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EVALUATION OF RESERVOIR MODEL PREDICTIONS FOR THE OLKARIA EAST GEOTHERMAL FIELD, KENYA

G. S. Bodvarsson,* K. Pruess,* C. Haukwa‡ and S. B. Ojiambo‡

*Earth Sciences Division
Lawrence Berkeley Laboratory
1 Cyclotron Road
Berkeley, California 94720

‡Kenya Power Company Ltd.
Electricity House
Harambee Avenue
Nairobi, KENYA

ABSTRACT

In 1984 a detailed three-dimensional well-by-well model was developed for the Olkaria geothermal field in Kenya. The model was calibrated against the production history of the field over the period 1977 through 1983, using porosities and permeabilities as adjustable parameters. During this period two 15-MW_e Units were put on-line at Olkaria; the third 15 MW_e Unit commenced operation in March 1985. The numerical model was used to predict the performance of the Olkaria wells and these predictions have been compared with the observed well behavior for the period 1984 to 1987. In general, the model predictions show satisfactory agreement with the observed well behavior, especially for those wells that had production histories exceeding two years. The predicted steam rates for most of the wells were accurate to within 1 kg/s for the period considered and the steam rate decline was well predicted by the model. Some differences between the observed and predicted total flow rates and enthalpies of individual wells were seen, especially in those wells with large enthalpy variation or unorthodox increases in total flow rate. The model also predicted that 3 make-up wells would be needed by the end of 1987, which is consistent with the observed decline in total steam rates. New performance predictions have been made using an updated model, including the effects of wastewater reinjection.

INTRODUCTION

The Olkaria East geothermal field has been producing electrical power since 1981 when the first of three 15 MW_e Units started operation. The other two 15 MW_e Units came on-line in 1982 and 1985, respectively, bringing the plant capacity to the current level of 45 MW_e.

Concurrent with the development of the Olkaria East wellfield, exploration drilling was carried out in other parts of the Olkaria field (Fig. 1). This exploration activity has been successful and has delineated two new areas for development. These are the Olkaria Northeast area, around the 700 series wells (north of the Olkaria East field) and the Olkaria West area around the 300 series wells (west of the Olkaria Hill). A decision has been made to continue development in Olkaria Northeast with a 60 MW_e power plant, planned to be commenced in 1992. In order to aid in the development of the geothermal development at Olkaria, a series of numerical simulation studies have been carried out.

The first study was conducted in 1980 with the objective of evaluating if fluid production should be limited to the rather thin vapor zone (about 100 m thick), or if the long term reservoir performance would improve with combined production from the vapor zone and the underlying two-phase zone (Bodvarsson et al., 1982). The second simulation study addressed the effects of adding a second 15 MW_e Unit on the long-term reservoir performance. Finally in 1984, a detailed three-dimensional model of the Olkaria East field was developed, which represented all wells individually. This model was calibrated against the existing flow rate and enthalpy histories of all wells for the period 1977-1983. The model results indicated that power generation of 45 MW_e at Olkaria East was possible.

With the commencement of the third 15 MW_e Unit significant flow rate declines were observed in many wells, as well as considerable enthalpy changes. This was of sufficient concern to lead to updating of the three-dimensional model with production data for the period 1984-1987; the work was completed in 1988. The updating of the model allowed for an evaluation of the accuracy of the model predictions during this period in terms of flow rates and enthalpies of all wells. This paper briefly describes the three-dimensional model of Olkaria East and evaluates its predictive performance. It also describes the model modifications that were necessary to match the additional data and the new performance predictions.

THE THREE-DIMENSIONAL MODEL

The three-dimensional model consists of three layers, with the top 100 m thick layer representing the initial vapor zone and the bottom two layers (250 and 500 m thick) representing the underlying two-phase liquid-dominated zone. These vertical dimensions and number of layers were considered sufficient to adequately represent the initial thermodynamic conditions of the reservoir and the major feed zones of the wells. The areal discretization of the model allows for individual grid block representation of all wells (Fig. 2) and extends

