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# Management of geothermal resources: PNOC-EDC experience

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**Abstract**

The Philippine National Oil Company - Energy Development Corporation (PNOC-EDC) has acquired considerable operating experience after more than a decade of managing its geothermal production fields in the Philippines. PNOC-EDC was able to formulate immediate and long-term reservoir management strategies for the sustainability of the resource through intensive monitoring and thorough understanding of the fields' behavior before and during exploitation. These management strategies are assiduously modified during the production stage to suit field behavior and optimize production. These management strategies including the monitoring aspects and parameters and the different methods of measuring these parameters are reviewed in this paper.

# 1 Introduction

A geothermal resource is generally considered a finite resource that requires proper management to sustain its production for a desired duration. The renewability and sustainability of the resource depends mainly on how the reservoir will be managed and its response to utilization. Uncertainty on the sustainability of the field arises when the resource shows negative response to production such as declining field capacity, and field management intervention is implemented to address this problem.

After more than a decade of managing its geothermal production fields in the Philippines, the Philippine National Oil Company- Energy Development Corporation (PNOC-EDC) has acquired considerable operating experience. This experience has aided PNOC-EDC in formulating suitable field development and management strategies that are constantly reviewed and modified during the exploitation stage to establish field sustainability and optimize production. Close monitoring of the response of the field has been the key parameter implemented by PNOC-EDC in formulating these strategies. Much of the discussion here is lifted from the recent work of Sarmiento (2000) where he outlined the major development strategies and physical monitoring activities PNOC-EDC has adopted in managing its production fields.

# 2 Resource assessment (exploration and delineation stage)

The primary objective during the exploration and delineation stages is to evaluate the magnitude of the resource and the size of the power station that can be supported over the project life. In general, the following desirable features are established in assessing a geothermal resource (Clotworthy, 1997):

1. Suitable resource temperatures for the proposed development (i.e. power or direct use).
2. A significant amount of stored heat for resource longevity.
3. Large reservoir permeability to provide high well outputs that would minimize well requirements.
4. A known injection area for brine disposal that would minimize the impact on the development.
5. Benign chemistry of the reservoir fluid that would give minimal tendency for mineral deposition or corrosion. Low levels of non-condensible gases.
6. Low risk of volcanic and hydrothermal activities.
7. Good site access.
8. Market proximity.

These features are usually seldom all satisfied which would require a trade-off between them in any geothermal development. The majority of these parameters will not be known at the early stage of development and this emphasizes the need for the resource evaluation to be updated during the exploration, development and production phases. As more data become available, assessment of the resource should become more certain although it is important that at each stage the uncertainties are fully appreciated, and the level of detail is appropriate without giving a spurious impression of precision.

Evaluations of geothermal prospects are based mainly on the results of geological, geophysical and geochemical surveys and investigations in the early stages of exploration. Surface mapping of faults, geology and sampling of hot springs and steam vents provide the basis for a geophysical survey program. The major geophysical technique employed is the measurement of underground resistivity using arrays of detectors with varying spacings and a current source on the surface. Areas of low resistivity are indicative of the presence of mineralized water in the rock, indicating potential targets for drilling. Other geophysical surveys such as aeromagnetics, magnetotelluric and seismic are conducted to complement the initial resistivity data.

The available geoscientific data are then examined to infer the nature, characteristics and the probable size of the geothermal resource and construct an initial model of the field. The exploration model usually represents the probable origin and source temperature of fluids used in deciding whether to conduct exploration drilling and/or additional geoscientific investigations.

Static formation temperature tests (SFTT) are performed once exploration drilling has begun. SFTT's are used to guide the setting of the production casing shoes. Completion tests are then conducted according to a standard program once the wells are completed, and monitoring of the temperature recovery of the wells by downhole surveys then follows. If the well will not self-discharge, appropriate stimulation technique is then recommended based on the results of the completion tests and heat-up surveys. The discharge of the well gives vital information on the temperature, enthalpy and chemical composition of the reservoir fluid. The behavior of the well on extended discharge gives additional information on the extent of permeability, particularly if pressure monitoring by other wells (interference testing) is possible (Sarmiento, 1993).

It is then possible to build an integrated picture (conceptual hydrological flow model) of the reservoir as a whole, in combination with geological and chemical models, once results are obtained from a number of wells. The key to successful resource assessment is to develop and maintain the conceptual hydrological model of the geothermal system, which makes use of available data from all disciplines (geophysics, geology, geochemistry, reservoir engineering, drilling, etc). Often data from one discipline can complement those of another in a way that may not be apparent until they are combined. The results of this preliminary resource assessment should indicate whether development drilling could go on, and the probable targets of future wells. The study in many cases includes an initial estimate of the capacity of the field.

The next stage for a successful development is the delineation phase, where production wells are targeted to define the boundaries of the reservoir and to provide information on possible areas for injection. Knowledge of the subsurface conditions is gained as development begins. It is also then possible to refine the initial conceptual model of the system and improve the quality of the resource assessment.

## 2.1 Reserve estimation

Reserve estimation is one of the most important activities in the planning stage of geothermal development. Any development cannot continue without the assurance that the field has a reserve capacity to produce over the projected life of the field. Reserve estimation also impacts on the infrastructure and investment requirements of the project. There are a number of techniques available that are used to assess geothermal resources. They depend on various parameters and have been useful at various stages of the resource development.

The most common method used is the volumetric heat-in place (stored heat) calculation (Muffler and Cataldi, 1978; Muffler, 1981). The principle in the stored heat method is to estimate the heat stored within the defined reservoir volume, above some base temperature, and converting it to electrical power using recovery factors and conversion efficiencies. The stored heat includes the heat stored in both the rock and the in-place reservoir fluid. The reservoir volume is usually taken as the aerial extent multiplied by the drilled depth plus some storage volume, commonly another 500 m.

This method has mainly been applied to electrical generation projects although it may also be useful on direct use projects. The method is normally used at the initial exploration stage although it is necessary to make assumptions regarding unknown parameters, such as resource volume, which have a significant impact on the results. As drilling proceeds, these parameters can be better defined which should result in a refinement of the technique.

The merit in doing a stored heat assessment is that it gives an understandable, rational basis for comparing the size of different geothermal resources, taking into account both volume and temperature. The value of the stored heat calculations can be reasonably demonstrated by applying them to known fields and establishing that they produce what has been confirmed to be a sustainable output (Menzies, 2000).

Another technique employed to estimate the geothermal resource is the heat flux method that is derived from physical estimates or chloride flux. This method is used at an early stage of the project and assumes that the minimum natural heat flux, reflects the absolute minimum that can be produced from the system. In practice, this estimate is normally very low and it may be possible, based on experience, to develop a factor that allows a more realistic estimate to be obtained (Menzies, 2000). However, care is taken in using this method, particularly in fields where there is little or no surface expression or where there is significant thermal activity.

## 2.2 Monte Carlo simulation

The stored heat method described above uses a “deterministic” approach to the estimation of reserves where uncertainty in the parameters is not addressed. In practice, it is more proper to allow the variables to vary over a defined range, with the probability of any particular value being determined from an appropriately defined distribution. This process becomes the basis of the “Monte Carlo Simulation” technique. The distributions used in the exploration stage may cover a wide range but as additional data becomes available, the parameter distributions can be refined.

In this simulation technique, "random numbers" are generated with the defined statistical distributions to determine the values of the parameters used to calculate the stored heat. This calculation is repeated, normally more than 1,000 times, until a defined probability distribution for the output parameter of interest, such as power potential is obtained.

There are a considerable number of possible statistical distributions that can be used to describe each of the variables. The most common set of distributions, are the triangular and lognormal distributions as they can be skewed to various degrees (see Figure 1). In the triangular distribution, the most likely minimum and maximum values are used to define the distribution. Such is the case in the reservoir temperature and area that may be described in this way. For the lognormal distribution, the mean and standard deviation need to be defined.

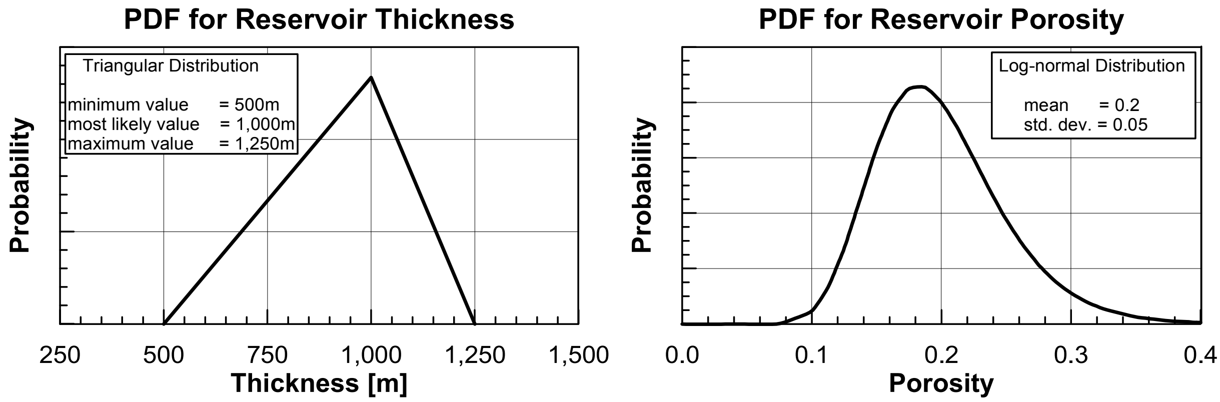


**Figure 1: Triangular and lognormal probability distributions (after Menzies, 2000).**

The results of the Monte Carlo simulation are usually presented as a Probability Density Function (PDF) of the number of occurrences of a particular value (reserve estimate) and as a plot of the Cumulative Distribution Function (CDF). These are shown in Figure 2. In this case, the most likely value of the reserve capacity occurs at 100 MWe. The CDF plot shows there is a 45% probability that the size of the field is less than 100 MWe and conversely, the probability that the field size is more than 100 MWe is 55%. Moreover, the ***median*** value occurs at a cumulative probability of 0.5 and is 105 MWe.

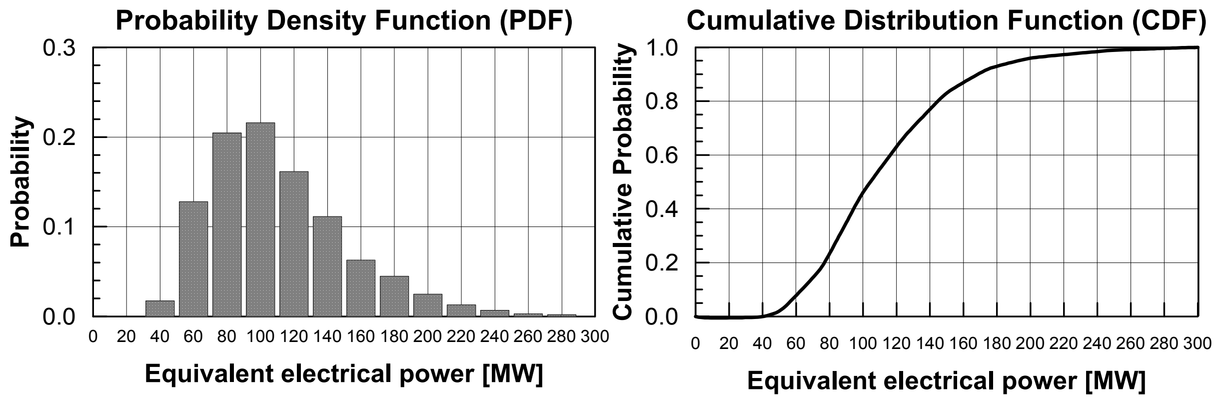


**Figure 2: Results of Monte Carlo simulation (after Menzies, 2000).**

### 2.3 Natural state model

The natural state computer model of the field is commonly developed after the stored heat assessment to verify the conceptual model of the system. Matching the temperature profiles and thermodynamic states of the wells and the pressure profile of the reservoir will provide an estimate of the fluid flow rate in the natural state. This can then be compared to the known or estimated flow through the system. A reservoir with a high throughput provides evidence of recharge that is usually not taken into account by the stored heat calculation. Production modeling based on the natural state model can provide an initial check on the size of the field, and will be very crude as the reservoir porosity and horizontal permeability have not been matched. It will also provide a check on the field size obtained from the stored heat method.

Reservoir modeling is conducted to understand and predict the dynamic behavior of geothermal systems. There are several methods that have been applied from relatively simple analytical and lumped parameter models to sophisticated three-dimensional numerical models that include heat and mass transfer, and phase changes. These methods are also conducted during the development stage, but are usually used during the production stage as a tool in reservoir management.

## 3 Development strategy (production stage)

Confirmation on the existence of the geothermal resource leads to the development of the reservoir to support a power station. In an ideal case, the resource is developed only after completion of fieldwide testing and evaluation of the development strategies that will correspond to the anticipated behavior of the field. A staged development in some cases is undertaken with an initial development that is comfortably within the field capacity such as in the case of Tongonan 1 (see Figure 24). The selection of a field development strategy is initially based on the reserve capacity, well characteristics, conceptual model, terrain and the economic cost of the project.

It is also important to obtain as complete a set of baseline data as possible before the reservoir is disturbed by full-scale production. The initial thermodynamic state of the fluid in the reservoir is characterized, together with the possible external interactions such as groundwater and deep recharge. Modeling of the performance of the reservoir is much more difficult if this baseline data has not been collected.

### 3.1 Engineering design

Engineering design of surface facilities (i.e. separator stations and pipelines) and power plant interface data are conducted where the characteristics of the wells drilled are taken into account, once a decision has been made to proceed with the development of the reservoir to support a power station. Siting of injection wells and estimates of their injection capacities are also crucial for pipeline and pump designs. Flexibility in the design stage is emphasized to account for variations in well and reservoir behavior with time. Facilities for measurements on wells (i.e. downhole surveys, inhibition test and output testing) are also considered before the design is finalized.

