Title

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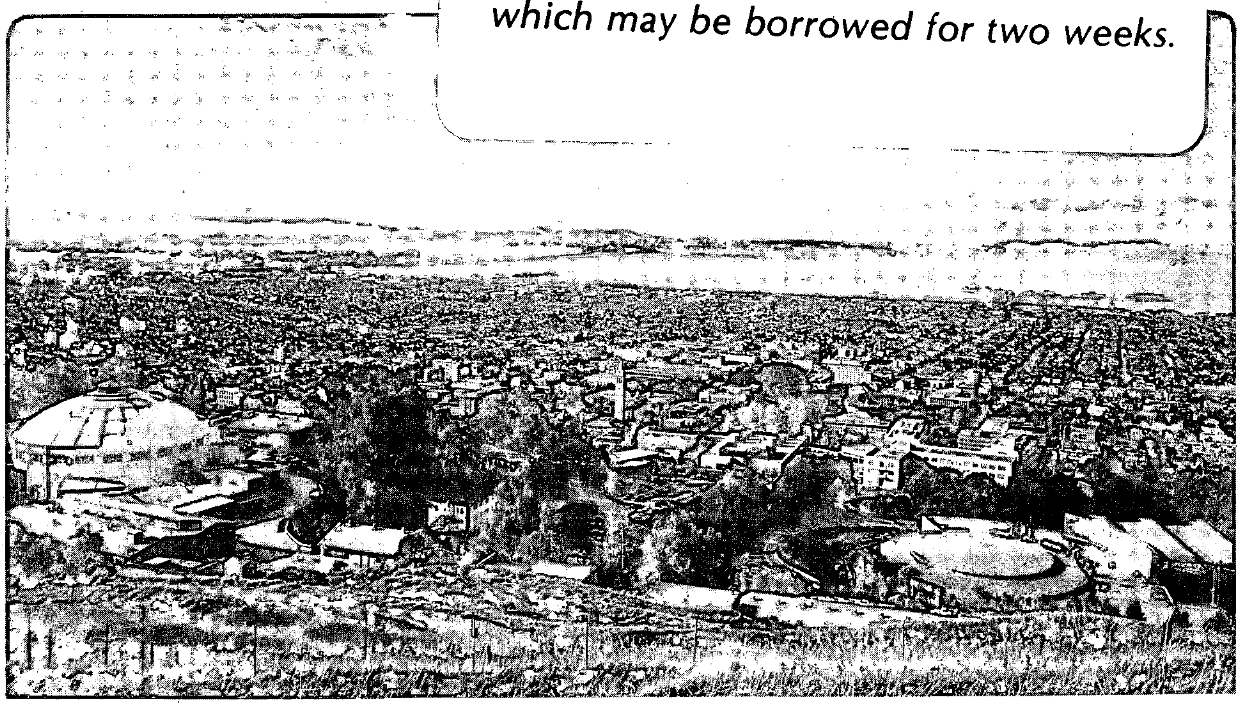

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DISCLAIMER

NUMERICAL MODELING OF GEOTHERMAL SYSTEMS WITH APPLICATIONS TO KRAFLA, ICELAND AND OLKARIA, KENYA

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INTRODUCTION

The use of numerical models for the evaluation of the generating potential of high temperature geothermal fields has increased rapidly in recent years. In the late 1970s and early 1980s there were many papers published on comparisons between the simple lumped-parameter models and the more complex distributed-parameter (numerical) models (e.g., Sorey and Fradkin, 1979; Castanier et al., 1980; Fradkin et al., 1981). These papers generally concluded that in most cases lumped-parameter models give just as reliable estimates as the distributed-parameter models for the potential of geothermal systems. In recent years, however, as more data have been collected from many geothermal reservoirs and the need for very comprehensive evaluations has arisen, the use of numerical models has greatly increased. One advantage of using the more complex numerical models is the fact that they are capable of utilizing most of the relevant field data, such as spatial variability in permeability and porosities, and this capability is very important as field data can help constrain the model.

In the evaluation of a geothermal resource, some of the questions that need to be addressed involve the overall generating potential of the resource, which includes appropriate power plant size, proper well density (spacing), number of development (make-up) wells required and the effects of reinjection on the overall performance of the reservoir. Of major concern is the development of a feasible and realistic injection place, because for most fields reinjection is necessary for environmental reasons. These questions can be addressed with reasonable success using the appropriate numerical model, providing that all important field data are integrated into the model, and experienced reservoir engineering staff are involved in the modeling process.

Recent reviews of the state-of-the-art in geothermal reservoir modeling include those of O'Sullivan (1986) and Bodvarsson et al. (1986). In the present paper a unified numerical approach to the modeling of geothermal systems is discussed and the results of recent modeling of the Krafla geothermal field in Iceland (Bodvarsson et al., 1984a,b,c; Pruess et al., 1984) and the Olkaria, Kenya (Bodvarsson et al., 1987a,b) are described. Emphasis is placed on describing the methology using examples from the two geothermal fields.

THE GEOTHERMAL FIELDS MODELED

In this section the geothermal fields at Krafla, Iceland and Olkaria, Kenya are briefly described in order to provide the necessary background for the sections that follow.

The Krafla geothermal field is located in the neovolcanic zone of northeastern Iceland. The zone is characterized by fissure swarms and central volcanoes. The Krafla field is located in a caldera (8 x 10 km) with a large central volcano, named Krafla. The field has been under development for the past decade. At present, 23 wells have been drilled at the Krafla field (Fig. 1). In the "old" wellfield (west of the Hveragil gully), the wells have encountered two major reservoirs (Fig. 2); the upper reservoir (200-1000 m depth) contains single-phase liquid water with a mean temperature of 205 °C. The deeper reservoir is two-phase, with temperature and pressures following the boiling curve with depth. The two reservoirs are separated by a thin (200-500 m) low-permeability layer, but seem to be connected near the Hveragil gully. In the new wellfield (east of Hveragil; wells 14 and 16-20), the two-phase liquid-dominated reservoir extends close to the ground surface.

The production characteristics of the various reservoir zones at Krafla are vastly different. The low temperature of the fluids in the upper reservoir in the "old" wellfield makes it unfavorable for the production of high-pressure steam. Consequently, in most of the wells in the old wellfield, the upper zone is cased off. In the lower zone, the temperature of the reservoir fluids is high (300-400 °C), but silica scaling and iron deposits hamper effective utilization of the fluids. In the new wellfield, the chemical composition of the reservoir fluids is more favorable, and scaling problems are minimal. A detailed description of the Krafla system is given by Stefansson (1981).