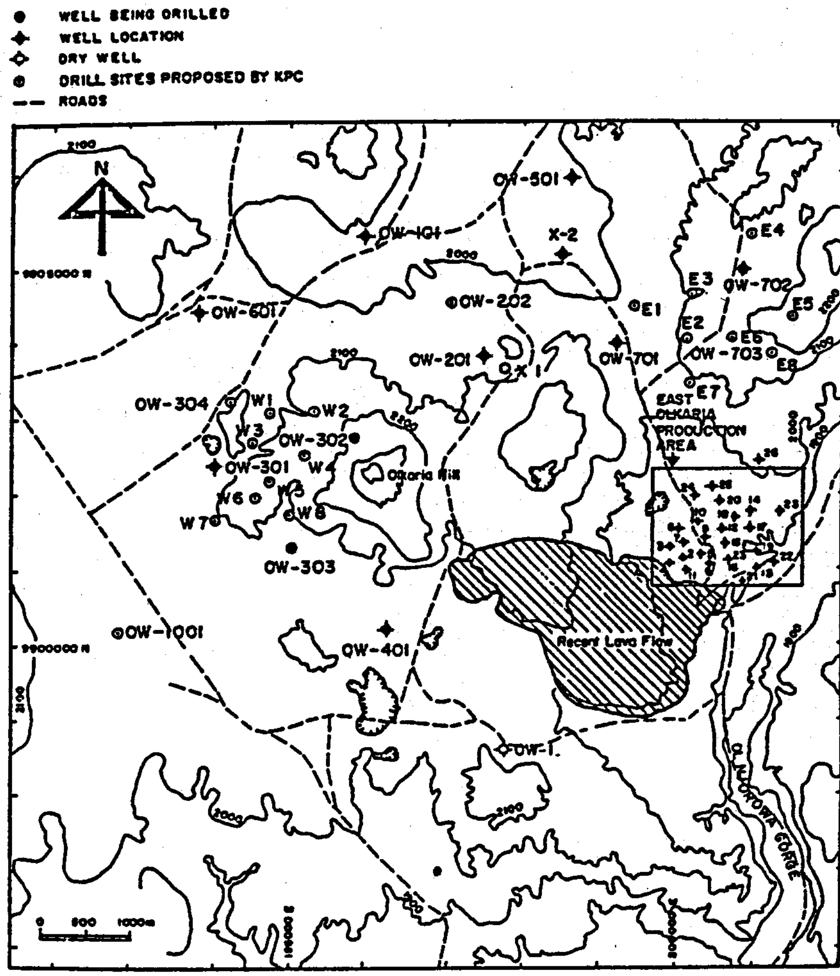

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Figure 1. Locations of exploration wells and Olkaria East production wells.

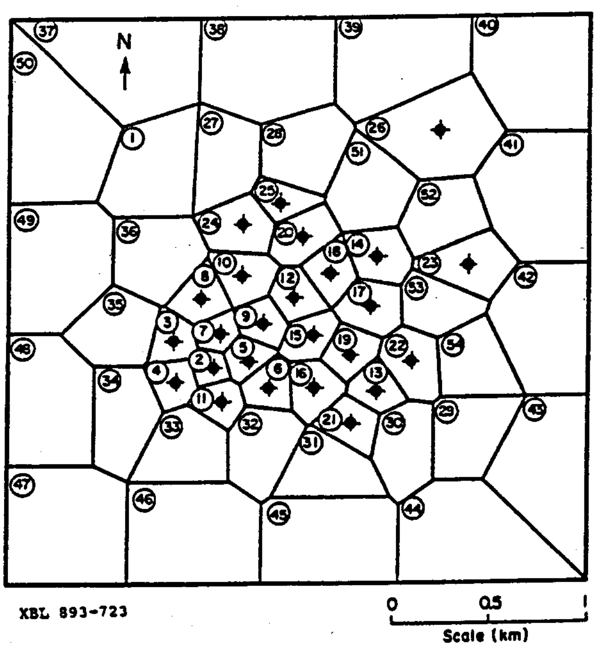

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Figure 2. Areal view of grid used in the numerical model.

over an area of some 9 km^2. Because of the two-phase conditions in the reservoir, this assumed areal extent of the reservoir is sufficiently large for the system to act as if it is infinite.

The three-dimensional model was calibrated against the flow rate and enthalpy histories of all wells, using reservoir porosities and permeabilities and productivity indices of the wells were used as adjustable parameters. As an example, Figure 3 shows the history match for well 11. The history match yielded average permeabilities of 7.5 md and 4.0 md in the steam zone and the underlying liquid-dominated zone, respectively. This corresponds to an average well transmissivity of about 3.5 Dm (Darcy-meters) which is similar to the average transmissivity determined from short-term well tests.