### 3.2 Production strategy

The main production philosophy in developing the resource normally focuses on the maintenance and sustenance of the field during exploitation where the total project cost and field capacity is optimized. Generally, production is spread out in the field from selected groups of wells if surplus capacity is available. A production strategy can also include drilling of additional wells within the two-phase zone (steam cap) of the reservoir to minimize the amount of brine for injection thereby reducing the effects of injection returns to production wells (e.g. Tongonan 1 and Palinpinon 1). However, production from the highly two-phase zone may be limited due to the faster anticipated run down and presence of unwanted non-condensible gases ($CO_2$ for example).

## 3.3 Injection strategy

Geothermal brine injection is primarily conducted to dispose of the waste fluid and provide pressure support in the reservoir during its exploitation. PNOC-EDC identifies brine injection as a critical component of field development. The overall injection philosophy includes deep injection to improve thermal recovery of the injection fluid and dispersal of injection fluids to avoid possible returns into a particular production sector. The harmful effects of injection returns into the production wells in Palinpinon have forced PNOC-EDC to locate most of the injection wells at the edges (or outside) the proven boundaries of the field. Gravity injection is implemented since the injection pads are usually located at lower elevation than production pads. This scheme translates to lower total project cost of the Fluid Collection and Disposal System (FCDS). Injection pumping is only adopted when targeted injection wells have higher elevations than separator stations.

PNOC-EDC has also adopted zero waste disposal schemes in support of the government's environmental policy and guidelines. This scheme includes the disposal of steam condensates from the power plant and discharges from well testing activities.

The overall development strategies implemented by PNOC-EDC are validated through close monitoring of production data such as temperature, enthalpy, massflow, chemistry and surface activity. Continuous monitoring of these production parameters will prove whether the resource is capable of sustaining production or expansion of the resource. Alternatively, whether the plant capacity was oversized for the available resource which would require additional reserves to be found. It is also through the changes in these monitoring parameters that must be established in order to continue updating the conceptual model of the system. Monitoring of a geothermal field provides an up-to-date evaluation of the resource.

The following management actions are undertaken when changes in the monitoring parameters are obtained (Sarmiento, 2000):

a) Validate well utilization strategy and make adjustments in the wells' production and injection schedule to meet steam interface conditions at the power station.
b) Predict the rundown rate of steam to the power station and the timing of maintenance and replacement (M & R) wells and well intervention (workover) to prevent steam shortfall and/or power outages.
c) Forecast reservoir performance by updating the initial natural state field model from recent field observations and implement changes on the current management strategy to sustain production and/or to determine whether an expansion of the field capacity is warranted.
d) Optimize the exploitation of the resource and keep the operating costs of the field at a minimum to attain a desired return of investment (ROI) by being able to avoid unnecessary maintenance works caused by deteriorating steam supply due to flawed management strategy.
e) Check the power station performance with regard to its steam consumption and efficiency.
f) Program well tests to confirm surface and subsurface abnormalities observed from the wells and/or the FCDS.

# 4 Field monitoring techniques

The aim of a long-term monitoring program is to establish a baseline prior to large-scale disturbance of the system, and then monitor the established parameters frequently enough to enable changes in the state of the system to be detected as they take place. The field monitoring techniques employed by the company generally includes downhole surveys, well discharge and flow measurements and chemical sampling. Downhole surveys and discharge and flow measurements deal with monitoring of physical parameters, while chemical sampling pertains to monitoring of chemical parameters in the reservoir and discharge fluid.

## 4.1 Downhole measurements

Downhole temperatures and pressures are measured using mechanical gauges and electronic instruments. These downhole surveys are conducted in the wells either during shut or flowing condition and taken periodically during the course of the field operation. Shut surveys taken prior to full-scale exploitation are used to determine the baseline (natural state) temperature and pressure condition of the reservoir, as well as identify the permeable horizons within the reservoir. Isotherms, isobars (pressure control point PCP plots) and permeability distribution are established from these surveys, which delineate the different features of the reservoir (i.e. upflow, outflows, natural recharge). Pressure transient tests (interference tests) are also conducted in the wells to establish well/reservoir permeability. Flowing temperatures and pressures are also taken to establish the permeable zones feeding the well during discharge. Similarly, downhole surveys conducted during injection will determine the zones where fluid is accepted into the reservoir.

The changes in the reservoir are then established from the variations of the updated parameters against baseline measurements. Frequency of the surveys depends on the availability of the wells. Availability of the wells is usually limited to periodic annual or biennial plant shutdowns (for preventive maintenance) and irregular shutdowns for unscheduled repairs. It is important to take advantage of these opportunities for additional surveys. Generally, downhole surveys in each well are conducted quarterly to provide a reliable trend on the reservoir temperature and pressure including an update on the condition of the wells (i.e. blockages, casing problems).

Regular downhole measurements are also taken in available monitor (marginal) wells to record the changes in reservoir pressures. These are used together with shut-in downhole pressure and temperature surveys to evaluate local variations in temperature or pressure decline.

Geophysical measurements such as micro-gravity can also supply independent data to supplement the downhole measurements discussed above. This can give an independent estimate of mass depletion or addition, and their aerial location if micro-gravity changes can be reliably monitored. For production sectors, this can provide an independent assessment of fluid saturation.

## 4.2 Discharge and flow measurements

Discharge output of the wells is generally computed either through a separator or by the James Lip Pressure method where the well is discharged through the silencer. The flows of separated water and steam through the separator are normally measured using orifice plates. Separating the water and steam phases in a cyclone separator and measuring the two phases is considered a more accurate method in testing the output of the well. The Lip Pressure method uses a set of equations derived from correlation of the critical discharge pressure (lip pressure), separated water flow (weir flow) and discharge enthalpy.

The plot of total discharge (massflow) and enthalpy against wellhead pressure gives the well characteristic curves that enable information about the reservoir to be deduced. The well output is then regularly monitored during the course of exploitation as shown in Figure 3 below. The field capacity (steam availability) is updated against plant load requirement to establish the performance of the reservoir. Moreover, the rundown rate of steam available for the power station is calculated which determines steam supply or injection capacity shortfall. This is then addressed by drilling replacement wells or by other well intervention techniques such as acid treatment. In some cases, discharge data for individual wells are not available so that trends of total massflow and enthalpy for a separator station are then monitored.

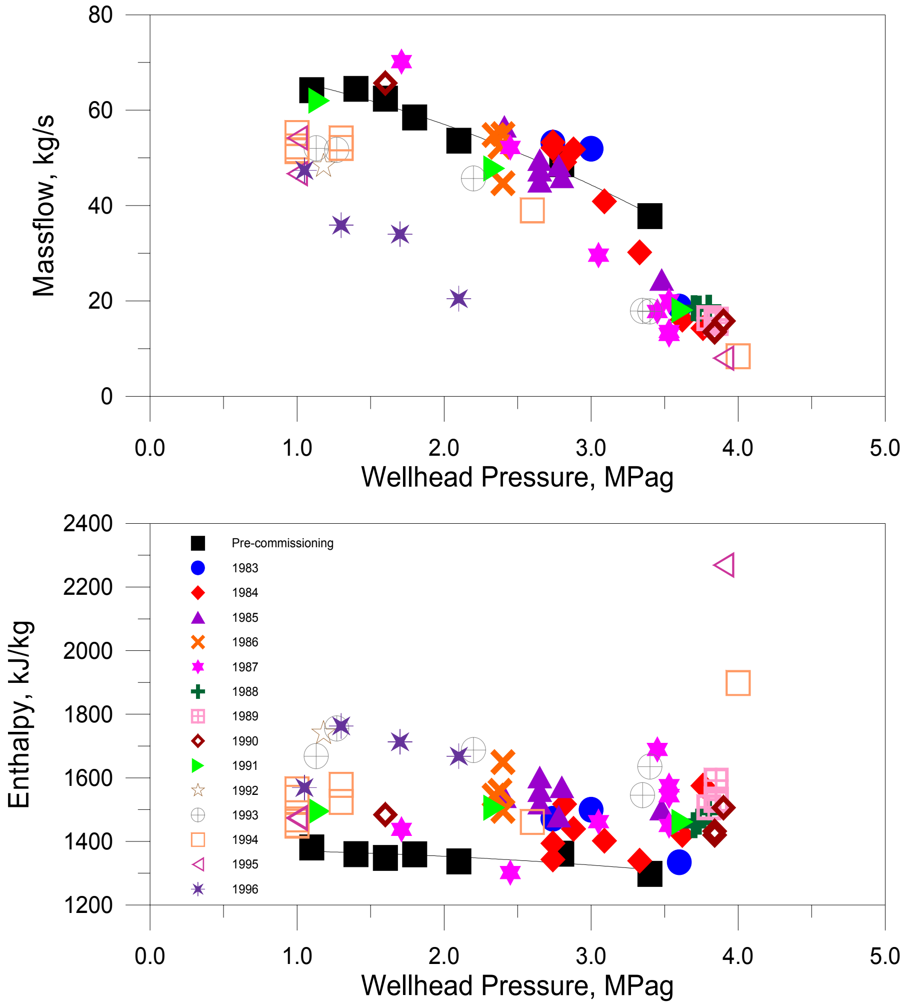


**Figure 3: Well output trend with wellhead pressure at various times during exploitation (after Sarmiento, 2000).**

The frequency of bore output measurements (BOM) using the silencer also depends on the availability of the wells. The output measurement is usually conducted in one opening only, normally at the operating wellhead pressure before the well was cut out. The output at other well openings is measured when the well is cut out at longer periods such as during scheduled plant shutdown. Recently, a tracer dilution method has been applied by PNOC-EDC to measure well outputs when the standard BOM through the silencer are not practical (Macambac et al., 1998; Magdadaro, 1998).

The injection of liquid and gas tracers simultaneously into the two-phase flow stream at known rates enables the mass flowrates of both the liquid and steam phases and enthalpy to be determined. Tracers must partition completely into their respective vapor or liquid phase. The liquid tracer must be highly soluble in water to facilitate injection and metering while the vapor phase tracer must have high vapor pressure (Hirtz and Lovekin, 1995).

The tracers used in flow measurements are magnesium chloride ($MgCl_2$), sodium flourescein (Na-flourescein) and sodium benzoate (Na-benzoate) for brine flow, and sulfur hexaflouride ($SF_6$) for steam flow measurements. $MgCl_2$ is normally used to measure brine flow in injection wells (e.g. capacity or reinjection load monitoring), while Na-benzoate together with $SF_6$ are used to measure the discharge output of the well. The tracer dilution method requires precise measurements of the vapor and liquid phase tracers injected into the two-phase flow stream. Analyses of the collected samples of each phase are evaluated to determine the tracer amount, from which the massflow of each phase is calculated based on the measured concentration and the injection rate of each tracer.

The liquid phase mass rate is given by:

$$m_L = \frac{m_T}{(C_{TL} - C_{BL})}$$

where, $m_L$ = liquid phase mass rate
$m_T$ = tracer injection mass rate
$C_{TL}$ = liquid-phase tracer concentration by weight
$C_{BL}$ = liquid-phase background concentration by weight

The vapor-phase mass rate is given by:

$$m_V = \frac{m_T}{(C_{TV} - C_{BV})}$$

where, $m_V$ = vapor phase mass rate
$m_T$ = tracer injection mass rate
$C_{TV}$ = vapor-phase tracer concentration by weight
$C_{BV}$ = vapor-phase background concentration by weight

The mass rates calculated are valid for the temperature and pressure at the sample collection point. The total fluid enthalpy can then be calculated using a mass and heat balance equation at the given separation pressure as shown by the equation:

$$H = ((m_V \text{ x } H_V) + (m_L \text{ x } H_L)) / (m_V+m_L)$$

where, $H_V$ and $H_L$ are the vapor and liquid enthalpies, respectively.

The tracer dilution method is also applied to measure steam supplied to the plant and brine flows that are disposed to the injection wells.

## 4.3 Chemical monitoring

Regular monitoring of water and steam chemistry in the discharge fluid also provides additional reservoir information that is vital to field management. These data include source of fluid recharge to the reservoir, cool dilute groundwater, condensate or injection fluids. Downhole chemistry of the fluid is also taken depending on the availability of the wells to be sampled. These geochemical observations are combined with the physical measurements to build up a more complete picture of the performance of the field.

# 5 Monitoring parameters

The various parameters prioritized by PNOC-EDC in monitoring of its operating fields can be summarized in Table 1.

**Table 1: Reservoir parameters monitored by PNOC-EDC to manage the geothermal fields (after Salera, 1991).**

**Production wells**
a) Output: massflows (steam/water), enthalpies, wellhead pressures
b) Downhole temperatures and pressures
c) Downhole blockages/obstructions: scraper samples
d) Fluid chemistry (discharge/downhole)

**Injection wells**
a) Injection capacity, pressures
b) Downhole temperatures and pressures
c) Downhole blockages/obstructions: scraper samples

**Injection lines**
a) Fluid chemistry: $SiO_2$
b) Scales samples

**Steam Header**
a) Fluid chemistry: $CO_2$, $H_2S$, Na
b) Steam flows

**Monitor/Observation wells**
a) Downhole temperatures and pressures, wellhead pressures
b) Downhole blockages/obstructions: scraper samples

**Field microseismicity**

**Field thermal manifestations, hot springs**

## 5.1 Temperatures

The changes in downhole temperatures can indicate inflow of natural recharge or injection returns into the reservoir. The source of the recharge can also be delineated from these changes together with the measurements of reservoir pressures and well output. Figure 4 shows the downhole survey of a well affected by injection returns. The decline in temperatures at shallow depths could also indicate inflow of cooler fluids. The well also registered a decline in discharge enthalpies and a drop in wellhead pressure. Conversely, Figure 5 shows a natural cold inflow into a well that is present before exploitation. Incorporating this observation in the isotherm plot including other wells could indicate the source of the cold fluid as shown in Figure 6. The presence of this feature (cold fluid) can provide early warning as to the possible negative effects to neighboring wells once pressure drawdown occurs in the sector.

