# RESOURCE ASSESSMENT IN AYDIN-PAMUKÖREN GEOTHERMAL FIELD

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# ABSTRACT

## RESOURCE ASSESSMENT IN AYDIN-PAMUKÖREN GEOTHERMAL FIELD

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Reasons like increases in the price and demand of energy in the last years, growing interest and support in the renewable energy resources, development of social environmental consciousness, interest in using domestic resources, having legal regulations has promoted the interest in the electricity production from geothermal energy.

For the effective and productive use of existing resources, important data of geothermal regions are obtained with well tests. Well tests are the studies which starts while the well is drilling, continues after the well completion during the process of operation planning with optimum performance suitable to geothermal source and presents continuation also in the operation stage as required for the dynamic structure of geothermal systems.

In Aydın Kuyucak Pamukören region three wells are drilled, achieved results are positive. At AP1 well only $CO_2$ emission is present, no test is done for this well. With the tests for AP2 and AP3 wells temperature, pressure and production values are determined. By the results of these tests, it is determined that this region will be one of the important fields in the West Anatolian Region with current temperature and production rate.

In this study, the geothermal energy recoverable from this region is calculated with volume method of geothermal resource assessment. Monte Carlo simulation technique is used with an add-in software program @RISK to Microsoft EXCEL.

Electrical power capacity of Aydın-Pamukören geothermal field is determined as 45.2 MW with 90 % probability. The most likely electrical power value was found to be 78.75 MW with a probability of 69 %. The number of wells required are 10 for a production capacity of 200 t/hr and 7 for a production capacity of 300 t/hr at each well head.

**Keywords:** Geothermal Well Tests, Resource Assessment, Pamukören, Monte Carlo Simulation, Volume Method,

# ÖZ

## AYDIN PAMUKÖREN JEOTERMAL SAHASI KAYNAĞININ DEĞERLENDİRİLMESİ

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Son yıllarda enerji fiyatlarında ve talebindeki artış, yenilenebilir enerji kaynaklarına olan ilginin artması ve özendirilmesi, toplumsal çevre bilincinin gelişmesi, yerli kaynak kullanımına olan ilginin artması, yasal düzenlemelerin yapılması gibi nedenler jeotermal enerjiden elektrik üretmeye olan ilgiyi artırmıştır.

Mevcut kaynakların etkin ve verimli kullanılabilmesi için jeotermal sahalara ait önemli bilgiler kuyu testleri ile elde edilebilmektedir. Kuyu testleri kuyular delinirken başlayan, kuyu bitiminden sonra jeotermal kaynağa uygun optimum performanslı işletme planlaması sürecinde devam eden ve jeotermal sistemlerin dinamik yapısı gereği işletme aşamasında da süreklik arz eden çalışmalardır.

Aydın Kuyucak Pamukören sahasında üç kuyu açılmış olup, elde edilen sonuçlar olumludur. AP1 kuyusunda sadece $CO_2$ gaz gelişi olduğundan, bu kuyu için test yapılmamıştır. AP2 ve AP3 kuyuları için yapılan testler ile sıcaklık, basınç ve üretim değerleri belirlenmiştir. Bu testler sonucunda, bu sahanın mevcut sıcaklık ve üretim miktarı ile Batı Anadolu Bölgesinde yer alan önemli sahalardan biri olacağı belirlenmiştir.

Bu çalışmada, bu bölgeden elde edilebilir jeotermal enerji, jeotermal kaynak değerlendirmenin hacimsel metodu ile hesaplanmıştır. Monte Carlo simülasyon tekniği, Microsoft EXCEL'e ek bir yazılım programı olan @RISK ile birlikte kullanılmıştır.

Aydın-Pamukören jeotermal sahasının elektrik üretim kapasitesi % 90 olasılıkla 45,2 MW olarak saptanmıştır. En olası elektriksel güç kapasitesi ise % 69 olasılıkla 78,75 MW olarak tayin edilmiştir. Sahanın tam kapasite ile kullanımı için gerekli olan kuyu sayıları; her kuyu başında 200 ton/saat üretim için 10 adet, 300 ton/saat üretim için 7 adet olarak hesaplanmıştır.

**Anahtar Kelimeler:** Jeotermal, Kuyu Testleri, Kaynak Değerlendirme, Pamukören, Monte Carlo Simülasyonu, Hacimsel Metot

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# CHAPTER 1

# INTRODUCTION

'*Geothermal energy*' is used to indicate that part of the Earth's heat that can, or could, be recovered and exploited by man (Dickson and Fanelli, 1995).

Geothermal energy is the heat energy of earth's inner crust which is molten. It originates from the deep circulation of groundwater and the intrusion of molten magma into the earth's crust not deeper than 5 km. The magma intrusion heats the surrounding groundwater.

The estimation of geothermal energy in the ground is evaluated by geothermal resource assessment methods. *Geothermal resource assessment* can be defined as the broadly based estimation of supplies of geothermal energy that might become available for use, given reasonable assumptions about technology, economics, governmental policy and environmental constraints. This assessment implies not merely the determination of how geothermal energy is distributed in the upper part of the earth's crust but also the evaluation of how much of this energy could be extracted for man's use.

The geothermal resource assessment involves determination of location, size and geological characteristics of each area to calculate the accessible resource base (thermal energy stored in the reservoir) and the resource (thermal energy recoverable at the well head) (Arkan and Parlaktuna, 2005).

Methodologies used for geothermal resource assessment were reviewed by Muffler and Cataldi (1978) and divided into four main categories: Surface thermal flux method, Volume method, Planar Fracture method, Magmatic heat budget.

The volume method is the primary method applied in past USGS assessments for evaluating the production potential of identified geothermal systems, in which the recoverable heat is estimated from the the thermal energy available in a reservoir of uniformly porous and permeable rock using a thermal recovery factor, $R_g$, for the producible fraction of a reservoir's thermal energy.

Volume methods are usually used to estimate stored heat and recoverable power reserves in the early life of a geothermal reservoirs. Estimation of the thermal energy requires geological and additional data including reservoir temperature, reservoir area, thickness, porosity, rock and fluid specific heats, etc. the values of these input variables have usually large uncertainties. In order to overcome these uncertainties Monte Carlo Method is used to construct histogram graphs and cumulative probability curves for a given reservoir.

In this study, stored energy and the electrical power obtainable from Aydın-Kuyucak-Pamukören geothermal field is estimated by volume method. For Monte Carlo Simulation studies @RISK program, an add-in software to Microsoft EXCEL is used.

This thesis is organized in 9 chapters and begins with an Introduction in Chapter 1. Chapter 2 covers a wide range of well tests. Chapter 3 presents the basic types of geothermal systems. Geothermal resource assessment and terminology are given in Chapter 4. In Chapter 5, the methodology used in geothermal resource assessment is presented. Statement of the problem is done in Chapter 6. The geology of Aydın-Pamukören geothermal field is explained in Chapter 7. Chapter 8 covers the results and the discussions. In Chapter 9, the conclusions drawn from this research study and the recommendations are presented.

# CHAPTER 2

# GEOTHERMAL WELL TESTS

Geothermal well tests are pressure, temperature and production measurements taken from well bores against time and depth. The aim of geothermal well tests is to acquire all the possible precise and accurate information about the region from the drilled well. As determination of the physical properties of well, by observing the behaviour of the well, it is also possible to get information about the reservoir. Final aim is to construct a reservoir model in the scope of the data gathered from the well. and by using this model to predict the future behaviour of the reservoir.

In order to construct a good and explaining reservoir model, all the wells in a geothermal region must be tested in a detailed and accurate program.

Geothermal well measurements are made for the following various purposes,

1. Basic study of a natural resource
2. Assessment of an underground thermal reservoir for possible exploitation
3. Assistance in drilling operations
4. Appraisal of individual wells for production
5. Mechanical engineering design requirements, including safety of equipment and personnel
6. Legal requirements, for ownership, safety or waste disposal
7. Fluid sales

8. Plant operation

If enough data gathered for (2) and (4), it is likely that most of the other needs will be satisfied.

The measurements that will be described include;

1. Reservoir investigation, in particular as to its size, permeability and temperature, and also the fluid composition and pressure

2. Well flow characteristics, specifically temperatures and pressures and the corresponding flow rates of the various components (steam, hot water and gas)

3. Down-hole engineering data, such as casing condition, mineral deposition, or levels of permeability

4. Miscellaneous observations carried out suitably by the well measurements personnel (Dench, 1973).

In a well test, the response of a reservoir is monitored against to the changing production (or injection) conditions. The characteristics of the reservoir can be predicted from the degree (big or little) of the response.

A mathematical model is used to relate pressure response (output) to flow rate history (input) in well test interpretations. The mathematical model and field mechanism must give same pressure outputs for the same flow rate history input.

Well tests have three major objectives;

-<u>Reservoir Evaluation:</u>

In the reservoir evaluation for the decision of production or investment in a well deliverability, properties and size of the well must be found. In order to find those values, the reservoir conductivity (kh, or permeability-thickness product), initial reservoir pressure and the reservoir limits (or boundaries)must be determined. Fluid samples must be inspected in laboratory for physical properties. The near wellbore conditions must be evaluated to determine if the well productivity is governed by well bore effects (like skin and storage) or the reservoir.

The conductivity (kh) controls flowing rate of fluids to the well. Kh is important in design of wells (spacing and number).

Reservoir pressure is a measure of reservoir's potential energy and an indicator of the production duration. By well tests we can predict the original pressure of the reservoir from the actual pressure at the well bore.

We can predict the reservoir limits. By this prediction we can find the left reserve and consider the reservoir boundaries (closed or open).

-Reservoir Management

During the operation period of the wells, monitoring performance and well conditions are important. To keep production at optimum level, changes in average pressure must be monitored and necessary measures must be taken into consideration accordingly. These can increase the efficiency and continuation of the production.

-Reservoir Description

Geological formations containing geothermal reservoirs are complex, may contain different rock types, stratigraphic interfaces, faults, barriers and fluid fronts. These factors may have impact on the pressure transient behaviour at a measurable degree, mostly will affect the reservoir performance. The reservoir description can be reached by well testing. Reservoir description will help in prediction of reservoir performance. Also, production plans can be developed by characterization of the reservoirs.

## 2.1 Temperature Tests

One of the most important parameters is the reservoir temperature in geothermal wells. Temperatures can be measured during drilling, and any break in drilling (overnight or over a weekend or holiday). This allows a check on the temperature recovery and determination of original temperature data of the passed formations. The temperature values are effective in the continuation of the drilling. After the completion of the well before initiating discharge temperature values must be measured. These measurements can be taken while the well is shut or discharging.

### 2.1.1 Static Temperature Test

Temperature test can be done while drilling, after the completion of drilling with drilling fluid in the well or after shutting the well after a certain production and waiting for an enough time for the well to recover its initial temperature.

This test is done while the well is shut. The aim of the test is determination of the temperature profile of the well in production.

This measurement is taken from the surface to the bottom of the well considering the depth of the well and measurement time with certain intervals depending on the depth of the well (every 10, 20, ..., 100 m) and waiting for enough time for the stabilization of temperature at every point.

The first temperature measurement taken doesn't give the original temperature values for the well because drilling fluid effects the well during the drilling operation but gives close values. This measurement later can be compared with later measurements or determination of the effect of drilling in the well. Static temperature test done after the production test gives the original temperature values depending on the production time and waiting time.

By drawing a graph of depth and temperature the temperature profile of the well is formed.

More realistic temperature values can be reached after waiting for longer periods of time. Since it is very costly to keep the drill rig on the well and also to avoid hazards, that may result from the cuttings and the mud used during the drilling, waiting time can not be kept too long and the production is started as soon as possible.

### 2.1.2 Dynamic Temperature Test

Dynamic temperature tests are done while the well is in production. This measurement is taken with certain intervals depending on the depth of the well (10,20, 50, .... ,100 m ) from surface to the bottom of the well together with measurement time period. During this measurement discharge rate of the well must be constant and allow free movement of the test equipment through the bore. By this test, the heat loss of geothermal fluid is determined as it rises in the well, together with any factor existing, which cools the geothermal fluid in the well (i.e. mixing of cold water). The final temperature of geothermal fluid entering the system can also be determined (Yeltekin, 2003).

By the well bore temperature profiles obtained from dynamic temperature tests while the well is in production, reservoir levels with different production levels and temperatures can be identified. Then using temperatures of different levels, well bore mixture temperatures, well bore phase changes and depths of changes can be found. By comparison of different dynamic profiles taken at certain time intervals it is possible to determine the temperature changes in the reservoir. Especially in the re-injection applications number of measurements must be increased.

### 2.1.3 Water Loss Test

Water loss test aims to determine well's production level or levels. This test is done while injecting fluid into the well dynamically. In the water loss test done after the completion of drilling well bore must be free of drilling mud and cuttings. For this reason firstly well must be washed by flushing drilling mud in the well with clean water. By starting slow production in the well, the well starts to warm up. During the warm up, the well cleans itself. In a later stage, according to a certain schedule the well completion tests are started. In the well completion tests, water loss test is done at first. In the water loss test cold water is injected to well at a constant rate. During the test temperature profile measurements are taken. This process can be done a few times. By these temperature profiles, levels where water is entering to reservoir or flow from reservoir to well can be determined. In the case of more than one production levels and insufficient pump rates, some levels can not be identified. In such cases more than one water loss test with different pump rates may be needed.

By pumping cold water to the well, the well is cooled. While pumping cold water into the well (uncased part) temperature measurements are taken in narrow intervals. Later by temperature measurements taken at different periods the warming up of the well is controlled. The production level will be cooler rather than warmer at the beginning as cold water is pumped into well. By analysis of temperature measurements taken, production level or levels can be determined.

The production levels determined by the tests will be the levels where the pressure instruments is lowered in Build-up, Draw-down, Injection and Fall-off tests.

### 2.2 Pressure Tests

#### 2.2.1 Static Pressure Test

This test covers the measurements taken while the well is shut and static before any production from well and pumping any fluid into well starts. It can be done for the determination of well bore pressure profile or also to monitor the pressure changes at certain depths.

Static pressure measurement taken before production of well does not give the original pressure value as the well is full of drilling fluid. But after the production is started, as the well is filled with original reservoir fluid, the static pressure measurement gives the original values.

As the graph of static pressure measurement values is drawn, the result will be linear. These values are the sum of hydrostatic pressure of the fluid in the well and the well head pressure.

By static pressure measurement, the water level at the well can be found. In the scope of well completion tests, during the warm up period of the well, static pressure measurements are taken in definite intervals. The density of fluid in the well and the pressure gradient are changing during the warming process. If an anomalous change is observed in the pressure profile at some depth, it is the depth that pressure transient tests must be done.

Average reservoir pressures, obtained from the static pressure measurements taken with definite intervals in wells are used to determine the change of mean reservoir pressure with time. Changes taking place in the average reservoir pressure of all wells in the region are evaluated together and used in the decision making for the region.

#### 2.2.2 Dynamic Pressure Test

This test is done the while the well is in production or fluid is pumped to well in dynamic state of the well. It is for the determination of well bore pressure profile.

During this measurement discharge rate of the well must be constant and allow free movement of the test equipment through the bore. While the well is in production, a graph of pressure values against depth is drawn beginning from the surface till the bottom of the well with certain intervals. By this measurement the depth at which geothermal fluid in the well passes from one phase to two phase is found. Pressure profile appearing linear from the well bottom converges to a curve at the depth where there exists two phases of geothermal fluid. Determination of this depth is important for the regions having scaling problems. Because scaling in the well starts at this point (flashing point). If scaling starts in the reservoir, it is a great problem. This problem can only be solved with an expensive method like acid injection. By adjusting the well head pressure it is possible to lower or rise this depth. By this adjustment the scaling depth can be raised from reservoir to the well bore and the well can be cleaned mechanically without acid injection.

### 2.2.3 Injection Tests

In this test, pressure changes in a well are evaluated while water is pumped with constant rate into the well. These tests can also be done with various pump rates (usually with increasing increments) but keeping constant for definite time intervals.

The important factors that determine duration of the test and injection rate are the supply of injection water, water storage capabilities at the well site, the rate and the pressure capacity of the pump that will be used for injection. This test is done generally after water-loss test of the well completion tests. This is because, the mud pumps and tanks should be used. During the injection, pumped water must be clean, pumping rates are constant and process must be organized to be executed without any interruption. During the test, well head pressure data and water level data must be gathered together with pressure data of well bore for evaluation purposes. Pressure measuring instrument must be lowered to main production level before the water injection starts and after a short stop, the water is injected. One of the important parameters, that is injectivity index preferably needed for the design and the operation of re-injection wells can be found by this test, although this test is not very common in production wells.

### 2.2.3.1 Single Rate Injection Test

After the removal of drill mud and cuttings from the well bore by flushing and by the production test, this test is done by recording pressure changes (rises) in the reservoir during water injection into the well. Reservoir parameters such as permeability can be obtained from these measurements. In this test, test device is lowered to reservoir level before water is injected and then water injection starts. During the water injection the pressure changes are recorded to test device. Single pump rate is applied during the test.

### 2.2.3.2 Multiple Rate Injection Test

Test is done by recording pressure changes (rises) during water injection to the well at different rates (from low to high) for the calculation of reservoir parameters and the injectivity index. In this test, test device is lowered to reservoir level before water is injected and water injection is done with increasing rates ( at least three rates).

### 2.2.4 Pressure Fall-off Test

In this test pressure changes, which occurs in the well by the stop of the injection at constant rate into the well, are recorded. At the end of the injection test practices in injection/re-injection wells, these tests can be done. The difficulties are to keep the rate constant in injection test and little variations in the rate effecting the well bottom pressures.

### 2.2.5 Pressure Build-Up Test

The test is conducted by producing a well at constant rate for some time, shutting the well in (usually at the surface), allowing the pressure to build up in the well bore, and recording the pressure (usually down hole) in the well bore as a function of time.

A graph is drawn log-to-log or semi-log with measured pressure values against time and by the slope value;

i- permeability-thickness (kh) value
ii- skin factor
iii- reservoir pressure

can be found.

The Productivity Index, PI, value is found by division of the production rate of the well just before the build-up test to the difference of pressure recorded before the test and the ending reservoir pressure of the test.

PI (Productivity Index)= Rate(ton/hour) / $\Delta$ Pressure (kg/cm2) Eq. 2.1

### 2.2.6 Pressure Draw Down Test

A pressure draw-down test is conducted by producing a well, starting ideally with uniform pressure in the reservoir. The rate and the pressure are recorded as functions of time. The objectives of a draw-down test usually include estimates of permeability, skin factor and reservoir volume. These tests are particularly applicable to;

1- new wells
2- wells that have been shut in sufficiently long to allow the pressure to stabilize
3- and wells in which loss of revenue incurred in a build up test would be difficult to accept.

Exploratory wells are frequent candidates for lengthy draw-down tests, with a common objective of determining minimum or total volume being drained by the well.

This test is the inverse of pressure build-up test. The pressure dropsat the bottom of the well with the start of well production is evaluated in the test. While the well is shut the pressure gauge is lowered to the level with highest permeability and after a short stop, the well is opened to production with a constant rate. By this way pressure drop resulting from production is recorded.

This test is not preferred in the field applications too frequently since it is not desired to open the well early to production before warm-up and also because of difficulties of keeping the rate constant in the warming period. Another reason is that the produced water, which is usually discharged into rivers, creeks, etc. may create environmental pollution. In order to avoid these disadvantages, tests can be done by starting the production with low rates and raising it with certain increments. By this way it is possible to determine well bore flow performance relations.

### 2.3 Flow Tests (Production Tests)

These tests are done for the following purposes;

- Determination of maximum and optimum production rates that the well can produce
- Finding the rates and enthalpy at different pressures at surface and/or bottom of the well bore
- and determination of maximum production pressure

At the end of the tests, measured flow rate figures are used in evaluation and interpretation.

The production tests done for the determination of wells' production characteristics and performances can be divided into two groups according to duration as short term flow tests and long term flow tests.

Short term tests are done usually in a few days and production values corresponding to different well head pressures are recorded.

Long term tests take long periods of time, such as months and in these tests changes of pressure at well head and rates are recorded.

For short term tests generally no precautions are taken for scaling in the well, but for long term tests inhibitor injection mechanisms preventing scaling are used during the testing period.

In the production tests discharging and shutting of well is done with steps and for each step it is waited until the production and pressure become constant and stable. Although this period is short for water dominated-high permeable geothermal fields, it can be longer for vapour dominated geothermal fields.

If the non-condensible gas content in geothermal fluid is high, calculated enthalpy and rate values are higher than the actual field values. Since the concentrations of non condensible gases are high in geothermal regions of Turkey, corrections must be made to field discharge observations due the effect of gas.

#### 2.3.1 Lip Pressure Method

This method is based on an empirical formula developed by Russell James and is considered to be the most versatile method for testing lower enthalpy wells (Grant, 1982). The lip pressure method is not as accurate as the separator method but is desirable because a minimum of hardware and instrumentation is required to obtain good results. The largest producing wells cannot be satisfactorily tested by any other method.

After the completion of drilling, before starting well completion tests, the first production test is generally done by this method. The well is cleaned by the removal of mud and cuttings from inside the borehole during the production. In the case of suitable environmental conditions, vertical or near to vertical production is done. In that case discharge pipe is connected to main valve. In severe environmental conditions, discharge pipe is connected to one end of a T-pipe attached to well head and horizontal production is done.

To use this method, the steam-water mixture is discharged through an appropriately sized pipe (diameter of pipe must be wide enough not to prevent flow and narrow enough to record discharge pressure) to remove the fluid under control. The lip pressure is measured at the extreme end of the discharge pipe (standard configuration is a 6 mm. diameter hole, centered 6 mm. from the end of pipe) using a liquid-filled gauge to damp out pressure fluctuations (Grant, 1982).

In field studies, usually a formula (Equation 2.2) is used to calculate total fluid rate. In this method, the discharge pipe's diameter and lip pressure absolute value can be measured, but the fluid's enthalpy can not be measured or calculated. Therefore, the enthalpy value corresponding to well bottom temperature is used for the wells discharged for the first time (Erkan, 2007).

$$M_t = 4 * 10^5 * \left( \frac{P_c^{0,96} * d_c^2}{h_0^{1,102}} \right) \qquad \text{Eq 2.2}$$

Mt= Total Fluid rate (ton/hour)

ho= Fluid Enthalpy (kJ/kg)

Pc= Observed Lip Pressure (Psi)

dc= Discharge Pipe Inside Diameter (meter)

### 2.3.2 Silencer-Weir Method

In this method the steam-water mixture is discharged into a silencer to separate the steam and water phases at atmospheric conditions (Fig.2.1). As steam is released to atmosphere from the upper part, water is directed to weir connected to the bottom of the silencer. Water rate passing through weir is calculated with weir formulas. By adding the evaporation amount of water at the silencer to the water rate through weir, the total production of the well is determined. While calculating the separated steam ratio, enthalpy of water and steam at atmospheric pressure and enthalpy of fluid discharged from the well are used. In order to use this method, the enthalpy of fluid discharged from well must be constant and known. The fluid at reservoir conditions is at single phase, found as pressurized water and enters the well in single phase and flashes into two phases in the well bore or in surface pipelines, as for the long term periods well bore heat losses can be neglected and enthalpy of water at the temperature entering the well can be used in calculations for fluid enthalpy.