Following the history match, performance predictions were made, that indicated that power generation in excess of 45 MW_e would be possible for 30 years at Olkaria East. It was recommended that the well spacing of future wells should exceed 300 m (11 wells per km^2) due to large interference of the present wells (average

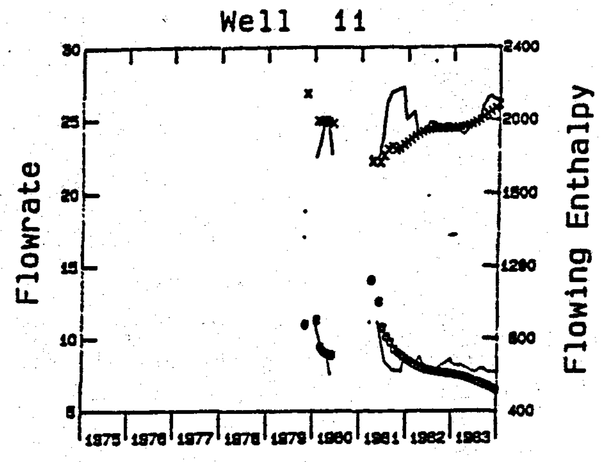

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Figure 3. History match with flowrates and enthalpies for well 11 during the period 1977 through 1983.

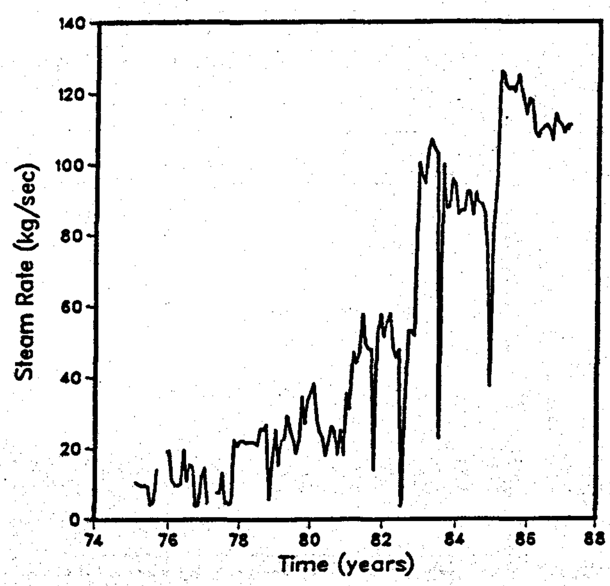

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Figure 4. Total steam production versus time for Olkaria East wells.

well spacing of 225 m). For all of the different exploitation and reinjection scenarios flow rate and enthalpy predictions were made for each well and the necessary replacement wells, so that the predictions could be directly compared to future well data. More details of the model are given by Bodvarsson et al (1987a, b), and Svanbjornsson et al. (1983) describe the reservoir conditions at Olkaria.

FIELD PERFORMANCE 1984–1987

During the exploitation of the Olkaria East reservoir 1981 to 1987, significant changes have occurred in well outputs. The total steam rate of all wells is given in Figure 4 and reflects the early testing of wells (period 1975 to 1981) and the startup of the three Units (the first 15 MW_e Unit in 1981, the second one in 1982 and the third one in 1985). The average steam rate of the wells (Fig. 5) also shows large variations during the early flow testing, as wells with different production capacities were tested. A significant increase in the average steam rate for the wells is seen in 1982, reflecting the fact that the wells feeding Unit 2 are in general better producers than those feeding Unit 1. The considerable decline in the average steam rate since 1985 is due to production from wells feeding Unit 3, with the associated reservoir pressure decline and well output decline. Table 1 gives a summary of the effects of the Unit 3 start-up on producing wells for Units 1 and 2. Many of these wells show considerable flow rate decline (1.5 to 4.0 kg/s) and an accompanied enthalpy rise (100-200 kJ/kg). It is rather interesting that the effects for most wells are felt very quickly after the start-up of Unit 3 (generally less than 1 month) in spite of the two-phase conditions of the reservoir. It is probable that this is due to single-phase vapor conditions in the expanding vapor zone, which allows rapid areal propagation of pressure changes.

The average enthalpy of the produced fluids (Fig. 6) shows that most of the wells produce high enthalpy fluids averaging about 1800 kJ/kg during the flow testing period (1975-1981). After Unit 1 came on-line in 1981, the average enthalpy increased rapidly to about 2200 kJ/kg due to the expanding vapor zone and well interference. This trend continued when Units 2 and 3 commenced so that in 1987 the average enthalpy was near 2500 kJ/kg, or close to that of saturated steam (≈2800 kJ/kg).