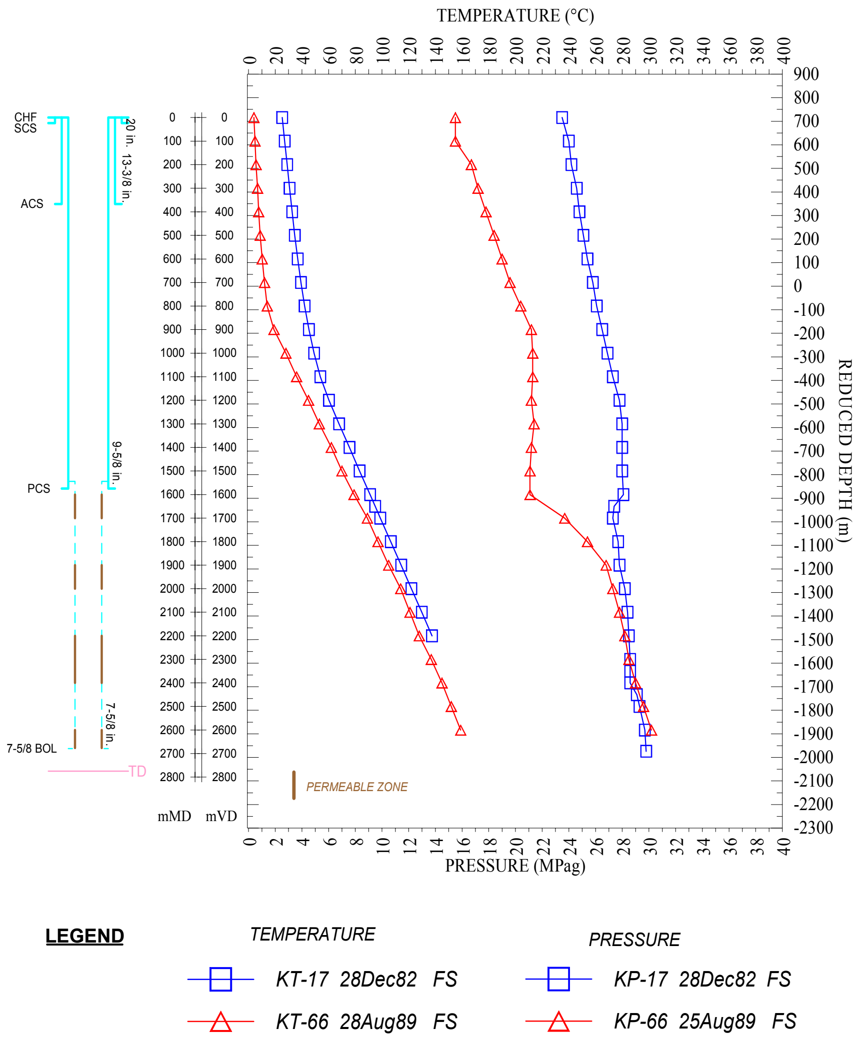


**Figure 4: Downhole temperature and pressure profile showing effects of injection returns (after Sarmiento, 2000).**

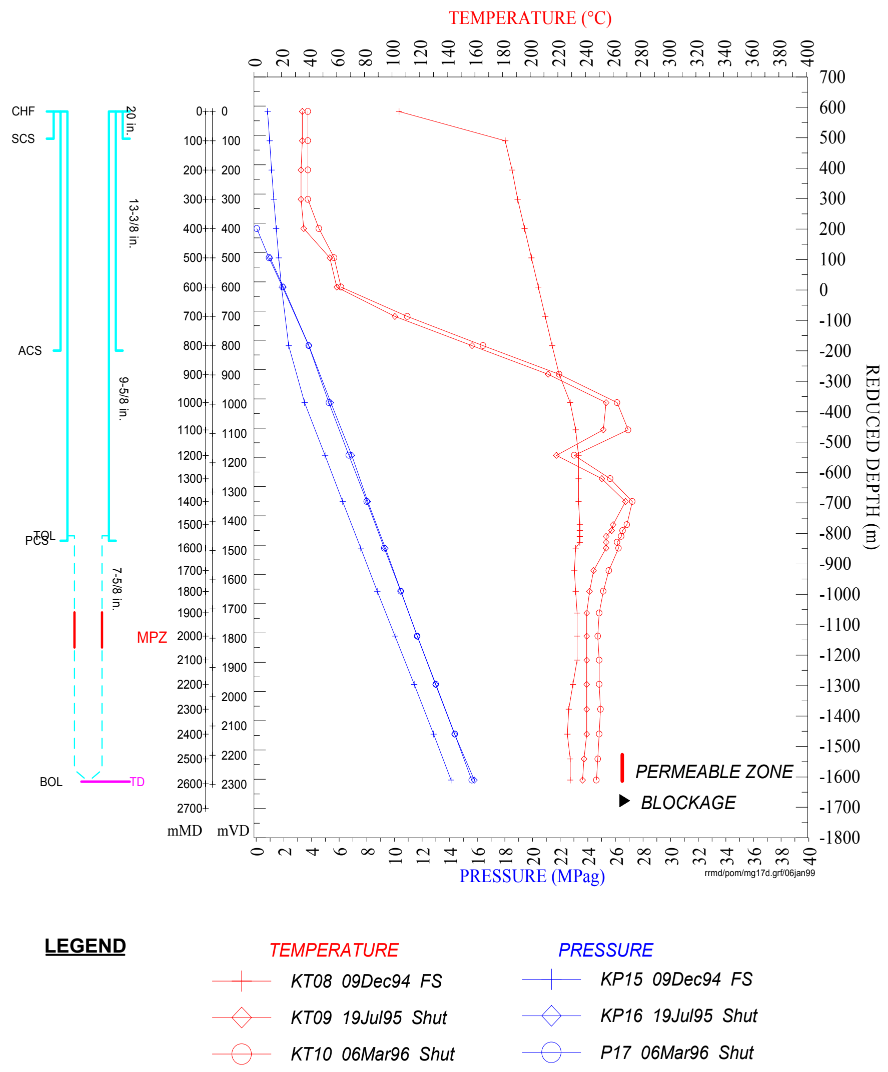


**Figure 5: Downhole profile showing cold inflow (after Sarmiento, 2000).**

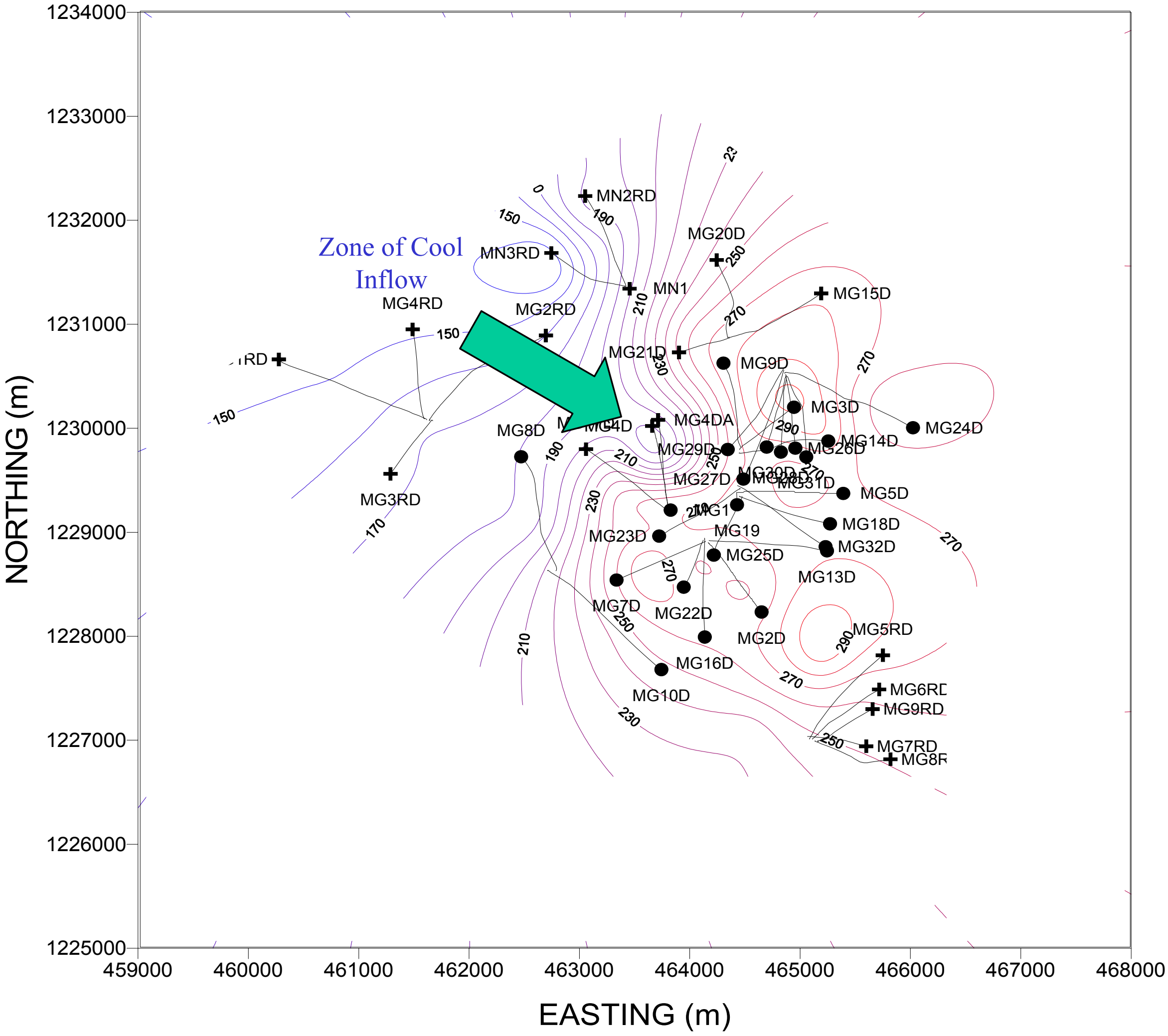


**Figure 6: Isotherms showing natural cold inflow from northwest (after Sarmiento, 2000).**

Flowing downhole temperatures can also illustrate fluid phase changes caused by fluid extraction with time. The well shown in Figure 7 was initially in the compressed liquid state, but later turned two-phase at shallow depths due to the pressure drawdown of the field.

## 5.2 Pressures

Downhole pressure monitoring with time can reveal the effects of increased mass extraction through faster reservoir pressure decline and recharge or injection returns through rebound in downhole pressures (Figure 8). A plot of reservoir pressure with mass extraction can show the likely time two-phase condition will set in as shown in Figure 9. The available reservoir fluid volume and remaining volume (assuming certain rock parameters) can also be determined from these measurements. The downhole pressure in Figure 9 did not reach two-phase condition as expected because of the influx of injection returns that resulted to stabilization of reservoir pressure in the well.

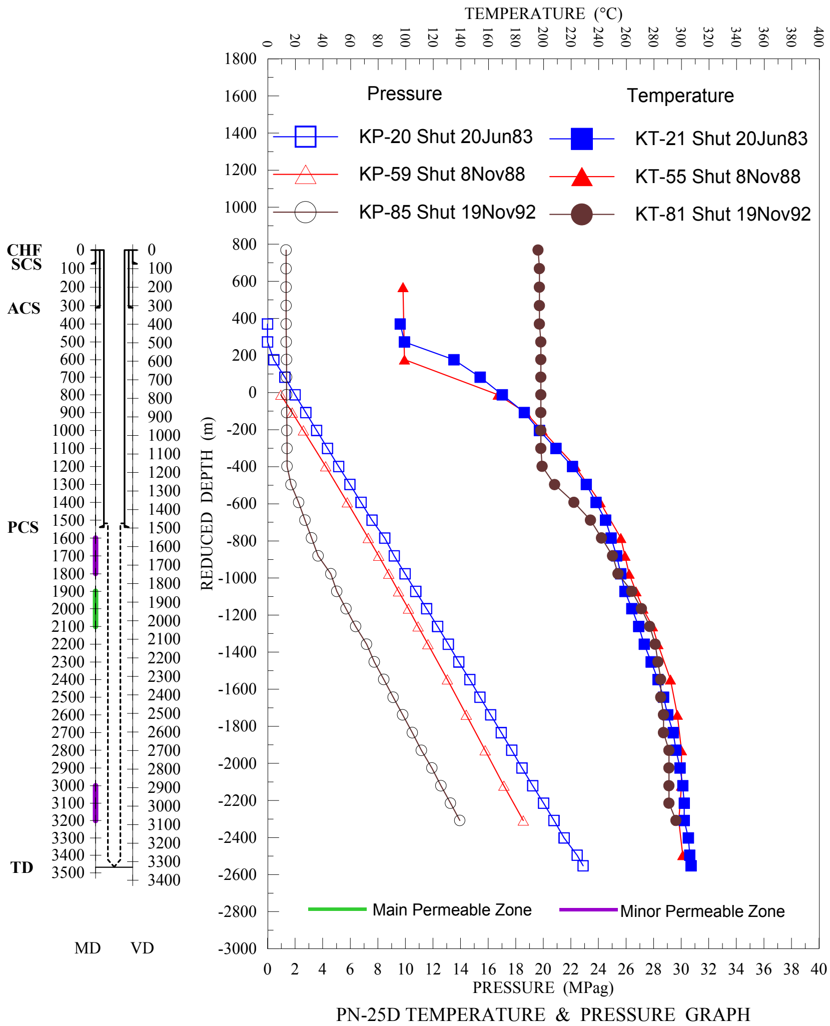


**Figure 7: Downhole profile of well showing transition from compressed liquid state to boiling (after Sarmiento, 2000).**