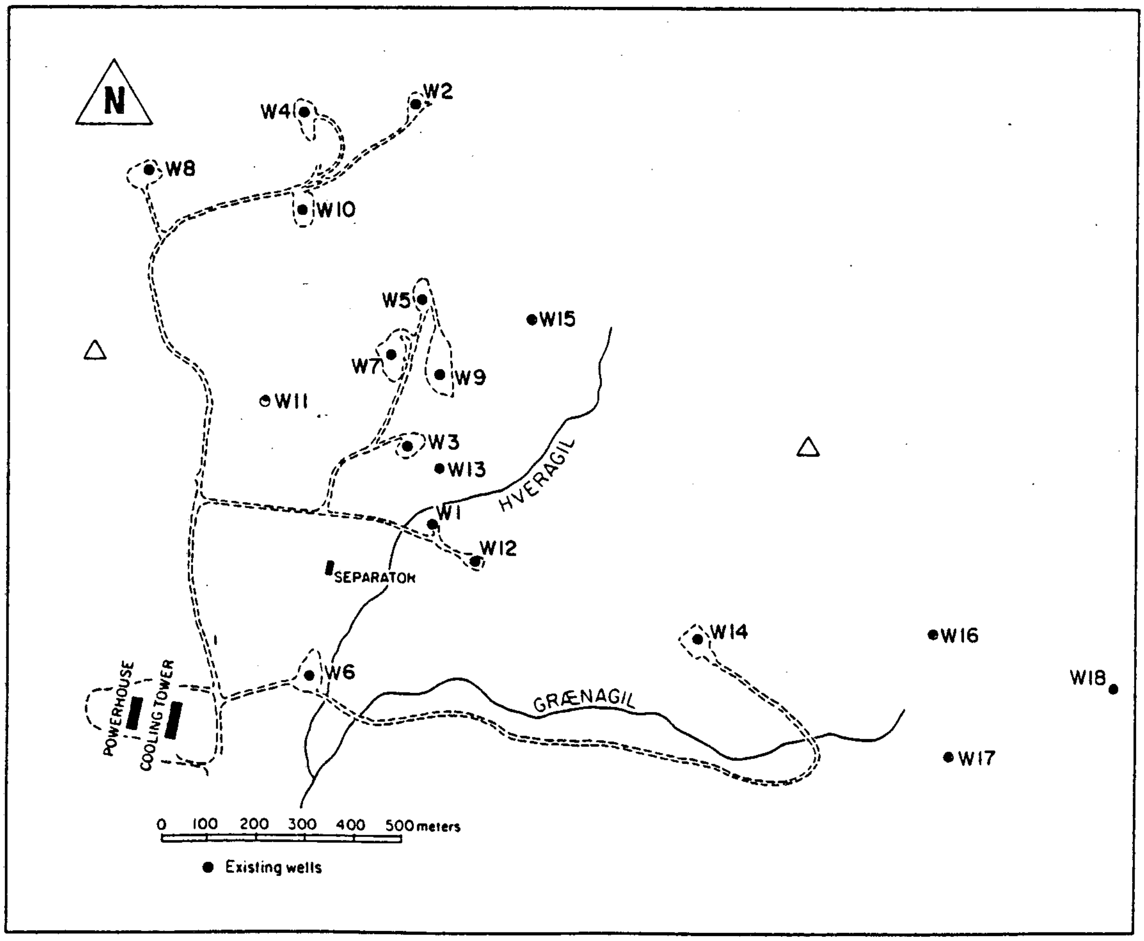

FIGURE 1. The Krafla wellfield, except for a few wells further to the south.

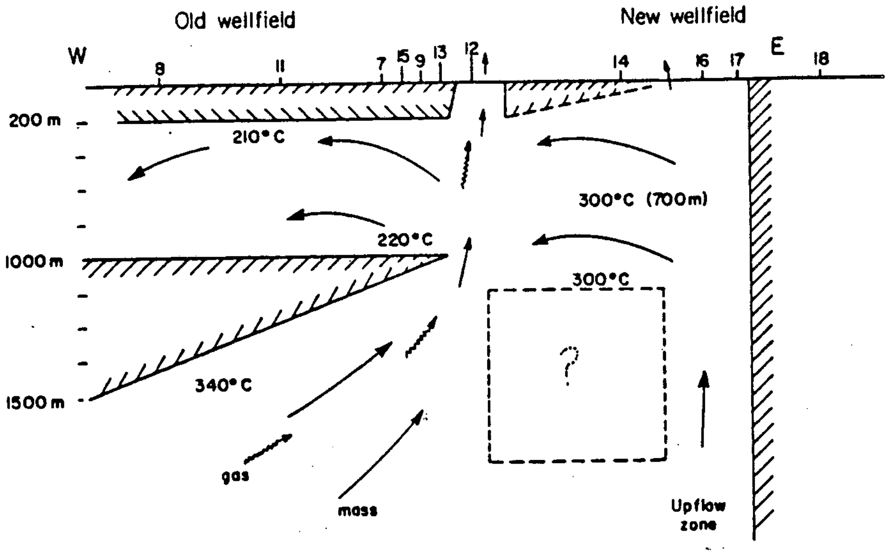

FIGURE 2. A conceptual model of the Krafla reservoir system (after Stefansson, 1981).

The Olkaria geothermal field is located in the Great Rift Valley, about 100 km northwest of Nairobi. The areal extent of the geothermal field has been estimated at about 50 km^2 on the basis of shallow temperature gradients and the occurrence of fumaroles (Noble and Ojiambo, 1975). Resistivity surveys have indicated a larger anomaly some 80 km^2 in areal extend (United Nations, 1976). Natural heat losses from the field amount to some 400 MW_t (Glover, 1972).

To date 25 wells have been drilled in the present production area in the eastern part of the Olkaria field (Fig. 3). Data from the wells have identified the presence of a thin steam layer (50-150 m thick) overlying a thick, liquid-dominated two-phase reservoir (Fig. 4). The rocks encountered are volcanic, with basaltic rocks dominating at depths of 500-700 m and acting as a caprock to the system. The reservoir rocks consist primarily of fine-grained lavas and tuffs (Browne, 1981; KPC, 1981, 1982a, 1983, 1984a). Fluid flow is concentrated along contraction joints in the lavas, scoria zones and lava contacts (KPC, 1984b). As shown in Figure 5, most of the wells have multiple feed points, often with internal flow between feed points in the steam zone and the underlying liquid-dominated zone (KPC, 1984b).

The reservoir fluids are of the sodium chloride type, with only about 200-700 ppm chloride. Noncondensible gas content is small (approximately 50 millimoles per kilogram of steam). The chloride concentration increases both with depth and from south to north. This, along with a pronounced pressure decrease (11 bar/km) from north to south, strongly suggests the presence of an upflow zone north of the present wellfield (Fig. 4). A detailed description of the conceptual model shown in Figure 4 is given elsewhere (KPC, 1982b; 1984b).

GENERAL APPROACH TO MODELING

In order to properly evaluate the potential of a geothermal field one must develop a model that is consistent with all of the data collected (Fig. 6). It must be consistent with observed thermodynamic conditions (pressure and temperature distributions both areally and vertically), available pressure transient data and the exploita-

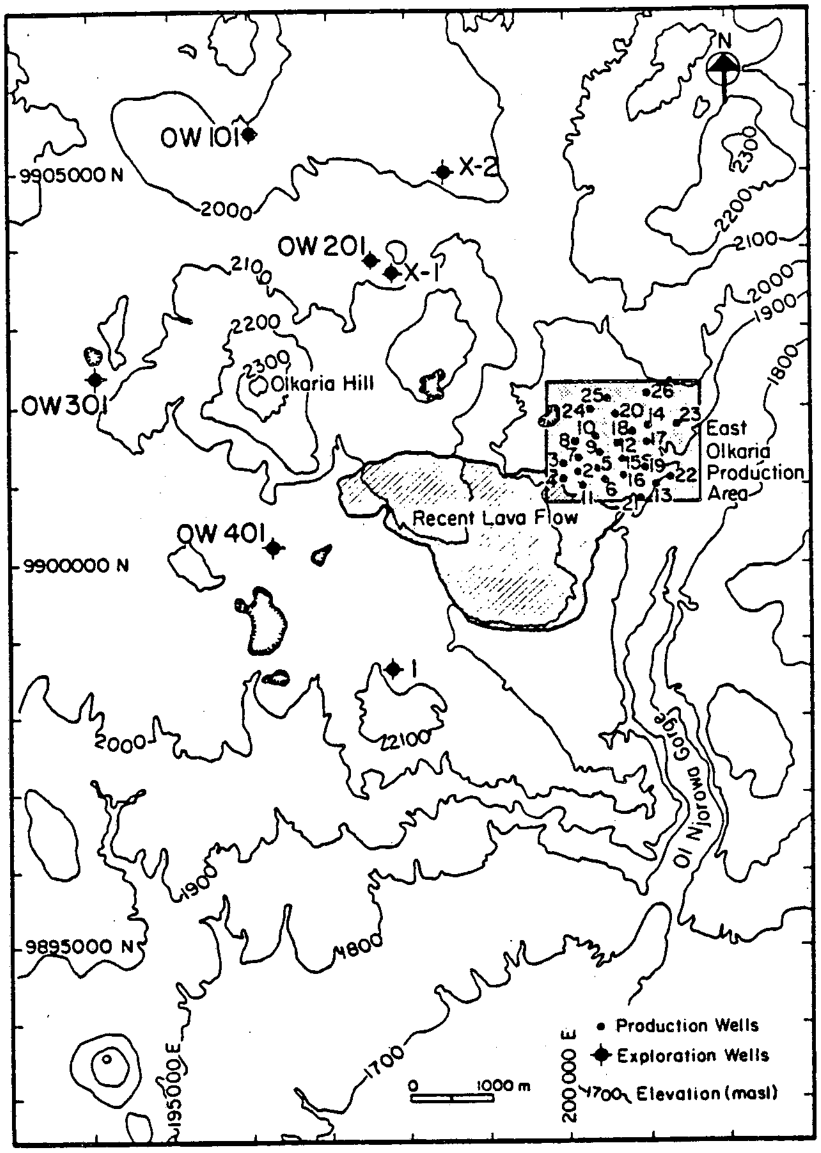

FIGURE 3. The Olkaria wellfield showing the present production area in the east and exploration wells.

tion history (flow rate decline of wells and the pressure decline in the reservoir). When a single model has been developed that is consistent with all of these data, it should provide the best predictive capabilities possible given the limitation of the database and inaccuracies in individual data sets.