It is of interest to evaluate how well the three-dimensional model predicted the performance of the wells during the period 1984 through 1987. This was achieved by incorporating the flow histories of the wells

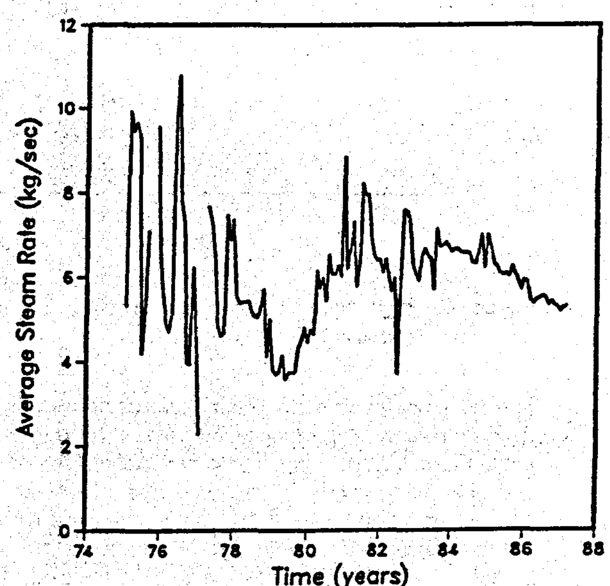

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Figure 5. Average steam rate per well versus time for Olkaria East wells.

Table 1. Effects of Unit 3 wells coming on-line on the performance of other Olkaria East wells.

Well	Flow rate change (kg/s)	Enthalpy change (kJ/kg)	Steam rate change (kg/s)	Comments
2	0	0	0	
5	0	0	0	
6	0	0	0	
7	?	?	?	masked by well 8
10	1.5	200	0	small lag time (layer 3 well)
11	2.0	0	1.0	small lag time (layer 3 well)
12	3.5	200	2.5	small lag time (layer 2-3 well)
13	(0.5)	(200)	0	6-month lag time (layer 2 well)
14	0	0	0	
15	0	0	0	layer 3 well
16	4.0	100	3.0	small lag time (layer 3 well)
17	1.5	150	1.0	small lag time
18	2.0	150	0.5	small lag time (layer 3 well)
19	0	0	0	layer 3 well

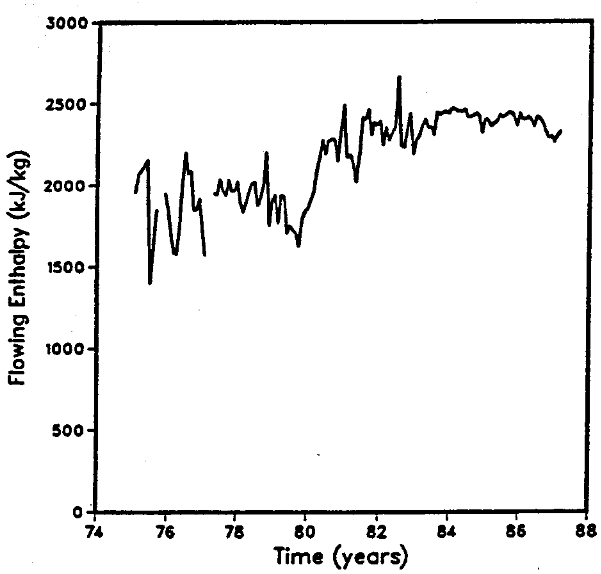

Figure 6. Average enthalpy of the produced fluids versus time.

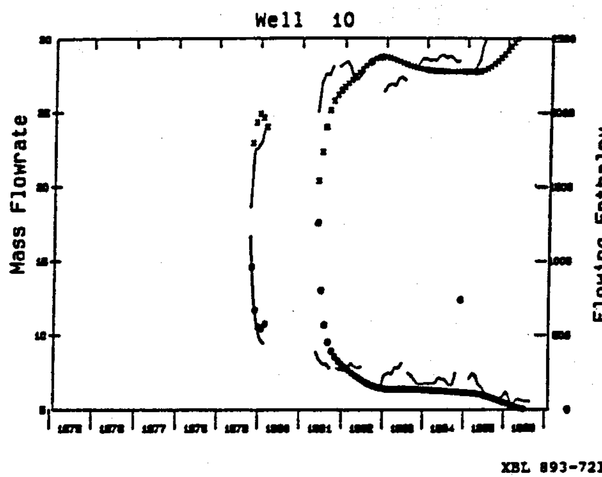

Figure 7. Comparison between predicted and observed flowrates and enthalpies (1984-1987) for well 10.

into the model, computing their performances during the four years and comparing the results with the observed data. Figures 7 and 8 give these comparisons for wells 10 and 11, respectively. The predicted flow rate and enthalpy behavior of well 10 agrees very well with that observed even to the extent that the late time rapid rise in enthalpy and decline in total flow rate is predicted. In the case of well 11 the predictions of the flow rate and enthalpy trends are rather poor, as the model overpredicts enthalpies by up to 500 kJ/kg and underpredicts the total flow rate by some 2 kg/s. However, it is most important that the steam rate at the separators is adequately predicted, as this controls how soon replacement wells are needed. Figure 9 shows that in spite of the rather poor enthalpy and flow rate predictions for well 11, the steam rate predictions are reasonably good.