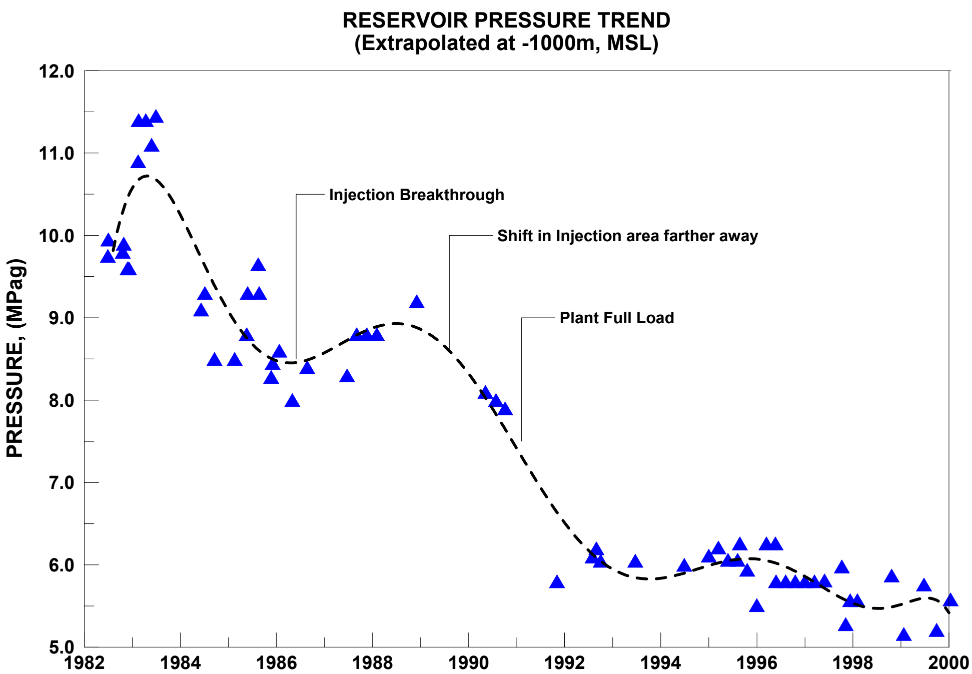


**Figure 8: Reservoir pressure with time showing effects of injection returns and increased mass extraction (after Orizonte et al., 2000).**

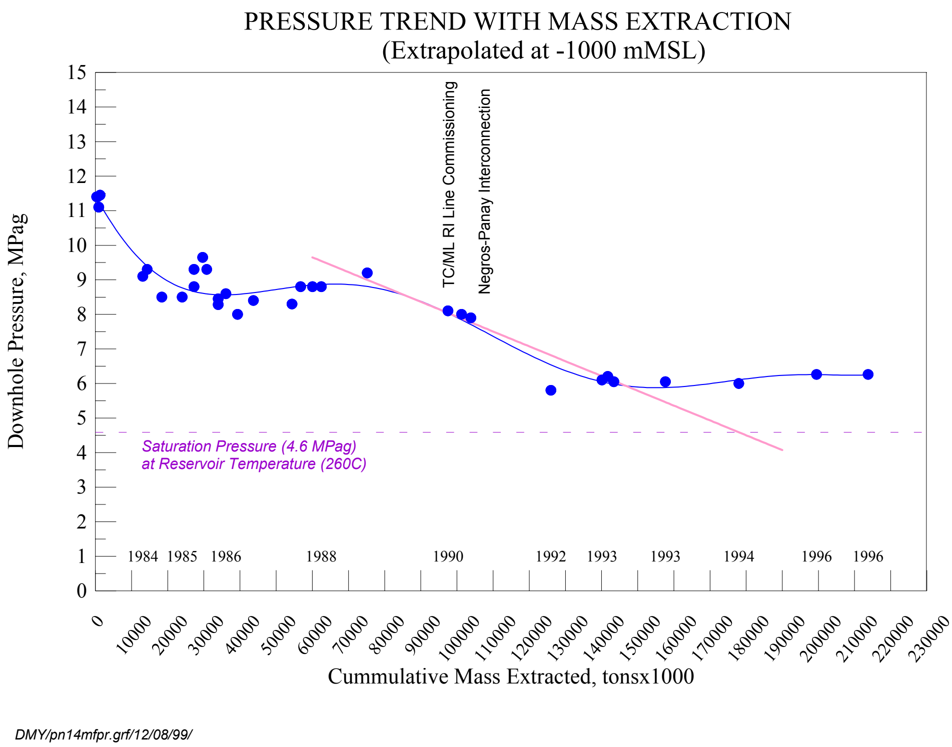


**Figure 9: Plot of downhole pressure versus time (after Sarmiento, 2000).**

Isobars at certain elevations can establish if production is evenly distributed across the field or concentrated in certain areas only. Significant pressure decline is usually seen in the production sector where mass withdrawal is highest while higher pressure values are recorded in areas where injection is located. The plot of downhole pressure (PCP) with depth for various wells provides the pressure gradient in the reservoir (Figure 10). Pressure gradients across the field can identify the source of natural recharge or injection. Monitoring of the changes in pressure gradient during exploitation provides information on reservoir drawdown and the change in water level in the wells, including the development of two-phase condition in the reservoir.

Wellhead pressure decline with time, especially with accompanying rapid decline in massflow, may indicate blockage in the well. In comparison, wellhead pressure rise at the same opening accompanied by increased enthalpies would indicate a shift in production to a much shallower depth due to development of two-phase condition in the reservoir. This trend is usually observed in the early part of the exploitation, especially in liquid-dominated systems.

### 5.2.1 Interference tests

Interference between wells is also evaluated from downhole pressure monitoring. Pressures measured in the observation wells are usually used to establish permeability within the area using standard welltest analysis techniques. The pressure interference data can also provide evidence on presence of recharge or reservoir boundaries. Figure 11 illustrates the pressure interference of a monitor well (shut condition) during injection into the neighboring wells. The increase in downhole pressures in the monitor well would reveal the presence of boundary in the area.

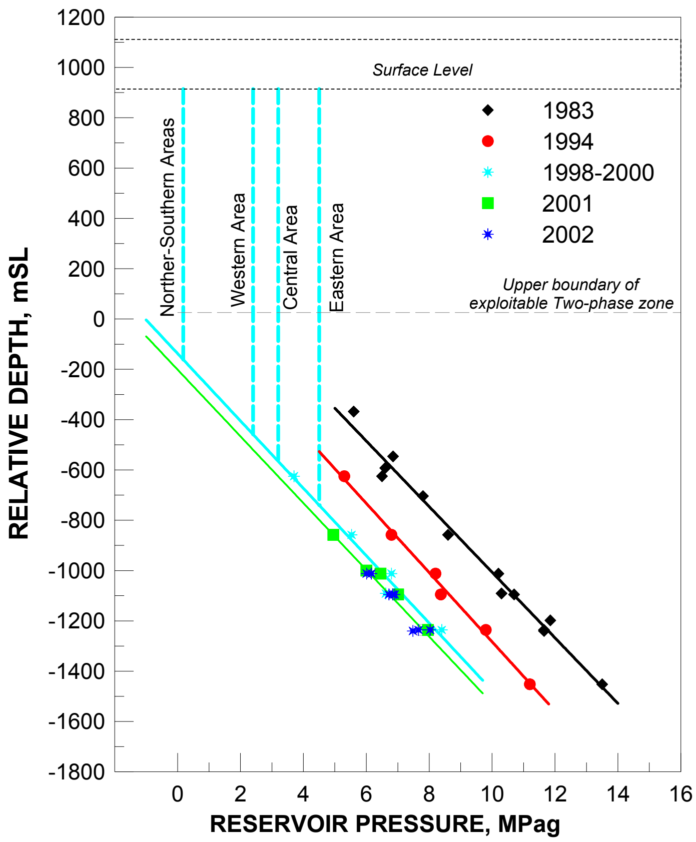


**Figure 10: Reservoir pressure vs. elevation plot (after Orizonte et al., 2000).**

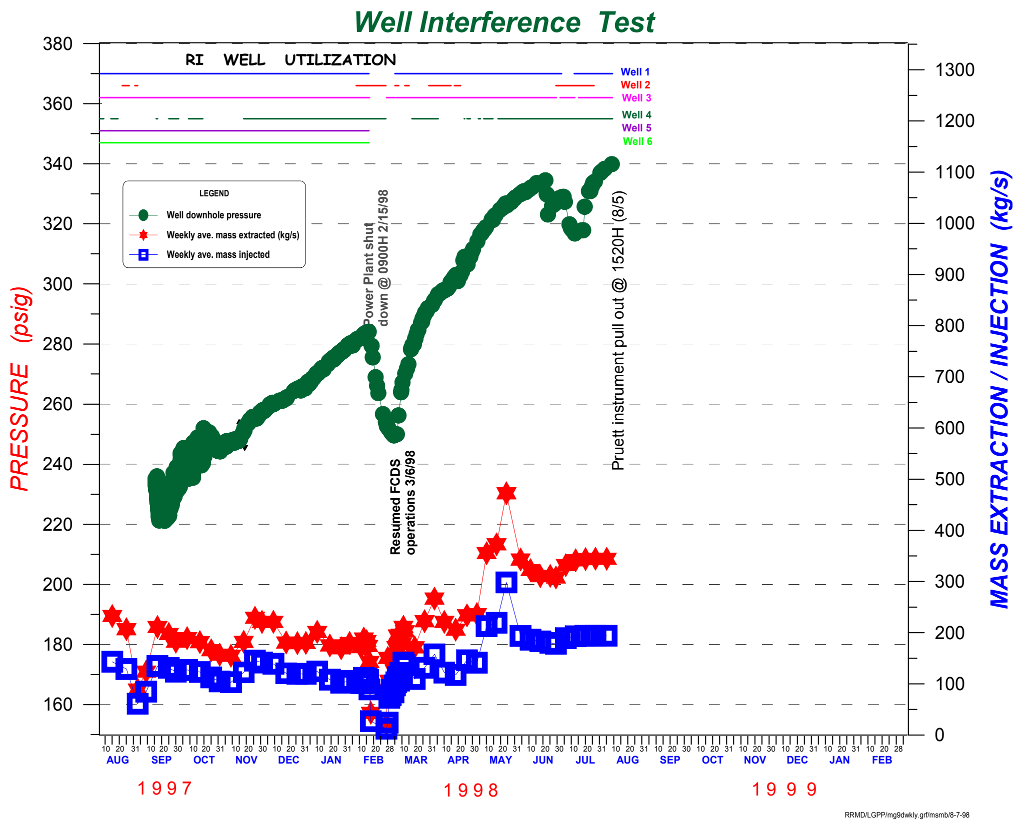


**Figure 11: Interference data showing increasing pressure during injection at neighboring wells (after Sarmiento, 2000).**

On the other hand, Figure 12 shows pressure drawdown in the monitor well that is a typical response due to exploitation. Simple lumped parameter models can then be used to match the pressure interference data and forecast the likely drawdown with continued extraction. The model gave a good fit to the measured data. The initial model results are then validated with the more detailed multi-dimensional reservoir models.

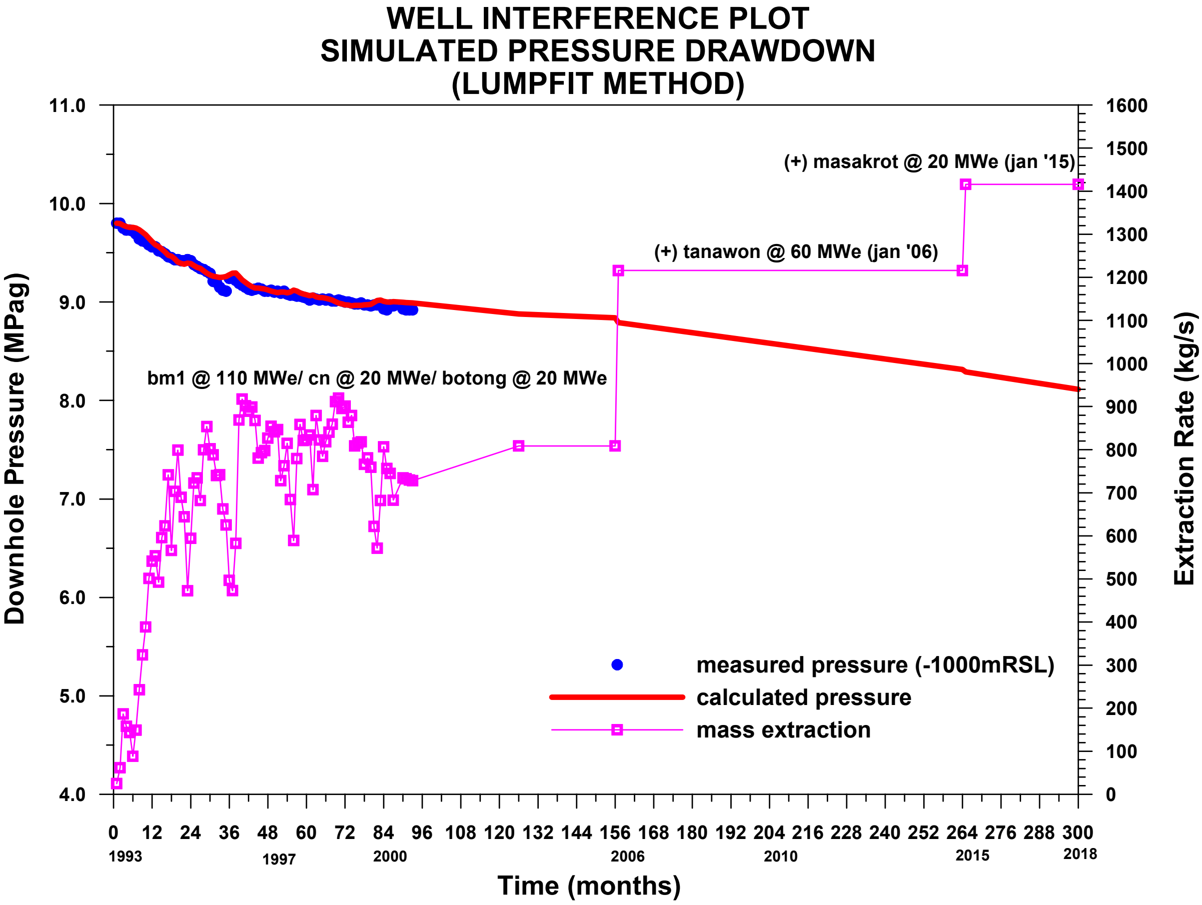


**Figure 12: Interference data shows declining pressure due to extraction in neighboring production wells. Plot also shows pressure match of lump parameter model with actual data (after Sarmiento, 2000).**

## 5.3 Permeability

Aside from interference tests, pressure transient tests such as drawdown-buildup and injection-falloff tests can also determine well permeability. The permeability values are then used to build permeability distribution of the field that will establish the likely reservoir fluid behavior during exploitation. These would include the probable source of recharge and the path of injection returns. The permeability distribution would also serve as information for the reservoir modeling studies of the field.