Weirs' front panels can be done in various shapes, but for wells with high production rates commonly rectangle-shaped panels are used (Figure 2.2). There are different standards and formulas available for the calculations. A common equation suggested for the weir rate calculation is given below (Equation 2.3). In order to prevent the waves resulting from the fluid passing through weir, metal plate wave barrier with holes on it, is mounted inside the weir (Erkan, 2007).

To increase the accuracy, the edges of the panel must be smooth and sharp, and weir pool must be cleaned from cuttings and dirts.

$$M_w = 60 * \rho_w * b * h^{1.5} * \left( 107.1 + \left( \frac{0.177}{h} \right) + \left( 14.2 * \frac{h}{D} \right) - \left( 25.7 * \frac{\sqrt{(B-b)+h}}{D*B} \right) + \left( 2.04 * \sqrt{\frac{B}{D}} \right) \right) \text{......} Eq.(2.3)$$

$M_w$ = Weir Fluid Rate (ton/hour)

$\rho_w$ = Weir Fluid Density ($gr/cm^3$)

Symbols b, h, D and B are illustrated in Figure 2.2.

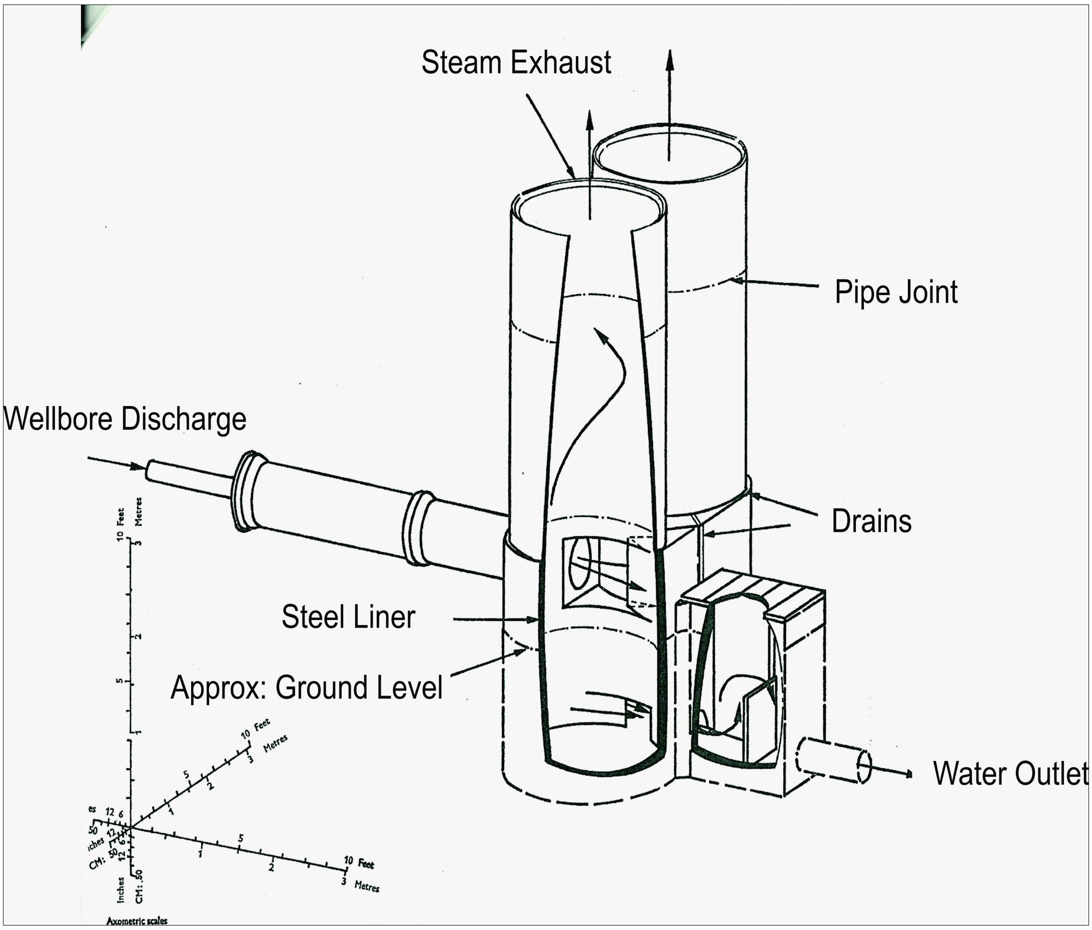


Figure 2.1  Silencer (Smith, 1973)

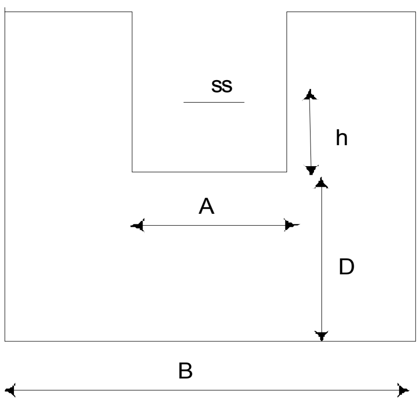


Figure 2.2 Front Panel of Weir

## 2.4 Gas Measurements

In all geothermal wells non condensible gases are present. The most common one is carbon dioxide which usually makes up the bulk of the non condensible gases. Gas measurements are done for the calculation of percentage of gas amount by weight in the geothermal fluid.

In the high temperature geothermal fields, for separated steam flows a sample is taken directly from the pipeline, and for two-phase flows a sample of the mixture is taken and separated in a mini separator. The resulting steam-gas mixture is cooled slowly by a method, and by this way steam is condensed. Water and gas are separated and gas amount is found.

If non condensible gases are present in significant amounts, corrections must be made to field discharge observations for the effect of gas. The amount of non condensible gases in the geothermal fluid must be known since it effects all the well tests considered.

## 2.5 Tracer Tests

In these days, re-injection applications are applied in all the geothermal fields for the following reasons;

i. to keep the pressure constant
ii. to increase the heat energy production
iii. to push back the waste water containing hot and polluting chemicals

It is important to determine the quantity of the injection fluid and place of the injection in the re-injection applications. In the production wells, early heat falls which causes enthalpy and production losses must be prevented.

By these tests, formation of the reservoir (homogeneous and fractured masses of rock), regional extension of the field, flow directions and flow parameters are measured first and then the heat losses in the production wells are predicted and evaluated by the modelling studies.

The tracers used in these tests are divided into three main groups as radio active, chemical and fluorescent dye. The factors in the selection of tracers are;

- stability of the material at high temperature

- chemical interaction with the geothermal fluid and rock
- sensitivity at very low amounts
- amount of tracer in the geothermal fluid
- quantity and price
- adverse effects to the environment and human health.

The most common tracers used are fluorescent dyes which can be detected at very low levels. Tracer material amount is measured with fluoro meter with a sensitivity of 0,01 -0.02 ppb.

Tracer at certain amount and concentration is injected to the reservoir from the re-injection well and the ideal injection is continued at constant rate. The tracer concentration is measured at production wells. Measurements, at early times, are taken frequently up to the highest concentration and then measurement frequency is decreased. A profile for tracer concentration change against the time is drawn.

The following parameters are important in the evaluation process;

- Shape of the profile
- first emerging time,
- time elapsed to reach maximum concentration,
- balanced concentration of tracer in the case of continuous re-injection of the produced tracer,
- and total regain amounts of tracer

Besides multi well tracer tests, there are also single well tests at which tracer is injected for a certain period of time and produced from the same well. In addition to artificial tracers, materials present in the composition of injected fluid (i.e. chlorine ) can be used as tracer.

### 2.6 Interference Tests

Interference test is one of the multi well tests. In this test, discharging well or wells are used together with the observation well or wells. The reactions at observation wells, resulting from discharge or injection are recorded. Interference tests are done for the following purposes;

- determination of interaction between wells

– measuring of regional parameters in a larger scale instead of near well bore parameters gained form one well test

– determination of reservoir's heterogeneous characteristics

– and determination of data which will form the basis for the modelling studies.

These tests are done in the scope of long term tests. In the operation stage of a field, these tests are the tests done by taking measurements continuously from observation wells according to the field observation plans.

CHAPTER 3

# GEOTHERMAL SYSTEMS

The essential requirements for a geothermal system to exist are (1) a large source of heat, (2) a reservoir to accumulate heat, and (3) a barrier to hold the accumulated heat (Figure 3.1). There is a suite of geological conditions that could result in a variety of geothermal systems. Consequently, all geothermal fields differ from one another. However, depending upon certain common characteristics, these can broadly be classified into the following categories: (1) hydrothermal, (2) geo-pressured, (3) hot dry rock (HDR), and (4) magma.

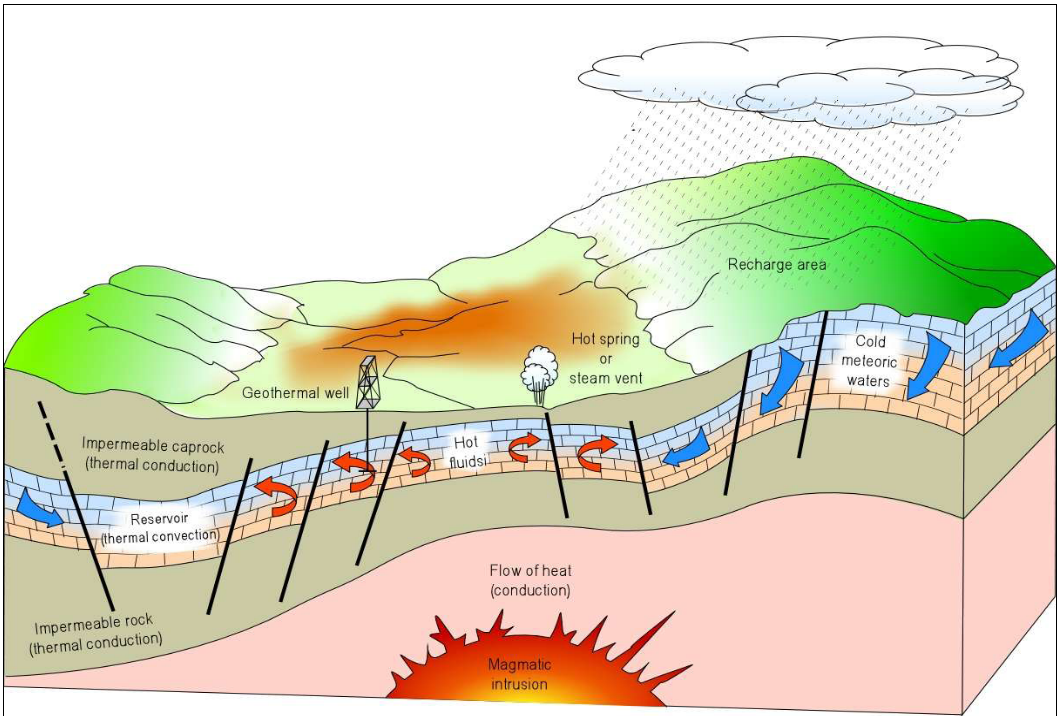


Figure 3.1 Schematic Representation of an Ideal Geothermal System

(Dickson and Fanelli, 1995)

### Heat Source

The vapor-dominated geothermal fields are situated in regions of recent (Miocene–Quaternary) volcanism. Since some of them being located on or close to volcanoes, it has been verified that magma is the source of heat. Young, high-temperature (500–1000 °C) magma intrusions within depths of a few to several kilometers from the Earth's surface allow the necessary heat to be accumulated in economical quantities. In hard compact rocks, faulting may provide a channel for the magma to reach the surface. Soft or plastic rocks, when present, can flow and block the fault space, causing the magma to spread at the contact between the soft and the hard rocks. Active volcanoes, fumaroles, hot springs and geysers are obvious surface manifestations of recent volcanic activity. In addition, certain geological environments, such as regions of Quaternary uplift and regions of Late Tertiary and Quaternary subsidence, are indicative of shallow magmatic intrusions.

### Reservoir and water supply

In order to form a heat reservoir, the anomalous magmatic intrusion should encounter porous and permeable, water-filled rock strata. Within the reservoir, convection currents of hot water and/or steam are set up, providing a good heat exchange, and the temperature difference between the top and bottom of the reservoir is not very significant. A variety of rocks have been found to constitute good reservoirs. At Larderello (Italy), it is fractured limestone and dolomite; at The Geysers (U.S.A.), it is fissured graywacke; at Wairakei (New Zealand), it is pumiceous breccia and tuff; and at Cerro Prieto (Mexico), it is deltaic sands. Good reservoirs could also be formed at geological unconformities and formation boundaries, provided that they are permeable and have good hydraulic continuity and water supply. The origin of geothermal fluids has been debated in the past. In addition to a meteoric origin, magmatic and juvenile origins for geothermal fluids have been suggested. However, recently conducted isotopic studies in geothermal fields have shown that at least 90% of the geothermal water has a meteoric origin. The permeable aquifers forming the reservoir must therefore have hydraulic continuity with large recharge areas for the rainwater to be available in continuous supply. The freshly supplied water is heated conductively at the impermeable base of the reservoir (Figure 3.1). Withdrawing of the heated reservoir fluid through boreholes, or its upward movement through vents and fissures, disturbs the hydrological balance. This is restored, fully or partially, by the inflow of new water. An idea about the amount of the inflow can be drived from the fact that a natural steam field operating a 100MW power plant lets out between 1,000 and 2,000 tons of water every hour. Some of the geothermal fields, such as the Larderello in ltaly, have easily identifiable recharge areas. At Larderello, the permeable reservoir terrain, consisting of Mesozoic limestones and dolomites, outcrops thereby providing an easy access to surficial water.

Cap rock - the barrier

An impermeable cap rock, or a cap rock with low permeability, overlying the reservoir, is necessary to prevent the escape of hot reservoir fluids through convection. The heat loss through conduction is not prevented by the cap rock. However, the amount of heat conducted is much smaller than that which could be lost through possible convection. Since volcanism associated with tectonic movements causes fissures, ideal unfissured impermeable cap rock is nowhere to be found. The geochemical processes associated with geothermal fields, i.e., hydrothermal alteration of rocks and mineral deposition, are helpful in sealing off the fissures. Typical examples of cap rocks rendered impermeable through chemical action and deposition are seen at The Geysers and Otake geothermal fields. At The Geysers, calcite- and silica-filled fractures, up to 1 in. wide, are commonly seen. Evidence of hydrothermal alteration is presented by the bleaching of graywacke as well as by the absence of vegetation in patches. The geochemical and hydrothermal processes are complicated and vary from place to place.

At many other steam-producing fields, original impervious rocks constitute the cap rock. Examples are the lacustrine Huka Formation at Wairakei (New Zealand), the deltaic clay at Cerro Prieto (Mexico) and Salton Sea (California) and the Flysch Formation at Larderello (Italy) (Gupta, 2008).

### 3.1. Hydrothermal Geothermal Systems

Hydrothermal resources arise, when hot water and/or steam is formed in fractured or porous rock at shallow to moderate depths (100m to 4.5km) as a result of either the intrusion in the earth's crust of molten magma from the earth's interior, or the deep circulation of water through a fault or fracture. High temperature hydrothermal resources, with temperatures from 180 °C to over 350 °C, are usually heated by hot molten rock, while low temperature resources, with temperatures from 100 °C to 180 °C, can be produced by either process.

Hydrothermal resources come in the form of either steam or hot water depending on the temperatures and pressures involved. High-temperature resources are usually used for electricity generation, while low temperature resources are used mostly in direct heating applications.

Hydrothermal resources require three basic components a heat source (e.g. crystallized magma), aquifer containing accessible water, and an impermeable cap rock to seal the aquifer.

### 3.2. Geo-pressured Geothermal Resources

A type of hydrothermal environment whose hot water is almost completely sealed from exchange with surrounding rocks is called a geo-pressured system (Jones, 1970; Duffield and Sass, 2003). Such systems typically formed in a basin in which very rapid filling with sediments takes place, resulting in higher than normal pressure of the hydrothermal water. Potential geo-pressured geothermal fields have been discovered mainly in the Texas-Louisiana Gulf Coast region. Similar systems may exist in other hydrocarbon bearing deep sedimentary basins elsewhere.

### 3.3. Hot Dry Rock Geothermal Systems

It is another category of geothermal resource where geothermal heat is stored in the hot and poorly permeable rocks at shallow depths within the Earth's crust, without any fluid availability to store or transport the heat. These resources are designated HDR (Figure 3.2). Large volumes of such rocks at high temperatures are known to exist below all major geothermal areas. Geologically young igneous intrusive bodies at shallow depths of the Earth's crust, which form potential targets for this energy resource, occur in several continental areas.

HDR technology envisages exploitation of Earth's heat stored in the high-temperature and impermeable rocks by artificially creating a fracture system at depth (that acts as a heat exchanger) and circulating water from an injection borehole towards a production borehole. Hydraulic fracturing, which involves injection of water at very high pressure into a reservoir to create new fractures or enlarge pre-existing cracks, has been one of the successful methods in creating permeability in the rocks at depth. It has been estimated that cooling of 1 $km^3$ of hot rock by 100 $^0C$ will enable operation of a 30 MW geothermal power plant for 30 years.. However, generation of large heat exchangers at depth and controlling the loss of circulation fluids present the biggest technological challenges in exploitation of the HDR geothermal energy.

### 3.4. Magma

Magma is the ultimate source of all high-temperature geothermal resources. Plate boundaries are the most common sites of volcanic eruptions. At several volcanic locales, magma is present within the top 5 km of the crust. The heat energy available from such sources, if harvested, would constitute very large additions to the global energy inventory. Extraction of thermal energy from magma was tested during the 1980s by drilling into the still-molten core of a lava lake in Hawaii. However, up to the present, the necessary technology has not been developed to recover heat energy from magma. Economical mining of heat energy from magma presents several practical difficulties such as locating such bodies accurately before drilling into them, the prohibitive costs of drilling and longevity of deployed plant materials in a hot corrosive environment (Gupta, 2008).

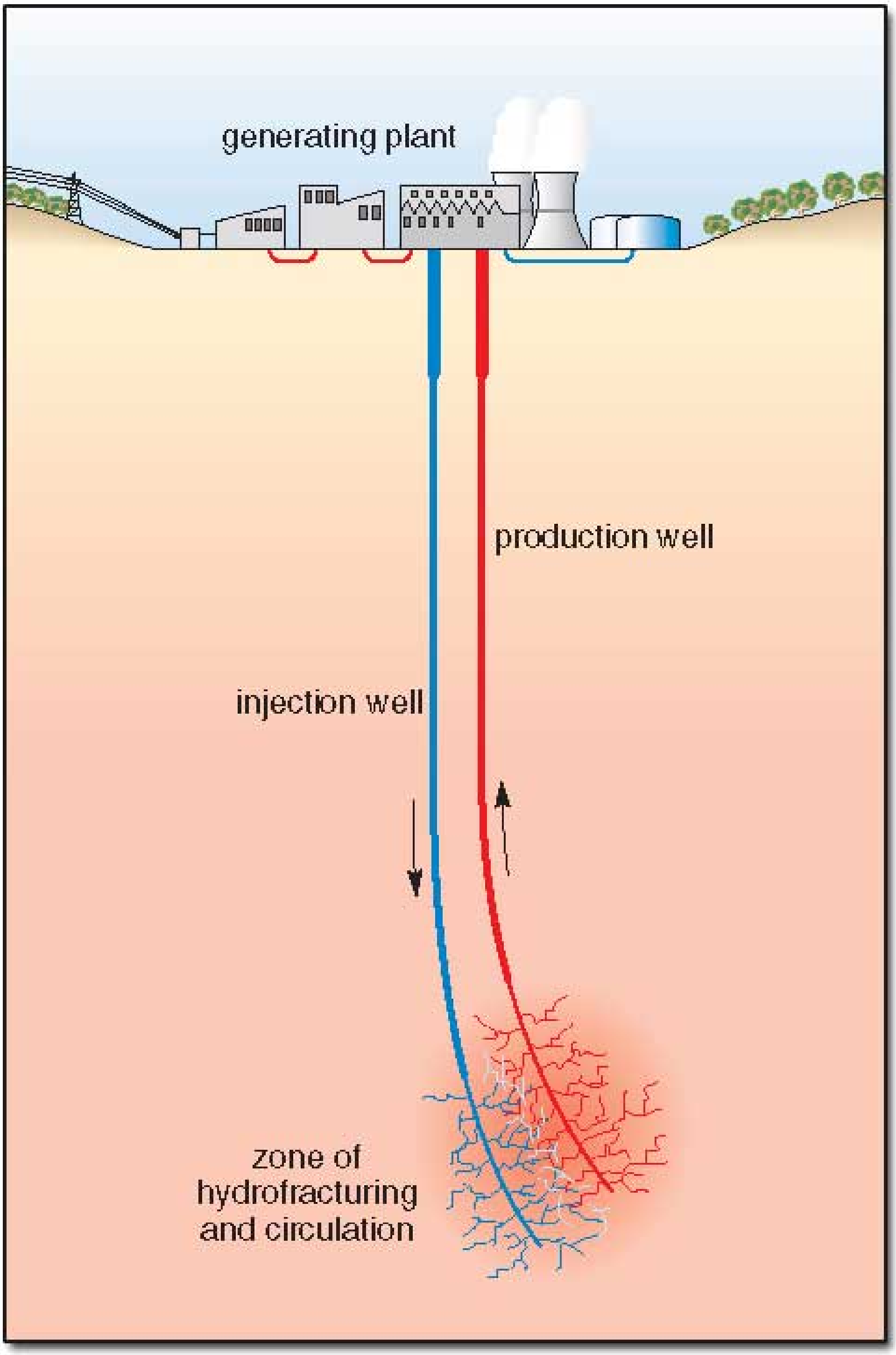

Figure 3.2 A Hot Dry Rock Circulation System (The Open University, 2010)

# CHAPTER 4

# GEOTHERMAL RESOURCE ASSESSMENT

## 4.1 Resource Assessment

Resource assessment is the estimation of the amount of a given raw material that might be produced from the Earth and used economically at a future time (Marshall, 1982).

Resource assessment includes not only the quantities that could be produced under present economic conditions, but also the quantities not yet discovered or that might be produced with improved technology or under different economic conditions.

Any resource assessment should be periodically updated in response to new information, new assessment methodologies, greater understanding of resource characteristics, improved exploration, extraction and utilization technologies and changed economic and social conditions. Such updating is particularly important in a rapidly developing field such as geothermal energy.

