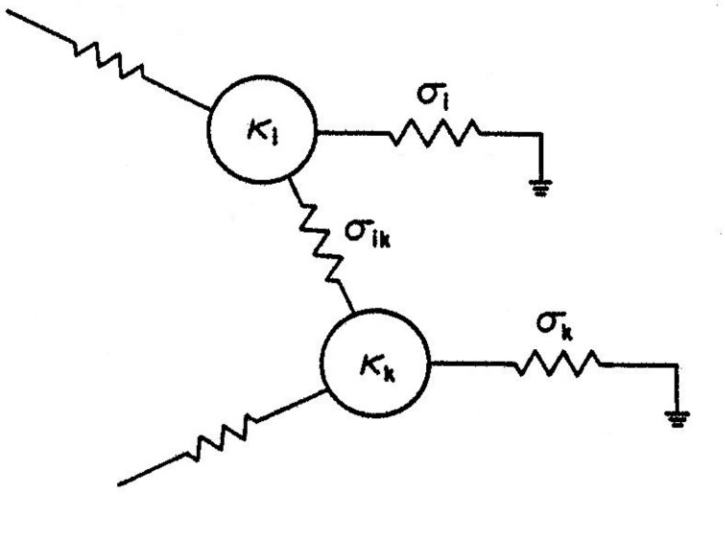

FIGURE 4: A general lumped parameter model used to simulate pressure changes in geothermal systems (from Axelsson, 1989)

In the lumped parameter model of Figure 5 hot water is assumed to be pumped out of the first tank, which causes the pressure in the model to decline. This in turn simulates the decline of pressure in the real geothermal system. When using this method of lumped parameter modelling, the data fitted (simulated) are the pressure (or water level) data for an observation well inside the well-field, while the input for the model is the production history of the geothermal field in question.

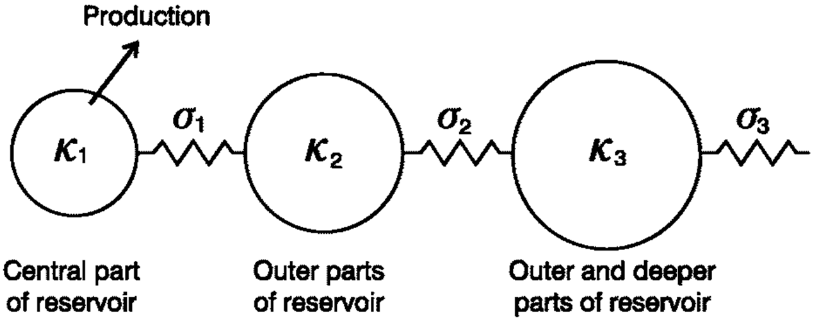

FIGURE 5: A 3-tank lumped ladder model commonly used to simulate geothermal systems (from Axelsson et al., 2005)

Axelsson et al. (2005) present examples of long pressure response histories of geothermal systems distributed throughout the world simulated by lumped parameter models. The examples show that in all of the cases the models developed simulate the pressure changes quite accurately. Yet because of how simple the lumped parameter models are, their reliability is sometimes questioned. Experience has shown that they are quite reliable, however, and examples involving repeated simulations, demonstrate this clearly (Axelsson et al., 2005). This applies, in particular, to simulations based on long data sets, which is in agreement with the general fact that the most important data on a geothermal reservoir are obtained through careful monitoring during long-term exploitation. Lumped parameter modelling is less reliable when based on shorter data sets, which is valid for all such reservoir engineering predictions. Figure 6 – 8 present examples of long pressure response histories of three geothermal systems distributed throughout the world. These are the histories of the Ytri-Tjarnir low-temperature system in N-Iceland, the Urban low-temperature sedimentary system in Beijing, China, and the Ahuachapan high-temperature volcanic system in El Salvador. These examples are all discussed in more detail by Axelsson et al. (2005), but the figures show that in all of the cases the lumped parameter models developed simulate the pressure changes quite accurately.

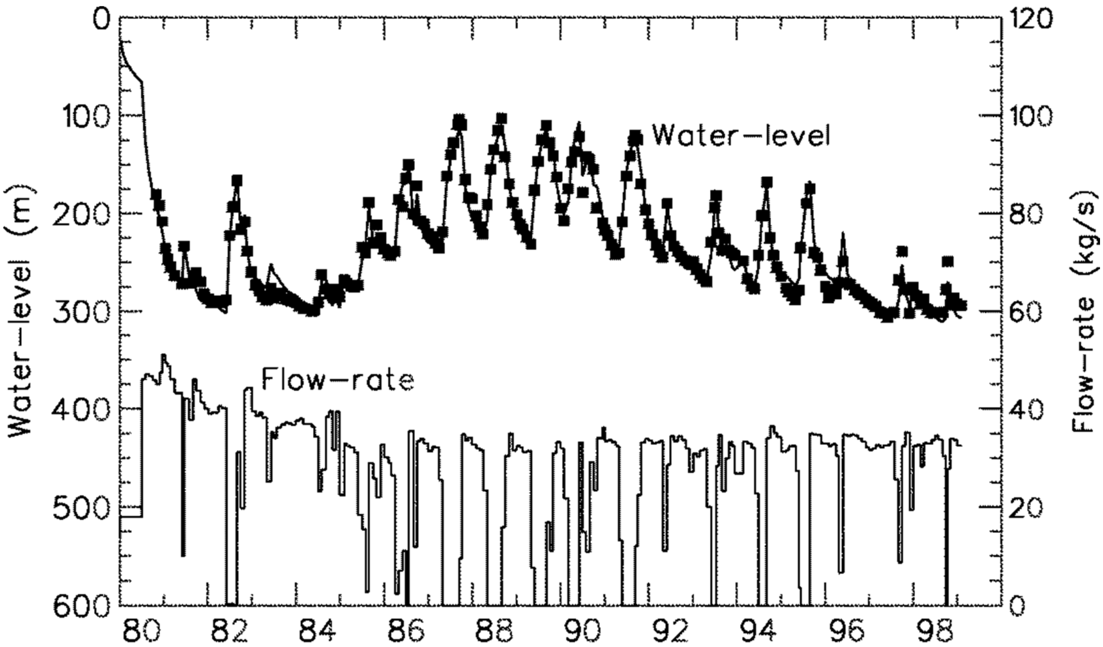

FIGURE 6: Production and water level history of the Ytri-Tjarnir low-temperature geothermal system in central N-Iceland 1980-1999. The water level history has been simulated by a lumped parameter model (squares = observed data, line = simulated data; from Axelsson et al., 2005)