## 5.4 Bore output measurements

Regular monitoring of individual well outputs during exploitation can provide information on well performance that will establish whether the well requires intervention when its discharge parameters have declined (Figure 13). In particular, the well shown in Figure 14 shows the rapid decline in massflow with time due to mineral (calcite) deposition. A drop in wellhead pressure at the same wellhead opening accompanied this decline. The increase in enthalpy

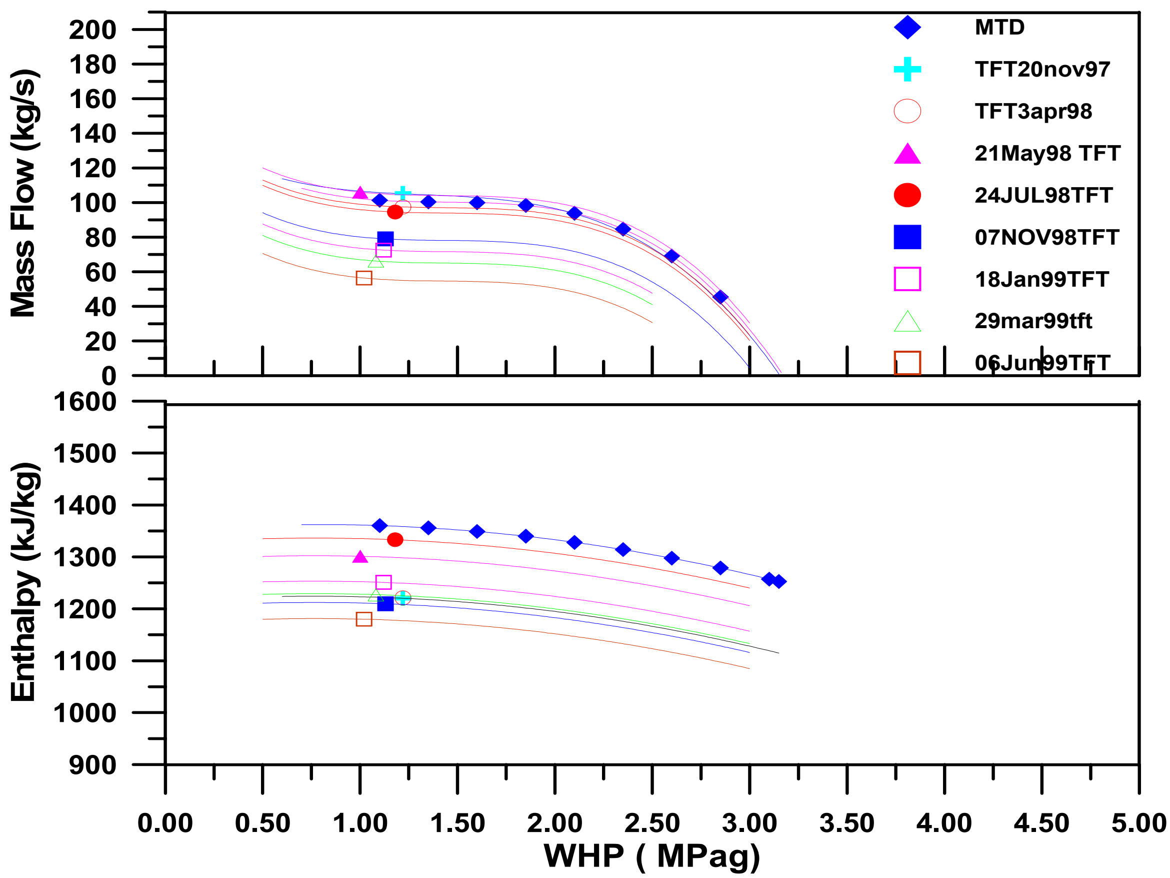


**Figure 13: Well output versus wellhead pressure at different times (after Sarmiento, 2000).**

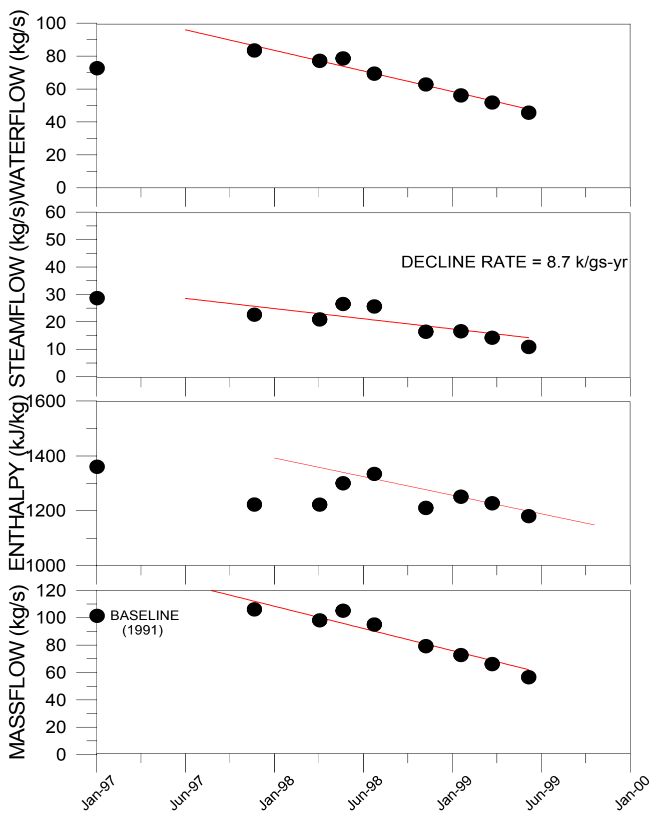


**Figure 14: Output of well showing decline in flow due to deposition (after Sarmiento, 2000).**

during its utilization is attributed to the shifting of major flow contribution from the deeper liquid feedzone to the shallower, high enthalpy feedzone. Remedial measures may include simple mechanical drillout of blockage and/or acid treatment of the permeable zones.

Figure 15, on the other hand, shows the changes in massflow of a well affected by drawdown that is supported by the increase in discharge enthalpy. The steamflow however remained constant. There was no blockage observed in the well that would confirm the decline in massflow.

Monitoring of the individual well mass withdrawal can also determine if the well utilization schedule implemented is optimized. High enthalpy wells with lower brine flows are usually prioritized. This should, however, be balanced by properly distributing mass withdrawal to a wider area in the field to prevent over-extraction in certain sectors that may cause additional problems such as induced influx of unwanted brine (injection returns).

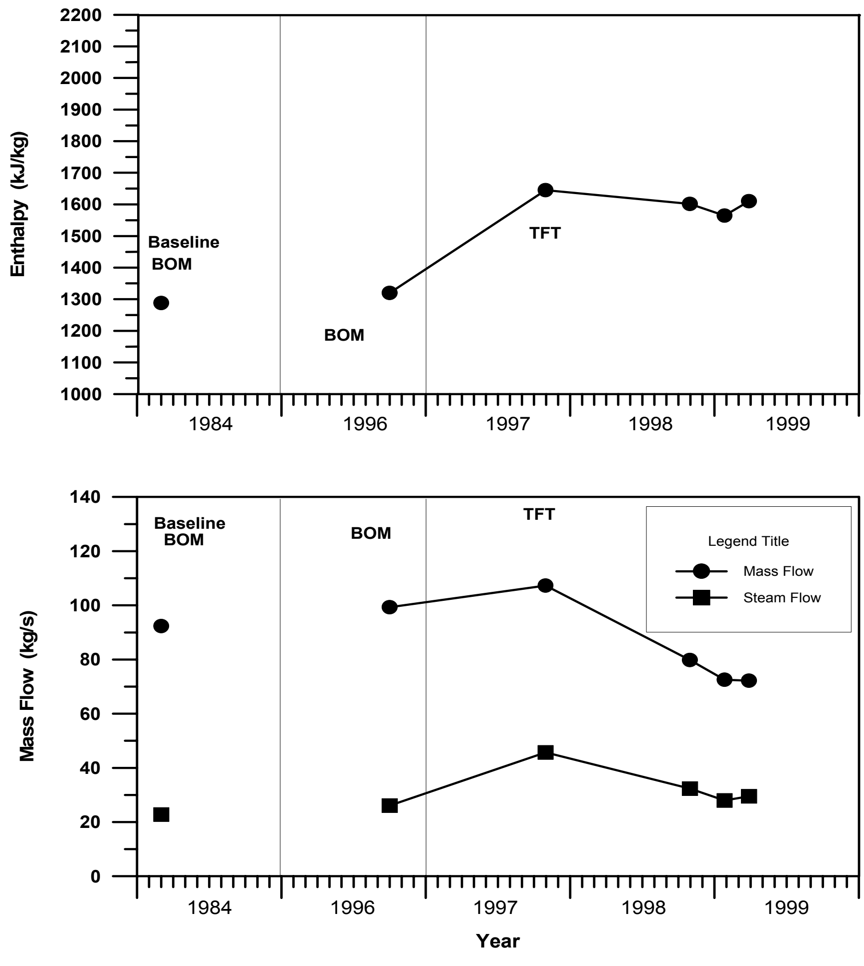


**Figure 15: Massflow decline due to drawdown (after Sarmiento, 2000).**

Changes in discharge enthalpy for individual wells can indicate reservoir changes that affect steam availability. Declining enthalpies at the same operating wellhead pressures can indicate reservoir cooling and usually necessitates increased mass extraction to maintain steam supply. The cooling may also be induced by inflow of either natural recharge or injection returns. Temperature decline normally accompanies this decline in enthalpy. Changes in the production and/or injection strategies (e.g. shifting of production or injection sector) is usually adopted to address the declines in temperature and enthalpy.

Increasing enthalpies would normally indicate drawdown resulting in expanding two-phase horizons and declining water levels in the well (Figure 16). This increase could also result in higher steamflow which could meet or even surpass the steam requirement for the plant. A review of the production strategy is usually undertaken when rapid rise in well and field enthalpies is observed which would indicate substantial depletion in the reservoir caused by the rapid expansion of the two-phase region.

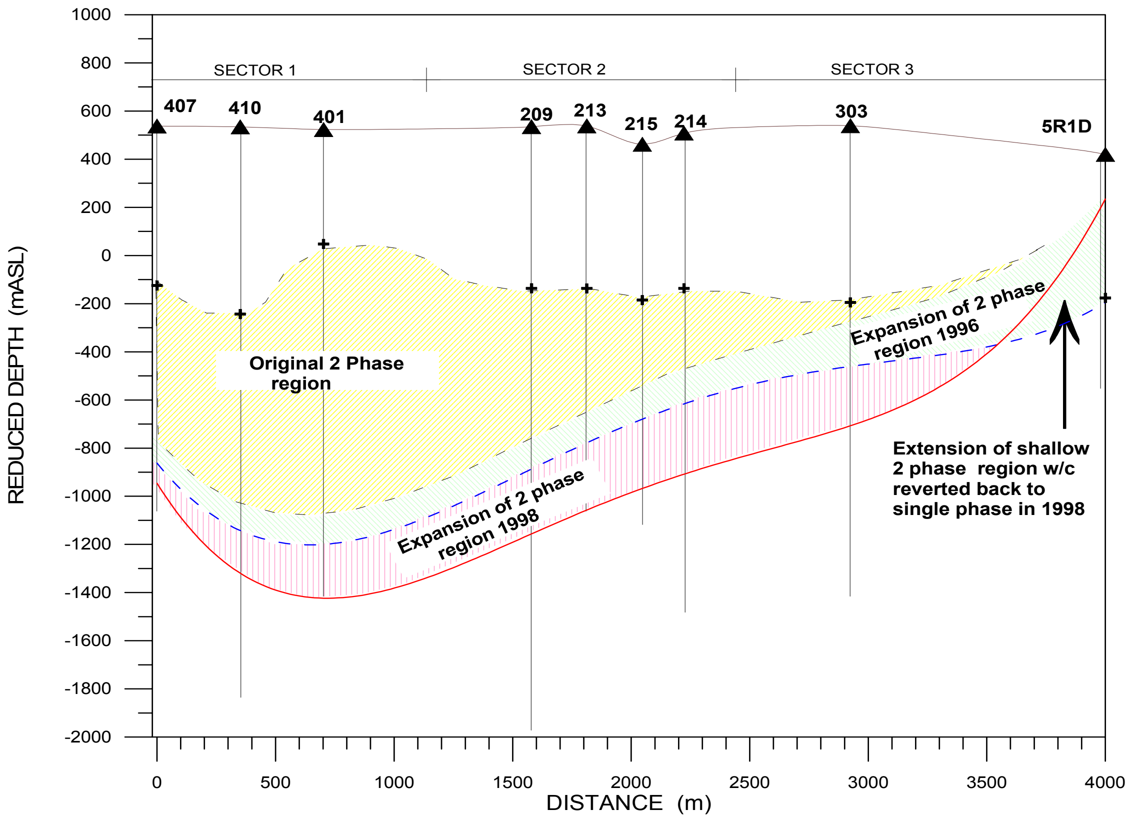


**Figure 16: Expansion of two-phase region with depth (after Sarmiento, 2000).**

## 5.5 Mass extraction

Periodic monitoring of the mass extraction and injection during exploitation provides information on the response of the field and power plant performance and verifies the suitability of the well utilization schedule implemented. Measurements of steam and brine flows and condensate flows are also collected and collated into an energy balance or audit. Figure 17 shows a typical fluid extraction and injection monitoring. These measurements together with field enthalpy trends can establish the performance of the reservoir in terms of the total steam produced and the amount of brine lost due to drawdown or gained due to recharge. A gain in field mass injection at relatively constant steam supply would indicate natural recharge or injection returns. This increase may also be accompanied by a decline in field enthalpies. Conversely, a rapid decline in mass extraction accompanied by an increase in enthalpies would show depletion of the reservoir. Regular review of the production well utilization schedule is then made, which would require changes in production and injection strategies. Corrective measures are then undertaken such as relocation of the production and injection loads to maintain steam availability.