In general, the model predicted adequately the steam rates and their decline for about 75% of the wells. For wells which had very short production history the model calibration was not sufficient to allow for reliable well performance predictions. Also, some of the wells showed

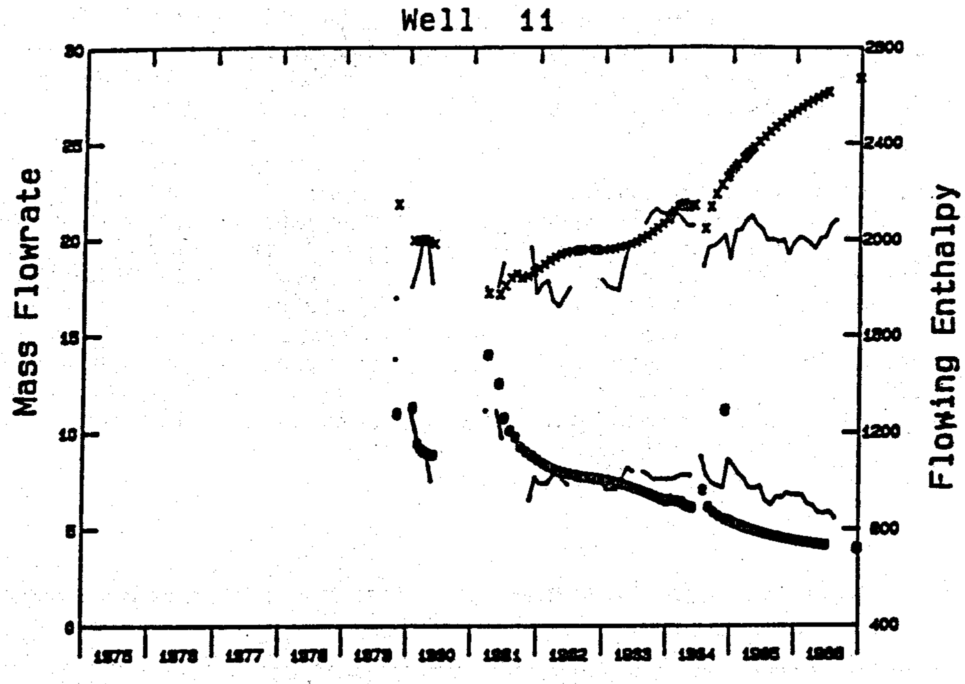

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Figure 8. Comparison between predicted and observed flowrates and enthalpies (1984-1987) for well 11.

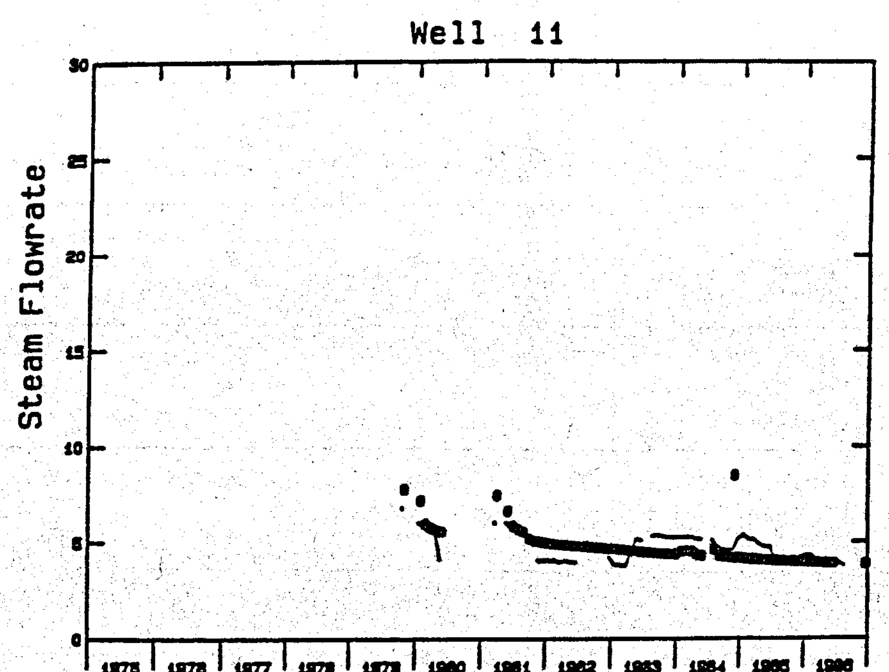

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Figure 9. Comparison between predicted and observed steam rates (1984-1987) for well 11.

very unorthodox behavior during the period 1984-1987, including large flow rate increases with little enthalpy changes. This type of behavior can only be explained by temporal permeability changes, which are not included in the model.