A good conceptual model of the field is a most important starting point of a reservoir evaluation study. The modeling exercise will certainly test the validity of the conceptual model in various aspects, but it makes the modeling work much harder and more costly if a detailed conceptual model is not developed a priori. The most important data that guide the development of a conceptual model are the temperature and pressure distributions and data on the chemistry of well discharges. This combination of data should allow for the determination of the location of upflow zone(s), fluid flow patterns and the discharge areas of the field.

When a reasonable conceptual model has been developed it should first be tested against the natural thermodynamic conditions of the field. This involves developing

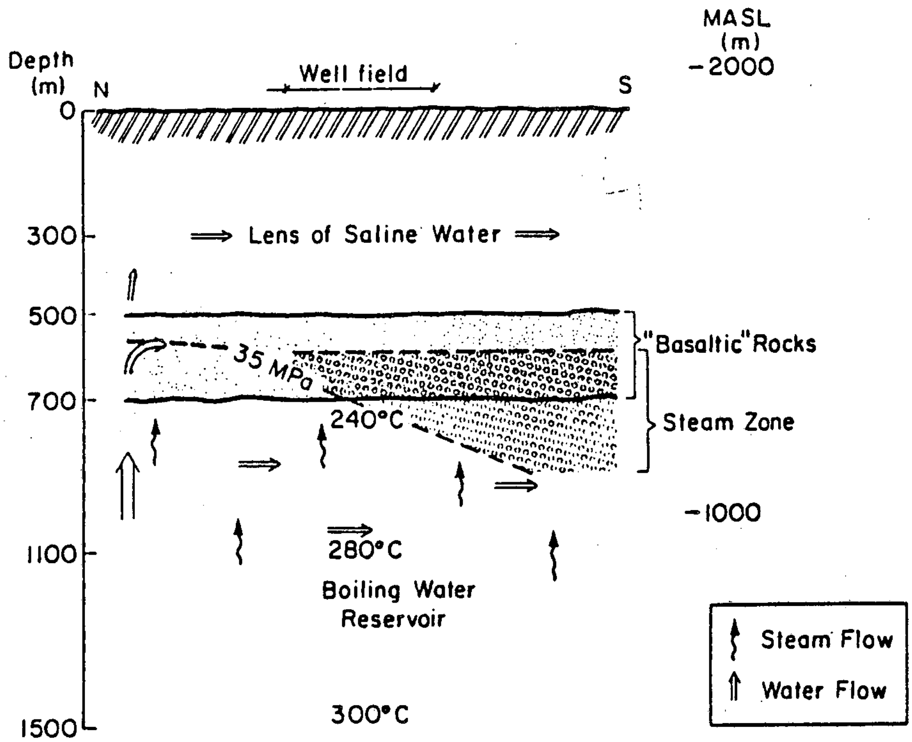

FIGURE 4. A conceptual model of the East Olkaria wellfield.

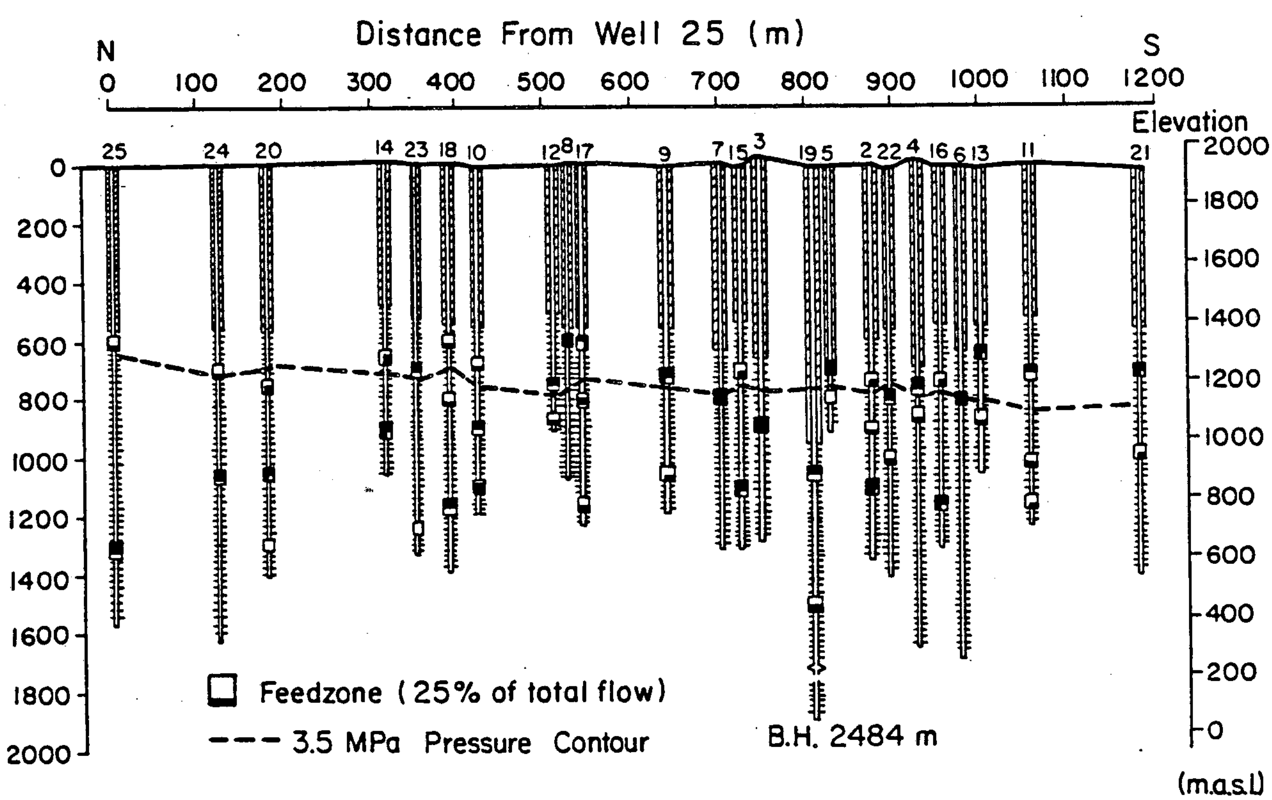

FIGURE 5. Major feed zones in Olkaria wells and their estimated contributions.

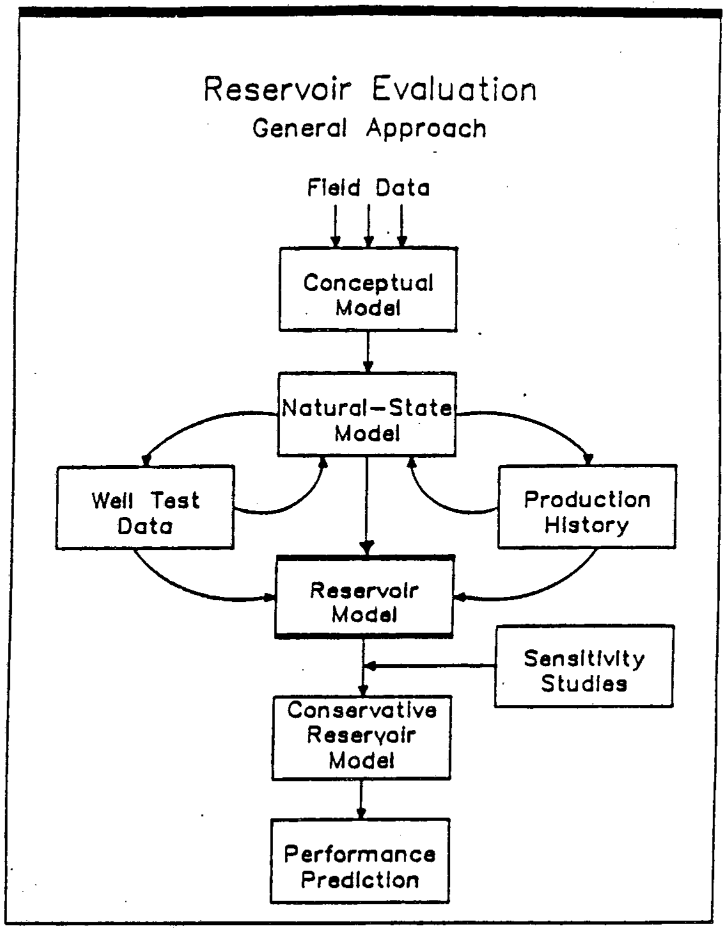

FIGURE 6. A general approach to geothermal reservoir evaluation.

a numerical model that is a simplified version of the conceptual model, but includes all the essential features of the field, such as major faults, primary geological units, upflow and discharge areas, and proper heat loss mechanisms. This "natural state" model is developed using trial and error procedures until it matches spatial distributions of temperatures and pressures. When fully developed, the natural state model will allow the determination of the rate of fluid recharge into the system, the flow of mass and heat within the system, and yield a coarse estimate of the permeability distribution.

