Proceedings World Geothermal Congress 2000
Kyushu - Tohoku, Japan, May 28 - June 10, 2000

ASSESSMENT OF STEAM SUPPLY FOR THE EXPANSION OF GENERATION CAPACITY FROM 140 TO 200 MW, KAMOJANG GEOTHERMAL FIELD, WEST JAVA, INDONESIA

Subir K. Sanyal[1], Ann Robertson-Tait[1], Christopher W. Klein[1], Steven J. Butler[1], James W. Lovekin[1], Philip J. Brown[1], Sayogi Sudarman[2] and Syafei Sulaiman[2]
[1] GeothermEx, Inc., 5221 Central Avenue, Suite 201, Richmond, California 94805 USA
[2] Pertamina Geothermal Division, Jl. Merdeka Timur 6, Jakarta 10110, Indonesia

Key Words: Indonesia, Kamojang, geothermal reservoir engineering

ABSTRACT

The Kamojang geothermal field has an installed generation capacity of 140 MW and another 60 MW is planned to be added. This paper presents an assessment of the feasibility of this expansion from the point of view of resource supply.

Volumetric assessment of reserves indicates an equivalent of at least 210 to 280 MW generation for 30 years, sufficient for the existing capacity plus the proposed expansion. The non-condensable gas content in the steam is low (<1%) with a modest amount of H_2S (<300 parts per million by weight). Silica scaling in flow lines and the turbines is being effectively handled and only one well produces corrosive steam. Therefore, the fluid chemistry presents no barriers to capacity expansion.

To date, 68 wells have been drilled with a high success rate (about 80%). Thirty-one wells (including 3 stand-by) are presently used to supply the existing plant, and more than sufficient wellhead steam capacity is available from the remaining wells for the expansion. Ample drilling sites are available for future make-up wells. The productivity of individual wells has declined at a very low rate (1 to 5% per year). Over the 15-year production history of the field, reservoir pressure has shown a modest drop (5 bars), implying that the reservoir storage and flow capacities are adequate for at least the existing generation level. The produced steam has not shown any significant superheating to date; this fact and the relatively small pressure drop imply that the reservoir still contains water saturation. The present average well productivity decline rate is about 4.2% and we have estimated that the capacity expansion will change this to approximately 6.4%, which is still a low decline rate. This rate of decline implies the need for 2 to 3 make-up wells per year following capacity expansion. At this rate of make-up well drilling, the well-spacing will be reduced over 30 years to 350 m which should not cause undue interference between wells. Therefore, we have concluded that the planned expansion of generation at Kamojang is entirely feasible from the point of view of response supply.

1. INTRODUCTION

1.1 Background

This paper presents the results of assessing resource supply at the Kamojang geothermal field in Central Java, Indonesia. This field supports an installed capacity of 140 MW, operated by PT PLN, the national electric utility. The field is operated by PN Pertamina, the national oil company. The goal of assessment was to determine whether the Kamojang resource would be able to support another 60 MW development (Units IV and V), to identify potential problems associated with the expansion, and to determine the likelihood that the steam supply can be maintained over the project life. Most of the wells to be dedicated to the expansion have already been drilled and tested.

1.2 Project History

The Kamojang field was discovered early in the 20th century, and five exploration holes were drilled in the late 1920s. Exploration resumed in the 1960s, and in late 1982 production of 30 MW (Unit 1) was started, supplied by 6 wells in the central part of the field (figure 1).

Development drilling continued and two 55 MW units (Units II and III) were added in 1987. At present, 31 wells, including stand-by wells, supply steam to the three units. The total number of production wells, including both active and ideal wells, is now 68. The upper plot on figure 2 shows versus time the total production from the field and the number of production wells on line. Since Units II and III started up, the total production from the field has remained relatively constant at about 1,100 tonnes per hour of steam. Production has been maintained by drilling make-up wells. As in other steam-dominated fields, productivity decline (and hence the need for make-up wells) is most severe in the first year or two, and stabilizes thereafter. Wellhead temperature and pressure data indicate that most wells are showing a drying trend over time; this is also indicated by the fact that condensate injection decreased from an average of about 225 tonnes/hr during the period from 1988 to 1992 to 150 tonnes/hr in mid-1996.

