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RESERVOIR SIMULATION OF THE GEYSERS GEOTHERMAL FIELD

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ABSTRACT

A model of the Geysers reservoir consistent with existing geological data has been calibrated against 30 years of production and pressure history. Three principal assumptions in the model were that natural recharge and discharge could be ignored, that 98% of the initial fluid mass-in-place was in the liquid phase within the range of drilled depths, and that temperatures increased with depth according to a vapor-static saturation gradient from 0 to 8,000 feet below sea level, and then according to a boiling-point-depth gradient from 8,000 to 12,000 feet below sea level in a zone which was superheated. Reservoir properties and production history in non-UNOCAL leaseholds were not well-constrained because of a lack of publicly available data. Steam from UNOCAL-NEC-Thermal (U-N-T) leases is used to supply 1,103 MW of installed generating capacity built by PG&E, while the gross installed capacity of The Geysers is 2,043 MW.

The model was constructed with a uniform Cartesian grid consisting of 32 x 15 x 6 cells each 2,000 feet on a side. The long axis of the model was aligned northwest-southeast roughly parallel to the regional geologic strike. A double-porosity formulation was used and 90% of the initial fluid mass-in-place was contained as liquid within the rock matrix. Pressure losses associated with wells on U-N-T and DWR-Bottlerock leaseholds were calculated individually in the model but the production from wells of other operators was lumped together within grid blocks. The model was history-matched for the period 1957 to 1987 by comparing measured reservoir pressures extrapolated to mean sea level against simulated values extrapolated to the same datum from the layer with the highest fracture permeability.

The model was used to forecast steam production from U-N-T leaseholds, and the results compared favorably with observed production for the period 1987 to 1989. Over the next 10 years the model predicted that U-N-T steam production would decline to about 8 million lb/hr.

INTRODUCTION

The model described in this report was developed in 1987 using the TS&E General Purpose Geothermal Reservoir Simulator developed for UNOCAL by a consultant. The algorithm was designed to simulate the flow of heat, steam and water through a three-dimensional porous medium, taking into account reservoir geometry, heterogeneity and wellbore pressure effects, but ignoring the effects of salinity and non-condensible gases.

The level of steam production from the reservoir for all operators (FIGURE 1) has increased steadily since Unit 1 was installed in 1960, from 20 Glbs/yr in 1971 to 250 Glbs/yr in 1987 with the cumulative total being approximately 1,800 Glbs by 1987. The model was used to make a 20-year deliverability forecast for U-N-T's leases.

Challenges to forecasting the future performance of the Geysers include:

- The reservoir is large and heterogeneous, covering an area of approximately 35,000 acres. Its thickness has not been determined by drilling and may exceed 10,000 feet in places. A large body of drilling data of variable quality exists for The Geysers and much of the data from non-U-N-T leases was not publicly available. The spatial variation of the physical properties of the reservoir has not been characterized on a continuous basis as is possible in the oil and gas industry where electric logging is widely used.

- Temperature/Pressure/Spinner logs in wells have shown that steam enters the wellbores through narrow discrete fracture zones hundreds or thousands of feet apart, but 90% of the fluid reserves are considered to be contained within the pores and microfractures of the "barren" rock between the major fractures. The permeability and liquid saturation of the zones between major fractures are difficult to determine so that the initial fluid mass-in-place in the model is poorly constrained.

- Adsorption and capillarity may inhibit the recovery of fluid from the reservoir but their effects are difficult to quantify. No attempt was made to model these effects in this study.

- The vapor-dominated reservoir evolved from a liquid-dominated one, and a liquid-dominated zone may still exist below drilled depths. The dynamic state of the reservoir under pre-exploitation conditions is not well-understood.

- Twenty-two percent of the mass produced has been returned to the reservoir as liquid at ambient temperature, but the thermodynamic effects of injection are not well-known because most of the liquid moves under gravity towards the bottom of the reservoir below drilled depths. This region is inaccessible to direct measurement and its temperature, effective fracture spacing and porosity may differ significantly from values in the shallower reservoir.