Once a natural state model has been developed, it must be calibrated against pressure transient tests (especially long-term interference tests), the flow rate and pressure decline histories and enthalpy changes. This merging of multi-model data into a single model is generally very tedious and time-consuming as it requires many parameter adjustments to allow fits with the various data sets. For example, after changes in the model have been made to account for some features of an interference test, one must then go back and test the consistency of these changes with the natural state data as well as the production history, which generally requires additional iterations.

After a reservoir model has been developed that is consistent with all the data considered (natural state, pressure transients, production history), it is generally advisable to conduct some sensitivity studies, especially regarding the most impor-

enthalpy changes are primarily controlled by the porosity and temperature distributions. After the sensitivity studies are completed a conservative model should be chosen and used in the performance predictions.
tant parameters that effect the performance predictions. Usually, these parameters are the permeability and porosity distributions, the temperature distribution, and the assumed nature of the reservoir boundaries (closed reservoir, infinite-acting reservoir, constant-pressure boundaries). The pressure decline is primarily controlled by the permeability distribution and the outer boundary conditions, whereas the

NATURAL STATE MODELING - KRAFLA

In modeling the Krafla system in its natural state, all of the major physical processes that have taken place in the reservoirs must be considered. These include mass transport, conductive and convective heat transfer, and boiling condensation. The major objectives of the present work are to (1) verify a conceptual model of the field, (2) resolve the mechanism that controls the low temperatures in the upper reservoir, which is recharged by fluid of much higher temperatures, (3) quantify natural mass and heat flows in the reservoir, (4) verify transmissivity values obtained from the analysis of injection test data, and (5) obtain a better understanding of the dynamic nature of the reservoir, i.e., develop the basis for modeling studies of the system under exploitation.

In the study we assume that the Krafla system is in a dynamic equilibrium. The simplified reservoir model used in the simulations is shown in Figure 7. The model is a two-dimensional vertical section, extending from wells 5 and 7 in the west to the

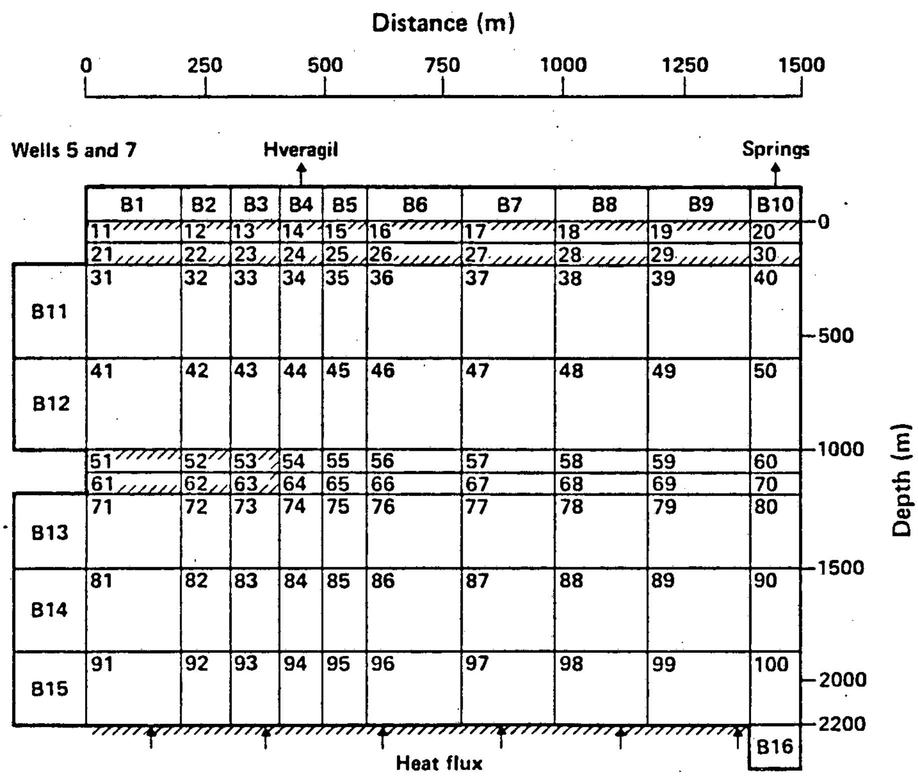

FIGURE 7. The numerical grid used in the two-dimensional natural state simulations of Krafla.

(impermeable) fault zone between wells 17 and 18 in the east (see Fig. 1). We do not model the reservoir system west of wells 5 and 7 because the inflow of cooler fluids from the north in the region would make the two-dimensional representation inadequate (Steingrimsson and Stefansson, 1977). In the reservoir model we assume that the confining layer separating the upper and lower reservoir in the old wellfield is of constant thickness (200 m) and that the caprock overlies the entire reservoir system. These geometric simplifications do not have significant impact on the results obtained.

The mesh used consists of 100 elements varying in size from 1 x 10^4 to 8 x 10^4 m^3. To adequately model conductive heat transfer, smaller elements are located close to the upflow zones in Hveragil and the "new" wellfield and in the confining layer and caprock. The rather coarse mesh is necessary because of the computation expenses; however, as the results will show, the mesh is adequate for the problem at hand.

In the development of the model we use a minimum amount of field data as input to avoid constraining the model any more than necessary. We have selected the best-known data (pressures in the upper reservoir close to wells 5 and 7) as model input, leaving less well-known parameters as computed output. This enables us to use most of the data from the field as a check on calculated results.

As shown in Figure 7, we use a number of boundary nodes to represent known thermodynamic conditions. Boundary nodes B1 through B10 are used to represent the pressure and temperature conditions at the ground surface, i.e., 1 bar and 5 °C in the old wellfield, and 1 bar and 100 °C in the new wellfield (steaming ground). In the new wellfield, data from wells 16 and 17 indicate boiling conditions all the way to ground surface, so a boundary condition of 100 °C is reasonable. In the west we postulate the existence of an impermeable fault and therefore use a no-flow boundary condition. Heat recharge from depth is modeled, but no mass flow is modeled except in upflow zones.

Surface manifestations in the reservoir region modeled are evident in Hveragil and in the new wellfield. The fluids discharged at these surface springs probably flow through faults or major fractures. In the present study we employ sinks of appropriate strength in the elements containing the faults. Thus, sinks are placed in elements 34 and 44 to represent mass and heat loss to surface springs at Hveragil; similarly sinks in elements 40 and 50 represent surface springs in the new wellfield. In order to match predicted thermodynamic conditions and flows with the field data, a lengthy process of trial and error is necessary.

No direct measurements are available regarding the mass flows of the surface springs in Hveragil and the new wellfield. However, best estimates indicate that the total mass outflow is 8 and 3 kg/s in Hveragil and the new wellfield, respectively (H. Armannsson and G. Gislason, personal communication, 1982). In our reservoir model we assume that the surface springs extend over a distance of about 1000 m, so that mass outflows of 0.008 and 0.003 kg/s m are estimated for Hveragil and the new wellfield, respectively.