The best evaluation of the model performance is to compare the overall predicted steam rate decline of all wells with that observed. This is a direct measure of how accurately the model predicted the number of replacement wells needed during the period 1984-1987, which is very important from the standpoint of the plant operation and the economics of the project. It turned out that the predicted decline in the total steam rate agreed very well with that observed, so that the model prediction of 3 make-up wells needed by the end of 1987 was correct.

Another test of the model concerned the relative contributions of the feed zones of the wells. Before the model was developed in 1984, the Kenya Power Company (1984) estimated the relative contributions of the various well feed zones using geochemical data (Table 2). These estimated relative contributions were used as initial "guesses" in the model development during the iterative history matching. However, these estimates had to be modified during the history matching, primarily because of the observed enthalpy transients. For many of the wells the enthalpies rose from 1500-1800 kJ/kg to over 2300 kJ/kg over a period of a year to a few years. This behavior is clearly inconsistent with majority of flow coming from steam zone feeds, but results from localized boiling around the feed zones in the liquid-dominated zone.

Table 2. Relative contributions of different feeds for Olkaria East wells, based on estimates from the flowing pressure surveys, the numerical model, and geochemical data.

Well	Zone	Pressure Surveys		Numerical Model		KPC (1984)
		Flow (%)	Enthalpy (kJ/kg)	Flow (%)	Enthalpy (kJ/kg)	Flow (%)
4	Steam	30	2800	18	2800	90
	Upper liquid	70	1500	82	1500	10
	Lower liquid					
9	Steam					50
	Upper liquid					
	Lower liquid	100	2435	100	2400	50
11	Steam	?		28	2840	60
	Upper liquid					
	Lower liquid	?		72	1930	40
13	Steam	26	2800	32	2830	90
	Upper liquid	74	1640	68	2390	10
	Lower liquid					
14	Steam	65	2800	66	2830	30
	Upper liquid	35	2485	34	2150	70
	Lower liquid					
15	Steam	35	2800	26	2840	20
	Upper liquid					
	Lower liquid	65	2150	74	2800	80
16	Steam	16	2800	5	2840	20
	Upper liquid					
	Lower liquid	84	2520	95	2330	80
17	Steam	6	2800	31	2840	33
	Upper liquid	0		12	2800	33
	Lower liquid	94	2000	57	2730	33

Table 2. Continued.

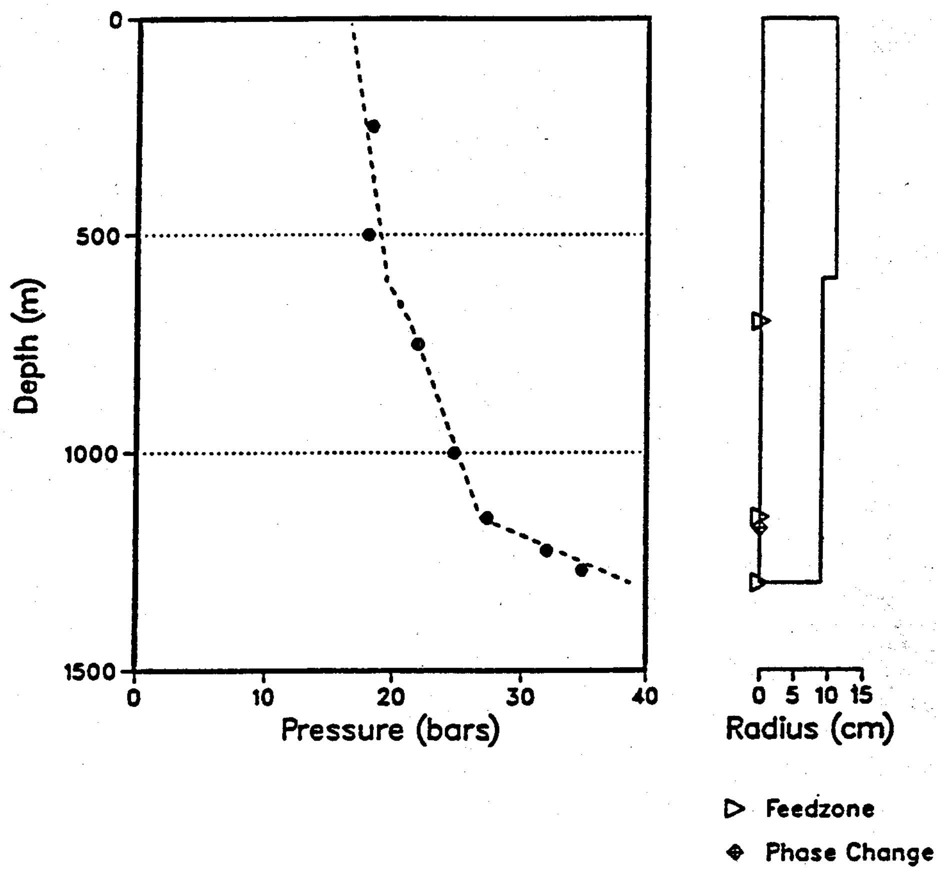
Well	Zone	Pressure Surveys Flow (%)	Pressure Surveys Enthalpy (kJ/kg)	Numerical Model Flow (%)	Numerical Model Enthalpy (kJ/kg)	KPC (1984) Flow (%)
	Steam	29	2800	11	2840	10
18	Upper liquid	0		10	2800	10
	Lower liquid	61	2600	79	2540	80
	Steam					
19	Upper liquid					
	Lower liquid	1000	2300	100	2470	100
	Steam	45	2800			
20	Upper liquid	0		8	2590	25
	Lower liquid	55	2480	92	2160	75
	Steam	29	2800	29	2850	80
21	Upper liquid	71	2550	71	1800	20
	Lower liquid					
	Steam	19	2800	20	2850	90
22	Upper liquid	81	2450			
	Lower liquid	0		80	2000	10
	Steam	54	2800	38	2800	90
23	Upper liquid	46	2220			
	Lower liquid	0		62	2220	10
	Steam					20
24	Upper liquid	0		25	2000	10
	Lower liquid	100	2200	75	2180	70