Silica scale has been found on the Unit I turbine blades and in the gathering system. Pertamina uses a combination of chemical and mechanical means to remove the pipeline scale periodically, and the turbine scale is mechanically removed during annual plant maintenance overhauls.

1.3 Summary of Resource Characteristics

The Kamojang reservoir is “steam dominated” and includes an area of 14 km^2 which is commercially proven by drilling productive wells; these presently supply on average about 5 MW per well with 7-inch production liner. The additional drilling needed to complete the steam requirement for Units IV and V will take place within this zone of proven production. Based on MT resistivity data and a limited amount of drilling data, it is likely that an additional area of 7 km^2 lying largely to the west of the area of present development is also commercially productive. Based on these areas and a typical reserve's range of 15 to 20 MW per km^2 for such volcanic systems, the proven reserves for the Kamojang field are estimated to range from 210 to 280 MW for 30 years.

Production is obtained from fractured andesites, with the reservoir top at an elevation of about +900m (msl) in the northeast part of the proven area, sloping from there gently to the west and south, and dropping sharply in the extreme south to about +200 msl (figure 3). Subsurface temperature data support this geometry (figure 4), as do electrical resistivity data from standard traverses and soundings, MT, and CSAMT (figure 5). Resistivity also shows a strong increase along the far east side of the project area (figure 5), which may indicate a field boundary to the east.

Chemical data from the project wells are typical for steam wells, with total non-condensable gas content generally below 1% by weight and H_2S gas content less than 300 parts per million by weight.

2. ANALYSIS OF WELLTEST AND PRODUCTION DATA

2.1 Well Productivity History

Figure 2 shows the total field steam production rate (upper graph), the number of wells being produced (upper graph), and the average production rate per well (lower graph) as a function of time. Average well productivity declined sharply in 1987 when generation capacity was increased from 30 MW to 140 MW. This decline is a result of drilling wells in areas of lower productivity than encountered for the first 30 MW project, and of interference between the wells. Figure 6 shows the production history of a typical well (KMJ-17), with steam flow rate, flowing wellhead pressure, flowing wellhead temperature and the superheat in steam.

The unit steam requirement for the existing plants is 8 tonnes per hour per MW. The wells supplying these plants have a combined capacity of about 142 MW, and there is spare capacity of about 9 MW from 2 more wells that are used infrequently. Many of the wells are being produced at wellhead pressures higher than the minimum acceptable (about 10 kscg), given the turbine inlet pressure and the pressure drops experienced in the pipelines. These wells can produce more if they are opened more, but some are kept throttled to prevent wellbore scaling, which is known to be an operating problem.

There is little evidence of superheating in the produced steam, which implies that significant liquid water saturation still exists in the reservoir. If the liquid in the reservoir boils off completely, there can occur a strong decrease of well productivity and potentially an increase in steam corrosivity.

2.2 Well Deliverability Test Data

Pertamina has tested 37 production wells for multi-point deliverability characteristics (flow rates at various wellhead pressures) before putting them into routine production. In addition to these initial deliverability tests, a single-point deliverability test (measurement of flow rate at a single wellhead pressure) has been conducted once a year as a means of monitoring changes.

We first defined the initial deliverability curve of each well by using numerical wellbore simulation to fit an appropriate curve to the initial deliverability data. Then, using the single point deliverability data for each well in January 1996, and again using wellbore simulation, we also defined the recent deliverability characteristics of each well. Figure 7 (well KMJ-36) is an example which shows the deliverability curves determined from the initial multi-point test in 1985 and annual single-point tests to 1995. (In this case, some data points are explained only by higher reservoir pressure than was initially apparent; this is not likely and some data may be in error.)