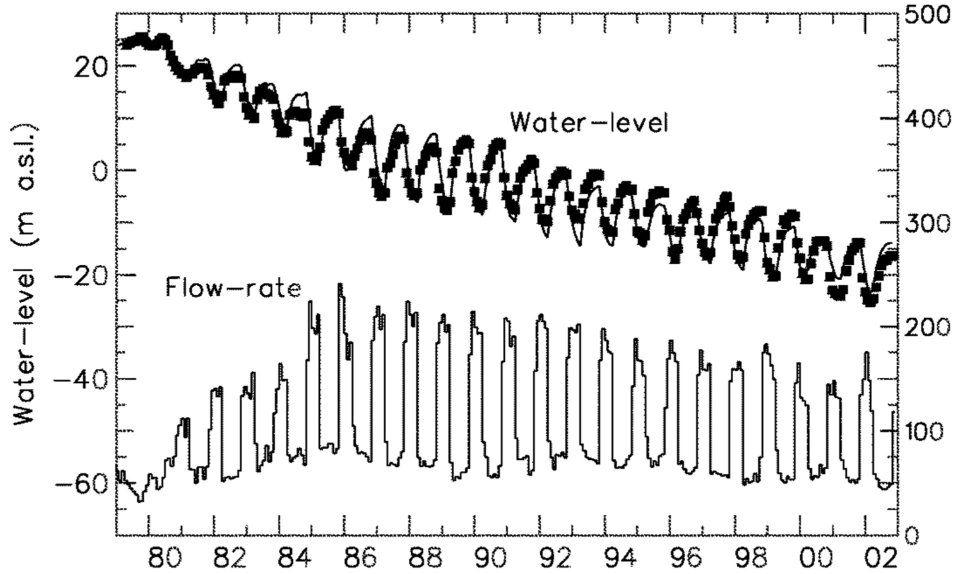

FIGURE 7: Production and water level history of the Urban sedimentary geothermal system in Beijing 1979-2002. The water level history has been simulated by a lumped parameter model (squares = observed data, line = simulated data; from Axelsson et al., 2005)

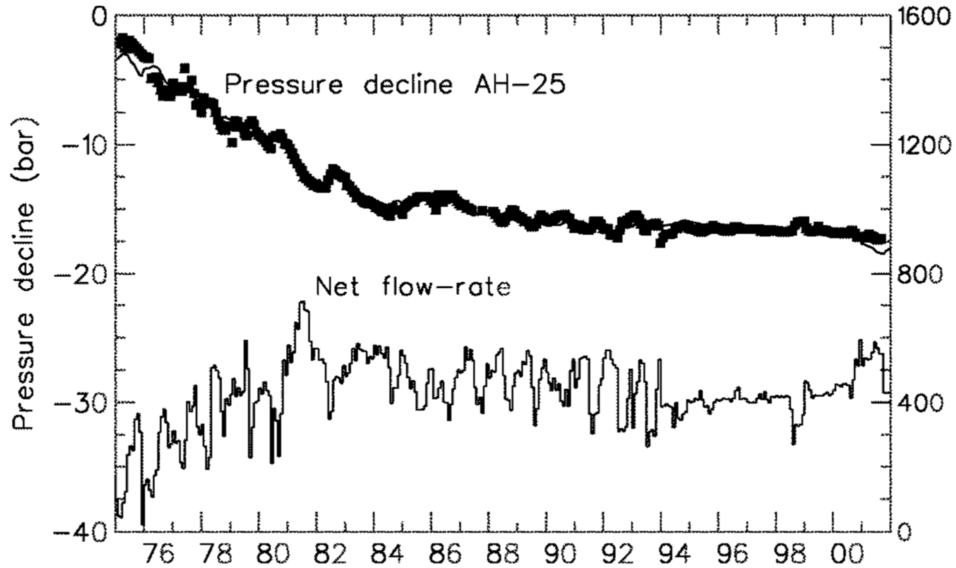

FIGURE 8: Production and pressure decline history of the Ahuachapan high-temperature geothermal field in El Salvador 1975-2001. The pressure history has been simulated by a lumped parameter model (squares = observed data, line = simulated data) based on the net production (mass extraction – infield reinjection; from Axelsson et al., 2005)

Once a satisfactory fit with observed pressure data has been obtained the corresponding lumped parameter models can be used to calculate predictions for different future production scenarios. Future pressure changes in geothermal systems are expected to lie somewhere between the predictions of open and closed versions of lumped parameter models, which represent extreme kinds of boundary conditions. The differences between these predictions simply reveal the inherent uncertainty in all such predictions. Real examples demonstrate that the shorter the data period a simulation is based on is, the more uncertain the predictions are (Axelsson et al., 2005). They also demonstrate that the uncertainty in the predictions increases with increasing length of the prediction period. Figures 9 and 10 below present two examples of lumped parameter model predictions. Both actually involve unusually long prediction periods, as they were calculated for sustainability studies (see Axelsson, 2010). Normally such predictions are only calculated for a few decades, or ideally for a prediction period of a length comparable to the data simulation period. In the case of the Hamar field (Figure 9) the divergence between the closed and open predictions (actually the uncertainty involved) after e.g. 30 years is relatively small. This is because the predictions are based on a 30 year data series.