In some cases, *plant load monitoring* is conducted to check the steam availability against power plant performance (steam consumption vis a vis power generated). This monitoring activity is essential in cases where the plant operators are different from the steam field operators, and contractual obligations to maintain a certain standard in power plant operation is required. Parameters monitored in the plant include the steamflow, pressures, turbine steam rates, condensation, plant parasitic load, noncondensible gases, and ambient temperatures.

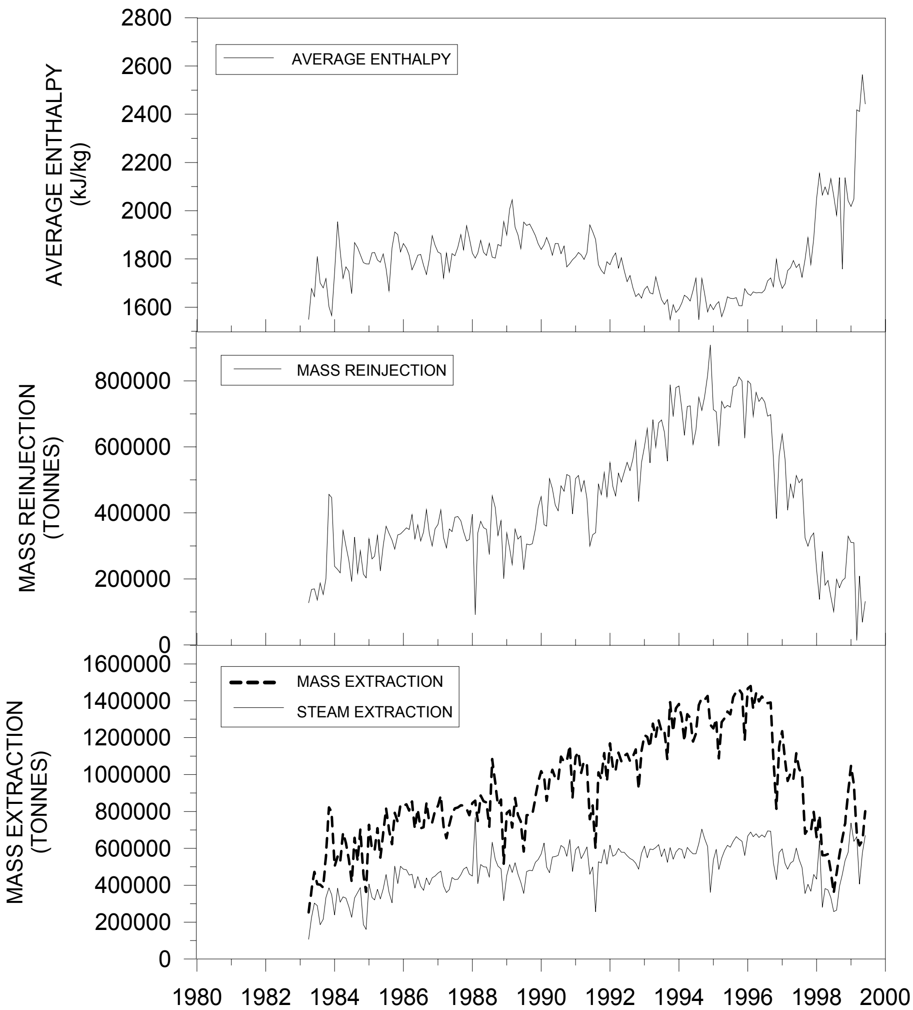


**Figure 17: Mass extraction and injection monitoring and field enthalpy trend (after Sarmiento, 2000).**

## 5.6 Injection capacity

Regular measurements of well injection capacities with time are also undertaken to monitor possible decline in injection capacity due to mineral (silica) deposition. Well workover is usually undertaken to regain injection capacity depending on the magnitude and trend of the decline. The workover operation may include plain mechanical drillout of mineral blockages or acid treatment to dissolve the mineral deposits around the wellbore and the immediate vicinity of the formation (Malate et al., 1997).

## 5.7 Tracer injection tests

Tracer tests in the Philippines have traditionally been conducted before full scale exploitation of the field to evaluate the likely behavior of the injection system. Correctly designed and performed, these tests can provide information on the speed (transit times) and volume of the injected brine returning to the production wells. Tracers usually employed are chemical dyes or radioactive materials. Chemical dyes such as fluoroscein or rhodamine WT are used due to their recognizable colors and fluoresence. These chemicals however, normally degrade at high temperatures and could produce interference with reservoir formation, which may give suspect results. Radioactive tracers on the other hand are thermally stable and decay at known rates. Their detection is relatively simple but can be difficult to handle and relatively more expensive than chemical dyes. Organic tracers such as benzoic acid can be used but they are also subject to thermal degradation. Chemicals monitored in the discharged and injected fluids (e.g. chloride) can also serve as "natural" tracers. Moreover, natural stable isotopes of oxygen ($\delta O^{18}$) and deuterium are used to establish the source of recharge fluid.

The quantity of tracer must be sufficient to be recognizable above any background in the reservoir in designing a tracer test. The concentration of tracer at production sampling points also needs to be sufficiently high for it to be accurately measured, but low enough to avoid any hazards. The minimum volume of the tracer is normally estimated based on the swept volume of the injected fluid to the observation well over a circular porous medium. The tracer concentration will be higher for flows along fractures or faults.

Figure 18 below shows the results of one of the recent tracer injection tests conducted by PNOC-EDC using radioactive iodine ($I^{125}$). The tracer was injected in one of the injection wells about 1.5 km aerial distance from the production wells. Positive tracer returns were monitored in three production wells with the fastest breakthrough of 20 days (Well A) from injection and mean residence time of 108 days. A percentage recovery of around 11% was calculated from the tracer breakthrough curve obtained (Delfin et al., 2000).

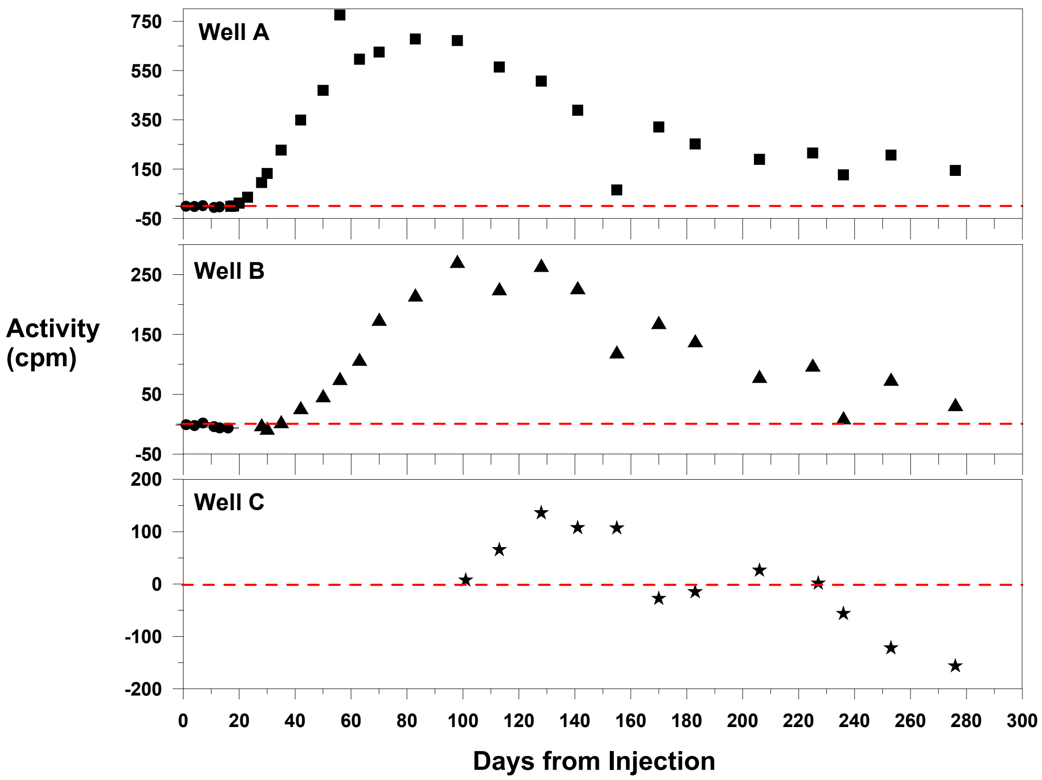


**Figure 18: Radioactive tracer ($I^{125}$) breakthrough curves (Delfin et al., 2000).**

In some cases, monitoring of the changes in the discharge chemistry of neighboring wells while a production well is being acidized can establish fluid movement in the reservoir. Increases in magnesium and fluoride content in the discharge fluid are usually seen due to the effect of acid injection.

## 5.8 Chemistry

Monitoring of the changes in chemical parameters of the discharge fluid can also provide information on the changes in thermodynamic processes in the wellbore and reservoir system. Figure 19 shows changes in reservoir chemistry (chloride and sulfate) for a well due to blockage. The chemistry trend obtained shows the distinct contribution of the upper feedzone after the development of blockage inside the wellbore. A decline in fluid temperature (Tquatz) and chloride content was observed but with higher discharge enthalpy due to the two-phase condition of the top zone.

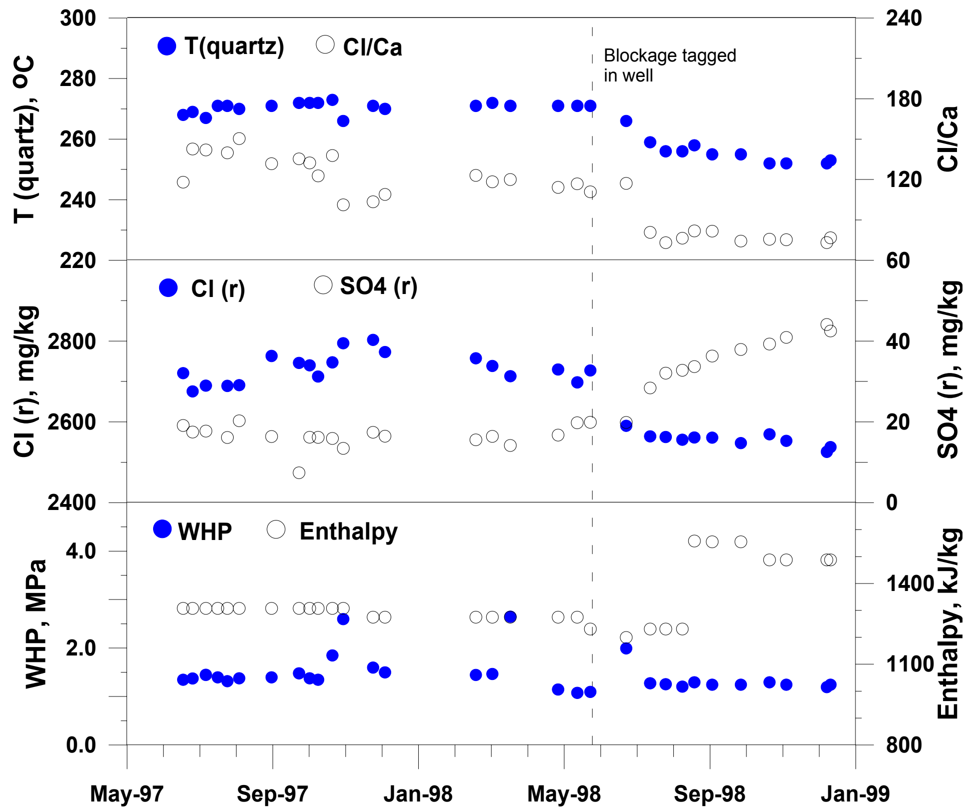


**Figure 19: Chemistry change in well due to blockage (after Herras and Siega, 2003).**

Chemical geothermometry can also be employed in establishing reservoir changes during exploitation in the absence of downhole temperature measurements. Declining temperatures from geothermometers may indicate several reservoir processes that include boiling, cooling due to influx of injection returns or development of blockage.