Table 1 presents for each well the estimated initial deliverability at 10 kilograms per square centimeter gauge (kscg) wellhead pressure (and on the date shown), as well as the deliverability as of January 1996 (also at 10 kscg). From table 1, it is clear that all wells have declined in productivity over time, as to be expected in any geothermal field. The significance of the initial annual harmonic decline rate shown in table 1 is discussed below.

2.3 Productivity Decline Trend of Wells

Table 1 and plots such as figure 6 are not sufficient to assess the true productivity decline of a well, because wellhead pressure has not been constant. Instead, an analysis of productivity decline trend requires several steps, as proposed in Sanyal, *et al* (1989). The first step is to calculate the static (that is, shut-in) wellhead pressure for each well using the equation:

$$W = C\,(p^2 - p_f^{\,2})^n \qquad (1)$$

where W is the steam flow rate, p is the static wellhead pressure, p_f is the flowing wellhead pressure, C is an empirical parameter and n is a second empirical parameter ("turbulence factor") having a value between 0.5 and 1.0. As production from a well declines, p declines steadily, n remains nearly constant and C declines relatively slowly. If C is assumed to be constant, it can be replaced in (1) by C_i, the initial value of C, as follows:

$$C_i = \frac{W_i}{(p_i^{\,2} - p_{fi}^{\,2})^n} \qquad (2)$$

where the subscript 'i' denotes initial conditions. A representative value of C_i for each well is determined statistically based on data from the first few weeks of production. Then the static wellhead pressure of a well can be calculated as a function of time using this C_i and any chosen n value; this method has proven valid at The Geysers steamfield in California.

Figure 8 shows the calculated static wellhead pressure plot for a typical Kamojang well (KMJ-17), using an n value of 0.75, along with measured shut-in wellhead pressures. The match between the measured and calculated static wellhead pressures is excellent for most wells. In cases where the measured pressure is low compared to the calculated, the measured data simply reflect insufficient build up time. This analysis showed that the static wellhead pressure has been declining for all wells, which is a direct reflection of declining reservoir pressure. Since the turbine inlet pressure has remained nearly constant with time, declining reservoir pressure has resulted in declining steam production rate.

The next step in our analysis was to "normalize" the production rate histories of the wells to a constant wellhead pressure of 10 kscg (Sanyal *et al,* 1989). Once the normalized production rate history of a well is calculated, its productivity decline trend can be assessed.

The long-term decline trend in well productivity in steam reservoirs has been observed to be harmonic. Harmonic decline implies that the decline rate (D) is not constant, but itself declines with time. Harmonic decline can be expressed as:

$$W = \frac{W_i}{1 + D_i t} \quad (3)$$

where W_i is the initial production rate, W is the production rate at time t and D_i is the initial decline rate.

Assuming harmonic decline, one can calculate the initial harmonic decline rate for each well using (3) and the initial deliverability and January 1996 deliverability values shown in table 1 for that well. The decline rates thus calculated are shown in the last column of table 1. The table shows that a majority of the wells have relatively low decline rates (18% or less), typical of steam wells. However, eight wells are showing unusually high decline rates. These wells are suspected of declining rapidly in productivity due to continuing wellbore scaling or some other form of gradual wellbore damage. Records indicate that at least wells KMJ-35, KMJ-42 and KMJ-44 were known to be damaged. We suspect that the other three wells with unusually high decline are also being affected by well damage and the decline does not reflect reservoir pressure drawdown alone.

It should be noted that (3) implies that a plot of log W versus cumulative production is linear, from the slope of which one can calculate the initial annual decline rate (Sanyal *et al*, 1989). Figure 9 presents a plot of normalized production rates (on a logarithmic scale) versus the cumulative production (on a linear scale) for a typical Kamojang well. Several wells with an apparent tendency towards well damage were not considered for such analysis. On each plot there are two linear trends, one corresponding to the 30 MW generation level (pre-1988) and one corresponding to the 140 MW generation level (post-1988). The slope of the pre-1988 data trend is much less than that of the post-1988 trend, reflecting the higher level of production after 1987. (In the case of well KMJ-17 on figure 9, the slope of the pre-1988 data trend is effectively zero, and 1988 starts at 2000 kilo Tonnes.)