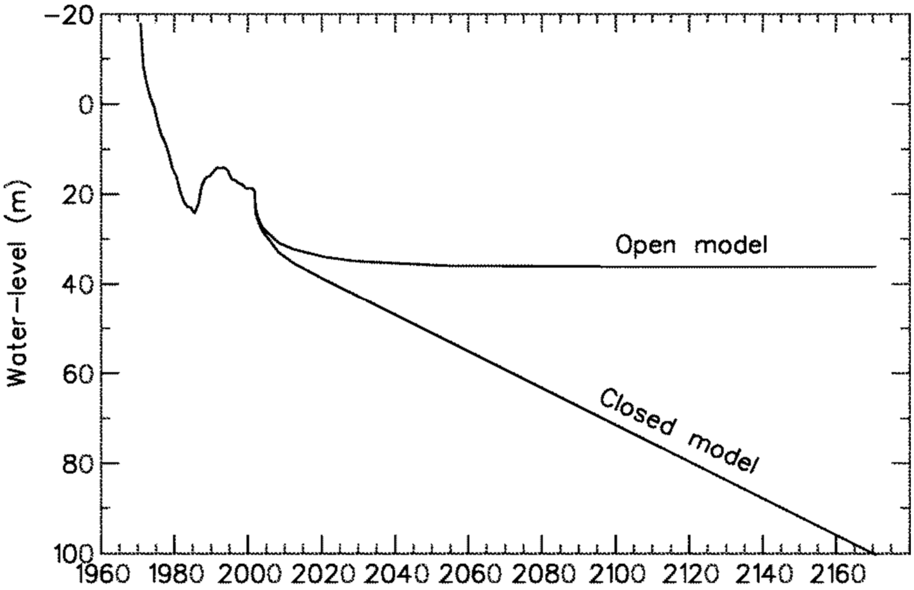

FIGURE 9: Long-term water level prediction for the Hamar low-temperature geothermal system in N-Iceland, as calculated by a closed and an open lumped parameter model. Prediction calculated for a constant rate of production up to 2170 for a sustainability study for the system (Axelsson et al., 2005)

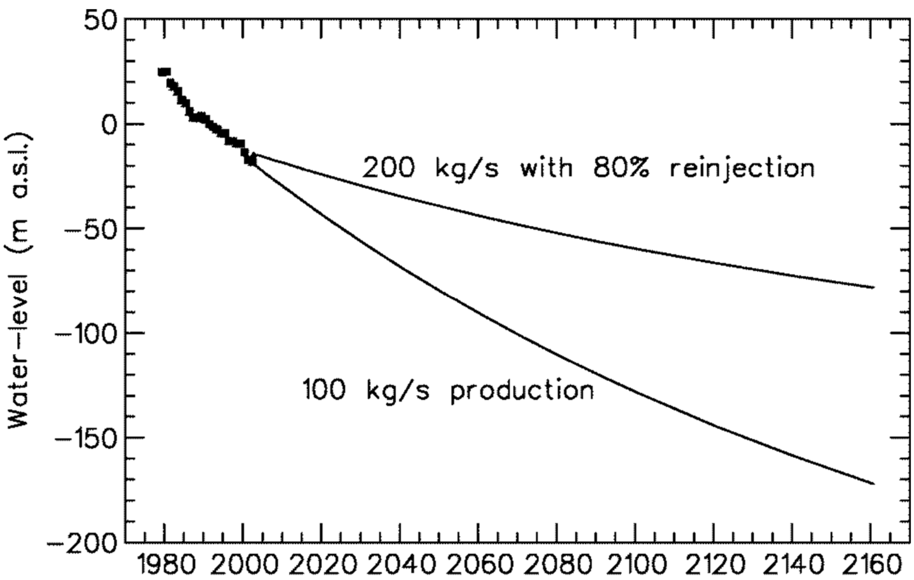

FIGURE 10: Predicted water level changes (pressure changes) in the Urban geothermal system under Beijing in China until 2160 for production scenarios with and without reinjection, averages of predictions calculated by a closed and an open lumped parameter model (from Axelsson et al., 2005)

Finally, it should be reiterated that even though lumped parameter models have been set up for high-temperature systems (see Figure 8) they are strictly developed for isothermal, single phase conditions. In addition, simulating internal changes in reservoir conditions and properties is beyond the capacity of lumped parameter models. Furthermore, the method of lumped parameter modelling discussed here is neither directly applicable to EGS-systems nor doublet-operations. Other types of simple models are more applicable for such situations.

The simple model shown in Figure 11 has been used to simulate geothermal systems of the open type (see section 2 above), i.e. systems where the pressure decline due to production has induced a recharge of colder water from outside the reservoir, in particular low-temperature systems in Iceland. It is presented here to demonstrate the characteristics of such systems. The model consists of a fixed volume production reservoir overlain by an infinite ground-water system. A fixed inflow of geothermal water into the production reservoir has a temperature and chemical content, distinctively different from that of the ground-water above. Production of water from the system induces a down-flow of ground-water, through some fractures extending to the surface, and into the production reservoir. This causes the chemical content and temperature of the water produced to decline. The equations describing the response of this model are presented by Björnsson et al. (1994).

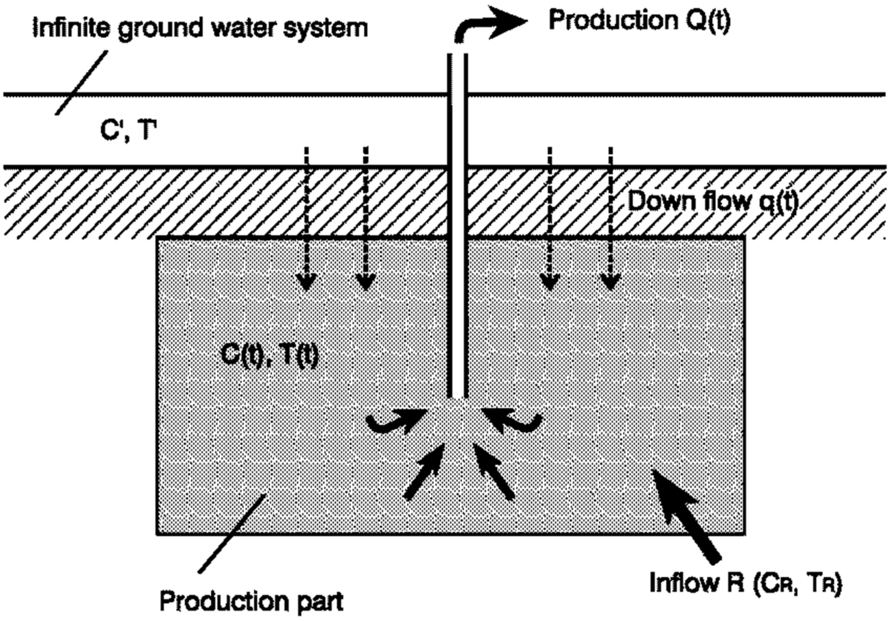

FIGURE 11: A simple model of a geothermal system with down-flow of colder ground-water (Axelsson, 2012)