Geothermal resource assessment is the estimation of the amount of thermal energy that might be extracted from the Earth and used economically at some reasonable future time. A resource assessment is regional or national in scope and thus provides a framework for long-term energy policy and strategy decisions by industry and government. A resource assessment is not intended to establish specific reserve figures for short term investment and marketing decisions, but instead to give an overall perspective at a particular time, using uniform methodology and data.

## 4.2 Geothermal Resource Terminology

*Geothermal resource base* is the thermal energy in place in the earth's crust (relative to a reference temperature). *Accessible resource base* is the thermal energy at depths shallow enough to be tapped by drilling in the foreseeable future (Muffler and Cataldi, 1978). The *Geothermal resource* is that fraction of the *accessible resource base* that could be extracted economically and legally at some reasonable future time (White and Williams, 1975; Muffler and Cataldi, 1978). This geothermal resource contains both identified and undiscovered components. *Geothermal reserve* is the identified geothermal energy that can be extracted legally today at a cost competitive with other energy sources (Muffler, 1979).

In the petroleum and mining industries, a careful distinction is made between reserve and the total amount found in a given deposit underground prior to extraction. It is that part of the deposit that might be extracted under predictable economics and technology. The recoverable part is expressed as the total deposit multiplied by a recovery factor.

If this factor is asked for geothermal sources, *geothermal recovery factor* is defined as the ratio of extracted thermal energy contained in a given subsurface volume of rock and water (Muffler and Cataldi, 1978).

The terminology adopted by Muffler and Cataldi (1978) for the subdivision of the geothermal resource base is still followed in USGS geothermal assessments (Williams et. al., 2008). The subdivisions are given in a modified McKelvey diagram (Fig. 4.1), in which the degree of geologic assurance regarding resources is set along the horizontal axis and the economic feasibility (effectively equivalent to depth) is set along the vertical axis (Muffler and Cataldi, 1978). USGS geothermal assessments consider both identified and undiscovered systems and define the “resource” as that portion of the accessible resource base that can be recovered as useful heat under current and potential economic and technological conditions. Similarly, the “reserve” is the identified portion of the resource that can be recovered economically using existing technology.

Within this framework, identified hydrothermal systems are divided into three temperature classes: low-temperature (<90ºC), moderate-temperature (90 to 150ºC), and high-temperature (>150ºC). High-temperature systems include both liquid- and vapor-dominated resources. Moderate-temperature systems are almost exclusively liquid-dominated, and all low-temperature systems are liquid-dominated. All three temperature classes are suitable for direct use applications, but in general only moderate- and high-temperature systems are viable for electric power generation. Systems at the upper end of the low-temperature range can be exploited for electric power generation if sufficiently low temperatures are available for cooling the working fluid in a binary power plant.

In the new USGS geothermal assessment, identified geothermal systems are also categorized as producing (the reservoir is currently generating electric power), confirmed (the reservoir has been evaluated with a successful commercial flow test of a production well), and potential (there are reliable estimates of temperature and volume for the reservoir but no successful well tests to date). Reservoir thermal energy and electric power production potential are estimated for all producing, confirmed, and potential geothermal systems above 90ºC in the contiguous United States and Hawaii, and above 75°C in Alaska (Williams et. al., 2008).

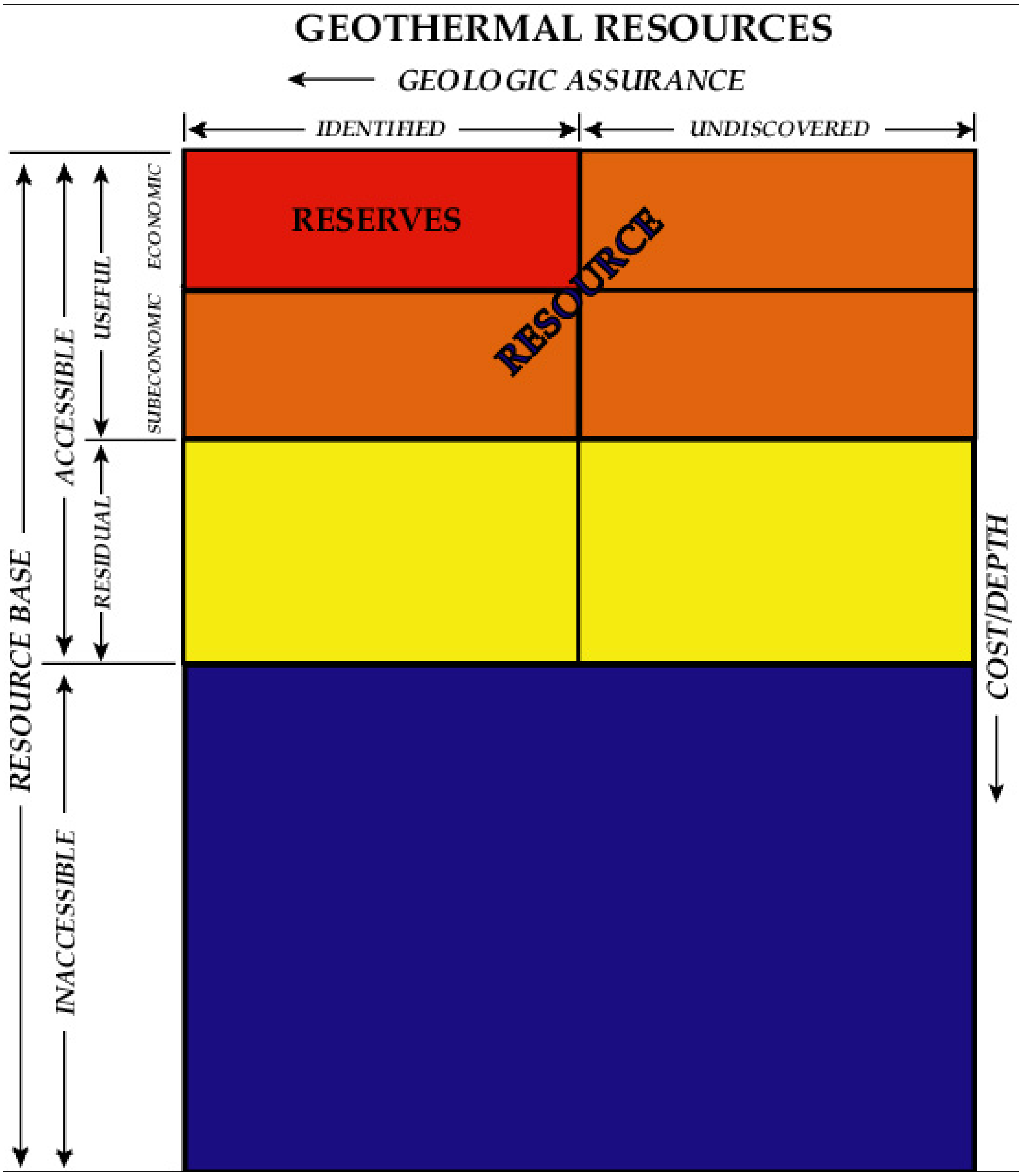


Figure 4.1-McKelvey diagram representing geothermal resource and reserve terminology in the context of geologic assurance and economic viability (Williams et. al., 2008)

# CHAPTER 5

# METHODOLOGY

## 5.1. Hydrothermal Convection Sytems with Reservoir Temperatures ≥ 90 $^0$C

In a *hydrothermal convection system* main components are;

- a heat source
- a fluid (usually water, in very rare cases steam)
- permeability (enough to allow hot low-density fluids to rise and be replaced by cooler fluids in most systems).

Most of the thermal energy in the earth is stored in rocks. Convective circulation of hot fluids is the primary mechanism whereby the energy is transported to reservoirs near enough to the earth's surface so that it can be economically extracted.

Geologic settings of hydrothermal convection systems are diverse. They most likely develop in areas where there is a residual heat related to relatively young volcanic activity and in areas where regional heat flow is high. Fault zones appear to be the most common conduits for movement of fluids in convecting systems. Locations of many systems seem to be controlled by intersecting structures. Reservoirs from which the hot fluids are produced can be either porous or fractured rock; fracture reservoirs are more important in high temperature systems.

Hydrothermal convection systems can be classified into two main types as vapour-dominated, and hot water, depending on whether steam or liquid water, respectively, is the continuous, pressure-controlling phase in the reservoir.

*Vapour-dominated systems* are rare. Their surface activity is characterized by fumaroles, acid-sulphate springs and acid-leached ground, with no neutral chloride-bearing springs. These systems produce saturated to slightly superheated steam with little or no liquid water when drilled. Reservoir fluid pressures show little change with depth, a characteristic indicating that steam is the pressure-controlling phase. Steam and liquid water coexist in the reservoir, although steam dominates the largest fractures. Liquid water is relatively immobilized in small pores and fractures, but is the major phase by mass (Brook et. al., 1979).

*Hot-water systems* are more common and are characterized by circulating liquid water which controls subsurface pressures and transfers heat from depth into the geothermal reservoir. Most of the known hot-water systems are identified by the presence of springs discharging neutral to alkaline chloride-bearing thermal water at the surface. However, some hot-water systems boil at depth and the escaping steam gives rise to fumaroles and acid-sulphate springs, similar to the surface features of vapour-dominated systems. In addition to the temperature and volume of water that can be produced from a hot-water reservoir, the amount and chemical character of dissolved solids in the water are important factors in determining what use can be made of the hot water (Brook et al, 1979)

## 5.2. Geothermal Resource Assessment Methods (Volume Method)

Muffler and Cataldi (1978) identified four methods for assessing geothermal resources: surface heat flux, volume, planar fracture and magmatic heat budget. Although there is some renewed interest in the surface heat flux approach, the volume method as developed by Nathenson (1975), White and Williams (1975), Muffler and Cataldi (1978) and Muffler (1979) was quickly established as standard approach.

According to Muffler and Cataldi (1978), the electric power generation potential from an identified geothermal system depends on the thermal energy, $q_R$, present in the reservoir, the amount of thermal energy that can be extracted from the reservoir at the wellhead, $q_{WH}$ , and the efficiency with which the wellhead thermal energy can be converted to electric power. Once the reservoir fluid is available at the wellhead, the thermodynamic and economic constraints on conversion to electric power are well known. The challenge in the resource assessment lies in understanding the size and thermal energy of a reservoir as well as the constraints on extracting that thermal energy. The total heat stored in the reservoir is calculated by using the following equation (Muffler and Cataldi, 1978).

Total heat stored in the reservoir is equal to the sum of heat stored in the (solid) rock and water.

$$H_t = H_s + H_w \qquad \text{Eq 5.1}$$

$$H_t = [(1-\Phi) c_s \rho_s A d (T_s - T_r)] + [\phi c_w \rho_w A d (T_w - T_r)] \qquad \text{Eq 5.2}$$

where;

H= Heat energy, kJ

Φ= Porosity, fraction

c= Specific heat, kJ/kg-$^0$C

ρ= Density, kg/m$^3$

A= Reservoir Area, m$^2$

d= Reservoir Thickness, m

T= Temperature, $^0$C

and subscripts r, s, t and w stand for reference, solid rock, total and water respectively.

For the equation 5.2, it is assumed that a local thermal equilibrium is always valid in the reservoir so that solid rock and water temperatures are identical ($T_s$=$T_w$=T). By using this assumption Equation 5.2 yields Equation 5.3.

$$H_t = [(1-\Phi) c_s \rho_s + \Phi c_w \rho_w] A d (T - T_r) \qquad \text{Eq. 5.3}$$

**Geothermal Recovery Factor**

For hot-water geothermal systems, the ratio of geothermal energy recovered at well head, $q_{WH}$, to the geothermal energy originally available in the reservoir, $q_R$ is called geothermal recovery factor, $R_g$.

$$R_g = q_{WH} / q_R \sim 0{,}05\text{-}0{,}2 \text{ (Williams, 2004, 2007)} \qquad \text{Eq. 5.4}$$

This value for $R_g$ came from an analysis by Nathenson (1975) on the factors influencing the extraction of heat from a geothermal reservoir through a "cold sweep" process, in which the hot reservoir fluid is gradually replaced by colder water through natural or artificial injection. The resource estimates in Circular 790 were based on a Monte Carlo uncertainty model with a triangular distribution for Rg with a most-likely value of 0.25 and a range from 0 to 0.5 (Muffler, 1979). More recent analyses of data from the fractured reservoirs commonly exploited for geothermal energy indicate that Rg is closer to 0.1, with a range of approximately 0.05 to 0.2 (Williams, 2004, 2007).

Total heat energy, $H_T$ given in Equation 5.1 can actually be referred as reservoir geothermal energy $q_R$ (Equation 5.4). So, one can assume that $H_T = q_R$

**Geothermal energy recovered at wellhead**, $q_{WH}$ is found by multiplying the geothermal recovery factor,$R_g$, with geothermal energy in the reservoir, $q_R$, .

$$q_{WH} = R_g * q_R \qquad \text{Eq. 5.5}$$

**Electrical Power**

The electrical power E ($kW_e$) obtainable from a geothermal reservoir is given by the Equation 5.6 (adapted from Arkan and Parlaktuna, 2005).

$$E = \frac{q_{WH} * \eta_u}{(t * LF)}$$ Eq 5.6

where;

E = Recoverable Electrical Power, ($kW_e$)

$q_{WH}$ = Recoverable Thermal Energy at the well head, (kJ)

$\eta_u$= Transformation yield. It takes into account the efficiency of transferring heat energy from geothermal fluid to a secondary fluid, fraction

LF= Load factor. Most of the energy applications of geothermal energy are not continuous throughout the year. This factor takes into account the fraction of the total time in which the geothermal power plant is in operation, fraction

t = Total project life, sec

In the actual implementation of this approach the mean values for the input variables are replaced with a range of values corresponding to estimated uncertainties, and these values are then used in Monte Carlo simulations to define the reservoir properties and productivity, along with the associated uncertainties (Muffler, 1979).

For power generation above 150°C, Brook et. al. (1979) used a constant value for $\eta_u$ of 0.4 down to the minimum reservoir temperature for electric power production above 150°C. A compilation of $\eta_u$ for existing geothermal power plants producing from liquid-dominated systems over a wide range of temperatures confirms $\eta_u$ equal to approximately 0.4 above 175°C (Fig. 5.1)(DiPippo, 2005). There is a linear decline in $\eta_u$ below 175°C as reservoir temperatures approach the reference state in binary power plant operations. In the new assessment the 150°C lower limit is revised downward to include binary power production from moderate-temperature systems (Williams et. al., 2008).

Load factor takes into account the fraction of the total time in which the geothermal power plant is in operation. The operation time for the geothermal power plant is taken as 8000 hours/year. A year equals to 8760 hours. Load Factor is calculated by division of 8000 to 8760 which is equal to 0.91.

Equations 5.1 through 5.6 cover the basic relationship used to estimate electric power generation potential for a given geothermal system. Uncertainties in the estimates are justified through a Monte Carlo simulation approach, which is shown in Figure 5.2. For each system, USGS investigators determine most likely, minimum and maximum values for reservoir temperature and volume. These values are used to generate triangular probability distributions for temperature and volume, and the resulting distributions are combined for an estimate of reservoir thermal energy. A uniform distribution for the geothermal recovery factor is introduced in the next step of the Monte Carlo analysis, and the resulting values for wellhead exergy are transformed to electric power estimates using the utilization efficiency relationship shown in Figure 5.2. In thermodynamics, the *exergy* of a system is the maximum useful work possible during a process that brings the system into equilibrium with a heat reservoir. The final result is a distribution of electric power generation estimates for each geothermal system (Figure 5.2), which includes values for the most likely, mean, median, 5 percent and 95 percent electric power generation potential.

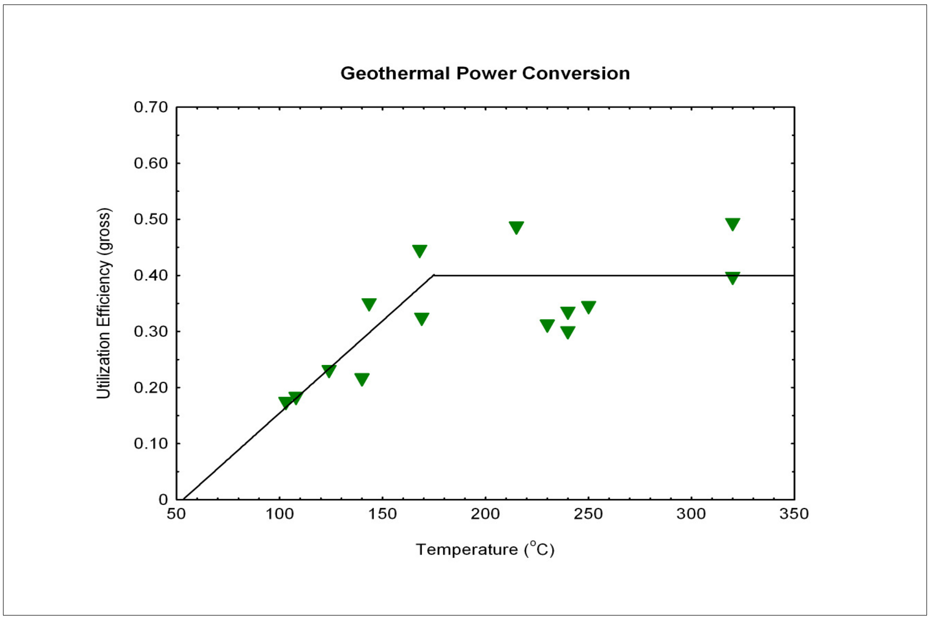


Figure 5.1 Utilization efficiency as a function of temperature for existing geothermal power plants studied by DiPippo (2005)

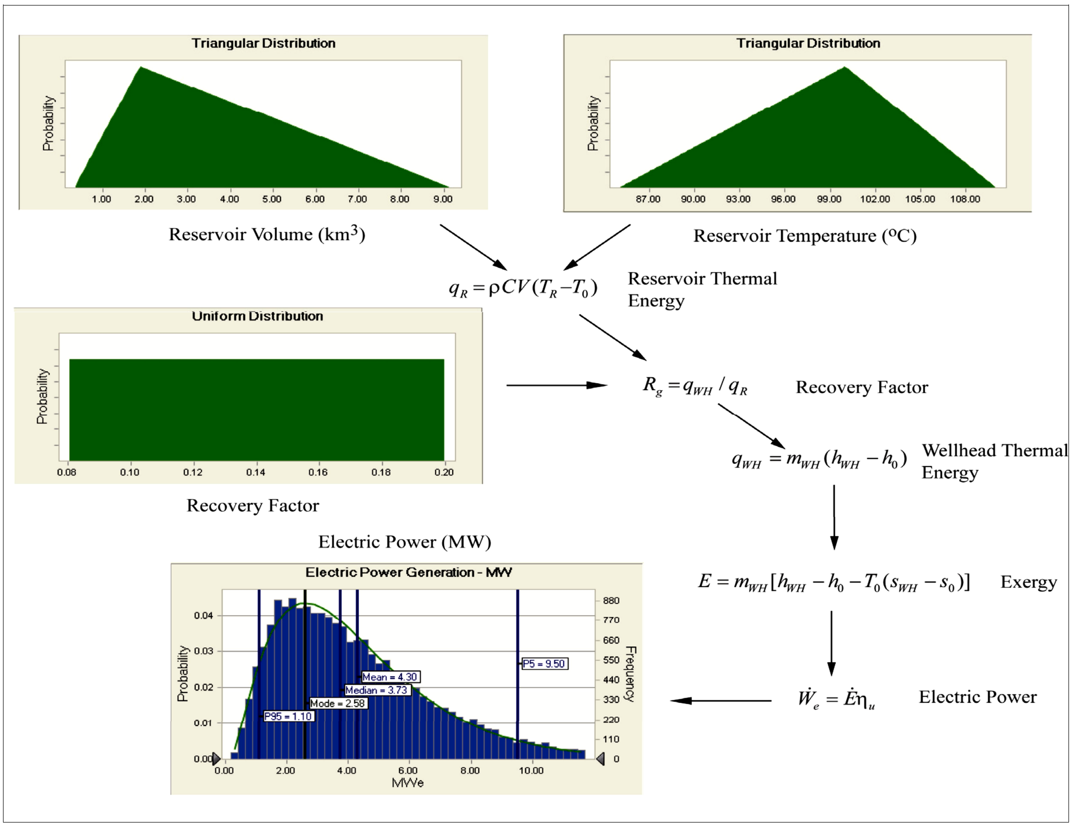


Figure 5.2 Schematic of the Monte Carlo uncertainty analysis (Williams et. al., 2008).

## 5.3. Monte Carlo Simulation

Monte Carlo simulation is a widely used computational method for generating probability distributions of variables that depend on other variables or parameters represented as probability distributions.

The defining characteristic of Monte Carlo methods is its use of random numbers in its simulations. In fact, these methods derive their collective name from the fact that Monte Carlo, the capital of Monaco, has many casinos and casino roulette wheels are a good example of a random number generator.

The Monte Carlo simulation technique has formally existed since the early 1940s, where it had applications in research into nuclear fusion. However, only with the increase in computer technology and power, the technique is more widely used.

This is because computers are now able to perform millions of simulations much more efficiently and quickly than before. This is an important factor because it means that the technique can provide an approximate answer quickly and to a higher level of accuracy, because the more simulations that one performs, the more accurate the approximation is. The technique is used by professionals in such widely disparate fields as finance, project management, energy, manufacturing, engineering, research and development, insurance, oil & gas, transportation, and the environment.

This availability has coincided with increasing dissatisfaction with the deterministic or point estimate calculations typically used in quantitative risk assessment; as a result, Monte Carlo simulation is rapidly gaining currency as the preferred method of generating probability distributions of exposure and risk. Monte Carlo methods are to be contrasted with the deterministic methods used to generate specific single number or point estimates of risk. Monte Carlo simulation would involve many calculations of the intake rate rather than a single calculation; for each calculation, the computation would use a value for each input parameter randomly selected from the probability density function for that variable. Over multiple calculations, the simulation uses a range of values for the input parameters that reflects the probability density function of each input parameter. Thus, the repetitive calculations take many randomly selected combinations into account, generating a probability density function or cumulative density function for the output. Based on the distribution of the output, a risk level representing the high end (e.g., 95th percentile), central tendency (median or mean), or any other desired level of probability can be identified.

The primary components of a Monte Carlo simulation method include the following:

- *Probability distribution functions (pdf's)* - the physical (or mathematical) system must be described by a set of pdf's.
- *Random number generator* - a source of random numbers uniformly distributed on the unit interval must be available.
- *Sampling rule* - a prescription for sampling from the specified pdf's must be given assuming the availability of random numbers on the unit interval.