A linear trend line has been fitted to the post-1988 period on each plot like figure 9 and, from the trend, the initial decline harmonic trend (D_i) for each well has been calculated (table 2). The initial harmonic decline trend of 1.6% to 9.5% and the average initial harmonic decline trend of 4.2% are typical of wells in a steam reservoir, providing that the wells are not undergoing scaling or other forms of continuous well damage and that the reservoir has not been developed beyond its sustainable capacity.

Table 2 also compares the annual harmonic decline trend estimated from the decline curve with that estimated from the deliverability curve (table 1; adequate deliverability data are not available for wells KMJ-45 and KMJ-46). Except for wells KMJ-25 and KMJ-34, which appear to be suffering from well damage, the decline rates calculated by both methods are similar. In fact, for the 14 comparable wells in table 2, the average decline rate from decline curves (3.8%) is close to that from deliverability curves (4.0%). Therefore, with mechanical control of well damage and for 140 MW of generation, the wells at Kamojang can be expected to decline at an initial annual harmonic rate of 4.2% starting 1988.

2.4 Analysis of Pressure Build-up Data

Pressure build-up data were available from many wells and from these we have calculated the individual well flow capacity. The results show a three orders of magnitude variation, from 328 to 350,000 in millidarcy meters, which is not uncommon in a geothermal reservoir. This wide variation in reservoir flow capacity is reflected in the wide variation in well productivity, from 0.4 to 14.8 MW (two orders of magnitude). There is a weak positive correlation between flow capacity and well productivity, but no areal distribution pattern of reservoir flow capacity or of well productivity could be deciphered. Therefore, certain randomness in drilling success is unavoidable.

Individual well pressure build-up data could also be used to determine the static pressure distribution in the reservoir. From this, it was concluded that the initial reservoir pressure was about 35 kscg, and after 15 years of production the reservoir pressure has declined by about 5 kscg. This change is relatively modest.

3. STEAM SUPPLY FOR CAPACITY EXPANSION

3.1 Introduction

The 31 wells connected to the existing plants (140 MW) have a maximum total capacity of about 155 MW, implying a 10.7% excess capacity. Nine existing wells are not connected to the existing plants and are, therefore, available for steam supply for the 60 MW expansion. These 9 wells have a maximum total capacity of 68.8 MW. If all nine wells are available for production, the needed steam supply for the start-up of the new 60 MW plant is theoretically available already. However, in practice it would be more prudent to drill a few more wells to allow operation at a higher wellhead pressure than 10 kscg (presumably to reduce silica scaling), to allow some stand-by capacity, and to provide for the needed injection capacity. Development drilling at Kamojang has enjoyed a high success rate (over 80% to date) and within the dedicated area ample drilling sites are available for additional development wells. Therefore, the needed production and injection capacities for the expansion can be readily secured, and the resource risk is minimal up to the time of start-up for the new plant. However, as at any geothermal project using a steam reservoir, there are some resource risks once additional generation starts. These risks are discussed below.

3.2 Main Resource Risks After Plant Capacity Expansion

The productivity of the wells at Kamojang has declined at a low rate (about 4% per year initial harmonic rate). Over the 15-year production history of the field, reservoir pressure has declined by about 5 kscg, which is a relatively modest pressure drop, implying that the reservoir storage and flow capacities are adequate for at least the existing generation level. The produced steam has not shown any significant superheating to date; this fact and the relatively small pressure drop imply that the reservoir still contains water saturation. However, there is some uncertainty about the extent of the liquid saturation at this time.