Figure 12 shows the response of this model to prolonged production, as relative changes in pressure chemical content and temperature. It demonstrates clearly the very different time scales of the different changes, pressure changes being very fast, whereas thermal changes are extremely slow, due to the thermal inertia of the rock formation involved. The figure also shows that colder down-flow may usually be detected as changes in the chemical content of the hot water produced, before its temperature starts to decline. This also shows in a simple manner why chemical monitoring is an essential part of geothermal reservoir management and for conceptual model development, as is discussed in a separate presentation at this short course (Jacobo and Montalvo, 2013).

Björnsson et al. (1994) present the results of the application of this model to the Thelamork low-temperature system in Central N-Iceland, where chemical changes during a nine-month production test clearly indicated colder water inflow into the system. Axelsson and Gunnlaugsson (2000) present the results of another comparable study for the Botn low-temperature system, also in Central N-Iceland, which has been utilised since 1981. Considerable chemical changes and cooling have been observed in the Botn field through its utilization history and the purpose of the modelling study was to evaluate the relationship between the rates of production and cooling, for future management of the field.

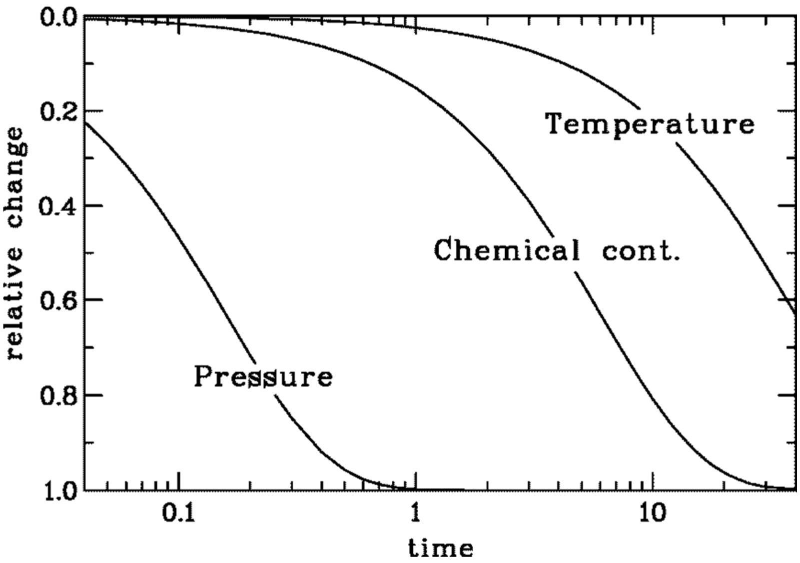

FIGURE 12: Pressure, chemical and thermal response of the model in Fig. 19 (logarithmic time-scale) (Axelsson, 2012)

3.3 Detailed numerical modelling

Detailed numerical reservoir modelling has become the most powerful tool of geothermal reservoir physics parallel with the rapid development of high-capacity modern-day computers and is increasingly being used to simulate geothermal systems in different parts of the world. This method will not be discussed here in detail. Instead the reader is referred to an early work by the pioneers in this field Bödvarsson et al. (1986), a later comprehensive review by O'Sullivan et al. (2001) and the detailed lectures of Pruess (2002). The numerical modelling method is extremely powerful when based on comprehensive and detailed data. Without good data, however, detailed numerical modelling can only be considered speculative, at best. In addition, numerical modelling is time-consuming and costly and without the necessary data the extensive investment needed is not justified.

The details and different aspects of detailed numerical reservoir modelling are described by Pruess (2002). The principal steps of the method involve dividing the whole volume of the reservoir/system into numerous sub-volumes (grid-blocks), often a few hundred to several thousand blocks. Each block (or in fact families of blocks) is assigned hydrological (permeability, porosity, etc.) and thermal properties (heat capacity, thermal conductivity, etc.). Sinks and sources are then assigned to selected blocks to simulate natural inflow and outflow as well as production wells and injection wells. In addition appropriate boundary conditions are specified. The above is mostly based on a comprehensive conceptual model of the geothermal system and to some extent on well-test data. Finite-difference methods, or finite-element methods, are subsequently used to solve relevant equations for conservation and flow of mass and heat.

The most elaborate part of the modelling process then involves varying the model properties listed above until the model adequately simulates all relevant data. Such models are required to simulate available data on pressure- and temperature conditions as well as main flow patterns in the system in question during the natural state. They also need to simulate observed changes in pressure- and temperature conditions during production as well as variations in well output (mass-flow and enthalpy). During the early days of numerical modelling, when computers were far less powerful than today, separate natural state models and production models were often developed (Bödvarsson et al., 1986). Today these are most often combined in one overall model. It should be mentioned that computer code developments have been underway for some time aimed at incorporating chemical data into the modelling process. Attempts have also been made to incorporate other data, such as surface deformation data, gravity data and resistivity data, into the modelling process. In principle all such additional data should aid in the modelling process, help constrain the models and make them more reliable.

Computer codes, like the well-known *TOUGH2*-code, are used for the calculations (Pruess, 2002). The items below are varied throughout the modelling process until a satisfactory data-fit is obtained:

- Permeability distribution,
- porosity distribution,
- boundary conditions (nature/permeability of outer regions of model),
- productivity indices for wells (the relation between flow and pressure drop from reservoir into a well),
- mass recharge to the system and
- energy recharge to the system.