- *Scoring (or tallying)* - the outcomes must be accumulated into overall tallies or scores for the quantities of interest.
- *Error estimation* - an estimate of the statistical error (variance) as a function of the number of trials and other quantities must be determined.
- *Variance reduction techniques* - methods for reducing the variance in the estimated solution to reduce the computational time for Monte Carlo simulation
- *Parallelization and vectorization* - algorithms to allow Monte Carlo methods to be implemented efficiently on advanced computer architectures.

Monte Carlo simulation performs risk analysis by building models of possible results by substituting a range of values—a probability distribution—for any factor that has inherent uncertainty. It then calculates results over and over, each time using a different set of random values from the probability functions. Depending upon the number of uncertainties and the ranges specified for them, a Monte Carlo simulation could involve thousands or tens of thousands of recalculations before it is complete. Monte Carlo simulation produces distributions of possible outcome values.

By using probability distributions, variables can have different probabilities of different outcomes occurring. Probability distributions are a much more realistic way of describing uncertainty in variables of a risk analysis. Common probability distributions include:

*Normal* – Or "bell curve." The user simply defines the mean or expected value and a standard deviation to describe the variation about the mean. Values in the middle near the mean are most likely to occur. It is symmetric and describes many natural phenomena such as people's heights. Examples of variables described by normal distributions include inflation rates and energy prices.

*Lognormal* – Values are positively skewed, not symmetric like a normal distribution. It is used to represent values that don't go below zero but have unlimited positive potential. Examples of variables described by lognormal distributions include real estate property values, stock prices, and oil reserves.

*Uniform* – All values have an equal chance of occurring, and the user simply defines the minimum and maximum. Examples of variables that could be uniformly distributed include manufacturing costs or future sales revenues for a new product.

*Triangular* – The user defines the minimum, most likely, and maximum values. Values around the most likely are more likely to occur. Variables that could be described by a triangular distribution include past sales history per unit of time and inventory levels.

*PERT* – The user defines the minimum, most likely, and maximum values, just like the triangular distribution. Values around the most likely are more likely to occur. However values between the most likely and extremes are more likely to occur than the triangular; that is, the extremes are not as emphasized. An example of the use of a PERT distribution is to describe the duration of a task in a project management model.

*Discrete* – The user defines specific values that may occur and the likelihood of each. An example might be the results of a lawsuit: 20% chance of positive verdict, 30% chance of negative verdict, 40% chance of settlement, and 10% chance of mistrial.

During a Monte Carlo simulation, values are sampled at random from the input probability distributions. Each set of samples is called an iteration, and the resulting outcome from that sample is recorded. Monte Carlo simulation does this hundreds or thousands of times, and the result is a probability distribution of possible outcomes. In this way, Monte Carlo simulation provides a much more comprehensive view of what may happen. It tells you not only what could happen, but how likely it is to happen.

Monte Carlo simulation provides a number of advantages over deterministic, or "single-point estimate" analysis:

- *Probabilistic Results.* Results show not only what could happen, but how likely each outcome is.
- *Graphical Results.* Because of the data a Monte Carlo simulation generates, it's easy to create graphs of different outcomes and their chances of

occurrence. This is important for communicating findings to other decision makers.

- *Sensitivity Analysis*. With just a few cases, deterministic analysis makes it difficult to see which variables impact the outcome the most. In Monte Carlo simulation, it's easy to see which inputs had the biggest effect on bottom-line results.
- *Scenario Analysis.* In deterministic models, it's very difficult to model different combinations of values for different inputs to see the effects of truly different scenarios. Using Monte Carlo simulation, analysts can see exactly which inputs had which values together when certain outcomes occurred. This is invaluable for pursuing further analysis.
- *Correlation of Inputs.* In Monte Carlo simulation, it's possible to model interdependent relationships between input variables. It's important for accuracy to represent how, in reality, when some factors goes up, others go up or down accordingly.

Monte Carlo simulation is often criticised as being an approximate technique. However, in theory at least, any required level of precision can be achieved by simply increasing the number of iterations in a simulation. The limitations are in the number of random number generating algorithm and, more commonly, the time a computer needs to generate iterations. For a great many problems, these limitations are irrelevant or can be avoided by structuring the model into sections (Vose, 2008).

# CHAPTER 6

# STATEMENT OF THE PROBLEM

There are 276 geothermal occurrences including nearly 110 fields having at least one drilled well known to exist in Turkey with surface temperatures ranging from 22.5 °C to 220 °C according to both MTA reports and private companies' records (Basel et. al., 2010). Most of these occurrences are mainly located along the major grabens at the Western Anatolia, the Northern Anatolian fault zone and Central and Eastern Anatolian volcanic regions. The surface temperatures in 80 of the occurrences are above 60 °C in 13 of them above 100 °C and in 8 occurrences above 140 °C (Basel et. al., 2010).

Aydın-Kuyucak-Pamukören geothermal field with well head temperature over 160 $^{0}$C (MTA, 2009d) is one of the high-temperature regions suitable for electricity generation. The capacity for the geothermal field has to be determined with limited data and uncertainties. In this study, assessment of Aydın-Kuyucak-Pamukören high-temperature geothermal field is realized by volume method. Monte Carlo Simulation Method is applied to account for uncertainties of the variables of the method.

# CHAPTER 7

# GEOLOGY OF AYDIN-PAMUKÖREN GEOTHERMAL FIELD

In this study, volume method of geothermal resource assessment is applied for determination of the accessible resource base and recoverable electrical power of Aydın-Kuyucak-Pamukören high temperature geothermal field. Monte Carlo simulation method is preferred since many uncertainties are present for the main input data. @RISK software is used for the calculations.

## 7.1. Aydın-Pamukören Geothermal Field

Aydın Province has a high potential about hot water resources. Springs generally occur along the faults forming Büyük Menderes Graben. Some of the wells drilled in the area have suitable hot fluid for electricity production.

Aydın Pamukören Geothermal field is located in the eastern part of Büyük Menderes Graben at West Anatolia. From lithological point of view, it is composed of metamorphites of Menderes massif and sediments settled in Graben formation.

Aydın is in Aegean Region of Turkey (Figure 7.1). Pamukören is located 10 km East of Kuyucak and 70 km away from Aydın. The town is 2 km away from the main road between Aydın and Denizli (Figure 7.2).

Figure 7.1 General Location Map of Aydın Province

Figure 7.2 Location Map of Pamukören Region

## 7.2. Regional Geology

Aydın Pamukören geothermal field is located at Eastern North margin of East-West trending Büyük Menderes Graben developed by normal faults. In the region, the basement units are represented by Menderes massif metamorphics (Figure 7.3) composed of Paleozoic para and ortho gneisses, chloride-schist, mica-schist, quartz-schist, quartzite, phyllites and intercalating marble layers. The gneisses are thrusted over schists and marble unit. In these units, the fractures and joints are filled by calcite and quartz minerals in addition to dense pyrite occurrences in geothermally active levels.

The tertiary sedimentary units unconformably overly Palaeozoic units and composed of coarse-fine grained sandstone, siltstone and well cemented conglomerates which are originated from tectonic activities and sedimentation in continental environment (Figure 7.4). In some levels altered and unaltered thin bedded marl bands are developed.

Throughout the Graben at some places the lignite seams are observed in lower part of Neogen units over the level of basalt conglomerates (Figure 7.4).

The youngest units in the area  are Quaternary age slope scree deposits and alluvial sediments (Figure 7.4). The slope scree deposits are developed by Graben bounding normal fault movements.

The alluvial sediments are confined to stream beds and uncomformably overlying all the older units. (MTA, 2009c)

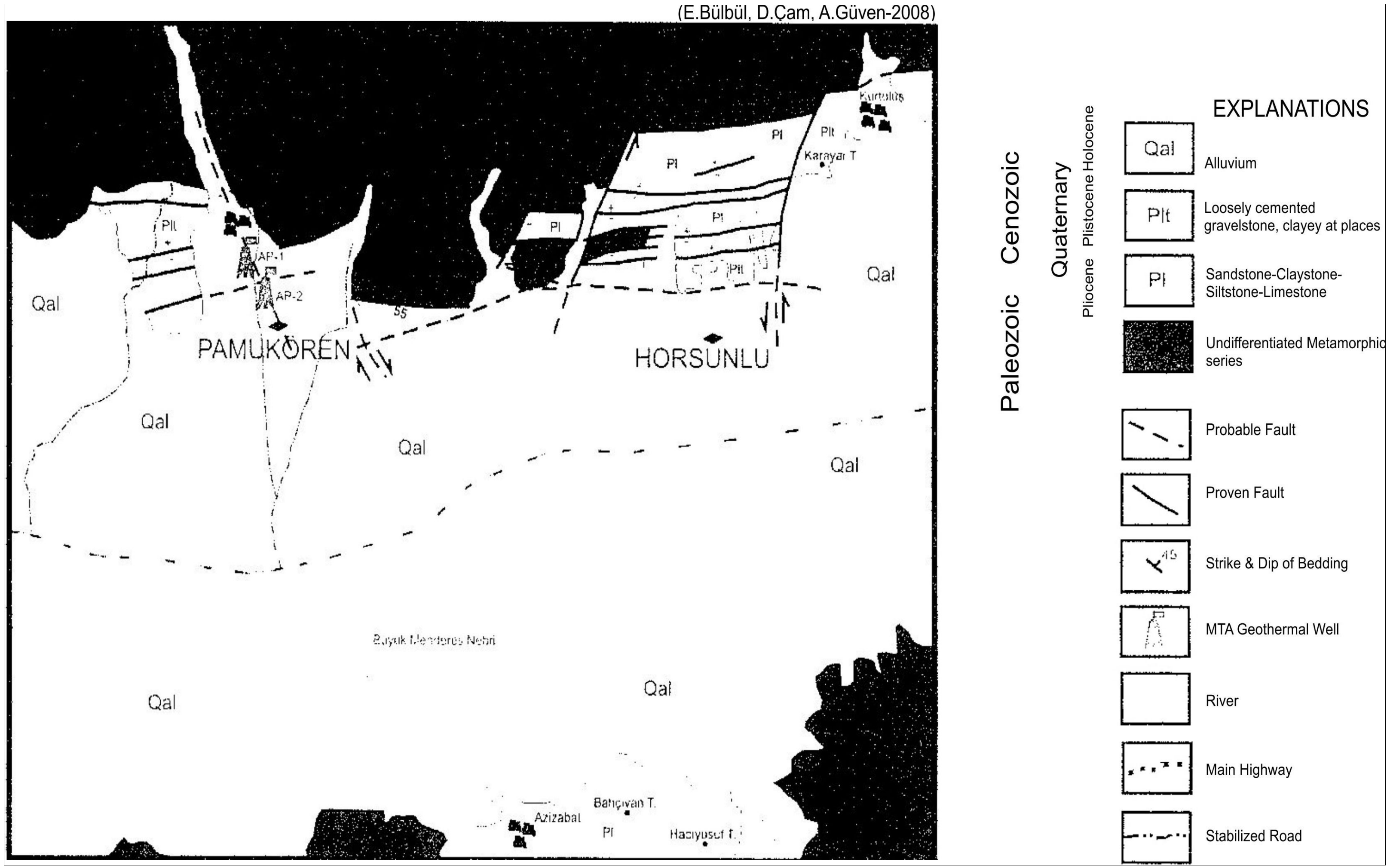


Figure 7.3 The Geological Map of Aydın-Kuyucak Pamukören Geothermal Region (MTA, 2009c)

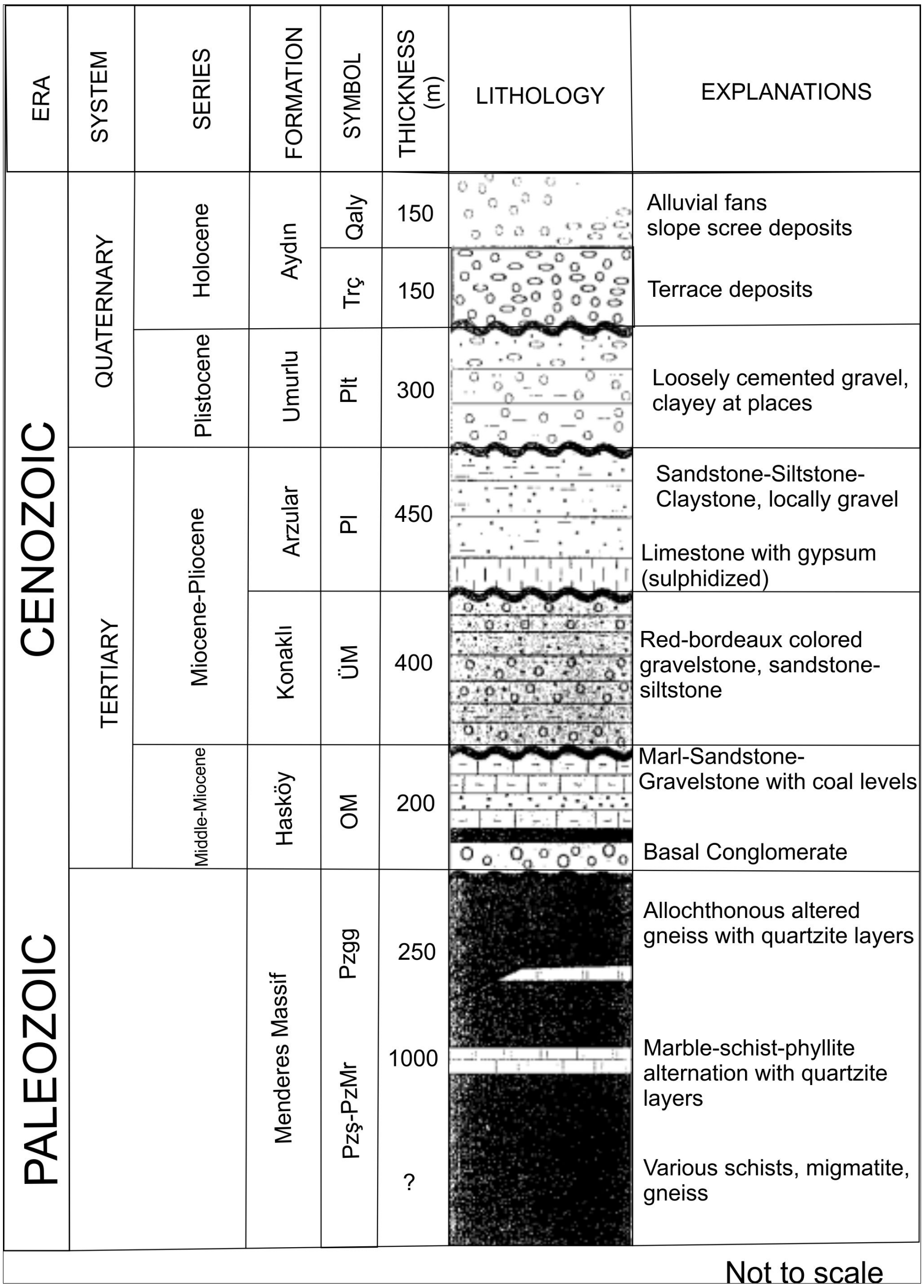


Figure 7.4 Generalized Columnar Section of Pamukören Region (MTA, 2009c)

### 7.3. Tectonics

Most of geothermal resources of Turkey are found in Menderes massif and they are mostly tapping the same geological environment. The Menderes Massif is one of the largest metamorphic massifs in Turkey, measuring roughly 200 km N-S, and about 150 km E-W in western Anatolia. It can be described as a dome-like structure, broken by faulting during the alpine orogeny. The Menderes Massif includes a core of paragneisses and orthogneisses wrapped in a variety of schists and dolomitic marbles. These rocks have been intruded by a number of granites.

The whole region shows a formation with E-W trending normal faults and transform faults intersecting these faults.

Since the Menderes Massif being located in a fractured region, occurrences of quartz veins, existence of hot water springs in the area and massif show the presence of a heat source in the area.

In the close area, observation of no young volcanic rocks supports the idea of heat source being magmatic origin.

In all of the geothermal fields in the Menderes Massif, the oblique and normal faults having strikes in N-S, NW-SE, NE-SW intersects E-W trending major normal faults. This fact also plays an important role for the geothermal system in Pamukören field. So the crossing zones of faults are taken into consideration for the selection of well locations. (MTA, 2009c)

### 7.4. Geothermal System

Aydın Pamukören Geothermal field is located in the Eastern part of Menderes Graben. In the region, the East-West trending Graben was formed by step-like fault systems as a result of uplifting of Menderes Massif in a north-south direction extensional tectonics.

In Pamukören geothermal field, meteoric water drained to underground is heated by magmatic activities, approaching to surface, related to thinning in the earth crust at depths. This heated water, which rises along the East-West trending step-like major faults forming Graben structure, are deposited in reservoir rocks, marl and gneiss. Some part of geothermal fluid discharges as springs along the faults, the sandy and pebbly levels of Neogen aged rocks forms the shallow geothermal reservoirs.

In the region the most suitable reservoir rocks that water can be deposited are gneisses and marbles of series of Menderes Massif. The gneisses have lateral continuity and sufficient thickness which also form the basement rocks. Sandy and pebbly levels of Neogen aged rocks forms the shallow geothermal reservoirs.

The clayey and silty parts of Quaternary and Neogen age rocks and schist of Menderes Massif have cap rock properties (MTA, 2009c).

# CHAPTER 8

# RESULTS AND DISCUSSION

## 8.1 Geothermal Wells in the Region

Mineral Research and Exploration General Directorate of Turkey (MTA) has drilled three wells in the region, namely AP1, AP2 and AP3 (Table 8.1).

Table 8.1 Coordinates of the Wells

| Name | X(Up) | Y(Right) | Z(Level) | Map No: |
|---|---|---|---|---|
| AP1 | 41,992.24 | 06,347.49 | 235 m | Aydın M21-a1 |
| AP2 | 41,989.09 | 06,348.85 | 182 m | Aydın M21-a1 |
| AP3 | 41,983.40 | 06,349.20 | 155 m | Aydın M21-a1 |

*AP1 Well* is planned to 700 m depth but drilled to 606 m depth. When the well is opened to production, a high concentration of gas emission is observed. In the gas measurements it is found out that the dominant gas is $CO_2$ and the percentage of $CO_2$ in the mixture is 99,5 %. The fluid produced from well has 1,0 l/sec production rate and temperature of 51,1 $^0$C at well head. No geothermal well test is done for this well.

At AP1 well there is huge amount of $CO_2$ gas production. The reserve of the gas can not be calculated with current equipment and conditions. But it is very important to determine the production figures of this gas which is harmless to environment and has lots of application areas used , and must be gained to economy.

*AP 2 Well* is drilled to 1,150 m depth and finished by GD-3000 Drilling Machine and run 7” liner. After installing the well head equipment and surface testing systems, well completion tests were started.

When AP-2 well is completed, the testing device could not be lowered deeper than 850 m depth and completion tests were done at this level. The cleaning of the scaling in the well was discussed, but RCHP (Rotating Control Head Preventer) System was in use at a different field, the cleaning was scheduled to a later date. As the results of the tests, acid injection was suggested.

The well-in production was cleaned with RCHP system. At 2009-07-07, 41,560 kg HCl with a concentration of % 30 is injected into the well. After acid injection, the tests are repeated and acid effect is evaluated.

In AP-2 well maximum static temperature is measured as 182.92 °C at 1,090 m. Maximum dynamic temperature is measured as 182.41 °C with a production rate of Q=171 tons/hour at 1090 m. Under dynamic conditions the wellhead temperature was measured as 168.20 °C.

Main reservoir zone of AP-2 well is determined between 800 and 925 m in water loss test. Deeper than 1000 m no permeability is observed at well bottom.

Productivity index (PI) of AP-2 well was found as 4.5 (tons/hour)/bar before acidizing operation. After acidizing PI is measured as 90.48 (tons/hour)/bar with an increase of 20 times.

Injectivity index (II) values were 20.77 (tons/hour)/bar and 88.08 (tons/hour)/bar for the conditions before and after acidizing, respectively. The change in II is 4.2 times of increase as a result of acidizing.

Acidizing also changed the production rate characteristics of AP-2 well. Before acidizing the maximum production rate (Q) was 58 lt/sec (209 tons/hour) at 1,5 bar well head pressure (WHP). After acidizing it changed as 156 lt/sec (561 tons/hour) at 5 bar WHP. The increase in production rate is 2.68 times.

The initiation point of calcite scaling at flow rate of 171 tons/hour at the beginning is found to be at 550 m depth. A sudden fall in temperature and pressure values is observed at 900 m depth while the well was producing with a rate of 171 tons/hour. This sudden decrease in both temperature and pressure was attributed to a probable dense gas intrusion ($CO_2$) at this level (MTA, 2009a).

*AP 3 Well* is drilled to 1,052 m depth and finished by WR-6 Drilling Machine and completed with 7" liner. After installing the well head equipment and surface testing systems, well completion tests are started. The well is cased with a 9 5/8" casing to 674 m and 7" slotted liner is placed to the interval of 664 m and 1052 m.

The maximum static temperature of AP-3 well is measured as 183.34 °C at a depth of 950 m. Maximum dynamic temperature is measured 182.79 °C with a production rate of Q=117 tons/hour at 900 m. The measured wellhead temperature is 165.32 °C at 177 tons/hour production rate.

Main reservoir zone is determined between 900 and 930 m from water loss test. Low permeability is also observed at well bottom.

A multi rate injection test, with three different rates of 11, 18 and 23 l/sec injection, is carried out. Because of shortage in water to be injected, testing intervals are taken short. Injectivity index (II) is calculated as a very high value of 90.5 (tons/hour)/bar.

Flashing depth (possible calcite scaling initiation point) is found to be 500 m at 117 tons/hour and 550 m at 170 tons/hour production rates. It is therefore concluded that at a production rate range of 150-300 tons/hour, scaling can start between 500 and 600 m.

Productivity index (PI) is estimated as 753.57 (ton/hour)/bar from pressure build up test. Although production rate is increased from 170 ton/hour to 211 ton/hour, no change is recorded in the reservoir pressure.

A sudden fall both in temperature and pressure values is observed at 950 m depth, while the well was producing with a rate of 170 tons/hour. As it was discussed for AP-2 well this sudden decrease in both temperature and pressure was attributed to a probable dense gas intrusion ($CO_2$) at this level (MTA , 2009b).

The maximum flow rate of AP-3 well is measured as 215 lt/sec (776 tons/hour) at WHP= 9 bar using silencer-weir production test facility. Since the environmental conditions were not suitable, maximum production is only done for 45 minutes. For the whole production test, production is done for 215 minutes. After providing suitable environmental conditions the well should be kept in production for longer periods (12-24 hours) for more detailed studies.

## 8.2 Accessible Resource Base Calculation

The methodology used in determining the accessible geothermal resource base for Aydın-Kuyucak-Pamukören geothermal field is the volumetric method. In this method the total stored heat and recoverable thermal energy (in terms of power) of the field are computed. In this methodology it is assumed that the geothermal reservoir under investigation is contained by hot solid rock and single-phase liquid water.