Figure 20 shows the trend of reservoir chloride with time that illustrates the effect of increased recharge in the production area due to injection returns. This immediate increase in recharge (chloride) occurred when injection was sited very near the production area. However, shifting of injection load much farther away from the production field caused the reservoir chloride to decline and stabilize with time. Conversely, an increase in production chloride with increase in discharge enthalpies would indicate boiling caused by pressure drawdown.

Noncondensible gases, mainly $CO_2$ in the steam phase, are also monitored as these could affect the performance of plant turbines. In most cases, noncondensible gas levels increase with time due to the increased boiling or expanding two-phase condition within the reservoir. The $CO_2$ gas levels would continue to increase with exploitation unless mixing of low gas injection fluids occurs in the reservoir. The gas levels may also decline with further depletion if natural recharge is not significant to offset the extraction of the gas-rich reservoir fluid. Figure 21 illustrates the initial increase in $CO_2$ levels with extraction that eventually declined due to depletion of gas in the reservoir. A plot of $CO_2$ distribution in the field can also indicate the likely source of the high NCG reservoir fluid.

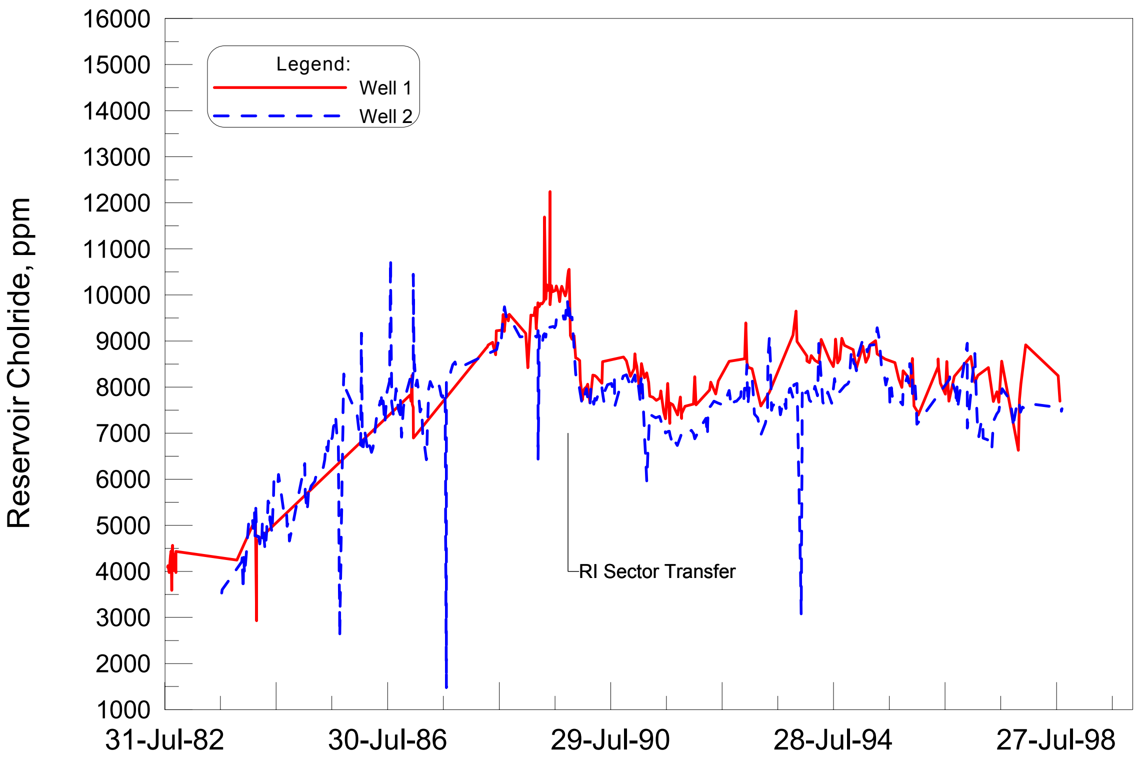


**Figure 20: Reservoir chloride trends with time showing effects of injection returns (after Sarmiento, 2000).**

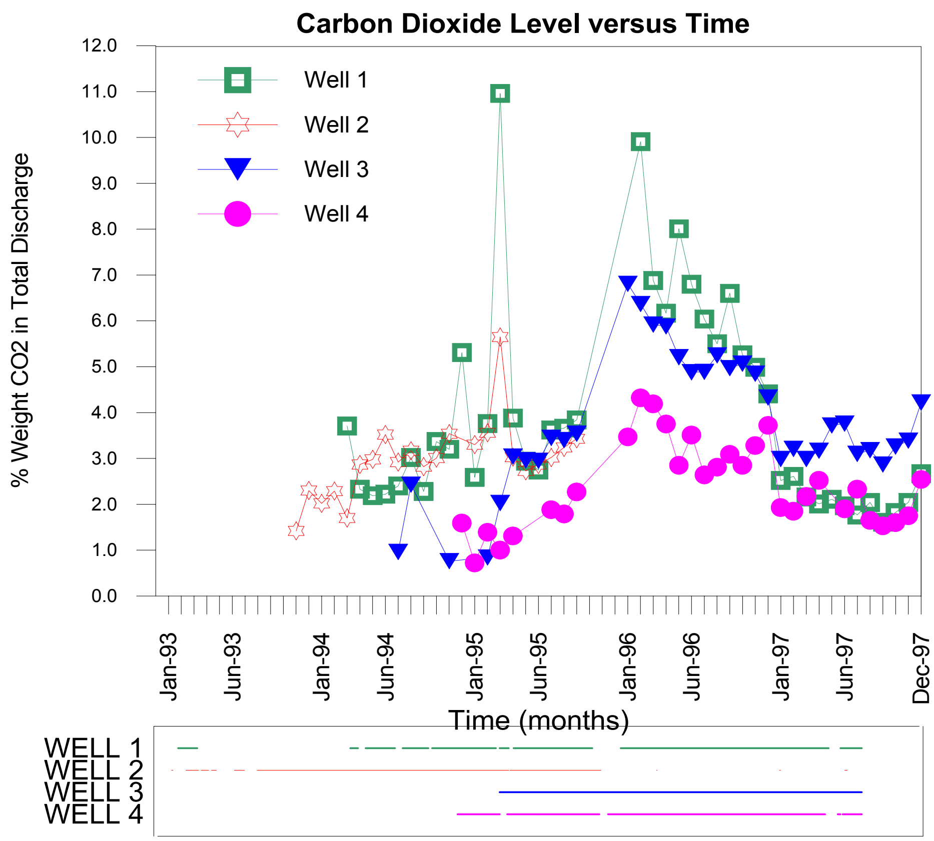


**Figure 21: $CO_2$ trends with time in some production wells (after Sarmiento, 2000).**

Regular monitoring of calcium, $CO_2$ and sulfate levels in the discharge fluid, including calcite and anhydrite saturation indices in production wells, and silica saturation index in injection wells can provide information on the potential for mineral deposition in the wellbore. Determining the magnitude and frequency of mineral deposition with time can provide management information on the timing of well interventions.

Other chemical components in geothermal discharges are also closely monitored to determine whether the chemical effluent meet the environmental standards. These chemical elements monitored are usually boron, mercury and arsenic in water discharges and $H_2S$ and $CO_2$ in steam. Monitoring of these chemical parameters is important, especially if the waste effluent will affect the local streams and the atmosphere, which may harm nearby communities. Philippine government regulations stipulate zero disposal of geothermal brine including power plant condensates, and therefore requires that injection wells be designated for the disposal of these waste fluids.

## 5.9 Reservoir simulation

Reservoir simulation is a very useful reservoir evaluation tool to evaluate the performance of the reservoir once production of the field commences. The production history gathered provides valuable input to the reservoir modeling studies to be used in predicting the reservoir behavior at different exploitation scenarios. Drilling of maintenance and replacement wells can then be scheduled based on the forecast obtained from reservoir simulation.

The numerical model employed is usually based on the conceptual (natural state) model developed for the field that would include salient features observed in the reservoir (i.e. hot recharge and outflows). Temperature, pressure and permeability distributions across the field derived from downhole measurements are incorporated in the model. In some cases, other parameters such as noncondensible gas ($CO_2$) and salts are included in the model if they are significantly high to affect the thermodynamic properties of the fluid (water).

The computer model is then validated against the production and injection history data obtained during exploitation. Control parameters (e.g. rock and fluid properties, permeabilities) are then adjusted to match the measured temperature, pressure and production data. Figure 22 shows the result of a good match of simulated pressure and enthalpy to the actual data of a production well. The model results can also be used in forecasting the well (reservoir) behavior at different development strategies. Figure 23 shows the forecasted output (total steam flow) of a reservoir based on a planned extraction rate. The schedule of make-up wells for drilling to meet the programmed development is also shown in the figure.

## 5.10 Power optimization

The performance of Tongonan 1 wells in Leyte, after more than 10 years of operation, has shown that the field can still sustain higher mass withdrawal based on minimal pressure drawdown. Moreover, the bore output characteristics of the wells showed a relatively stable output over a wide range of operating wellhead pressures. The forecasted reservoir performance of Tongonan 1 at higher extraction rates using reservoir simulation supported the possibility of increasing its plant generation (Sarmiento et al., 1992, 1993). It would then appear that the operation of Tongonan 1 at higher pressure operating conditions could be optimized from the results of the intensive monitoring and numerical simulation studies.

Higher pressure turbine operating conditions results in improved thermodynamic and generation efficiencies (lower steam rate). For the turbine inlet pressure of 6 Bars in Tongonan 1, a reduction of around 20% in steam flow requirement (at constant power load), or an increase of about 30% in generation potential (at constant steam rate), can be realized at higher operating turbine conditions (Sarmiento et al., 1993). These results also became the basis of optimizing the turbine inlet pressure of the other plants in the Upper Mahiao and Malitbog production sectors in Tongonan and the Mahanagdong area (Figure 24).