Recently the *iTOUGH2* addition to *TOUGH2* has enabled the use of an iterative inversion process, akin to the method used in the lumped parameter modelling method presented above, to estimate model properties.

Various examples of small-scale and large-scale numerical modelling studies are available in the geothermal literature. Some of the smaller scale studies actually involve kinds of theoretical exercises while others involve modelling of small geothermal systems, or systems in the early phases of development. The large-scale studies mostly involve the modelling of large high-enthalpy geothermal systems where considerable drilling has been performed and some production experience has been gathered. Björnsson et al. (2003), O'Sullivan et al. (2009) and Romagnoli et al. (2010) provide information on three large-scale reservoir modelling projects, to name examples. These are the Hengill geothermal region in SW-Iceland, the Wairakei geothermal system on the North Island of New Zealand and the Larderello-Travale geothermal system in Italy.

In addition Axelsson and Björnsson (1993), Hjartarson et al. (2005), Lopez et al. (2010) and Rybach and Eugster (2010) provide examples of numerical modelling of a fracture controlled low-temperature geothermal system in Iceland, of two sedimentary geothermal systems (in China and France) and of a small-scale ground-source heat-pump system, respectively. Figures 13 – 19 provide glimpses into some of these models; the computational grids, data simulations and predictions. The reader is referred to the relevant references for further information on each of the models.

4. CONCLUSIONS AND RECOMMENDATIONS

Modelling plays a key role in understanding the nature and estimating the properties of geothermal systems. It is also the most powerful tool for predicting their response to future production and consequently to estimate their production capacity as well as being an indispensable part of successful geothermal resource management during utilization. The principal dynamic modelling methods have been reviewed in this paper whereas the volumetric assessment method, which is the main static modelling method, is reviewed in another presentation at this short course. The dynamic modelling methods apply simple analytical models (analytical mathematical response equations can be derived), lumped parameter models (geometry ignored) or detailed numerical models to simulate the nature and production response of geothermal systems as well as to calculate future predictions, all of which have their advantages and shortcomings. All reliable models of geothermal systems, whether static or dynamic, should be based on an accurate conceptual model of the corresponding system, the subject of this short course. The process of developing and calibrating a model of a geothermal system may, moreover, lead to changes in their respective conceptual models, e.g. if the modelling indicates discrepancies between what is physically acceptable and the conceptual model.

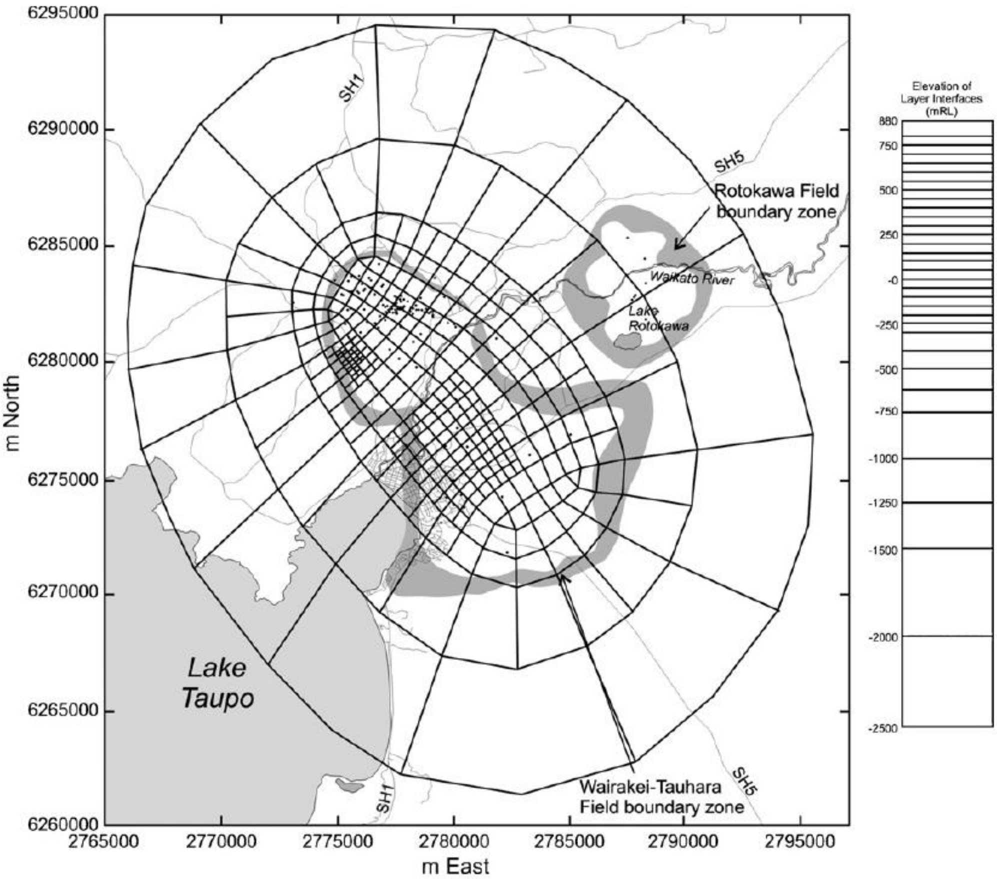

FIGURE 13: A sketch of the computational grid of the most recent numerical reservoir model for the Wairakei geothermal system in New Zealand (O'Sullivan et al., 2009)