Total heat stored in the reservoir is equal to the sum of heat stored in the (solid) rock and water.

$$H_t = H_s + H_w \qquad \text{Eq 8.1}$$

$$H_t = [(1-\Phi) c_s \rho_s A d (T_s - T_r)] + [\Phi c_w \rho_w A d (T_w - T_r)] \qquad \text{Eq 8.2}$$

where;

H= Heat energy, kJ

Φ= Porosity, fraction

c= Specific heat, kJ/kg-$^0$C

ρ= Density, kg/m$^3$

A= Reservoir Area, m$^2$

d= Reservoir Thickness, m

T= Temperature, $^0$C

and subscripts r, s, t and w stand for reference, solid rock, total and water respectively.

For the equation 8.2, it is assumed that a local thermal equilibrium is always valid in the reservoir so that solid rock and water temperatures are identical ($T_s$=$T_w$=T). By using this assumption Equation 8.2 yields Equation 8.3.

$$H_t = [(1-\Phi)c_s\rho_s + \Phi c_w\rho_w] Ad(T - T_r) \qquad \text{Eq. 8.3}$$

Mineral Research and Exploration Institute of Turkey (Erisen *et al*., 1996) defines eighteen geothermal fields and anomalies along the Büyük Menderes Graben. Except one field (Tekkehamam) which is found in the southern part, all fields and anomalies are situated in the northern part of graben region along a main E-W fault. Five anomalies are located at the intersection of Büyük Menderes Graben with the Gediz and Curuksu grabens at the easternmost part of the region. Some 34 deep (up to 2,300 m) and several hundreds of shallow gradient wells have been drilled in this region. The geology of the area has been extensively studied for the last 35 years. Regional and as many as 12 local resistivity and gravity surveys have been carried out. The well known high enthalpy field is Kizildere geothermal reservoir that was discovered in 1968. Since the anomalies and the fields were the result of the same geologic event-that is, tectonism within the same geological environment (Menderes Massif)-their stratigraphy, their resistivity anomalies and their water chemistry are very much similar. Therefore, this region can be considered as a geothermal basin (Serpen et al., 2000).

Since the similarities in the geological environment have been established, available porosity, density and fluid property data from well-studied geothermal reservoirs -such as Kizildere may be extended to the other geothermal structures in the basin (Serpen et al., 2000).

The following data and the assumptions are taken into consideration for calculation;

<u>Porosity:</u>

Porosity values for the region are adapted from Kızıldere Geothermal Region. The minimum, most likely and maximum porosity values are taken as 1 %, %3 and %7 respectively.

Specific heat for rock:

This parameter is taken constant 0.88 kJ/kg-°C for marble-reservoir rock (http://www.engineeringtoolbox.com/specific-heat-solids-d_154.html).

Density of Rock:

The density of rock was defined by uniform distribution for Kızıldere Geothermal Region with minimum 2,500 kg/m$^3$ and maximum 2,700 kg/m$^3$. The same assumption is adapted for this study.

Subsurface Area:

The data gathered from Resistivity Studies in Nazilli–Kuyucak-Karacasu Region (MTA, 1986); an electrical anomaly is observed between the measurement points coded as 35D-50D-60D in BASE profile (E-W cross section). The length of this anomaly is approximately 2,600 meters (Figure 8.1 and 8.2). Also at 50D Profile (N-S cross section) stepwise graben is observed 4,650 m long along the measurement points coded as 18G-22K(Figure 8.3 and 8.4). The reservoir area can be considered as a rectangle with dimensions of 2,600 m by 4,650 m. The maximum reservoir area is nearly 12.1 km$^2$ .

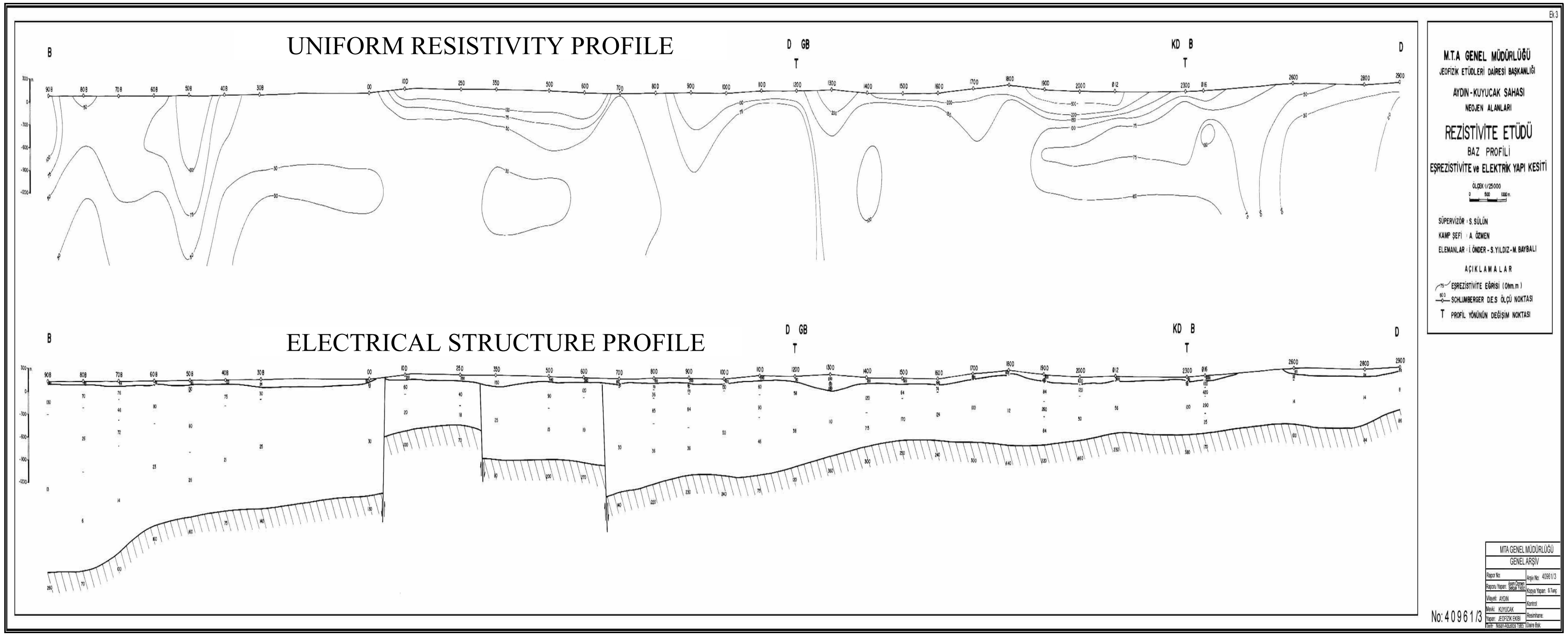


Figure 8.1 Uniform-resistivity and Electrical Structure for BASE profile in E-W direction (MTA, 1986)

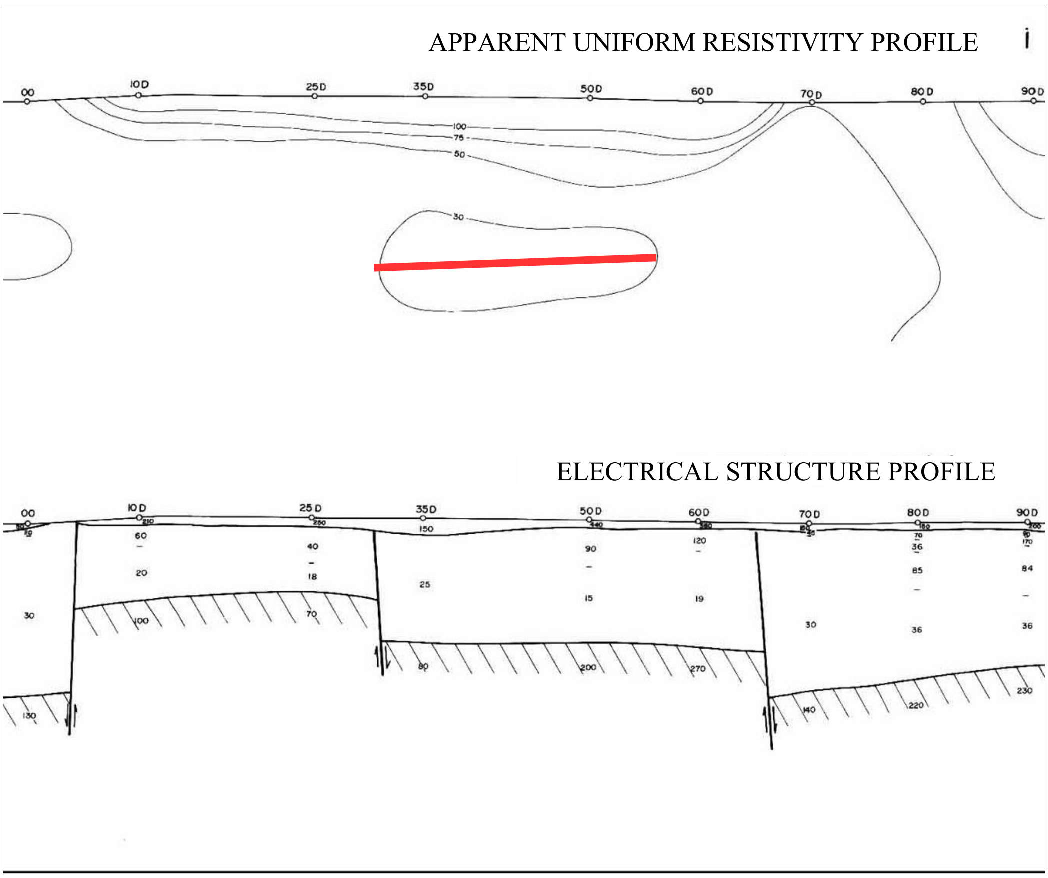


Figure 8.2 Detail of Uniform-resistivity and Electrical Structure
for BASE profile (E-W) (MTA, 1986)

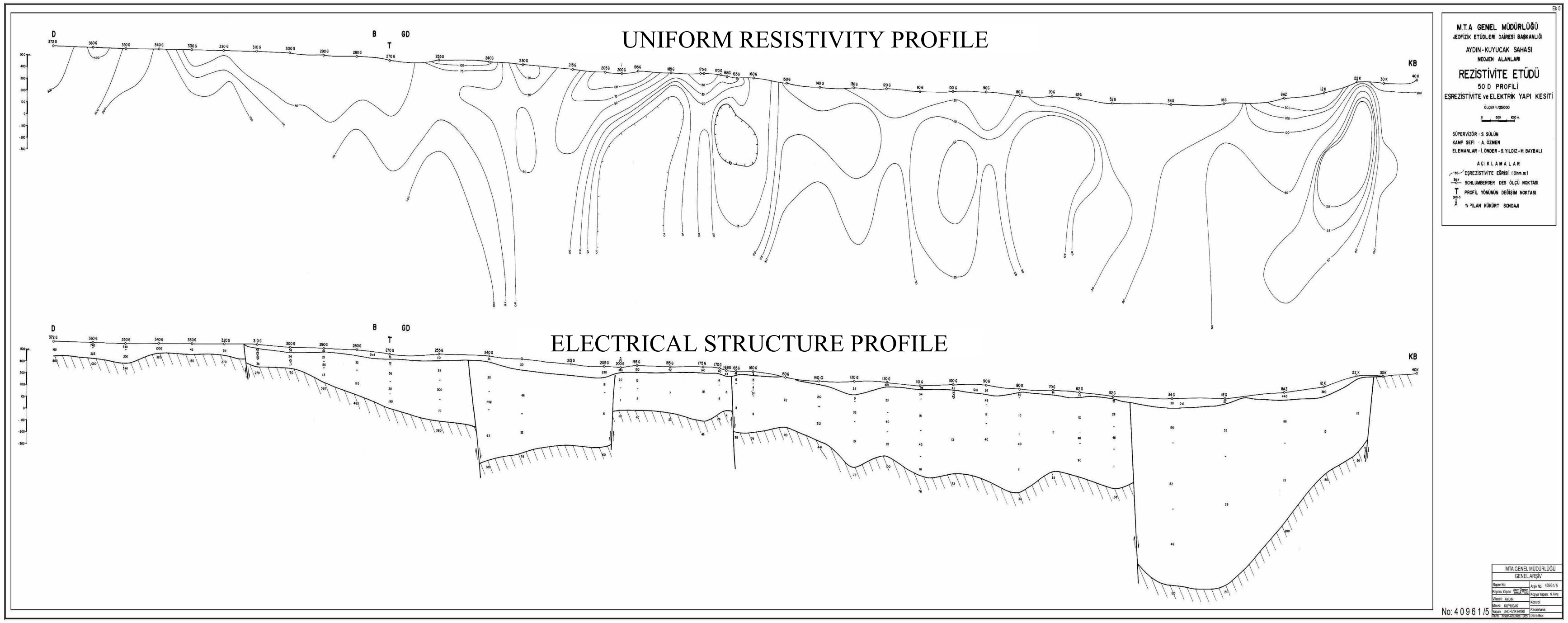


Figure 8.3 Uniform-resistivity and Electrical Structure for 50D profile in N-S direction (MTA, 1986)

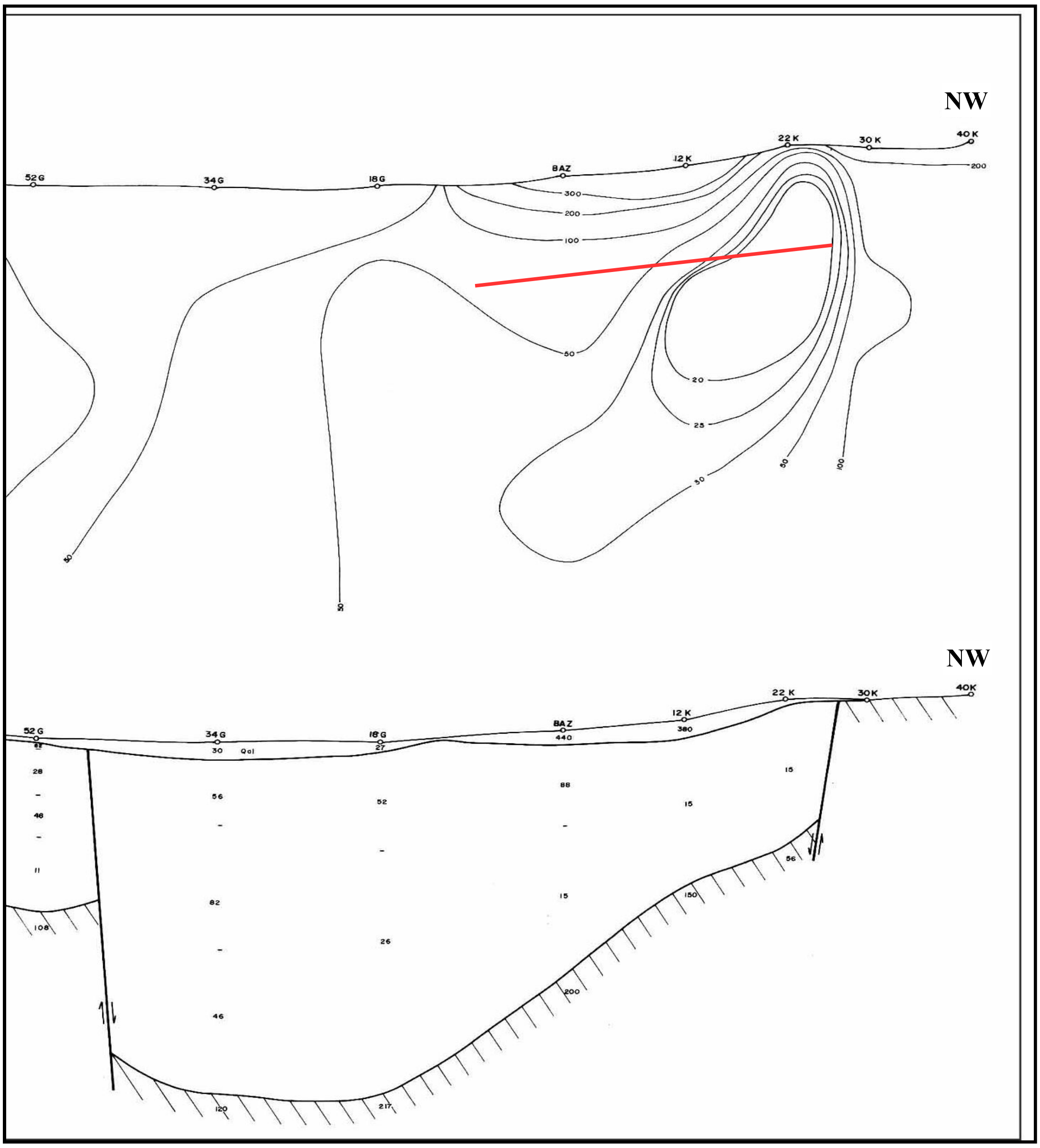


Figure 8.4 Detail of Uniform-resistivity and Electrical Structure for 50D profile (N-S) (MTA, 1986)

Where the only evidence for existence of a hot water reservoir is a single spring or well or a group of springs in a small area, a minimum area of 1 $km^2$ and a maximum of 3 $km^2$ with a most likely area of 2 $km^2$ should be assumed (Muffler, 1979).

By using the above given assumption, a minimum area of 3 $km^2$ near the AP2 and AP3 wells is considered in this study.

The most-likely value for the area is considered to be 8 $km^2$ with personal communication.

Thickness:

In the region MTA has drilled three wells (AP1, AP2 and AP3). In AP1 well the reservoir rock formation is determined between 425 m and 606 m and may continue to depths. Observed thickness is 180 m. But the thickness for this well should be more than 180 m. Since no water flow observed at this well, the reservoir may be below this level and must have a higher reservoir thickness (Figure 8.5).

For AP2 well the reservoir formation is observed between 800 m and 1150 m. The observed reservoir thickness for AP2 well is 350 m (Figure 8.6). Also for AP3 well the reservoir formation is penetrated through 700-1050 m and the observed thickness is 350 m (Figure 8.7).

Considering the above given data, minimum reservoir thickness can not be estimated thinner than 350 m.

The geophysical and electrical studies mentioned above shows a deep bedrock. The depth of the bed rock varies from 1,000 m to 4,000 m in North-South direction along 50 D profile (MTA, 1986) (Figure 8.8).

In USGS Circular 790 (Muffler, 1979), it is said that the estimates of assessment involve thermal energy up to a depth of 3 km below the surface. For this study, the depth of reservoir rock bottom is taken as 3 km at maximum. The thermal accessible resource beyond 3 km is not taken into calculation. The electrical structure profile shows a maximum depth of 4,000 m in the region. AP1 well has shallowest depth of reservoir rock and the formation is cut at the depth of 425 m. The difference between the maximum reservoir bottom and the shallowest top surface of the reservoir (maximum thickness) can be taken as approximately 2,600m.

In the central parts of the region, as a result of the inclination of the curved bed rock, 1,500 m thickness will be more likely value for the region.

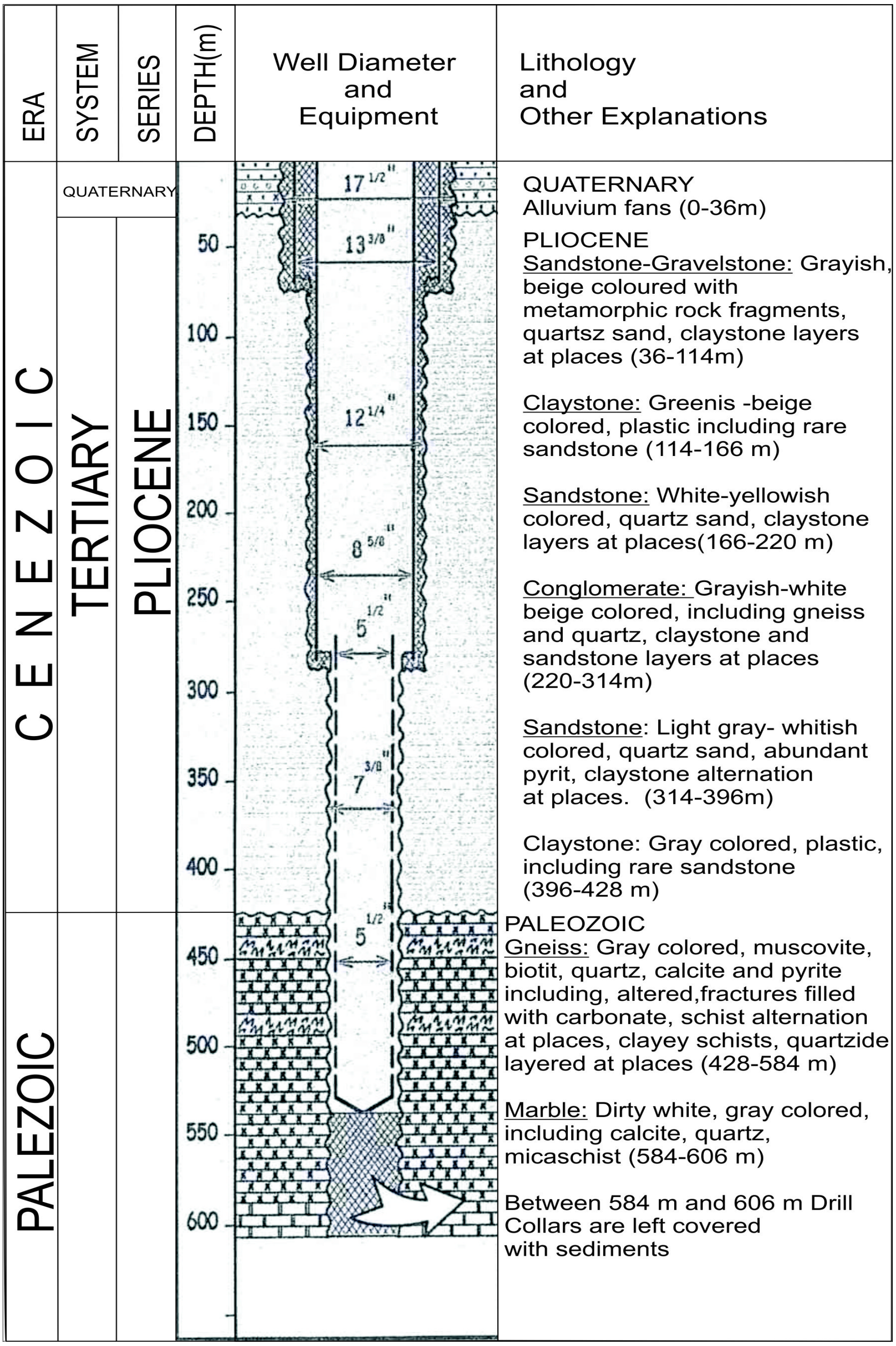


Figure 8.5 Well logging for AP1 well(MTA Report,2009c).