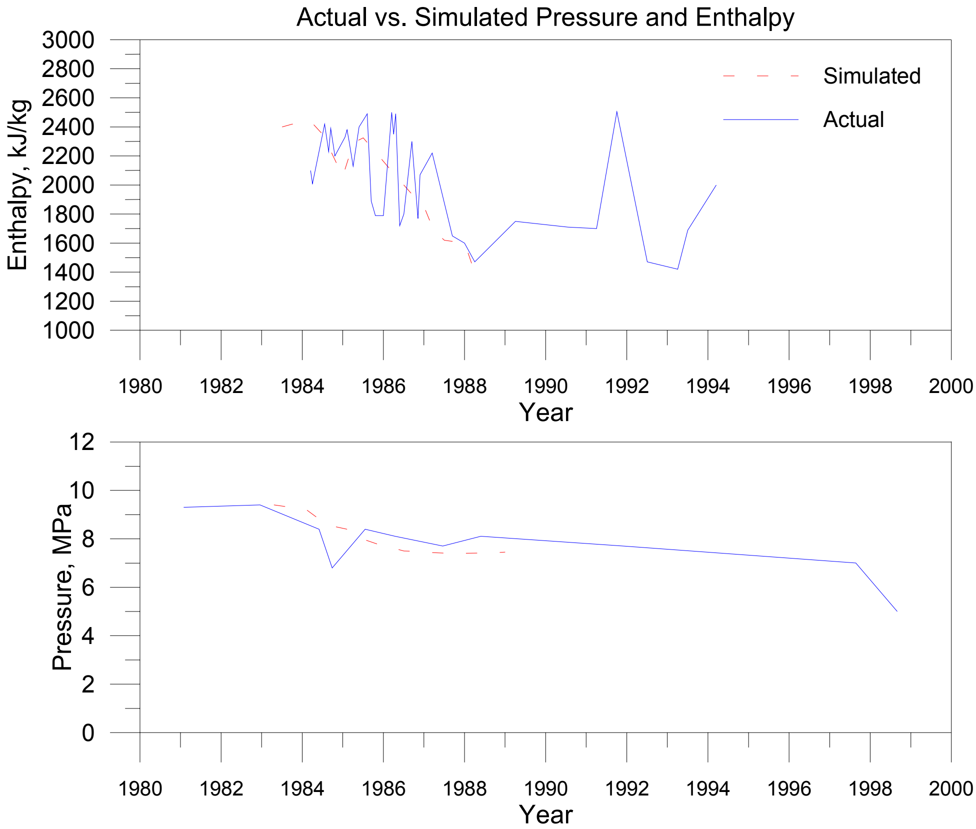


**Figure 22: Enthalpy and pressure history match of simulated and actual data (after Sarmiento, 2000).**

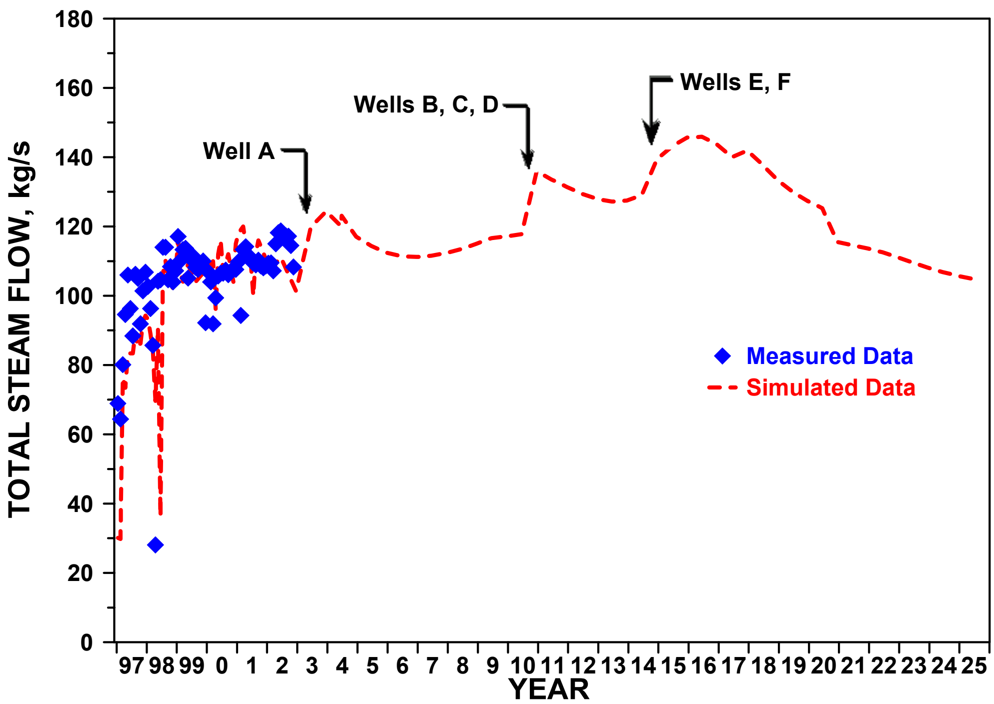


**Figure 23: Forecasted reservoir output based on simulation vs. actual data (after Esberto, 2002).**

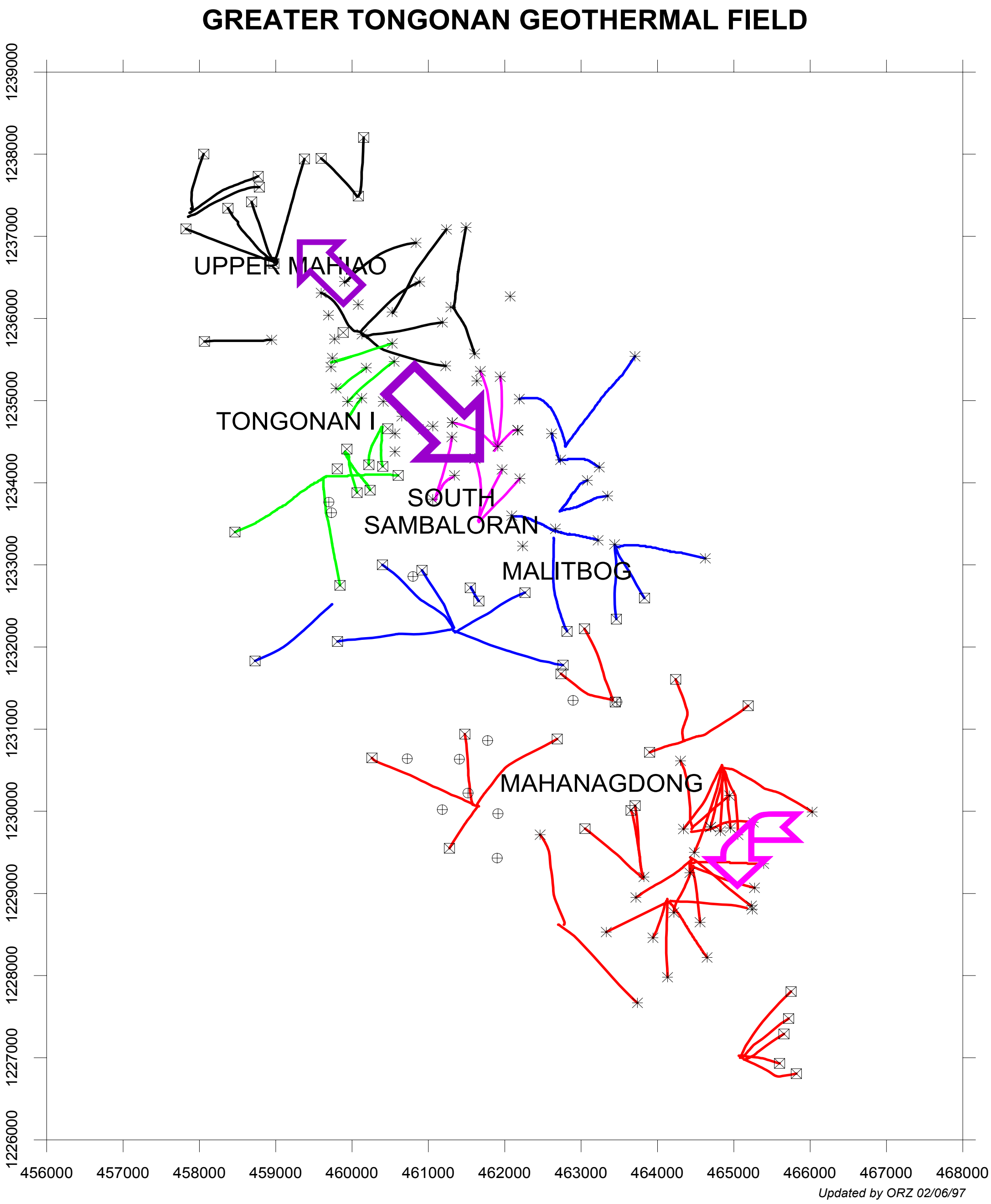


**Figure 24: Location map of Greater Tongonan Geothermal field (after Sarmiento, 2000).**

The likely generation capacity for each of the sectors were then determined based on process optimization of high pressure or intermediate and low pressure plants. Different plant model operation scenarios were evaluated using reservoir simulation to determine the optimum capacities of the plants the field can support. This also includes the likely number of maintenance and replacement wells to be drilled during the expected plant life.

A power plant using high pressure upstream back pressure turbines and an intermediate condensing pressure plant downstream was installed in Mahanagdong with an intermediate pressure turbine as the main plant. A plant set-up with a separate high pressure turbine (using high pressure steam), and a separate intermediate pressure condensing turbine utilizing steam from secondary flash of separated brine was installed at Malitbog/South Sambaloran with a high pressure turbine as the main plant. In Tongonan 1, a high pressure topping plant (back pressure turbine) was installed upstream of the plant to further optimize the output of the

Mahiao/Sambaloran wells. In Upper Mahiao, the plant system installed was a combined high pressure and intermediate pressure turbine where the steam from the high pressure turbine is used in a series of binary OEC units (Ormat Energy Converter) to provide additional generation. In addition, a brine OEC was installed in Upper Mahiao utilizing the separated water of the Upper Mahiao and South Sambaloran wells. Table 2 summarizes the plant generation of the Greater Tongonan Field with a total power capacity of around 708 MWe. The new plants were commissioned in 1996 and 1997 and have supplied power to the Luzon and Visayas grids via submarine cables.

**Table 2: Interface pressures and installed capacities of Tongonan plants (after Sarmiento, 2000).**

| Field/Sector/Plant | Plant Cap. MWe | Interface Pressure, ksca | | |
|---|---|---|---|---|
| | | Low | Intermediate | High |
| Greater Tongonan | | | | |
| Tongonan I | | | | |
| Main | 3 x 37.5 | | 6 to 7 | |
| Topping plant | 3 x 5.75 | | | 10 to 11 |
| Upper Mahiao | | | | |
| Main (Combined cycle) | 4 x 31.815 | | | 10 to 11 |
| Brine OEC (Binary) | 4.6 | | | 10 to 11 |
| Malitbog/S.Sambaloran | | | | |
| Main | 3 x 77.5 | | | 10 to 11 |
| Bottoming Plant | 14.56 | | 6 to 7 | |
| Mahanagdong | | | | |
| Main Plant A | 120 | | 6 to 7 | |
| Main Plant B | 60 | | 6 to 7 | |
| Topping Plant A | 2 x 6.35 | | | 10 to 11 |
| Topping Plant B | 6.38 | | | 10 to 11 |

## 5.11 Steam line interconnection

The early stages of production at Mahanagdong production sector in 1997 have been marked by rapid decline in available steam that has resulted in a significant reduction in output of the Mahanagdong plants. The decline in steam output of the production wells has been attributed to a) pressure drawdown leading to decline in massflow rates of production wells; b) enthalpy declines caused by incursion of cool waters; and c) calcite deposition in a number of wells that has adversely affected their productivity. The reservoir pressures have declined by as much as 3 MPa in the central part of the reservoir and 1-2 MPa in the rest of the field. The steam shortfall at Mahanagdong is most acute in the Mahanagdong A production wells (southern part) where the plant output is approximately 45 MWe below the installed capacity of 132 MWe. The production wells in Mahanagdong B (northern part) sector have maintained a level of steam production only marginally below (7 MWe) the plant requirement of 66 MWe at the start of operation. These wells have shown less susceptibility to calcite scaling.

PNOC-EDC has programmed the workovers of the wells affected by mineral deposition and/or intrusion of cold water to address the steam shortfall. In addition to well workovers, new wells were programmed to be drilled in the existing cellars in the Mahanagdong A area. Although the well workovers and makeup drilling will improve the steam supply situation, it is likely that the problems of calcite scaling and pressure drawdown will continue and available steam will again decline. Regular workovers or calcite inhibition and makeup drilling will therefore be required to maintain steam supply to the plants. In the long-term, the steam supply will be constrained by the limited availability of cellars on existing wellpads and additional production from other locations will be required.

To augment the steam supply in the medium term, the company has programmed to construct a "steam highway" that will allow all production sectors of the Tongonan and Mahanagdong fields to be interconnected. With the progressive commissioning of about 600 MWe field expansion in greater Tongonan between 1996 and 1997, reservoir pressure drawdown increased further. The drawdown has reached over 4 MPa over the central part of the reservoir from the Upper Mahiao area through to Malitbog. Despite the fact that significant drawdown occurred in the greater Tongonan, steam production rates have remained at or above the rates required by all of the power plants. The increase in steam flow from all sectors is essentially due to the increase in field enthalpies as a consequence of pressure drawdown and the subsequent formation of two-phase conditions in the production zones. The average enthalpies have risen to above 2000 kJ/kg with most wells in Tongonan field producing at close to dry steam conditions. An excess capacity of at least 100 MWe within the production sectors of the Tongonan field was evaluated.

The excess steam from Tongonan will be transported to Mahanagdong through a 14 km long 36″ main steam line called the Steam Line Interconnection (SLI), which connected the existing FCDS of both fields (Figure 25). The SLI was then commissioned in late 2001 and delivered 40 MWe of steam to the Mahanagdong A and B plants, maintaining their full load

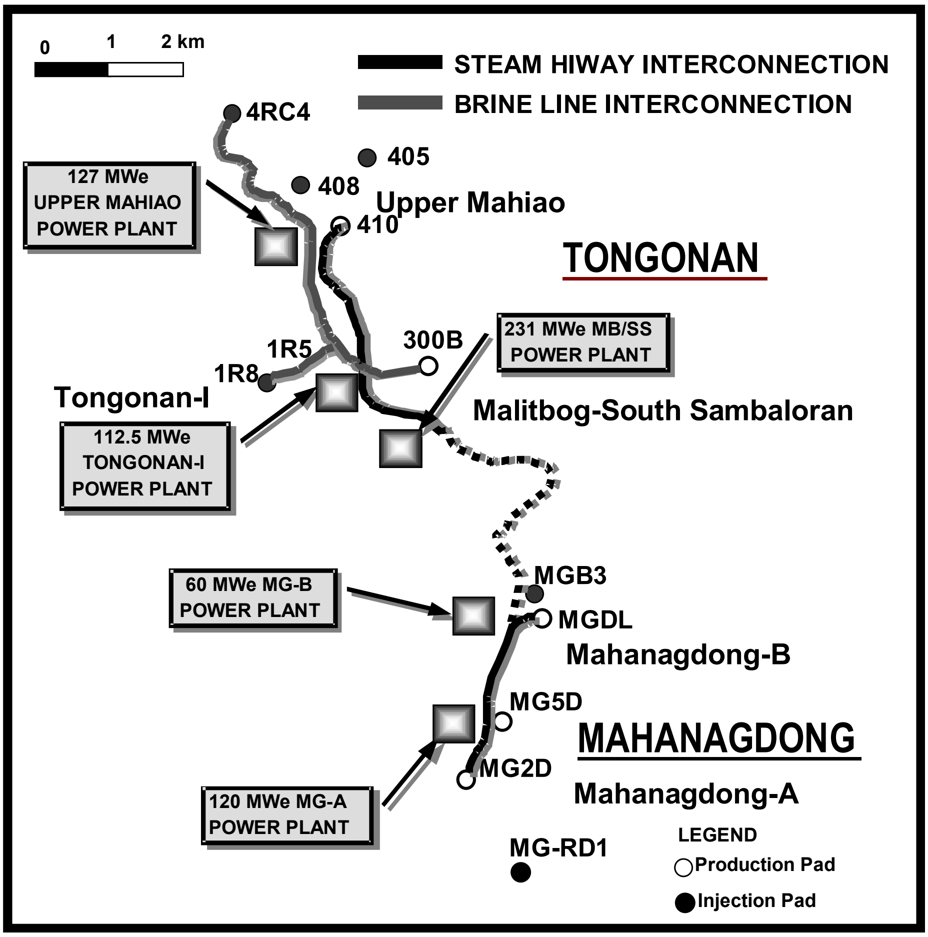


**Figure 25: Trace of the steam line interconnection (SLI) connecting the FCDS of Tongonan and Mahanagdong fields (after Herras and Siega, 2003).**

capacities of 132 and 66 MWe respectively. The operation of the "steam highway" will help reduce the stress on the Mahanagdong steamfield by increasing the production requirements of the larger Tongonan reservoir that translated to the use of the excess steam capacity in Tongonan. It has also enabled an integrated approach to steamfield management in both reservoirs (Recio and Habacon, 2002).

The long-term goal of sustaining the steam supply at Mahanagdong involves the development of the potential resource further east of the present area. Wellbore data indicates increasing temperatures and pressures towards the potential resource that was also delineated by magnetotellurics survey. Production well drilling will commence in 2004 to probe the area and possibly delineate the eastern boundary of the Mahanagdong resource.

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