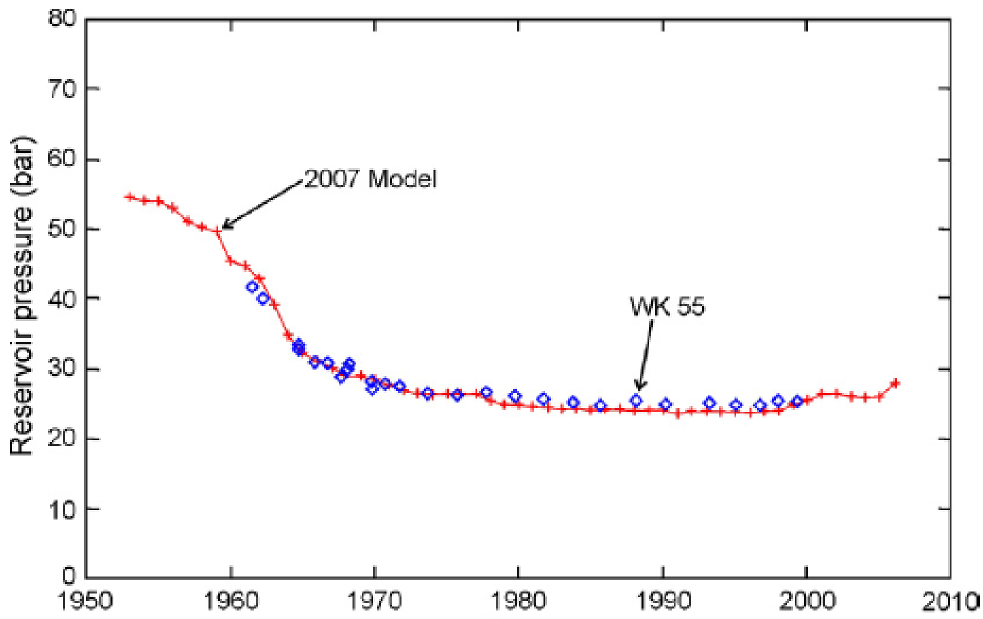

FIGURE 14: Observed pressure changes in the Wairakei geothermal system simulated by the numerical model of Figure 13 (O'Sullivan et al., 2009)

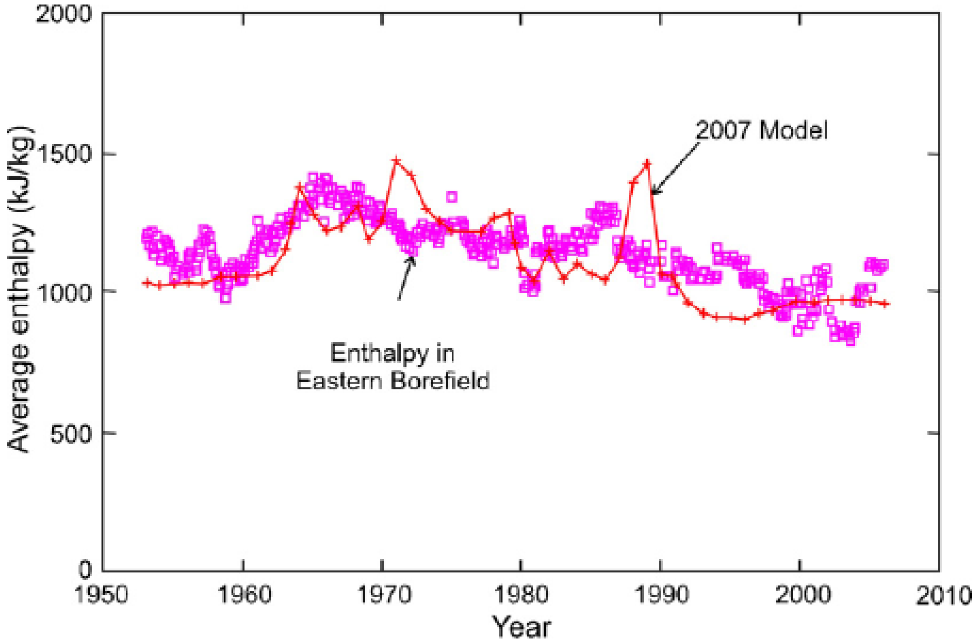

FIGURE 15: Observed enthalpy changes in the Eastern Borefield of the Wairakei geothermal system simulated by the numerical model of Figure 13 (O'Sullivan et al., 2009)