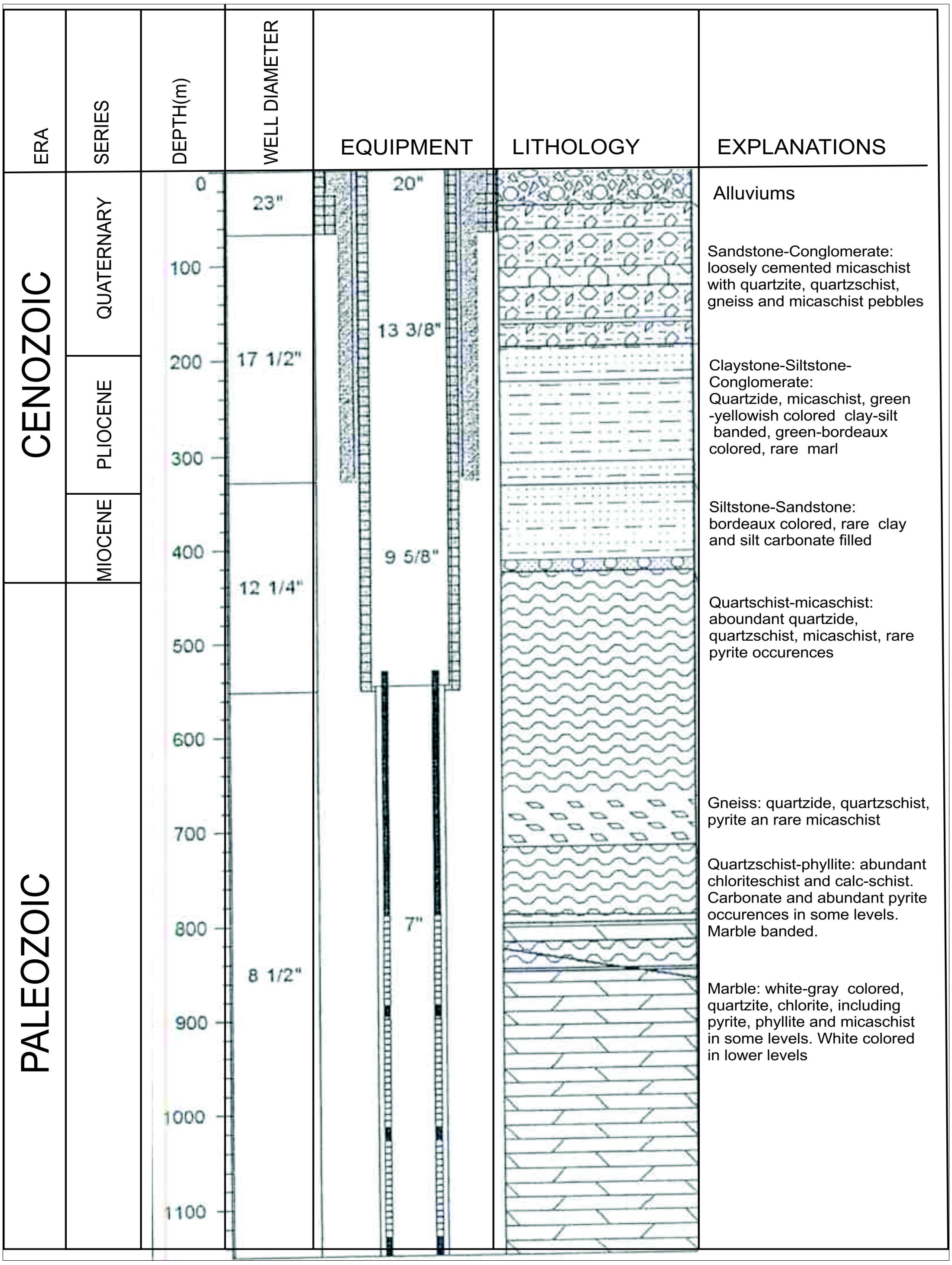


Figure 8.6 Well logging for AP2 well (MTA Report,2009c).

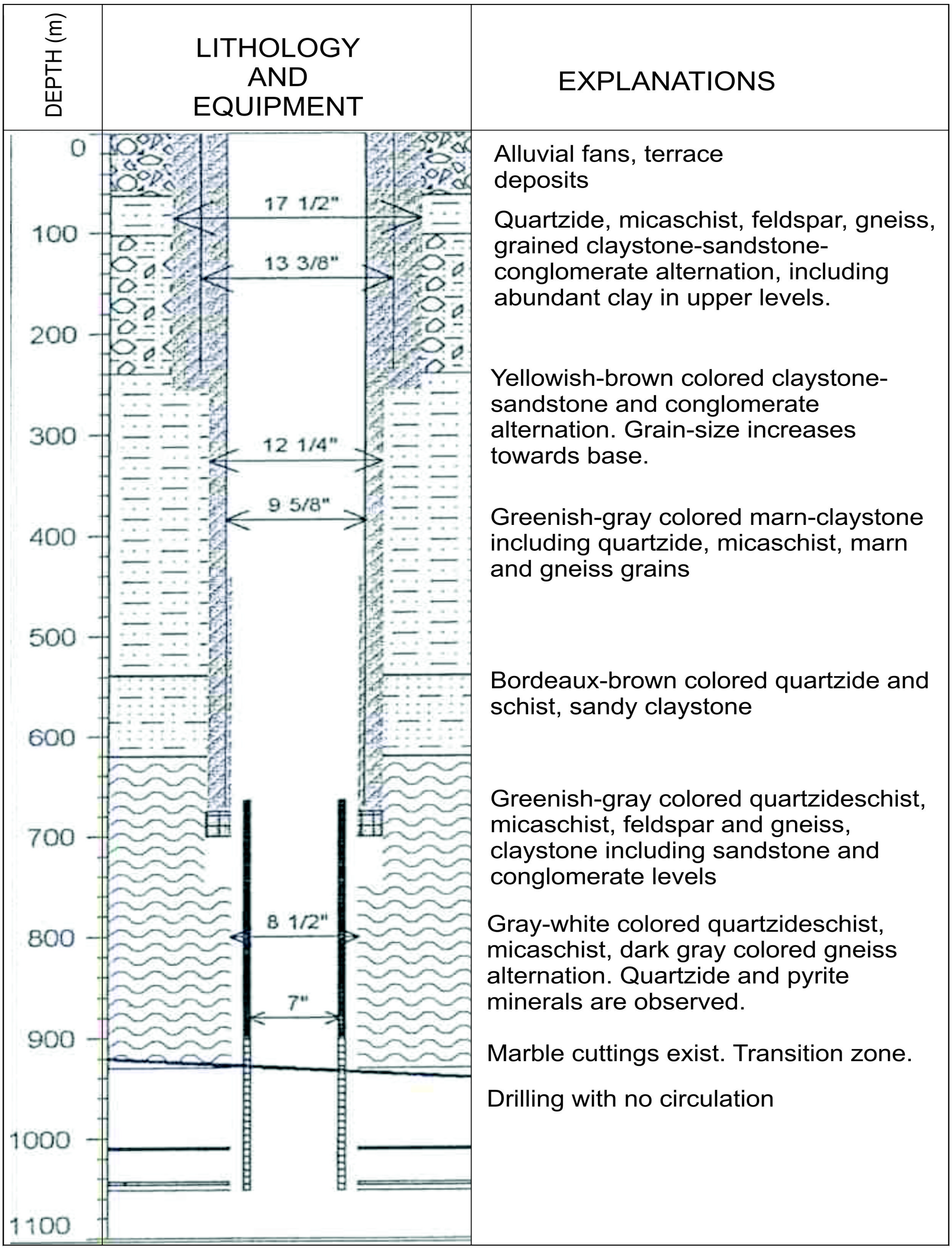


Figure 8.7 Well logging for AP3 well (MTA Report,2009d).

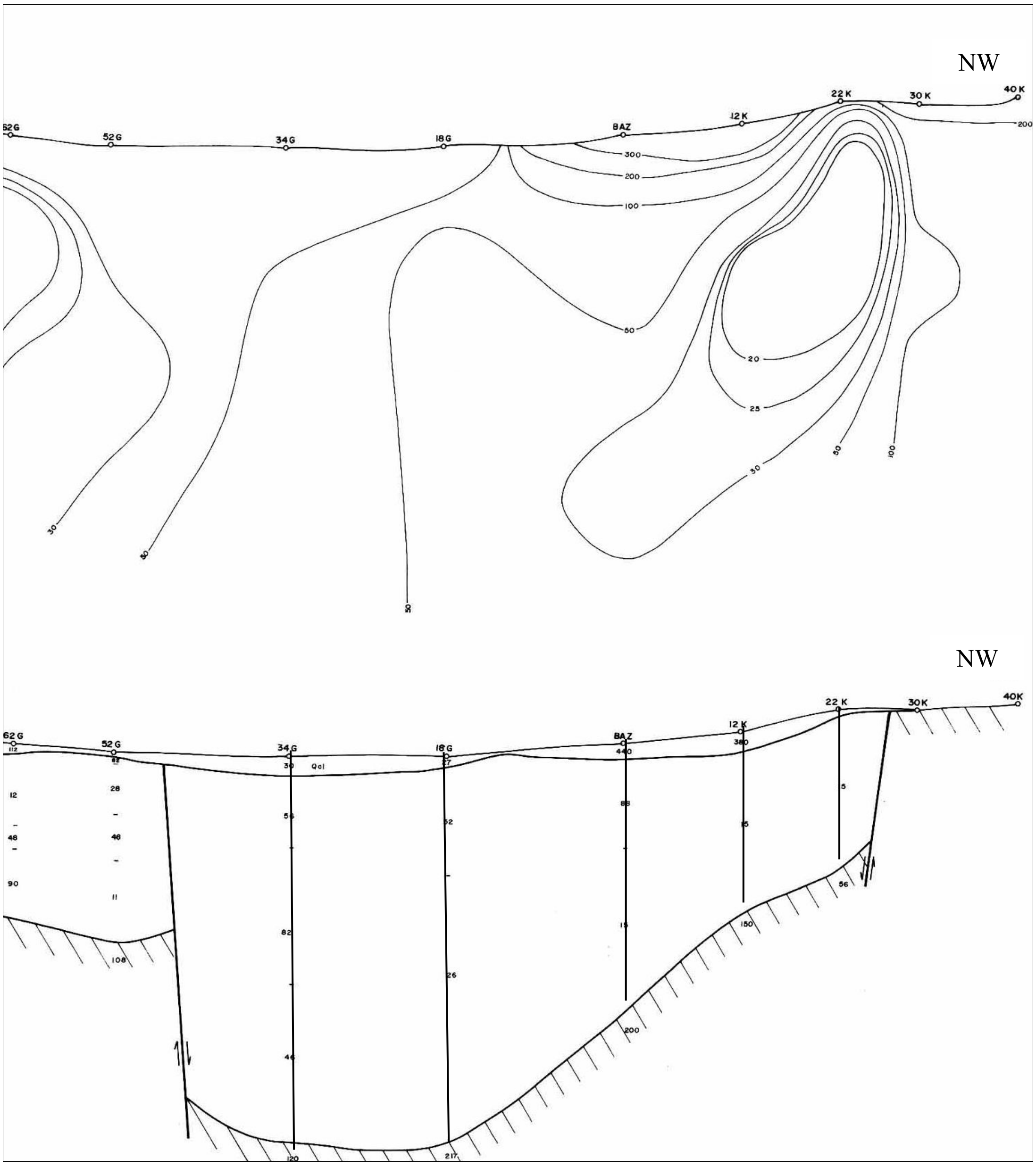

Figure 8.8 Close in View of 50D Profile showing the bed rock (MTA, 1986)

Temperature:

In AP2 and AP3 wells, the static temperature is measured as nearly 185 °C. As this figure is actually measured in the field, this can be taken as most likely temperature (Figure 8.9).

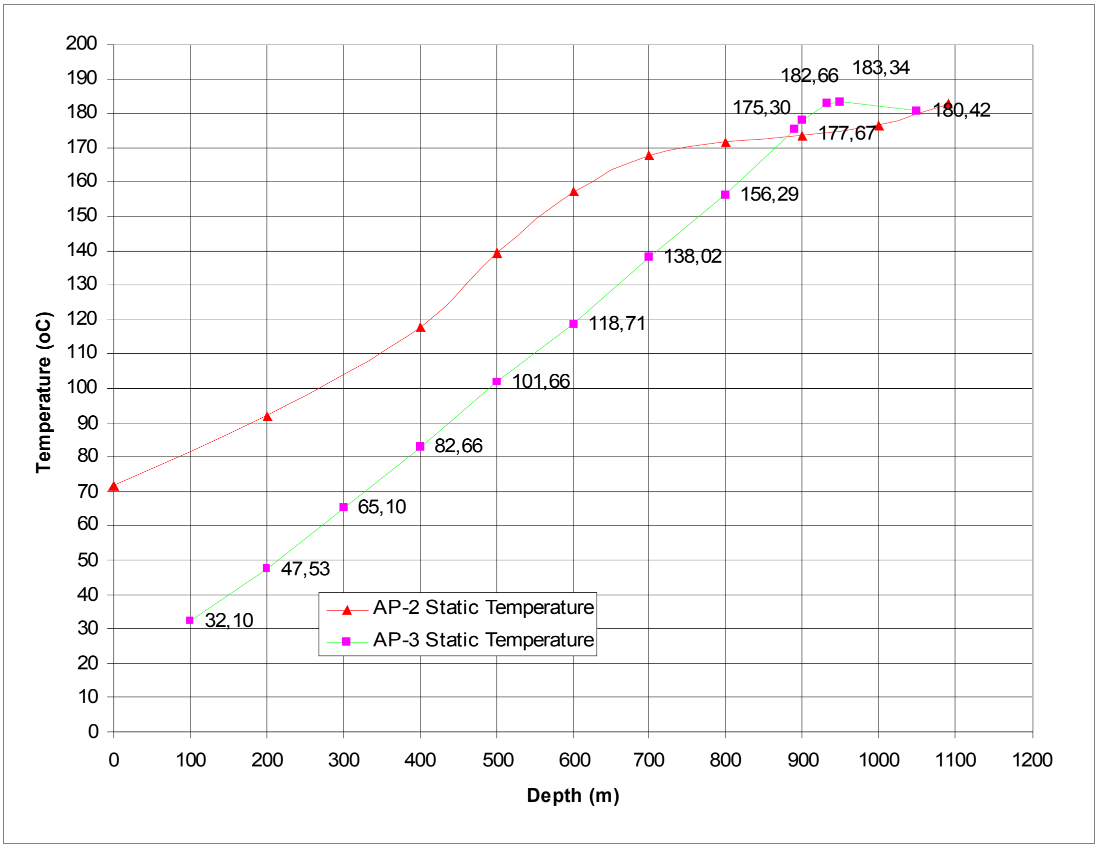


Figure 8.9 Static Temperatures for AP2 and AP3 Wells (MTA Reports, 2009a and 2009b)

The calculation of subsurface temperatures from chemical analyses of water and steam collected at hot springs, fumaroles, geysers and shallow water levels is a standard tool of geothermal exploration and fulfills the need to estimate the subsurface temperature of a geothermal prospect area before any deep wells are drilled (Williams et. al., 2008).

In Pamukören geothermal filed geothermometer-based temperature measurements are not available.

Similarities in the geological environment in most of the fields in western Anatolia are well known, data like available porosity, density and fluid properties from well studied geothermal reservoirs like Kızıldere and Germencik geothermal fields may be extended to the other geothermal systems in Western Anatolia (Serpen et. al., 2008).

The temperature distribution in Büyük Menderes Graben varies from 101 °C to 242 °C. The geothermal fields near Pamukören are Kızıldere and Salavatlı fields with temperatures of 242 °C and 172 °C. Regarding to these values, the maximum temperature of Pamukören geothermal field is taken as 210 °C.

The minimum temperature of the field was taken as 140 °C which can be considered as the minimum source temperature for electricity generation.

Reference Temperature (rejection temperature):

For the final state of hot-water systems, the choice of rejection temperature (exit temperature of geothermal power plant) is important because of the large effect it has on *available work* ($W_A$). For the electrical power generation rejection temperature can be taken as 70 °C with today's technology (15 °C is mentioned for thermal applications in Circular 790).

Specific heat of water:

Specific heat of water at 140 °C, 185 °C and 210 °C are given 4.247 kJ/kg°C, 4.353 kJ/kg°C and 4.438 kJ/kg°C respectively (http://www.thermexcel.com /english/ tables/eauboui.html).

Specific density of water:

The specific density values for water are listed in Table 8.2;

Table 8.2 Specific Density Values for Water
(http://www.thermexcel.com /english/ tables/eaubou1.html)

| Temperature °C | Specific density (kg/m$^3$) | |
|---|---|---|
| 140 | 926.168 | Maximum |
| 185 | 881.646 | Most likely |
| 210 | 852.700 | Minimum |

The values of all variables to be used in Equation 8.3 are given in Table 8.3

Table 8.3 Parameters of Aydın-Kuyucak-Pamukören Geothermal Region for Accessible Resource Base Calculation

| Parameter | Distribution Type | Minimum | Most likely | Maximum |
|---|---|---|---|---|
| Porosity (%) | Triangular | 0.01 | 0.03 | 0.07 |
| Specific Heat of Rock (Marble) (kJ/kg-°C) | Constant | | 0.88 | |
| Density of Rock (kg/m$^3$) | Uniform | 2.500 | | 2.700 |
| Area(m$^2$) | Triangular | 3.00E+06 | 8.00E+06 | 1.21E+07 |
| Thickness (m) | Triangular | 350 | 1500 | 2600 |
| Temperature of Rock (°C) | Triangular | 140 | 185 | 210 |
| Reference Temperature (°C) | Constant | | 70 | |
| Specific Heat of Water (kJ/kg-°C) | Triangular | 4.247 | 4.353 | 4.438 |
| Density of Water (kg/ m$^3$) | Triangular | 852.700 | 881.646 | 926.168 |

While applying Monte Carlo Simulation, the number of iterations was chosen as 10,000 which is the maximum number that can be applied in @RISK Software. Then the @RISK software program assigns random numbers to each variable based on the type of distribution and limits.

In Table 8.4 the mean, minimum and maximum values of the variables for the use in Equation 8.3 are given as the result of simulation study of @RISK. Figures 8.10-8.18 give the histograms of the output of @RISK. According to Table 8.4, the mean value for accessible resource base of Aydın-Pamukören geothermal field is 2.91E+15 kJ. The most likely accessible resource base was found to be 2.57E+15 kJ from Figure 8.10. The most-likely accessible resource base has an approximate probability of 53 % (Figure 8.11). The accessible resource base was determined as 1.42E+15 kJ with a probability of 90 % (Figure 8.11).

Table 8.4 Simulation Summary for Accessible Resource Base

| **@RISK Input Results** | | | | | |
|---|---|---|---|---|---|
| **Name** | **Min** | **Mean** | **Max** | **10%** | **90%** |
| Porosity (%) | 0.01006748 | 0.03690439 | 0.069819 | 0.02097114 | 0.05469265 |
| Density of Rock (kg/m$^3$) | 2500.018 | 2599.511 | 2699.99 | 2519.74 | 2679.021 |
| Area(m$^2$) | 3010943 | 7708195 | 12068340 | 5061431 | 10217450 |
| Thickness (m) | 372 | 1485 | 2598 | 857 | 2098 |
| Temperature of Rock (°C) | 140.45 | 178.48 | 209.95 | 158.02 | 196.89 |
| Specific Heat of Water (kJ/kg-°C) | 4,25 | 4,35 | 4,44 | 4,29 | 4,40 |
| Density of Water (kg/m$^3$) | 853.25 | 886.75 | 925.66 | 867.39 | 908.33 |
| **@RISK Output Results** | | | | | |
| **Name** | **Min** | **Mean** | **Max** | **90 %** | **10 %** |
| Accessible Resource Base (kJ) | 3.21E+14 | 2.91E+15 | 8.67E+15 | 1.42E+15 | 4.60E+15 |