The model estimates of relative feed zone contributions have been compared to those obtained from the analysis of flowing pressure surveys using a multiple feed zone wellbore model (Bjornsson and Bodvarsson, 1987). As an example, Figure 10 shows the analysis for well 16, which yields the majority of the fluid inflow from the liquid-dominated zone (84%), in good agreement with the model results. Note also the high enthalpy of the feed zone at 1150 m depth, indicating a large degree of boiling around the well. As shown in Table 2 the results of the flowing surveys analysis yielded relative contributions of the feed zones that generally agree well with the model results. However, this is by no means a reliable check on the model as the results of the analysis of flowing pressure surveys are often very non-unique.

UPDATING OF THE MODEL

Although the three-dimensional model predicted the performance of many wells adequately, parameter modifications were necessary to match other wells. This new round of history matching involved all of the available data from 1977 through 1987. In general, little changes in productivity indices of the wells and permeabilities of the different layers were required. For a few wells the productivity indices of the steam zone feed zones had to be increased to maintain stable flow. The permeability distribution in the wellfield required rather localized changes around individual wells, but the average permeabilities of the steam zone (≈ 7.5 md) and the underlying liquid-dominated zone (≈ 4 md) remained unchanged. The permeability adjustments were primarily needed to properly represent the effects of Unit 3 coming on-line.

The main parameter adjustment needed for the model was an increase in the average porosity of the liquid-dominated zone from 2% to 4%. We believe that this parameter change reflects an artifact of the porous medium model used for this fractured reservoir. The need for a higher average porosity in the liquid zones in the present simulations is probably due to increasing



OLKARIA WELL OW-16
Pressure log during discharge. Measured 30-april-1981
Downhole pressures calculated for the following conditions.

Wellhead pressure (bar abs.)	:	16.50
Wellhead temperature (C)	:	202.00
Wellhead dryness	:	0.817
Wellhead enthalpy (kJ/kg)	:	2440.00
Wellhead total flow (kg/s)	:	13.00

Feedzone no:	Depth (m)	Flow (kg/s)	Enthalpy (kJ/kg)
1	700.0	2.0000	2800.1
2	1150.0	10.0000	2520.0
3	1300.0	1.0000	1054.3

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Figure 10. Analysis of a flowing pressure survey for well 16.

recharge from the high-porosity matrix blocks to the fractures. At early time fracture effects dominate as localized fluid depletion is occurring near the wells. The rapid rise in enthalpy of many of the Olkaria wells at early production times is controlled by the low fracture porosity (the volume fraction occupied by the fractures) and the complex fracture/matrix interactions. This early rise in fluid enthalpy can only be represented in our porous medium model by small porosities near the wells, which most likely will lead to conservative performance predictions.