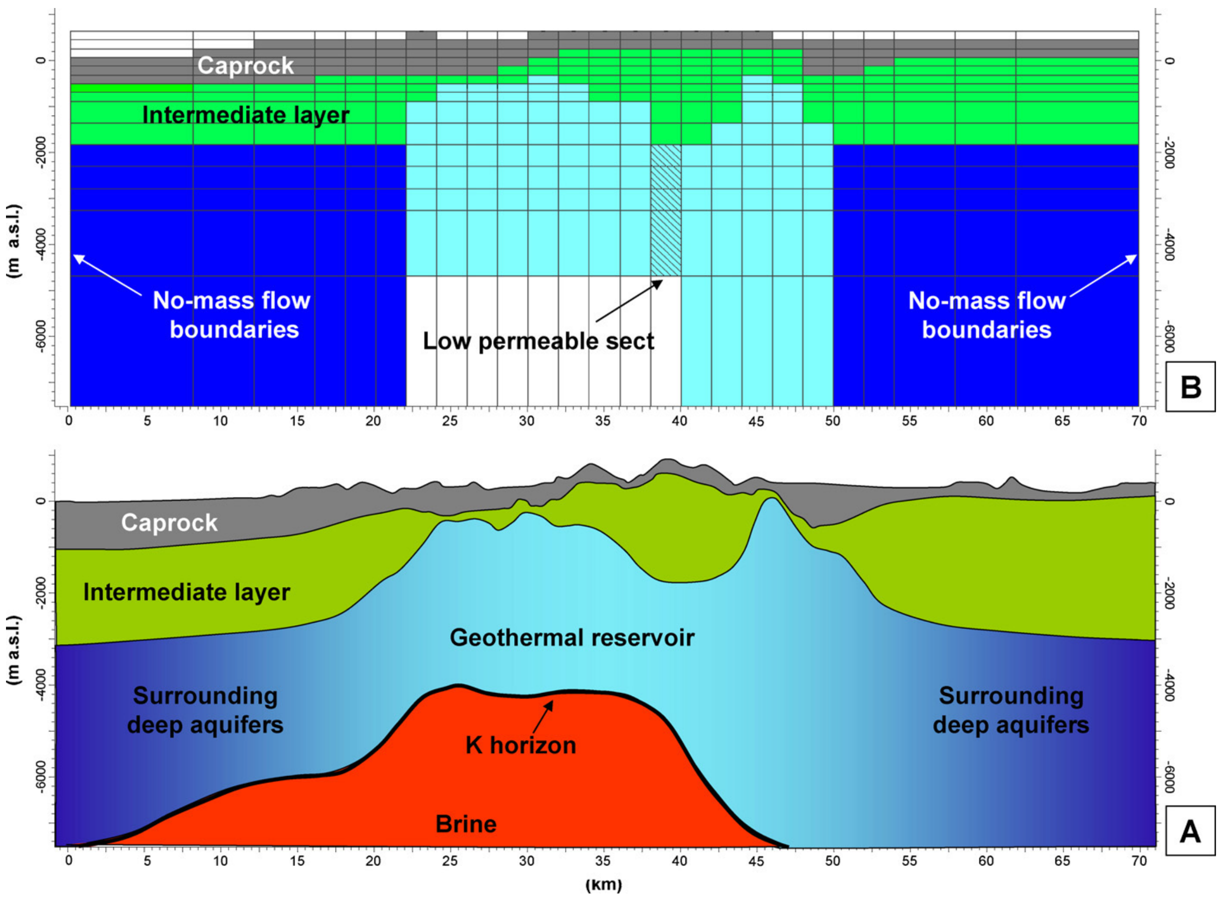

FIGURE 16: Comparison of geology (A) and the grid of the numerical model (B) of the Larderello-Travale geothermal system in Italy on a W–E cross-section (from Romagnoli et al., 2010)

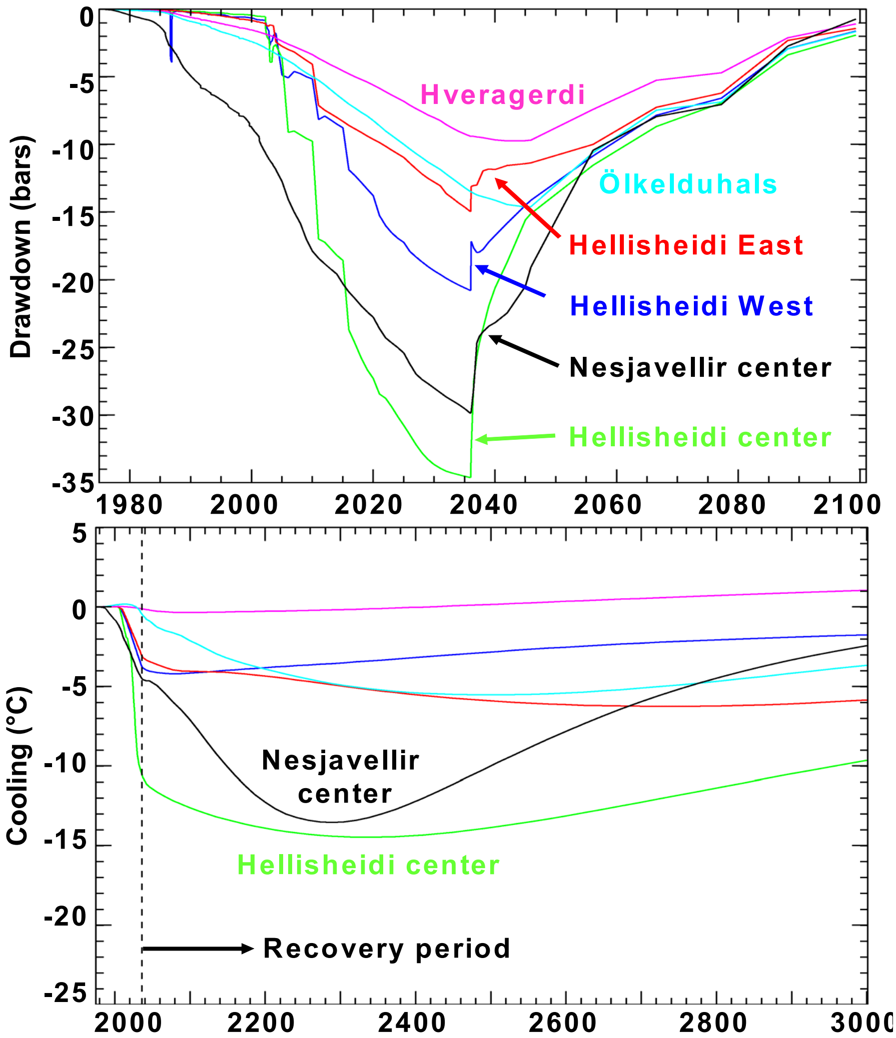

FIGURE 17: Calculated changes in reservoir pressure and temperature in different parts of the Hengill area, including the central part of the Nesjavellir geothermal reservoir, during a 30-year period of intense production, and for the following recovery (production stopped in 2036). Predicted temperature changes are not well constrained because no cooling has been observed as of 2010. Figure from Axelsson et al. (2010); see also Björnsson et al. (2003)

In simple models (simple analytical and lumped parameter models), the real structure and variable properties of a geothermal system are greatly simplified and they often only simulate one aspect of a geothermal system's response. Detailed and complex numerical models, on the other hand, can accurately simulate most aspects of a geothermal system's structure, conditions and response to production. Simple modelling takes relatively little time and only requires limited data on a geothermal system and its response, whereas numerical modelling takes a long time and requires powerful computers as well as comprehensive and detailed data on the system in question. The complexity of a model should be determined by the purpose of a study, the data available and its relative cost. In fact, simple modelling is often a cost-effective and timesaving alternative. It may be applied in situations when available data are limited, when funds are restricted, or as parts of more comprehensive studies, such as to validate results of numerical modelling studies. This applies in particular to lumped parameter modelling of the pressure response of a geothermal system, which can very accurately simulate and predict long-term pressure changes in geothermal reservoirs. It should be kept in mind that detailed numerical models can also be misused when they are based on limited data, and considered more reliable than they actually are, because of their calculation power.