Best Model

After a lengthly process of trial and error we have developed a model that reproduces well the observed data on the natural state of the Krafla field. In the model we use eight different zones that represent rocks with different material properties. The different zones are shown in Figure 8 and their material properties are given in Table 1. All of the zones are assumed to have the same values for rock density, heat

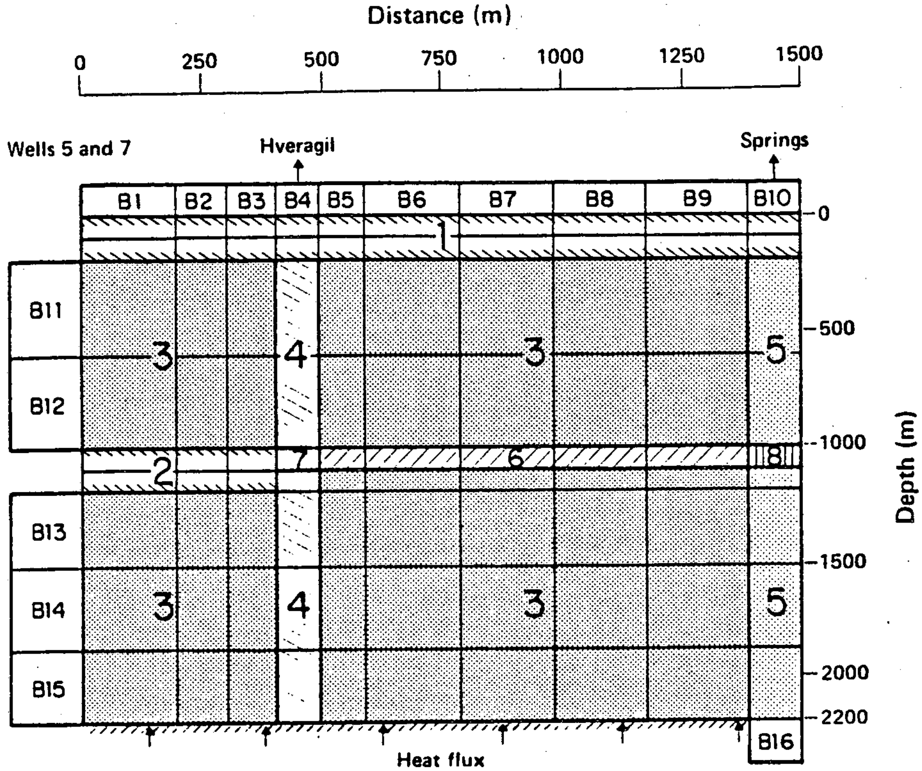

FIGURE 8. Major reservoir zones inferred from the modeling work on the natural state of Krafla.

capacity, and porosity. These parameters do not affect the results presented here, since steady state conditions do not depend upon storage-type parameters. Relative permeabilities are assumed to be linear functions of vapor saturation, with irreducible liquid and gas saturations of 0.30 and 0.05, respectively.

In Figure 8, zone 1 represents the caprock (hyaloclastite), which is assumed to have low permeability and thermal conductivity. The permeability values used for

Table 1. Material properties of reservoir zones.

Zone	Density kg/m^3	Heat Capacity J/kg$\,^\circ$C	Thermal Conductivity J/m s$\,^\circ$C	Porosity	Horizontal Permeability m^2	Vertical Permeability m^2
1	2650.	1000.	1.5	0.05	2×10^{-18}	2×10^{-18}
2	2650.	1000.	1.7	0.05	2×10^{-18}	2×10^{-18}
3	2650.	1000.	1.7	0.05	2×10^{-15}*	2×10^{-15}
4	2650.	1000.	1.7	0.05	2×10^{-15}	3×10^{-14}
5	2650.	1000.	1.7	0.05	2×10^{-15}	2×10^{-14}
6	2650.	1000.	1.7	0.05	1×10^{-14}	2×10^{-15}
7	2650.	1000.	1.7	0.05	1×10^{-14}	3×10^{-14}
8	2650.	1000.	1.7	0.05	1×10^{-14}	2×10^{-14}

*This value is fixed based upon the results from the injection test analysis (Bodvarsson et al., 1984).

this material are low enough so that fluid flow is negligible. Zone 2 represents the confining layer. Its material properties are identical to those of zone 1 except that the thermal conductivity is slightly higher.

The reservoir system is subdivided into six zones (Zones 3-8). Zone 3 represents the average rock/fracture material, which has a permeability equivalent to the average permeability determined from the injection tests (2.0 x 10^{-15} m^2). Zones 4-6 are regions of higher permeability (major fractures), which were needed to obtain a satisfactory match to field data. Zone 4 represents the major fracture that intersects the surface at Hveragil. Similarly, Zone 5 is necessary to model the upflow zone in the new wellfield. Zone 6 represents a major horizontal fracture zone in the new wellfield at a depth of about 1000 m. There is evidence for this fracture zone in all of the wells drilled to date in the new wellfield.

The calculated temperature distribution in the system is shown in Figure 9. The figure shows that temperatures of 300 °C are found at a depth of about 1000 m and over 340 °C at a depth of 2000 m. At shallower depths the temperatures in the new wellfield are considerably higher than those in the upper reservoir in the old wellfield. This is due to boiling in the Hveragil fracture and the discharge of high enthalpy fluid to surface manifestations (springs) at Hveragil. The model shows that 0.0084 kg/s m of high-enthalpy vapor escapes to the surface at Hveragil. This compares well with the 0.008 kg/s m estimated by H. Armannsson and G. Gislason (personal communication, 1982). Similarly, the model indicates that 0.0023 kg/s m of vapor feeds surface springs in the new wellfield, which also closely agrees with the

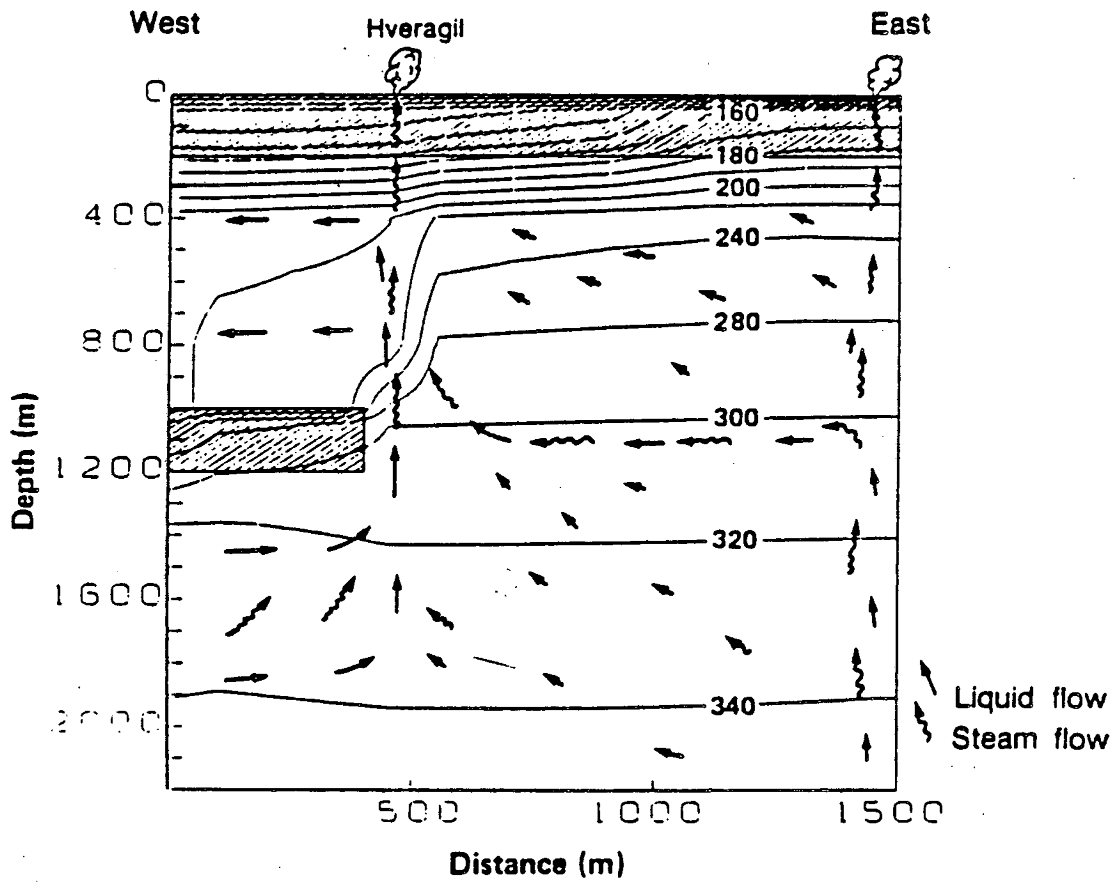

FIGURE 9. The natural state temperature distribution and the fluid flow patterns computed for the Krafla field.

estimated value of 0.003 kg/s m. Figure 9 shows that the temperature gradients are highest in the low-permeability caprock and the confining layer where conduction dominates the heat transfer.