The above uncertainty notwithstanding, we believe that the expanded capacity of 200 MW can be supported for the project life for the following reasons:

- the recoverable geothermal energy reserves appear to be adequate for the expanding capacity;
- the unusually small pressure drawdown in the reservoir and decline in well productivity indicate a relatively high storage capacity in the reservoir;
- there is little indication of superheat in the produced steam to date, indicating the presence of liquid saturation;
- there are no major problems associated with steam chemistry; and
- there has been a high success rate in development drilling.

However, the expansion may present certain operational challenges; therefore, the operations and maintenance costs per MW may be greater than hitherto experienced. One operational challenge may be an undue increase in the well productivity decline rate, which would also increase the make-up well requirement. This issue is discussed below. Another operational challenge may be superheating of steam, with consequent aggravation of silica scaling and increasing the chances of corrosion.

3.3 Forecasting Productivity Decline Following Plant Capacity Expansion

We have estimated approximately the expected increase in the productivity decline rate of wells following the capacity expansion. While this approximate calculation must be verified and refined by numerical simulation, it does give an estimate of at least the minimum limit of the expected decline rate. The approximate methodology that we have used is as follows.

The reserves of steam available from any well can be estimated as:

$$Reserves\ (R) = \int_0^{t_a} W dt, \tag{4}$$

where t_a = abandonment time. Therefore using equation (3),

$$R = W_i \int_0^{t_a} \frac{dt}{1 + D_i t} \tag{5}$$

$$= \frac{W_i}{D_i} \ln\left(\frac{W_i}{W_a}\right) \tag{6}$$

Similarly, one can show that if a higher initial production rate W_iN is imposed, and D_iN is the corresponding initial harmonic decline trend, then

$$R = \frac{W_i'}{D_i'} \ln\left(\frac{W_i'}{W_a}\right) \tag{7}$$

Therefore, $$\frac{W_i}{D_i} \ln\left(\frac{W_i}{W_a}\right) = \frac{W_i'}{D_i'} \ln\left(\frac{W_i'}{W_a}\right) \tag{8}$$

And from (8), we get $$D_i' = \left(\frac{W_i'}{W_i}\right) \frac{(\ln W_i' - \ln W_a)}{(\ln W_i - \ln W_a)} D_i \tag{9}$$

One can then calculate from equation (9) the increase in the harmonic decline rate from D_i to D_iN in consequence of an increase in the production level from W_i to W_iN.

To verify the above equations, let us note that the initial harmonic decline rate at Kamojang has been 4.2% per year at a 140 MW generation level. Using equation (9) we can calculate the initial harmonic decline rate for a 30 MW generation level. Let us assume an abandonment level of 1 MW. Then D_IN is calculated at 0.6%. Indeed, linear fit through the pre-1988 data points in the plots of normalized flow rate versus cumulative production for the wells verify that the initial harmonic decline of approximately 0.6% prevailed between 1982 and 1987. Figure 9 clearly shows, for well KMJ-17, the change from 0.6% prior to 1988 to about 4% after the capacity increased to 140 MW.

Going forward, from equation (9) we can make an approximate estimate of the initial harmonic decline rate following capacity expansion from 140 MW to 200 MW: this is 6.4%. Therefore, the decline rate will remain relatively low even after a capacity expansion by 60 MW. Assuming that the 200 MW capacity will be supplied by 40 production wells (31 supplying the existing plants and 9 available for the new plant), this rate of harmonic decline will require about 2.5 make-up wells per year (that is, 2 to 3 make-up wells will need to be drilled each year). In 30 years, the total number of make-up wells would reach about 75. The 40 wells at start up plus 75 make-up wells would mean 115 wells in 30 years. Given that the proven productive reservoir at Kamojang is 14 km^2, 115 wells would have an average drainage area of 122,000 m^2 per well. This implies an ultimate average well spacing of about 350 m. This level of ultimate well spacing should not give rise to undue interference between wells. In fact, we often use the rule of thumb of 300 m minimum well spacing to assess the adequacy of dedicated productive area for a geothermal project.

In conclusion, we believe, subject to verification by numerical simulation, the above analysis indicates that the resource risk associated with productivity decline is low.