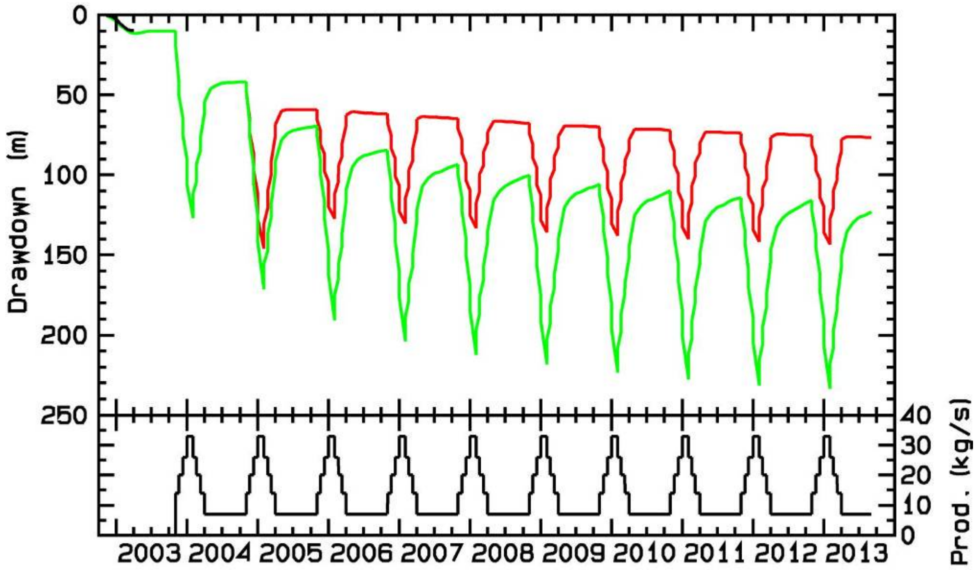

FIGURE 18: Water level predictions for well BY-1 in the Lishuiqiao area of Beijing, calculated by a numerical model (Hjartarson et al., 2005) for two production scenarios, one with 50% reinjection (red line) and the other without any reinjection (green line)

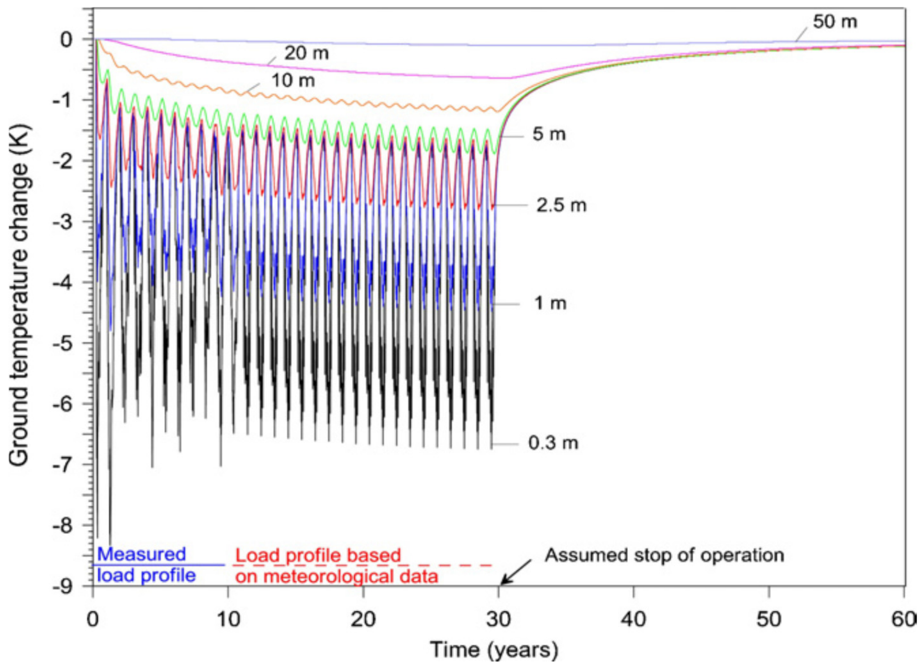

FIGURE 19: Simulated ground temperature changes of a borehole heat-exchanger, at Elgg in Switzerland, relative to the undisturbed situation in December 1986 over 30 years of operation and 30 years of recovery (from Rybach and Eugster, 2010)

The methods of geothermal reservoir modelling, in particular the methods of numerical modelling, are persistently evolving, both through the development of general modelling methods (e.g. the numerical methods applied) and advances more specific for geothermal applications. Discussing this is beyond the purpose of this paper, but the following are some of the relevant issues:

- Efficient coupling of reservoir and well-bore models
- Boundary conditions (open, closed or mixed) are not well known, what data can be used to calibrate them

- Nature of bottom boundary, does hot natural recharge e.g. increase during production
- How to model fractured media accurately and efficiently
- How to model effect of reinjection, e.g. reservoir and well cooling; difficult to model in detail with full-scale models
- How to model production induced cold recharge
- How to model long-term (~100 yrs) utilization, both production and reinjection effects
- Modelling of chemical processes such as mineral dissolution and precipitation, which affect reservoir properties
- Modelling of high temperature and pressure conditions, even supercritical conditions
- How should geophysical data (resistivity, seismicity, gravity changes, etc.) be used, in addition to reservoir data, to calibrate geothermal models
- Estimating uncertainty in predictions
- Modelling the deep roots of volcanic systems, i.e. small and large magmatic intrusions.

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The author would like to acknowledge numerous colleagues for fruitful discussions and cooperation during the last two – three decades or so, on different aspects of geothermal system modelling, in particular the late Gudmundur Bödvarsson, who was a genuine pioneer in numerical reservoir modelling. The late Gunnar Bödvarsson, a true grandfather of geothermal reservoir science, proposed the method of lumped parameter modelling discussed above. The relevant geothermal utilities and power companies are also acknowledged for allowing publication of the case-history data presented.

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