The fluid flow patterns shown in Figure 9 reflect closely the high permeability fracture/fault zones in the Hveragil area and in the inferred upflow zone to the east, as well as the horizontal fracture zone at a depth of 1000 m.

EXPLOITATION MODELING - OLKARIA

The tasks of a reservoir engineer include estimation of the generating capacity of a field and of well decline rates and evaluation of alternative development plans. These tasks can best be accomplished by developing a model that makes comprehensive use of all available field data. Figure 10 shows schematically the different modeling approaches. The lumped-parameter model consists of a single reservoir block with an adjacent recharge block. It can only be expected to give a rough estimate of the generating capacity, although several investigators have attempted to use it to match enthalpy and chemical data. The lumped-parameter model is not capable of predicting long-term changes in enthalpies and chemical concentrations because of the time-independent conditions of the recharge block. However, the lumped-wellfield model may give better estimates of the generating capacity. In

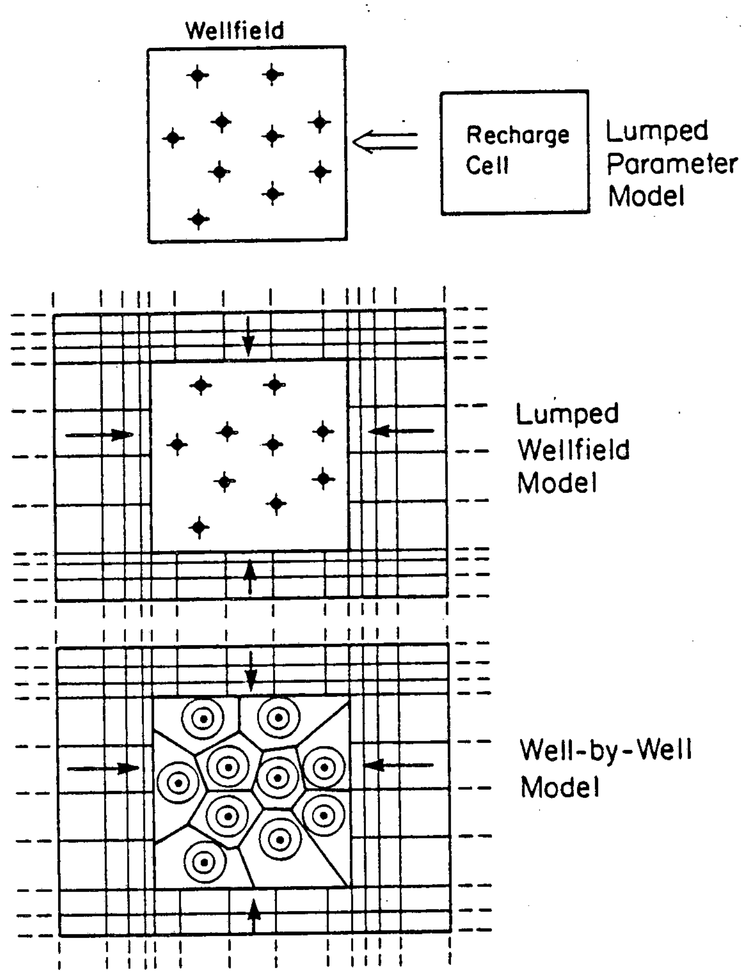

FIGURE 10. Schematic representation of the different modeling approaches.

addition, it has the capability of predicting the long-term characteristics (enthalpy and chemical composition) of the produced fluids.

The well-by-well model has the capability of addressing several other important questions, such as the proper well spacing and the effect of reinjection on individual wells, but for most complex geothermal systems it will have to be fully three-dimensional. The development of such models initially requires substantial man-power and computation expense, when the model is calibrated against all available well data. A detailed three-dimensional well-by-well model was developed of the Olkaria field (Bodvarsson et al., 1987a,b). In developing a well-by-well model one must first obtain a history match with all relevant data. For each individual well the model is calibrated against measured flow rates and enthalpies and, if possible, variations in chemical composition (dissolved solids or noncondensible gases) of the discharge. The model should also be calibrated against the observed reservoir pressure decline. Subsequently, performance predictions for individual wells and for the entire field can be made.

An areal view of the grid used in the Olkaria model is shown in Figure 11. Note that the nodal points of grid blocks 2 through 26 correspond to actual surface locations of Olkaria wells 2 through 26. When short-term (on the order of months) flow rate and enthalpy behavior of wells is to be matched, a grid such as the one shown in Figure 11 is too coarse. However, satisfactory match with the early time data can be obtained by embedding a radial mesh into the grid blocks containing the wells (Pruess et al., 1984; Bodvarsson et al., 1987a).

The vertical dimensions of the grid are primarily determined by the locations of well feed zones. The major feed zones encountered in Olkaria wells and their relative contributions are shown in Figure 5. Note that at Olkaria there is a steam zone at a depth of approximately 650-750 m as indicated by the 35 bar pressure contour

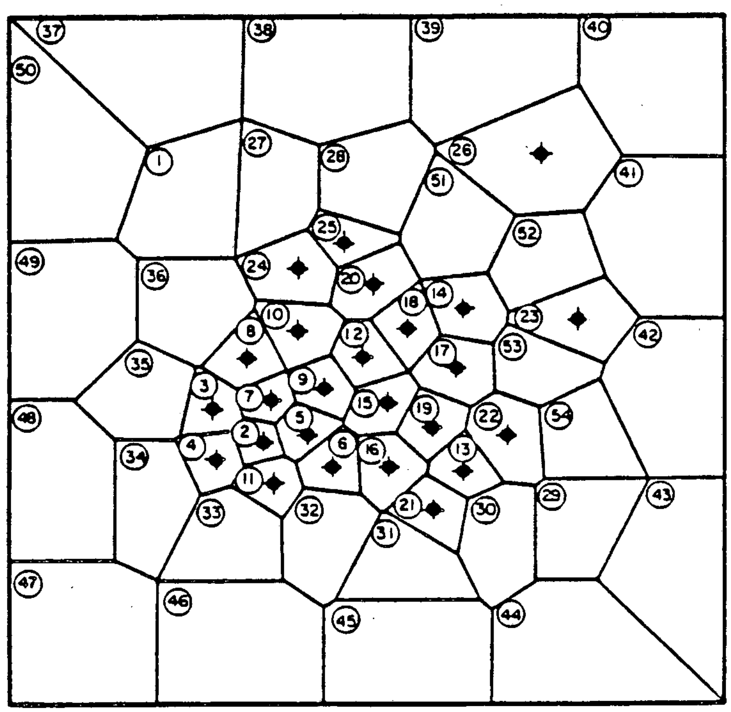

FIGURE 11. The numerical grid used for the well-by-well model of Olkaria.

(Fig 4.). Based upon the feed zone data shown in Figure 5, the feed zones were grouped into three layers, a steam zone layer (100 m thick) and two underlying liquid zone layers (250 and 500 m thick).

In most geothermal simulations it is necessary to maintain a certain rate of steam flow to the turbines. In well-by-well models the flow rate and enthalpies from individual wells are not prescribed, but calculated based upon a productivity index (PI), fluid mobilities and the reservoir pressure adjacent to the feed zone (deliverability model). At present, however, no satisfactory methods have been published for modeling geothermal wells with multiple feed zones in two-phase conditions.

The history-matching process involves numerous iterations and parameter adjustments until a reasonable agreement is obtained with the time-dependent production history. Ideally, a match with flow rates and enthalpies of all production wells, downhole pressures in observation wells, and concentrations of dissolved solids and noncondensible gases in the discharge of each well should yield a rather unique solution. In practice, however, history match models may retain a certain amount of ambiguity because available data tend to be incomplete, and because the scope of a modeling effort is limited by cost considerations (each additional component adds one equation per grid block).

In the Olkaria simulations three sets of adjustable parameters were used: productivity indices, permeabilities and porosities. There parameters were adjusted until the calculated data matched observed flowrates and enthalpies of all wells, and the reservoir pressure decline. The productivity index primarily affects the early time flow rate, the permeability the flow rate decline, and the porosity the enthalpy rise. The fact that the adjustable parameters influence the simulated behavior of individual wells quite differently suggests that a rather unambiguous determination is possible.