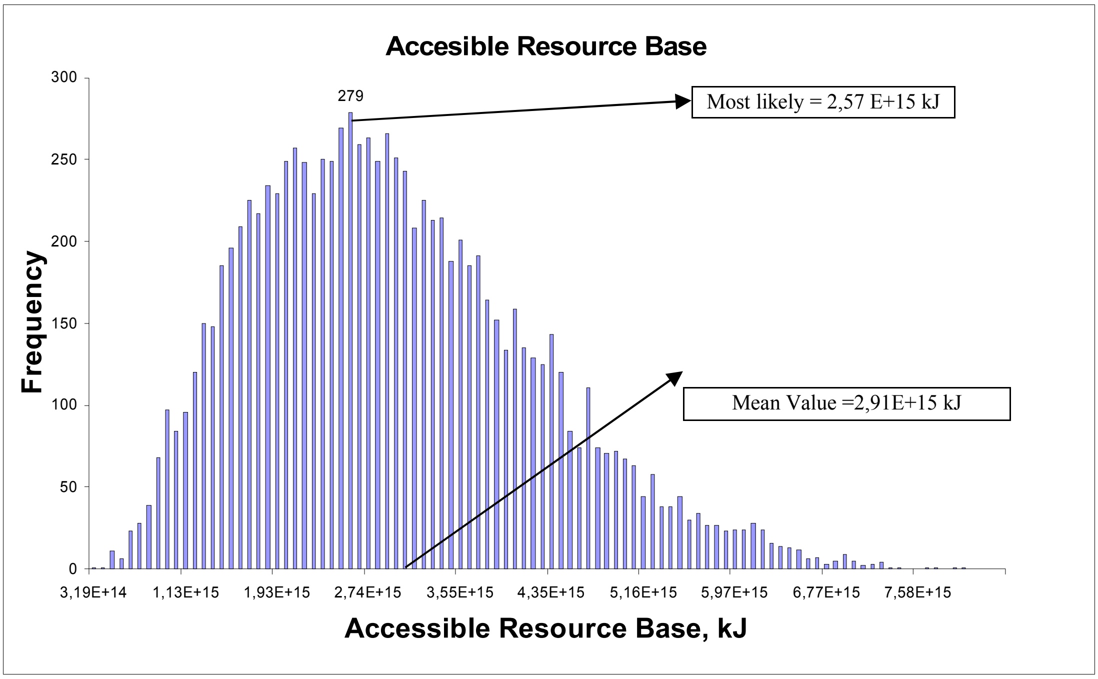


Figure 8.10 Histogram Graph for Accessible Resource Base

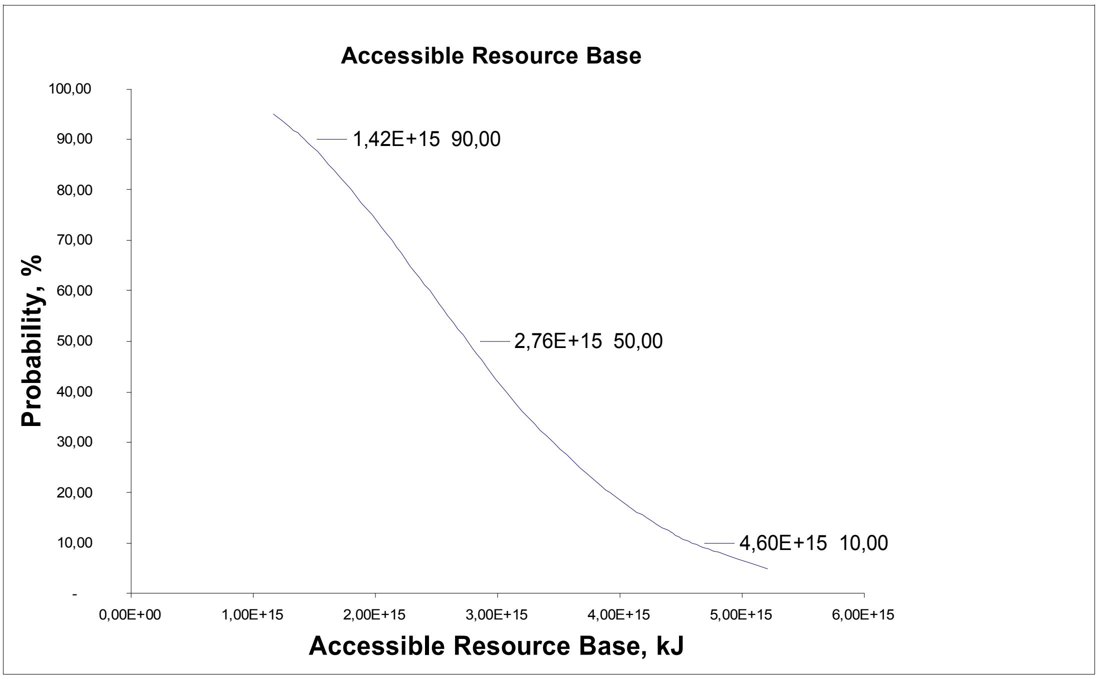


Figure 8.11 Probability Graph for Accessible Resource Base

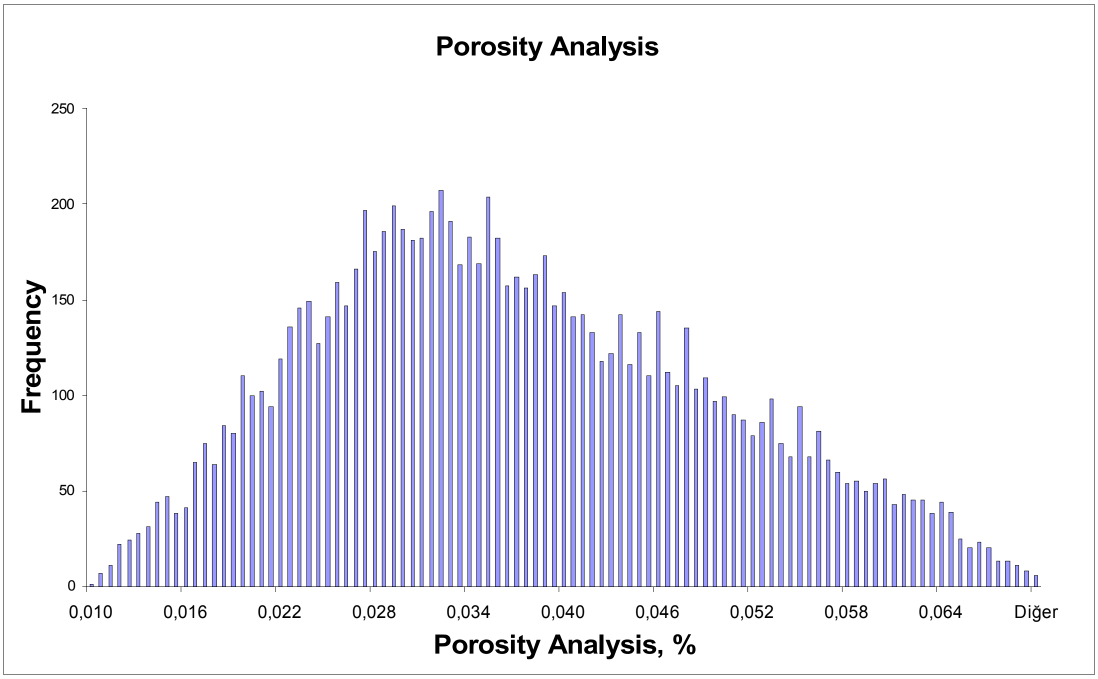


Figure 8.12 Histogram Graph for Porosity

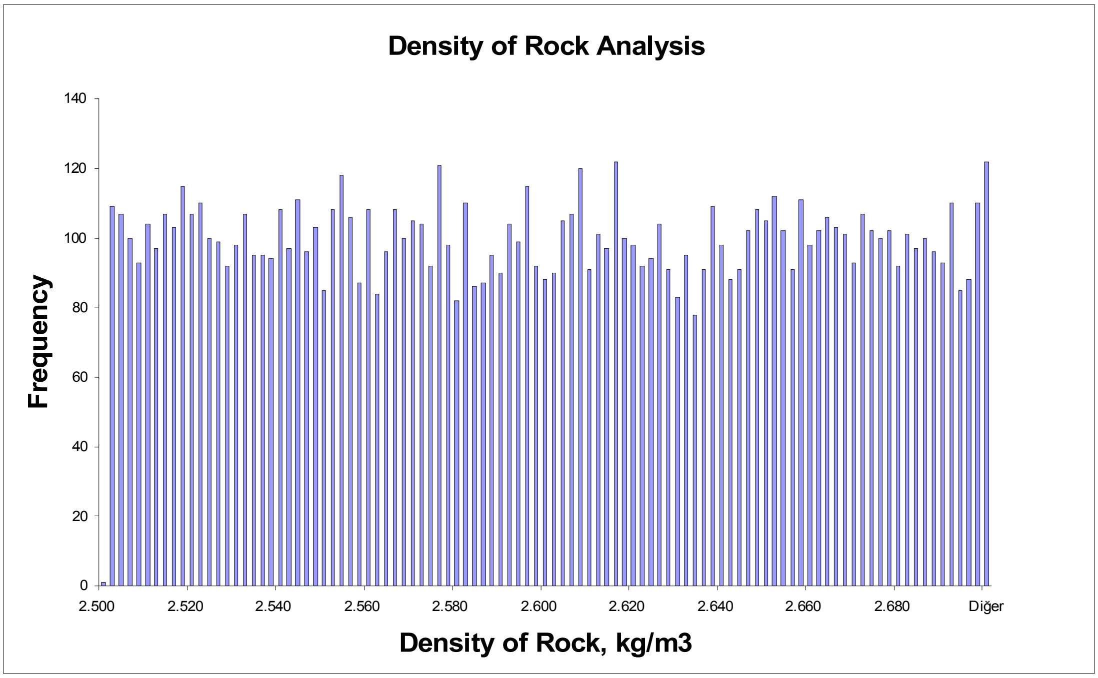


Figure 8.13 Histogram Graph for Specific Heat of Rock

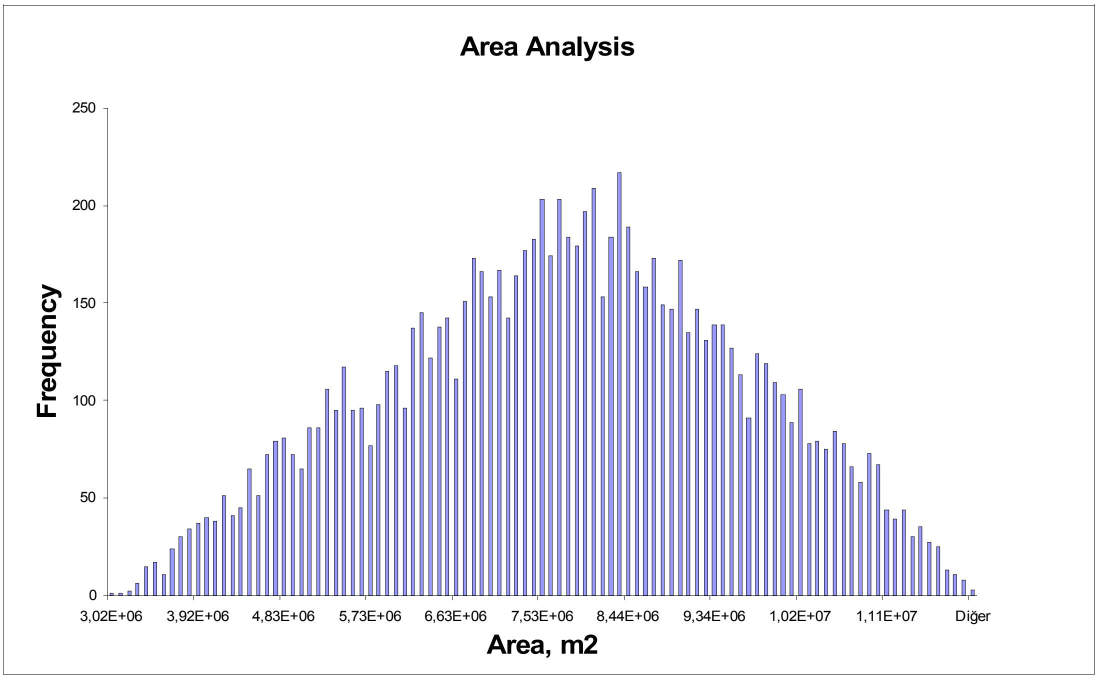


Figure 8.14 Histogram Graph for Reservoir Area

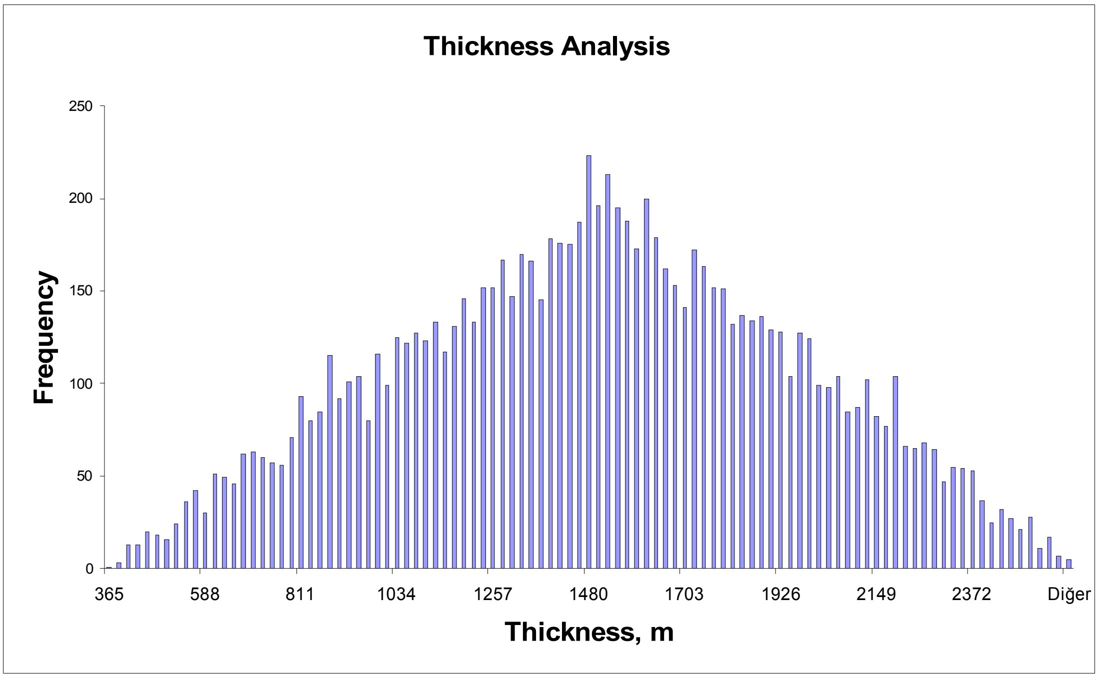


Figure 8.15 Histogram Graph for Reservoir Thickness

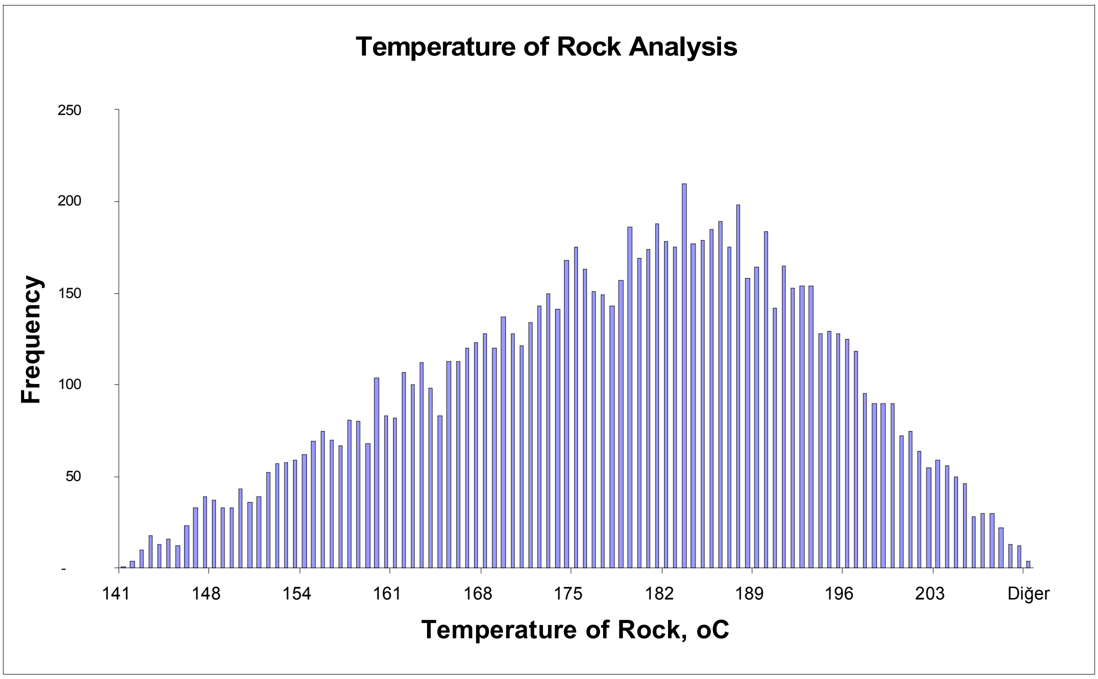


Figure 8.16 Histogram Graph for Temperature of Rock

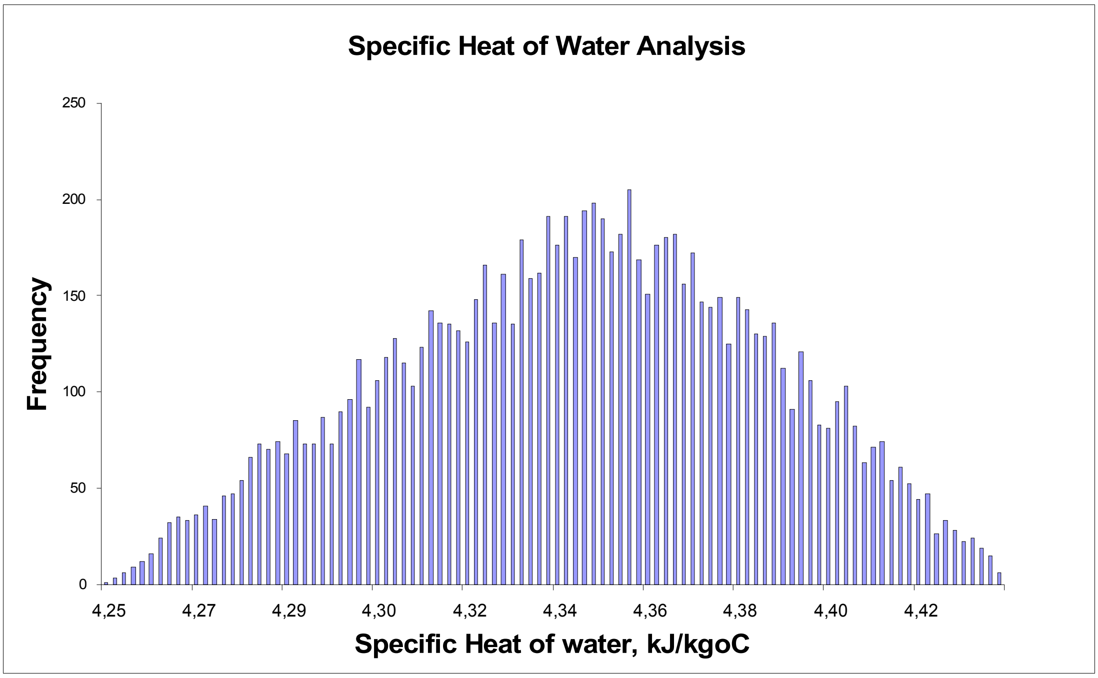


Figure 8.17 Histogram Graph for Specific Heat of Water

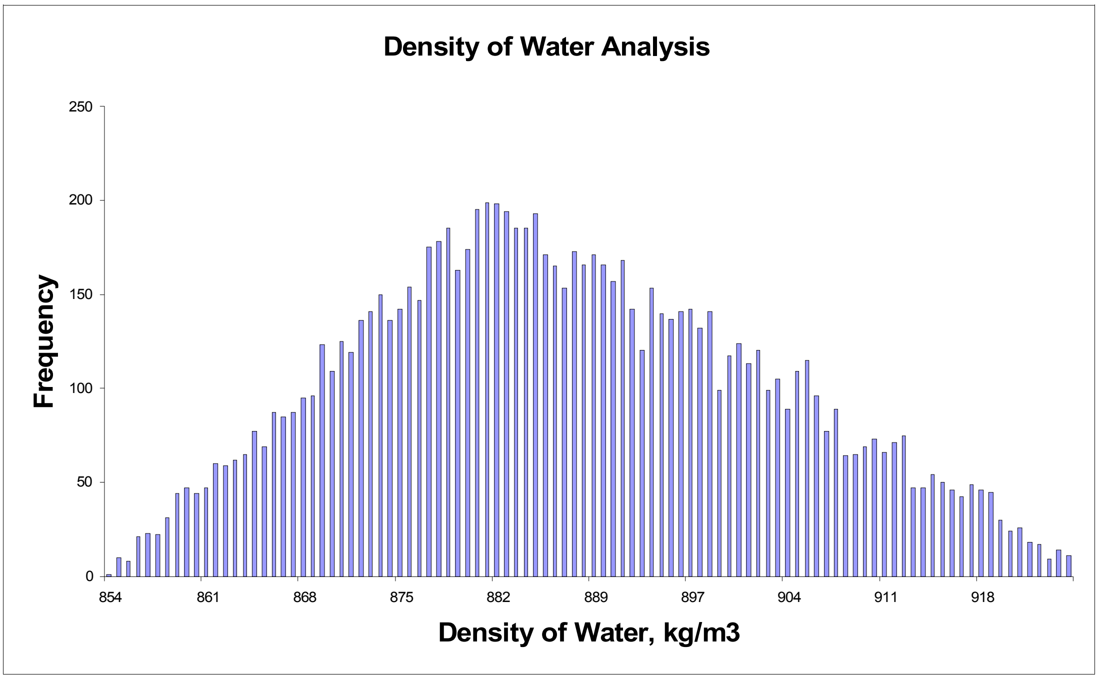


Figure 8.18 Histogram Graph for Density of Water

## 8.3 Resource Determination

### Geothermal Recovery Factor

For hot-water geothermal systems, the ratio of geothermal energy recovered at well head, $q_{WH}$, to the geothermal energy originally available in the reservoir, $q_R$, is called geothermal recovery factor $R_g$.

$R_g = q_{WH} / q_R$ ~ 0,05-0,2 (Williams, 2004, 2007) Eq. 8.4

The distribution type for geothermal recovery factor is considered uniform. The minimum and maximum values are accepted as 0.05 and 0.20 respectively in this study.

Total heat energy, $H_T$, given in Equation 8.2 can actually be referred as reservoir thermal energy, $q_R$ (Equation 8.4). So it is assumed that $H_T = q_R$ . The values computed for $q_R$( $H_T$) from Monte Carlo Simulation are given in Table 8.4. The values for $q_R$ as minimum, mean and maximum are 3.21E+14 kJ, 2.91E+15 kJ and 8.67E+15 kJ respectively (Table 8.4).

**Geothermal energy recovered at wellhead**, $q_{WH}$ is found by multiplying the geothermal recovery factor,$R_g$, with geothermal energy in the reservoir, $q_R$, .

$$q_{WH} = R_g * q_R \qquad \text{Eq. 8.5}$$

According to summary statistics of @RISK given in Table 8.5, the mean value of Recoverable Thermal Energy is 3.66E+14 kJ. The most likely Recoverable Thermal Energy was found to be 2.16E+14 kJ (Figure 8.19). The probability of most likely available energy is approximately 73 % (Figure 8.20).