ACKNOWLEDGEMENTS

The authors would like to thank Pertamina for their support of this project and permission to publish these results, and Dr. Keshav Goyal of Calpine Corporation for reviewing this paper.

REFERENCES

Sanyal, S.K., Menzies, A.J., Brown, P.J., Enedy, K.L, and Enedy, S. (1989). A systematic approach to decline curve analysis for the Geysers steam field, California. *Transactions, Geothermal Resources Council.* Vol.13, pp.415-422.

	Initial Deliverability			Estimated January 1996 Deliverability		Initial Annual
Well	Tonnes/hour	Date	MW	Tonnes/hour	MW	Harmonic Decline (%)
KMJ-11	85	5/85	10.6	68	8.5	2.3
KMJ-14	61	5/85	7.6	41	5.1	4.6
KMJ-17	72	5/85	9.0	55	6.9	2.9
KMJ-18	118	5/85	14.8	100	12.5	1.7
KMJ-22	94	12/81	11.8	74	9.3	1.9
KMJ-24	47	8/88	5.9	37	4.6	3.6
KMJ-25	27	8/88	3.4	8	1.0	32.0
KMJ-26	91	4/83	11.4	49	6.1	6.7
KMJ-27	92	7/83	11.5	57	7.1	4.9
KMJ-28	56	8/83	7.0	31	3.9	6.5
KMJ-29	41	7/85	5.1	33	4.1	2.3
KMJ-30	32	3/85	4.0	7	0.9	33.0
KMJ-31	47	7/84	5.9	23	2.9	9.1
KMJ-34	50	8/84	6.3	15	1.9	20.0
KMJ-35	32	6/84	4.0	8	1.0	26.0
KMJ-36	118	7/85	14.8	99	12.4	1.8
KMJ-37	73	4/88	9.1	63	7.9	2.1
KMJ-38	40	4/85	5.0	23	2.9	6.9
KMJ-39	25	10/85	3.1	4	0.5	51.0
KMJ-41	94	7/85	11.8	85	10.6	1.0
KMJ-42	64	2/86	8.0	23	2.9	18.0
KMJ-43	46	3/86	5.8	10	1.3	36.0
KMJ-44	53	1/87	6.6	12	1.5	38.0

Table 1: Analysis of Well Deliverability at 10 kscg Wellhead Pressure

Well	Initial Harmonic Decline Rate (%)	
Name	From Decline Curves	From Deliverability Curves
KMJ-11	2.6	2.3
KMJ-14	2.9	4.6
KMJ-17	2.9	2.9
KMJ-18	1.8	1.7
KMJ-22	1.6	1.9
KMJ-24	2.0	3.6
KMJ-25	6.5	32.0?
KMJ-26	6.0	6.7
KMJ-27	5.5	4.9
KMJ-28	4.5	6.5
KMJ-31	9.5	9.1
KMJ-34	9.1	20.0?
KMJ-36	2.5	1.8
KMJ-37	4.5	2.1
KMJ-38	4.8	6.9
KMJ-41	2.0	1
KMJ-45	2.1	-----
KMJ-46	5.4	-----
Average	4.2	