In general, one attempts to match enthalpy to within 100-200 kJ/kg (which is basically the data accuracy), and flow rate to within 1 kg/s. An example of the results of the history match for Olkaria well 11 is shown in Figure 12. This well was

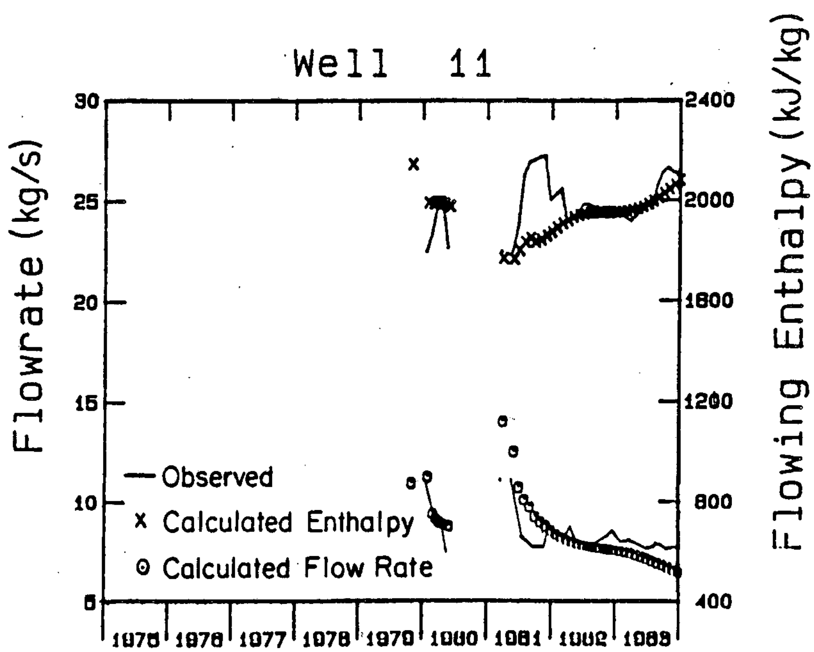

FIGURE 12. History match for Olkaria well 11.

flow-tested for a short period in 1980, and was connected to the first 15 MW_e unit in 1981. The history match for all wells will give estimates of the permeability and porosity distribution in the system. Figures 13 and 14 show the porosity and permeability distributions, respectively, for the lower liquid layer in the Olkaria model. It should be noted that the effective porosities determined by our porous medium model represent effective porosity, which is a combination of the fracture and matrix porosities. In this layer the porosity varies between 0.5 and 5%, with an average value of some 2%. The permeability varies from 0.25 to 17.5 md with an average value of about 3.5 md. The average transmissivity of the reservoir was determined from the modeling to be about 3.75 Dm, which is slightly higher than average values from interpretation of pressure transient well data. The history match yields the pressure, temperature, and vapor saturation conditions throughout the system at all times.

When the history matching is completed, the model can be applied to predict future field performance for various exploitation scenarios. A rule of thumb is that reliable predictions can only be made for as many years as the history match period. However, in most cases predictions for longer periods are desired in order to obtain estimates of long-term behavior. Whereas most models can only assess the overall field capacity, the well-by-well models can actually predict future performance of all existing wells, the number of additional wells needed and proper spacing of make-up wells.

The Olkaria simulations show that the present well density used, 20 well/km^2 (225 m spacing), is too high and that a well density of less than 11 well/km^2 (200 m spacing) should be used in future drilling. Figure 15 shows predictions for the number of make-up wells needed at Olkaria for 45 MW_e power production over the next 30 years for the two different well densities. It is probable that when the long-term flow

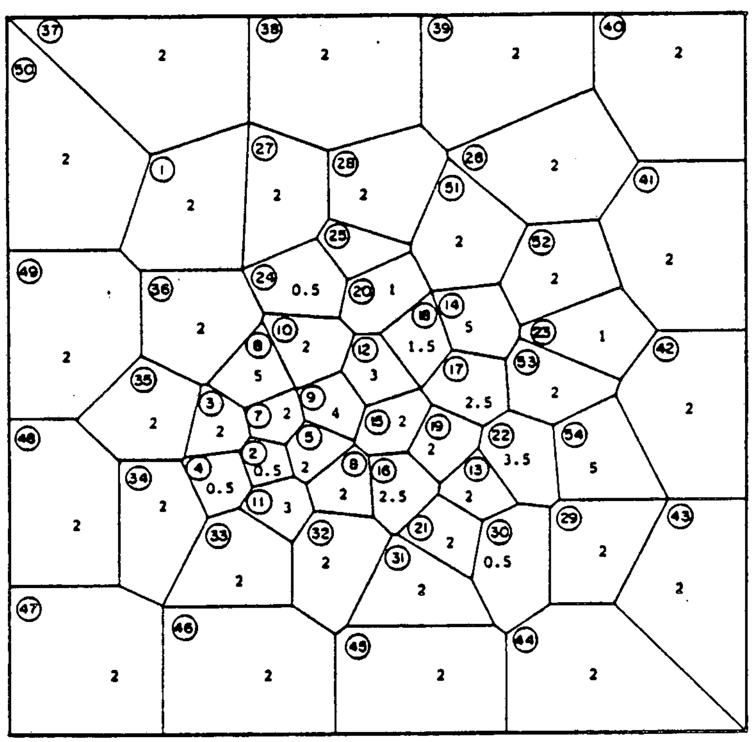

FIGURE 13. The porosity distribution in the lower liquid zone.

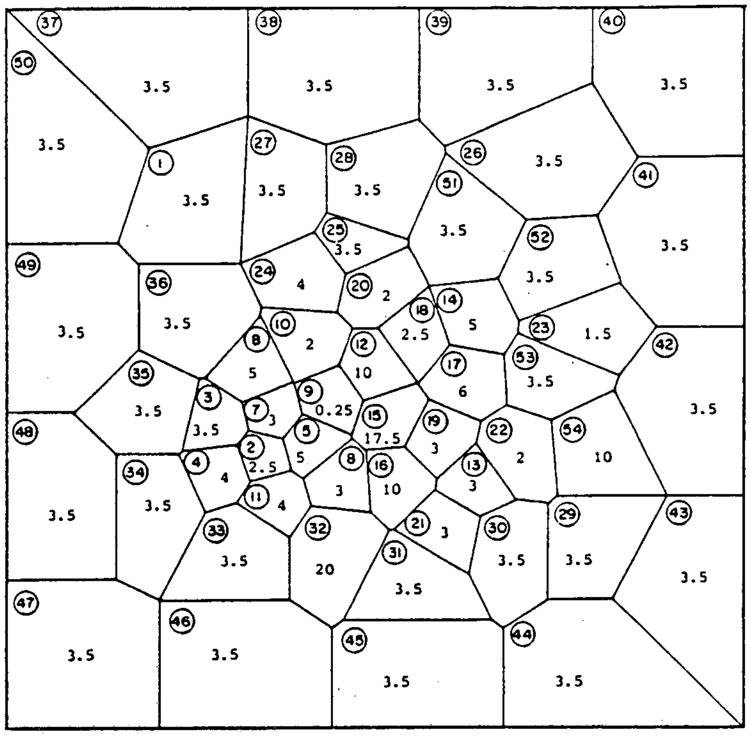

FIGURE 14. The permeability distribution in the lower liquid zone.

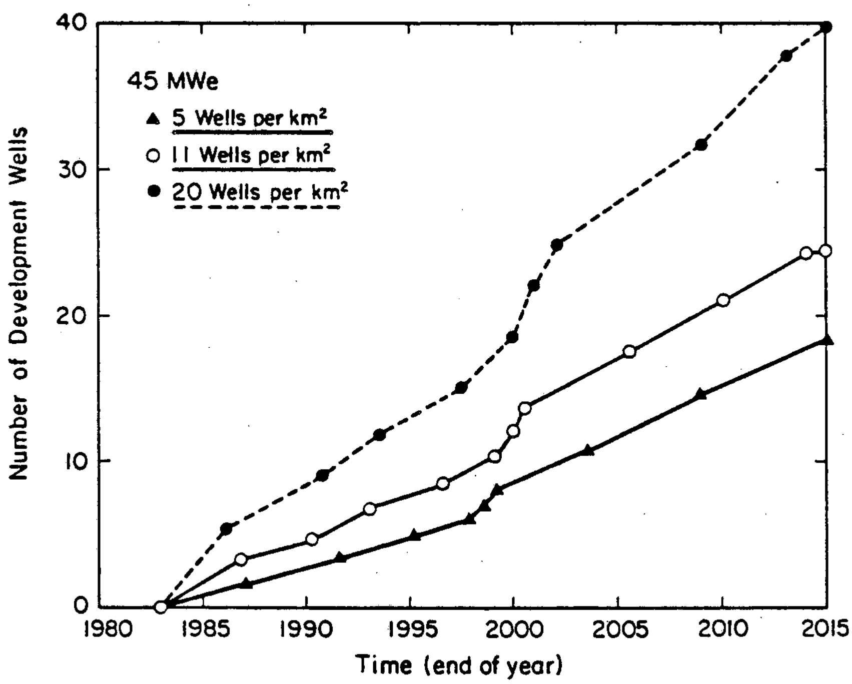

FIGURE 15. Number of development wells for different well densities (45 MW_e power production).

rate declines are considered, well densities are too high in most geothermal fields. However, other factors such as cost of fluid transmission lines must also be considered when well spacing is determined. The model also predicted that most wells will become dryer and eventually produce steam only as Figure 16 suggests for well 15. This will occur because of boiling in the formation and the development of an expanding steam zone. It is predicted that the entire wellfield will produce practically only steam after about a decade.