Table 8.5 Simulation Summary for Geothermal Energy at well head ($q_{WH}$)

| **@RISK Input Results** | | | | | |
|---|---|---|---|---|---|
| **Name** | **Min** | **Mean** | **Max** | **90%** | **10%** |
| Geothermal Recovery Factor $R_g$ | 0.05004242 | 0.125681 | 0.199983 | 0.06551971 | 0.1858446 |

| **@RISK Output Results** | | | | | | |
|---|---|---|---|---|---|---|
| **Name** | **Min** | **Mean** | **Max** | **Mode** | **90 %** | **10%** |
| Recoverable Thermal Energy, $q_{WH}$ (kJ) | 2.67E+13 | 3.66E+14 | 1.61E+15 | 2.84E+14 | 1.38E+14 | 6.51E+14 |

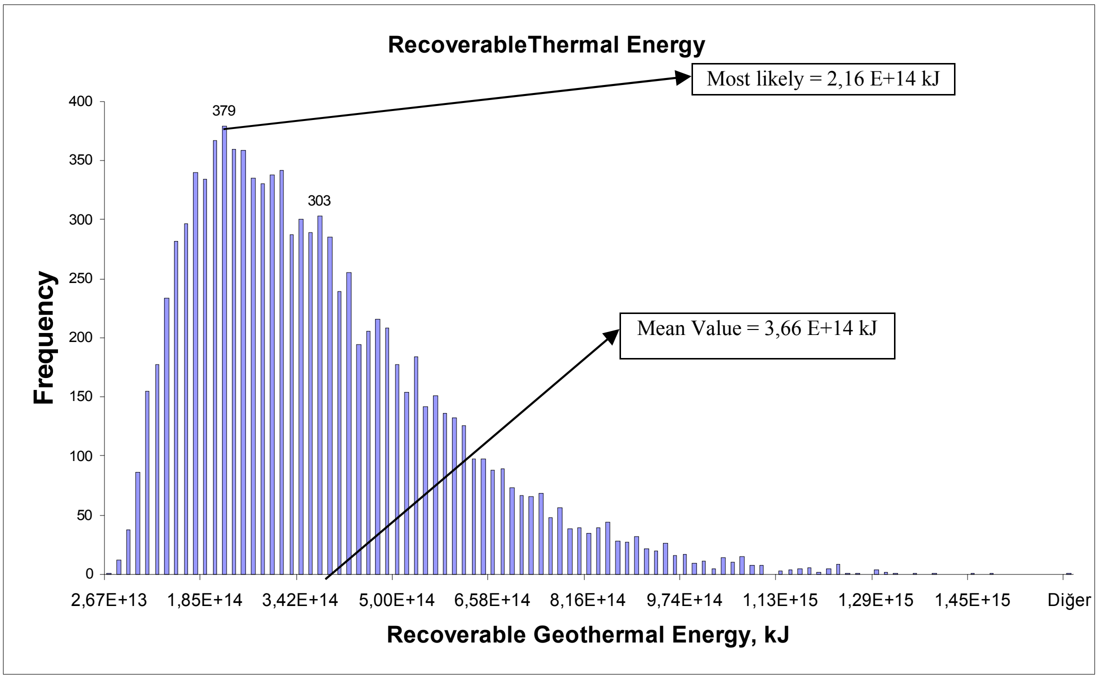


Figure 8.19 Histogram Graph for Recoverable Thermal Energy

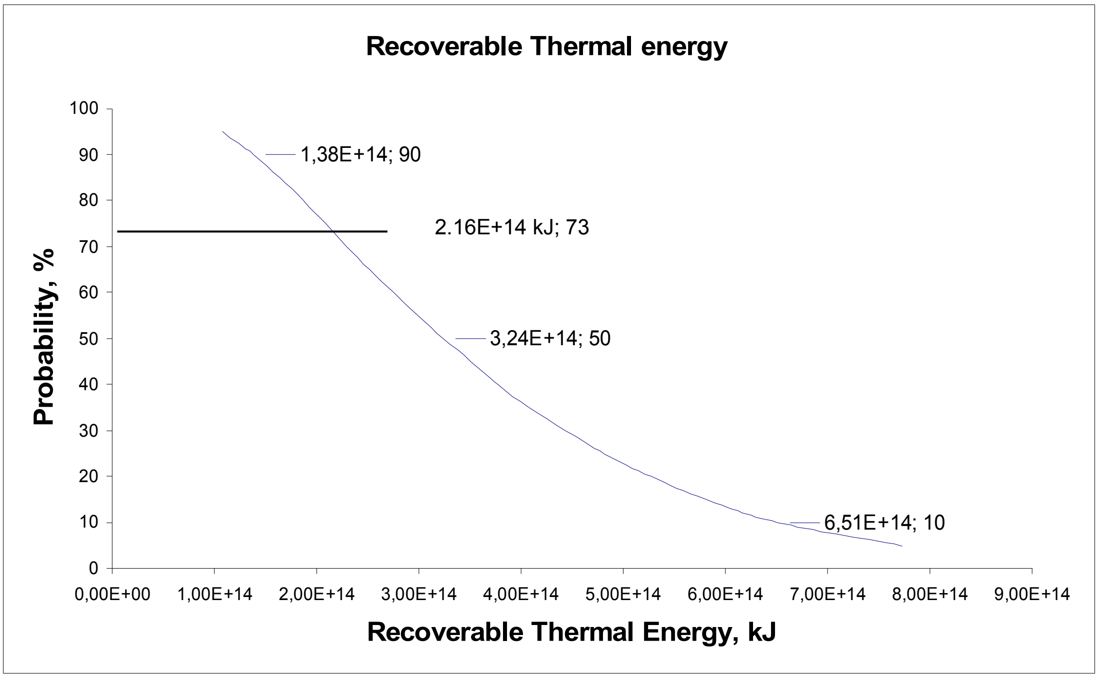


Figure 8.20 Probability Graph for Recoverable Thermal Energy

Figure 8.21 gives the histogram of geothermal recovery factor as an output of @RISK Software. Analysis of the results of @RISK shows that Aydın-Pamukören geothermal field has Recoverable Thermal Energy of 1.38E+14 kJ at optimistic approach (90% probability), 3.24E+14 kJ (50 % probability) and 6.51E+14 kJ at pessimistic approach (10 % probability).

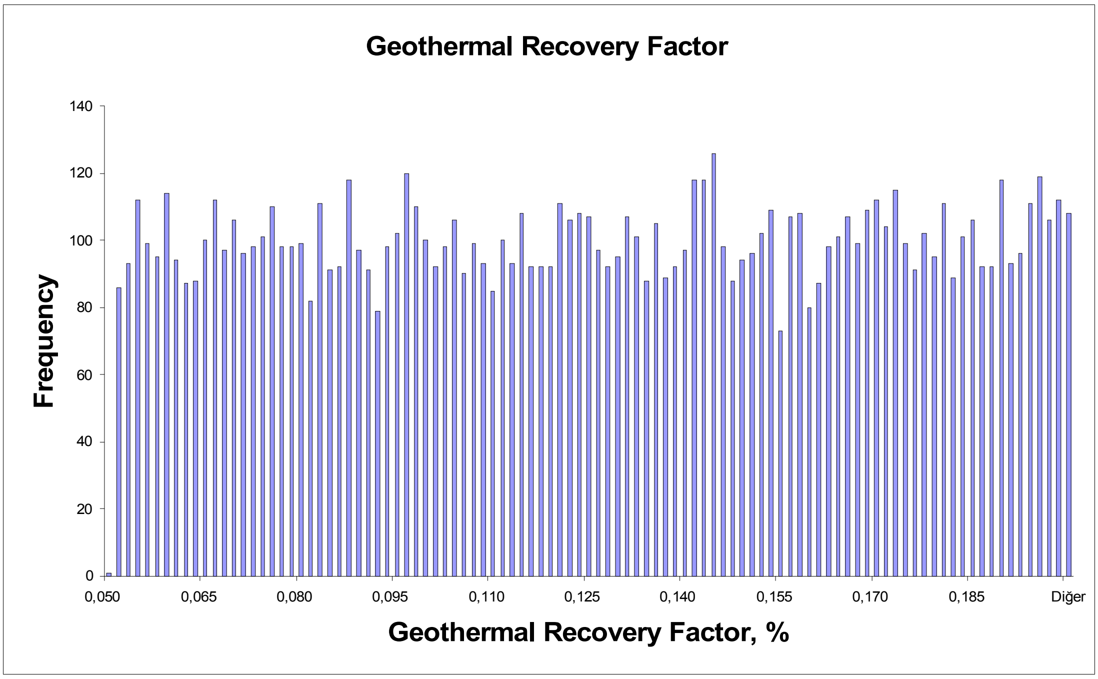


Figure 8.21 Histogram Graph for Geothermal Recovery Factor

## 8.4 Electrical Power Estimation

The electrical power E ($kW_e$) obtainable from a geothermal reservoir is given by the Equation 8.6 (adapted from Arkan and Parlaktuna, 2005).

$$E = \frac{q_{WH} * \eta_u}{(t * LF)} \qquad \text{Eq 8.6}$$

where;

E = Recoverable Electrical Power, ($kW_e$)

$q_{WH}$ = Recoverable Thermal Energy at well head, (kJ)

$\eta_u$= Transformation yield. It takes into account the efficiency of transferring heat energy from geothermal fluid to a secondary fluid, fraction

LF= Load factor. Most of the energy applications of geothermal energy are not continuous throughout the year. This factor takes into account the fraction of the total time in which the geothermal power plant is in operation, fraction

t = Total project life, sec

The value of $\eta_u$ varies from 0 to 0.4 up to 175 °C and stays constant for higher temperatures in the new USGS assessment (Williams et. al., 2008). In this study $\eta_u$ was assumed to change between 20 % and 40 % with an uniform distribution.

Load factor takes into account the fraction of the total time in which the geothermal power plant is in operation. The operation time for the geothermal power plant is taken as 8000 hours/year. A year equals to 8760 hours. Load Factor is calculated by division of 8000 to 8760 which is equal to 0.91.

Total project life is calculated for 30 years. This corresponds to 9.46E+08 seconds as project life. Table 8.6 lists the parameters for the determination of electrical power.

Table 8.6 Parameters of Aydın-Kuyucak-Pamukören Geothermal Region for Determination of Electrical Power

| Parameter | Distribution Type | Minimum | Mean | Maximum | Most likely |
|---|---|---|---|---|---|
| Recoverable Thermal Energy ($q_{WH}$) (kJ) | Triangular | 2.67E+13 | 3.66E+14 | 1.61E+15 | 2.16E+14 |
| Utilization Factor ($\acute{\eta}_u$) | Uniform | 0.20 | | 0.40 | |
| Project Life (sec) (30 years) | Constant | | 9.46E+08 | | 9.46E+08 |
| Load Factor (Fraction) | Constant | | 0.91 | | 0.91 |

According to summary statistics of @RISK Software given in Table 8.7, the mean value of Electrical Power is 127,681.7 kWe. The most likely Electrical Energy value was found to be 78,750.98 kWe (Figure 8.22). The probability of most likely available work is approximately 69 % (Figure 8.23).

Analysis of the results of @RISK shows that Aydın-Pamukören geothermal field has Electrical Power capacity of 45.2 MWe at optimistic approach (90% probability), 110.45 MWe (50 % probability) and 233.1 MWe at pessimistic approach (10% probability) (Figure 8.23).

Table 8.7 Simulation Summary for Electrical Power for Aydın-Pamukören Geothermal Field

| **@RISK Input Results** | | | | | | |
|---|---|---|---|---|---|---|
| **Name** | **Min** | **Mean** | **Max** | **Mode** | **90 %** | **10 %** |
| Utilization Factor , $\acute{\eta}_u$ | 0.2000195 | 0.299958 | 0.3999951 | 0.3220078 | 0.2201797 | 0.3793451 |
| **@RISK Output Results** | | | | | | |
| **Name** | **Min** | **Mean** | **Max** | **Mode** | **90 %** | **10 %** |
| Electrical Power (kWe) | 8974.644 | 127681.7 | 590444.1 | 78750.98 | 45239.77 | 233089.4 |

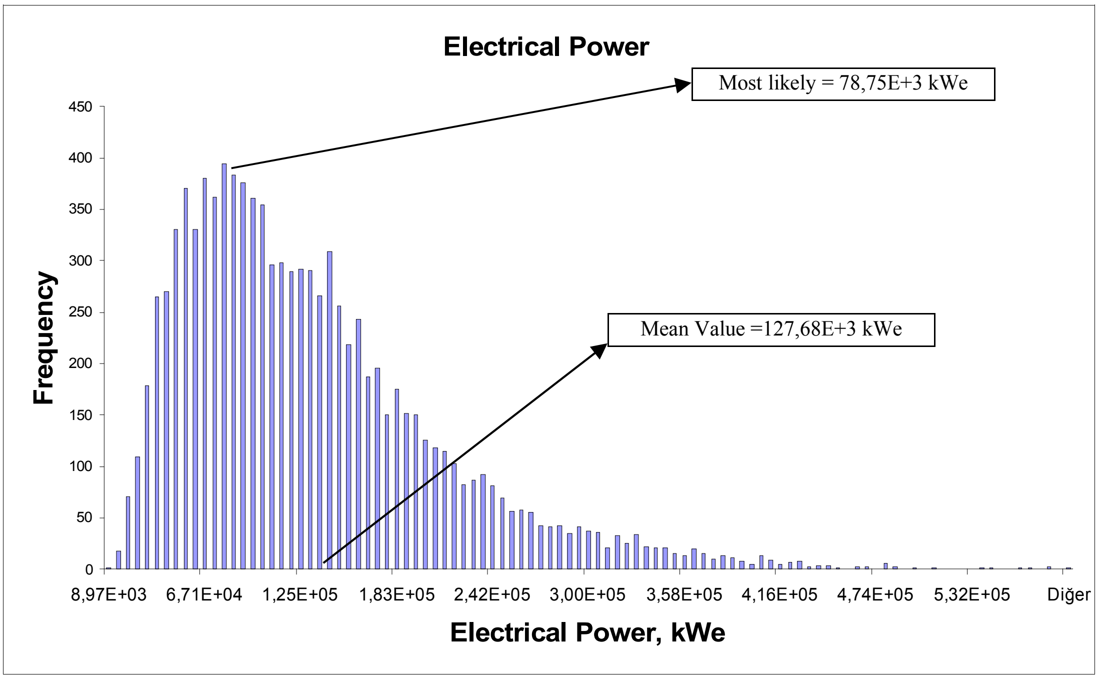


Figure 8.22 Histogram Graph for Electrical Power

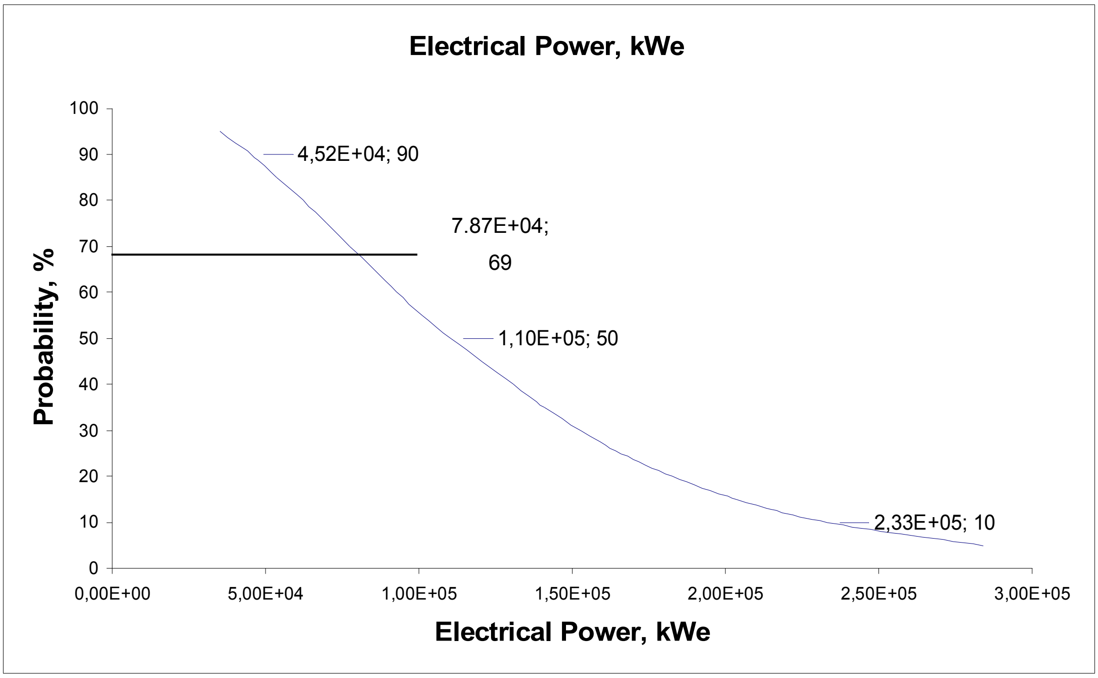


Figure 8.23 Probability Graph for Electrical Power

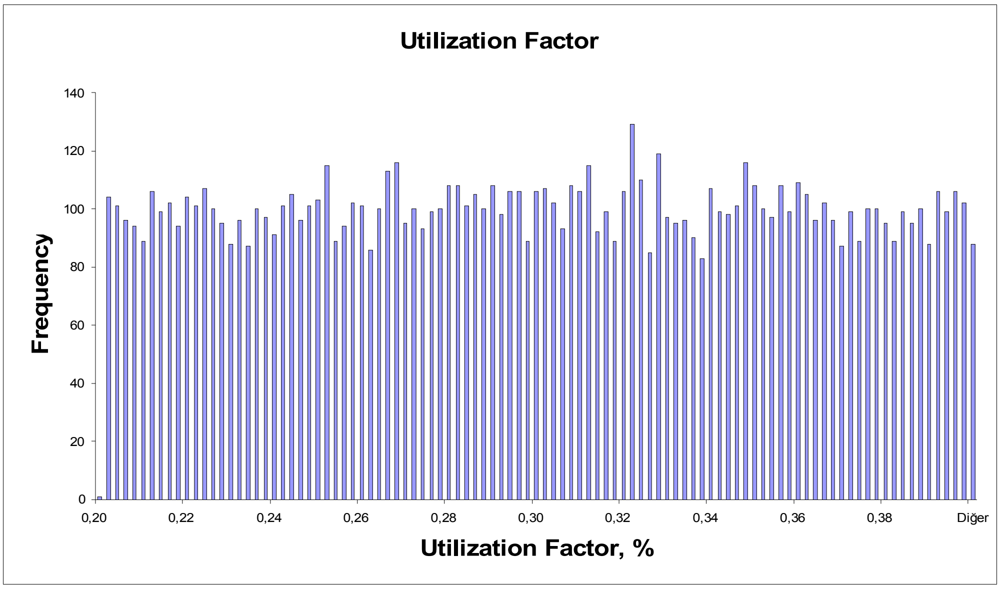


Figure 8.24 Histogram Graph of Utilization Factor, ηu

## 8.5 Number of Wells required for full Capacity in the Region

For the calculation of number of wells required for the region, the following assumptions are made;

**1-** All the wells will be considered identical.

**2-** Maximum dynamic temperature is considered 165 °C at well head for all wells.

**3-** Specific heat of fluid is taken as 4.36 kJ/kg°C.

**4-** Calculations will done for two different production scenarios of 200 tons/hour (55.6 kg/s) and 300 tons/hour (83.3 kg/s).

**5-** Values for the number of wells will be rounded to nearest whole numbers.

Geothermal energy at well head, $q_{WH}$, for the identical wells can be calculated with;

$$q_{WH} = m_{WH} * C_{fluid} * (T_{WH} - T_{ref})$$ Eq. 8.7

where;

$q_{WH}$= Geothermal Energy at well head (kJ)

$m_{WH}$= mass of fluid produced at well head (kg/s)

$C_{fluid}$= Specific heat of fluid 4.36 kJ/kg°C at 165 °C

$T_{WH}$= Temperature at well head (°C) (165 °C)

Tref= Reference Temperature (°C) (70 °C)

$$E_{well} = q_{WH} * \eta_u$$ Eq. 8.8

where;

$E_{well}$= Electrical Energy for well ($kW_e$)

$q_{WH}$= Geothermal Energy at well head (kJ/s)

ηu = Utilization Factor (constant) (0.20)

The geothermal energy, $q_{WH}$ is found in kJ/s, and then kJ/s is converted to kW. To find the electrical energy potential of an identical well, the geothermal energy found in kWe is multiplied by utilization factor, ηu, that is 0.20 (Equation 8.8). The electrical energy of Aydın-Pamukören geothermal field is divided by electrical energy of a well in order to find the number of wells required to fully utilize the whole electrical capacity of the field. The numbers of wells are rounded to whole numbers. The parameters and calculations for 200 t/hr (55.6 kg/s) production are found in Table 8.8. For 300 t/hr (83.3kg/s) production parameters and calculations are found in Table 8.9.

In Table 8.10 the summary for the number of wells required for two different production scenarios are given. By these calculations, it is seen that at least 7 or 10 wells at maximum must be taken into production in the geothermal field to be able to generate electrical power at full capacity.

Table 8.8 Parameters for Determination of Number of wells for Aydın-Pamukören Geothermal Field for 200 tons/hour

| Parameters | % Probability | | |
|---|---|---|---|
| | 90 | 50 | 10 |
| $m_{WH}$ (kg/sec) | 55.6 | 55.6 | 55.6 |
| $C_{fluid}$ (kJ/kg°C) | 4.36 | 4.36 | 4.36 |
| $T_{WH}$ (°C) | 165 | 165 | 165 |
| $T_{ref}$ (°C) | 70 | 70 | 70 |
| $q_{WH}$ (kJ/sec) | 23029.52 | 23029.52 | 23029.52 |
| Utilization factor ($ή_u$) | 0.20 | 0.20 | 0.20 |
| Electrical Energy (well) ($kW_e$) | 4605.90 | 4605.90 | 4605,.90 |
| Electrical Energy (field) ($kW_e$) | 45240 | 110450 | 233089 |
| Number of wells | 9.82 | 23.98 | 50.61 |
| Number of Wells (200 t/hr) | **10** | **24** | **51** |

Table 8.9 Parameters for Determination of Number of wells for Aydın-Pamukören Geothermal Field for 300 tons/hour

| Parameters | % Probability | | |
|---|---|---|---|
| | 90 | 50 | 10 |
| $m_{WH}$ (kg/sec) | 83.3 | 55.6 | 55.6 |
| $C_{fluid}$ (kJ/kg°C) | 4.36 | 4.36 | 4.36 |
| $T_{WH}$ (°C) | 165 | 165 | 165 |
| $T_{ref}$ (°C) | 70 | 70 | 70 |
| $q_{WH}$ (kJ/sec) | 34502.86 | 34502.86 | 34502.86 |
| Utilization factor ($ή_u$) | 0.20 | 0.20 | 0.20 |
| Electrical Energy (well) ($kW_e$) | 6900.57 | 6900.57 | 6900.57 |
| Electrical Energy (field) ($kW_e$) | 45240 | 110450 | 233089 |
| Number of wells | 6.56 | 16.01 | 33.78 |
| Number of Wells (300 t/hr) | **7** | **16** | **34** |

Table 8.10 Summary of Number of Wells for the Field

| Probability (%) | Electrical Power ($kW_e$) | Number of wells | |
|---|---|---|---|
| | | Q = 200 t/hr | Q = 300 t/hr |
| 90 | 45240 | 10 | 7 |
| 50 | 110450 | 24 | 16 |
| 10 | 233089 | 51 | 34 |

# CHAPTER 9

# CONCLUSIONS AND RECOMMENDATIONS

The following conclusions can be drawn from the results of the current study,

1. Analysis of the results of @RISK software shows that Aydın-Pamukören geothermal field has an Electrical Power Capacity of 45.2 MWe at optimistic approach (90 % probability), 110.45 MWe (50 % probability) and 233.09 MWe at pessimistic approach (10 % probability).
2. The mean value of Electrical Power is 127.68 MWe. The most likely Electrical Power value was found to be 78.75 MWe. The probability of most likely available work is approximately 69 %.

The following recommendations are made to fully utilize electric generation capacity of Aydın-Pamukören geothermal field;

a) Number of wells to be taken into production is 10 for a production capacity of 200 t/hr at each well-head.

b) Number of wells to be taken into production is 7 for a production capacity of 300 t/hr at each well-head.

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