Table 2: Estimated Rates of Well Productivity Decline

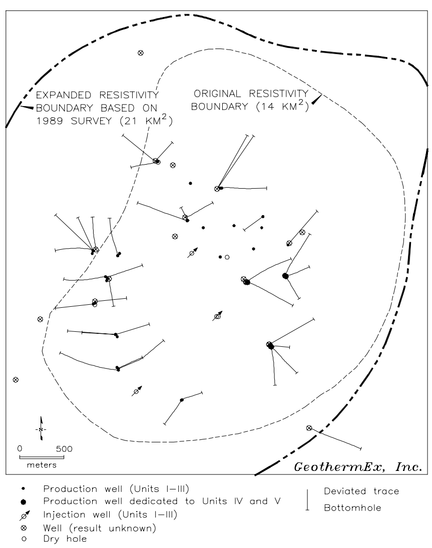

Figure 1: Well location map

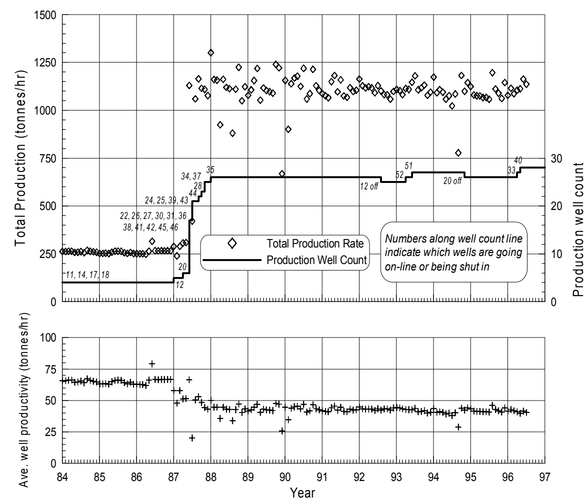

Figure 2: Total production, number of wells on line and average well productivity

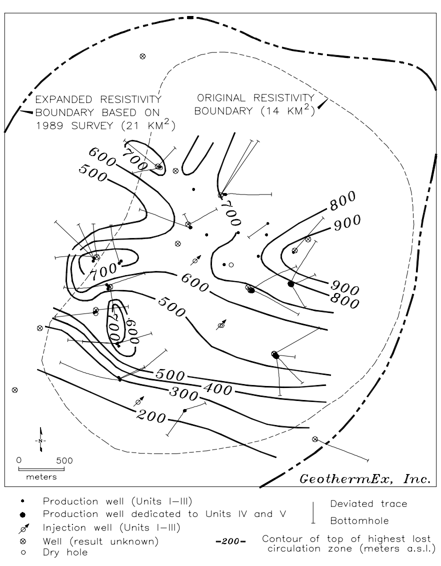

Figure 3: Elevation of highest lost circulation zone

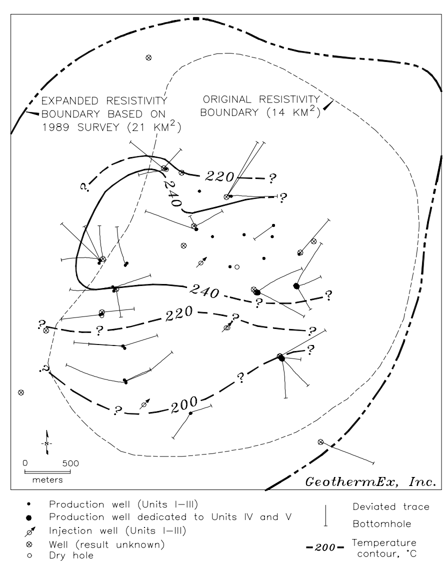

Figure 4: Temperature distribution at +600 m (msl)