The Olkaria model was used to predict the effects of reinjection on individual well performance as well as the overall behavior of the reservoir. Figure 17 shows the effects of reinjecting 40% of the produced fluids into wells 3, 4 and 9 on the flow rate and enthalpy behavior of well 15. This figure shows drastic mobility effects with the flow rate increasing greatly and the enthalpy declining drastically. This effect is caused by the pressure support due to injection that causes condensation and consequently more liquid water production (Bodvarsson et al., 1983).

The results of the injection studies also showed beneficial effects on the number of development wells that had to be drilled to maintain 45 MW_e power production. As shown in Figure 18, if full reinjection (100%) is used, only 11 development wells need to be drilled in the 30-year period, compared to about 26 wells when no injection is used.

SUMMARY

Numerical modeling of a geothermal system provides the most reliable estimates for the power generation potential of the system because detailed field models can be developed that include much of the important field data collected. In additional, numerical models can give valuable information regarding what well spacing should be used, how the individual wells will behave in the future and how these wells will be affected by reinjection. However, the detailed response of individual wells can only be obtained by use of a well-by-well model which considers all wells in their proper locations.

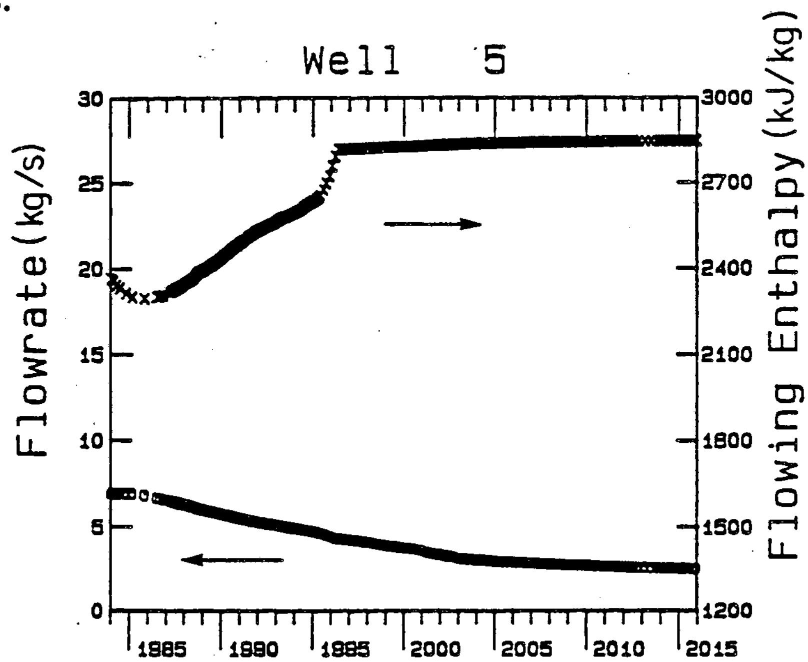

FIGURE 16. Predicted flow rate and enthalpy data for Olkaria well 5.

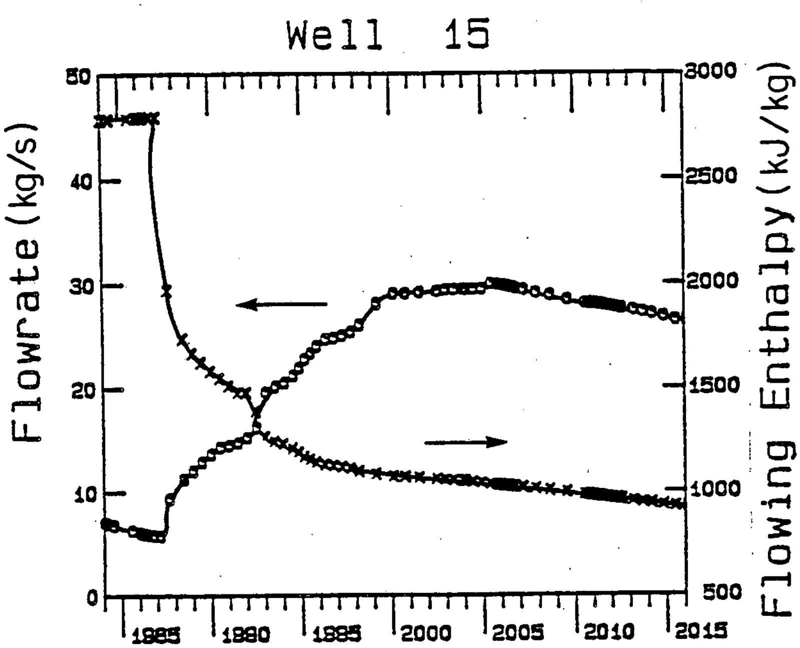

FIGURE 17. Predicted flow rate and enthalpy data for Olkaria well 15 for 100% reinjection.

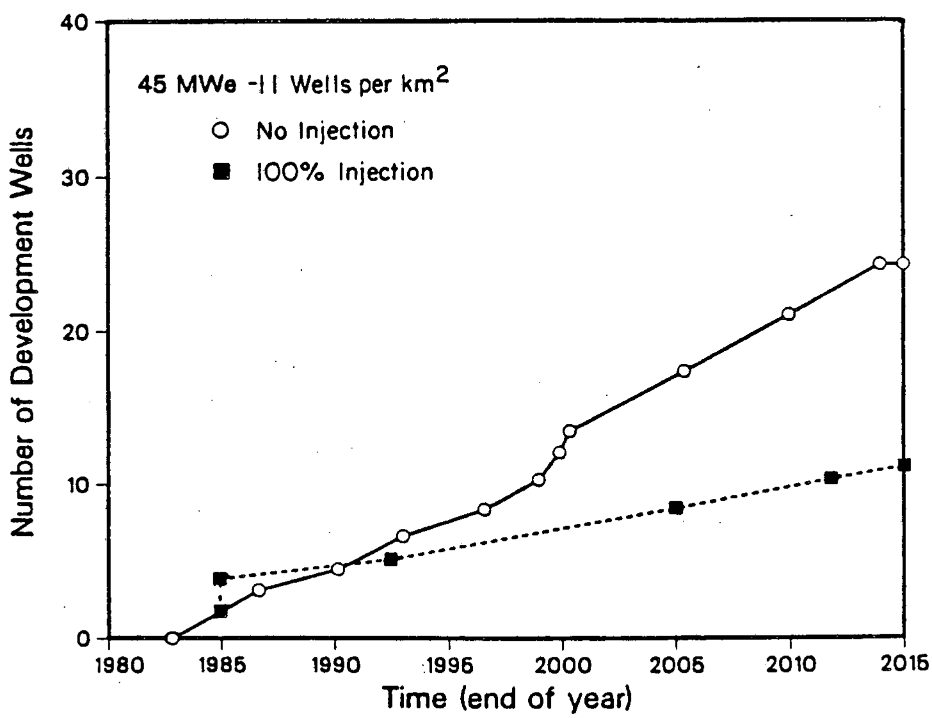

FIGURE 18. Number of development wells needed to maintain 45 MW_e power production without injection and with 100% injection.

A general approach to numerical modeling of geothermal systems involves a number of steps, including natural-state modeling, incorporation of well test data and the calibration of the model to production histories of all wells. The development of such a unified model is very time consuming because it requires numerous iterations between different submodels. However, when such a model has been developed it represents the best working model possible, and therefore, should yield the most reliable results. In the present paper various modeling steps were illustrated using modeling results on the Krafla geothermal field in Iceland and the Olkaria geothermal field in Kenya.

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