After significant fluid production has taken place the enthalpy of the produced fluids is controlled by the enthalpy of fluids recharging the wellfield. At this time the effects of fractures are not as important, except of course in locations where colder fluids are migrating from outer regions to the reservoir. In the present simulation, data are available for a 10-year period and we believe that currently the enthalpies of most wells are controlled by fluids recharging the wellfield. It was found during the history match iterations that porosities of 2% in the liquid zones outside the wellfield caused fluids with high enthalpy to recharge the wellfield, and consequently the enthalpies of the producing wells were too high. The 4% porosity seemed to provide the proper enthalpy of fluids recharging the wellfield. In the earlier history match simulations (Bodvarsson et al., 1987a) the production period was too short to allow reliable estimates of the porosity of the recharge zones to be made.

Figure 11 shows, as an example, the porosity and permeability distribution in the lower liquid zone. The figure shows that a rather wide range of porosities (1-10%) and permeabilities (1->15 md) are needed to match the data. In general, high permeabilities are needed close to the best producers (e.g. wells 12, 15 and 16) and low porosities close to those wells that showed large enthalpy increases during the early production period. It is acknowledged that the porosity and permeability distribution shown in Figure 11 is by no means unique, as other (probably similar) distributions would also yield reasonable history matches for all wells.

PERFORMANCE PREDICTIONS

The updated numerical model shows that the effects of Unit 3 on the well flow rates and enthalpies have subsided, and new quasi-steady conditions have been reached in the system. It is estimated that four replacement wells need to be drilled to bring the plant up to maximum capacity (48 MW_e; the rated capacity is 45 MW_e). Figure 12 shows the predicted plant outputs until the end of 1991, assuming that these replacement wells will be drilled and connected. The first replacement well is assumed to be on-line by the end of 1989 and the last one by the end of 1990. The model predicts that the plant output will gradually decline to 38 MW_e before the first replacement well comes on-line. The model was used to investigate various alternatives for future development of Olkaria East including effects of reinjecting the waste water.

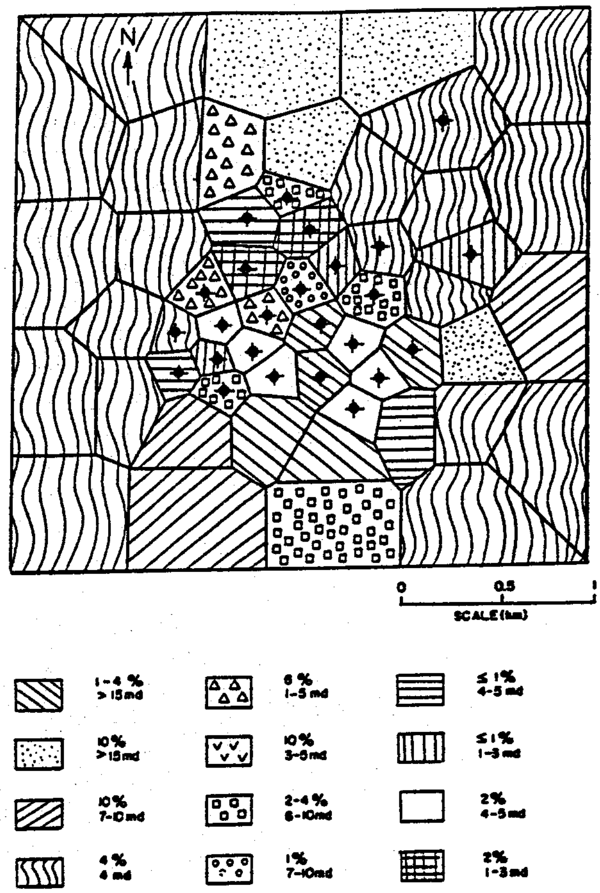

Figure 11. Estimated permeability and porosity distributions for the lower liquid zone.

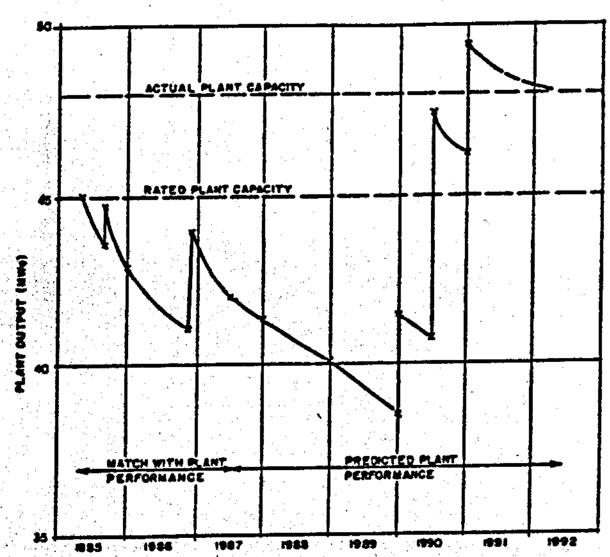

Figure 12. Predicted power plant output for the period 1987 through 1991.

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