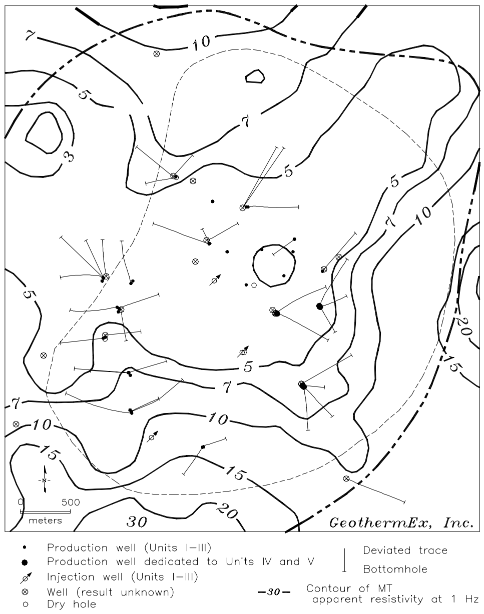

Figure 5: MT apparent resistivity at 1 Hz

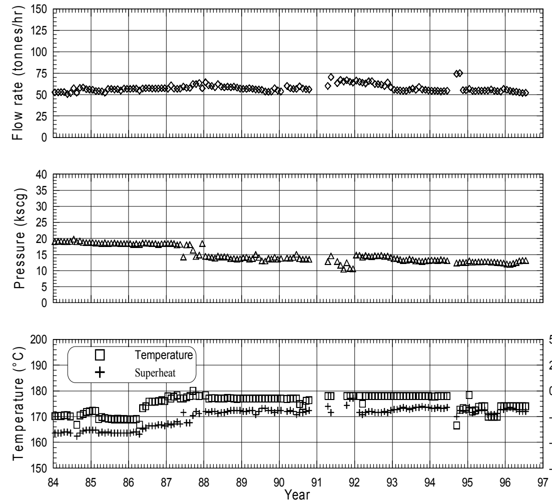

Figure 6: Production history, Kamojang well KMJ-17

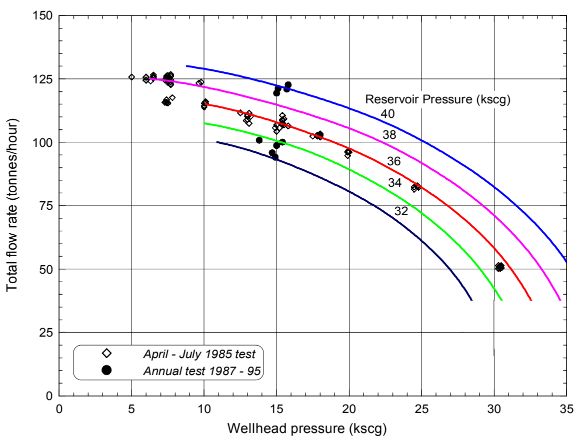

Figure 7: Deliverability data, Kamojang well KMJ-36

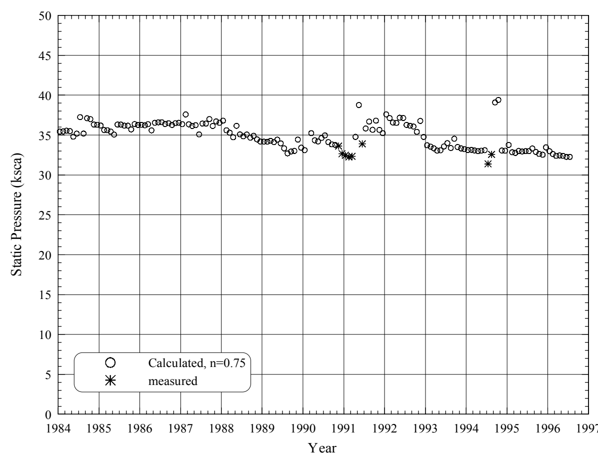

Figure 8: Changes to static pressure vs. time, Well KMJ-17

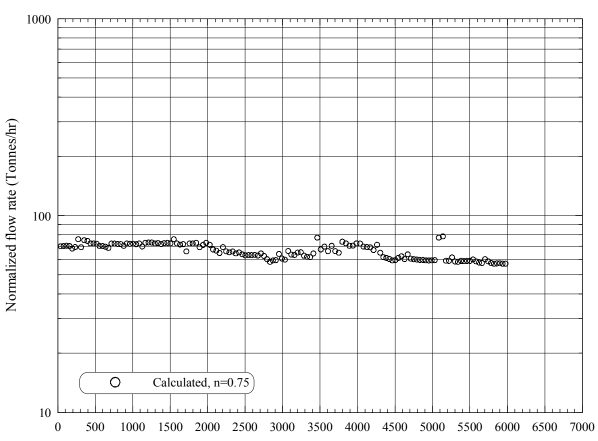

Figure 9: Log normalized flow rate vs. cumulative production, Well KMJ-17