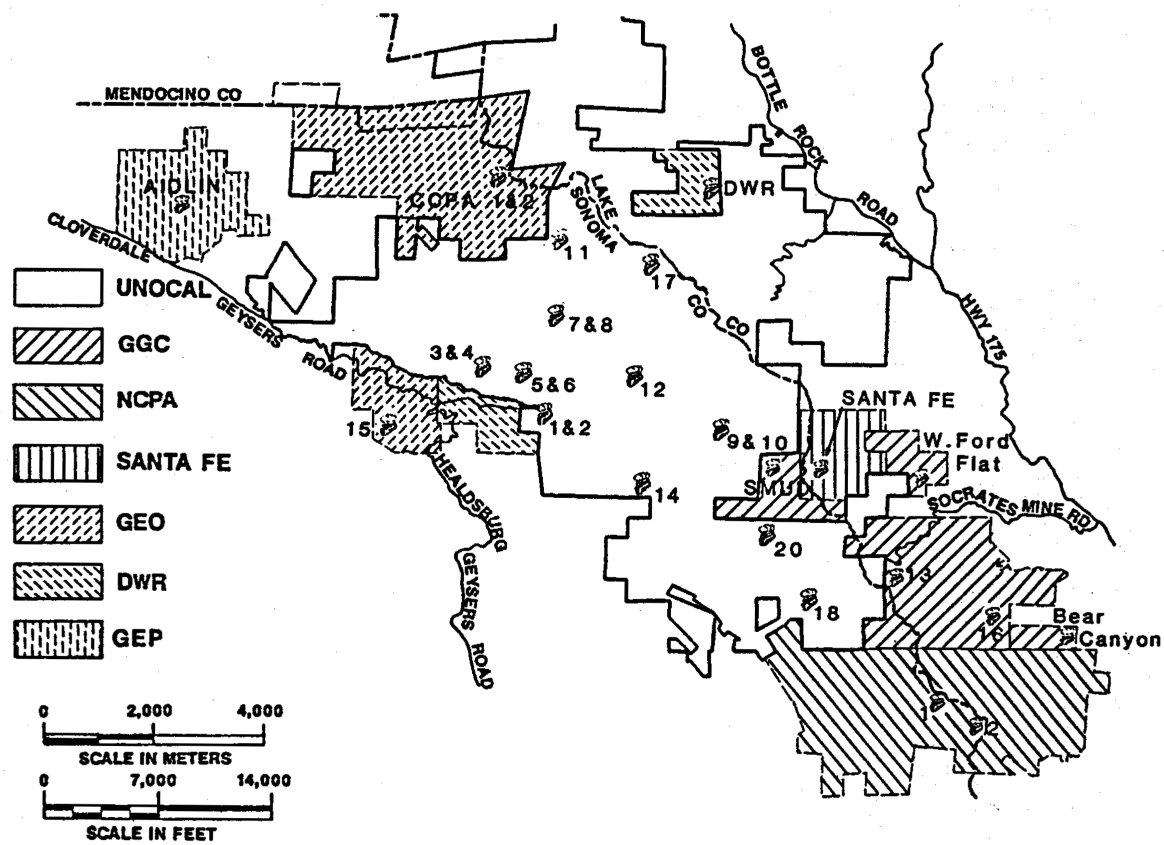

Figure 1. The Geysers Geothermal Field. Developers and Power plants.

- An effect of exploitation is to lower pressures in the fracture system from > 500 psia to < 200 psia, and this has the potential to draw cool water into the reservoir from surrounding aquifers which could be a source of pressure support or accelerated pressure decline. The extent of this process is presently unknown, but geochemical data suggest it may be occurring in the southern part of the field.

CONCEPTUAL MODEL

A conceptual model of The Geysers was developed to be consistent with existing geological data. As described below, features such as reservoir thickness, liquid saturation, deep reservoir temperature and influx-efflux conditions at boundaries are not well-constrained but have some supporting geological data. Features such as zones of high and low connectivity, liquid saturation of the fracture domain and reservoir bottom were added or modified during the history-matching phase of model development.

Thermodynamics

Pressure and temperature logs, and wellhead pressure observations of wells throughout U-N-T leases prior to exploitation indicated initial reservoir pressures of 514 psia ± 8 psia at mean sea level. Vertical pressure gradients were roughly

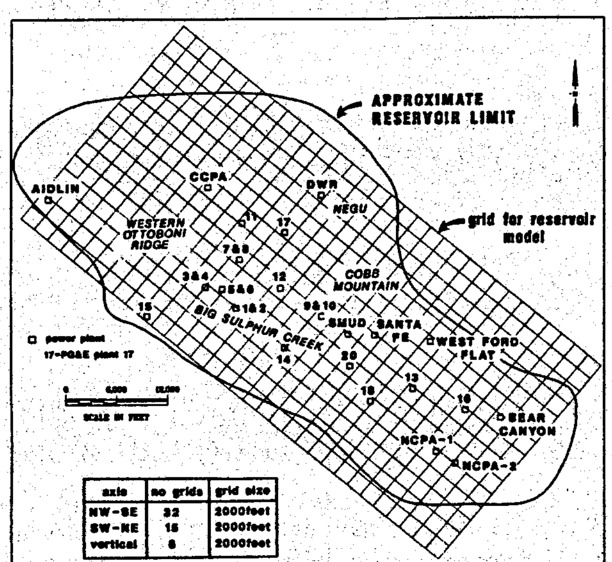

Figure 2: Reservoir limits and model dimensions.

consistent with vapor-static conditions. Temperature logs were less accurate, but showed that temperatures did not deviate significantly from saturation conditions except below around 6000 to 7000 feet below sea level in the northwest parts of The Geysers. The existence of approximately saturated conditions throughout the reservoir indicated that liquid and vapor coexisted within drilled depths, with the possible exception of the deep "high temperature" areas in the northwest.

The presence of liquid water within the reservoir could also be inferred from simple mass balance considerations. By 1987, 1,800 Glbs of steam had been produced fieldwide and 400 Glbs of water injected. Steam production of 1,400 Glbs (net) corresponds to 0.03 x 10^{12} ft^3 liquid or 1.3 x 10^{12} ft^3 vapor at 514 psia. This compares with an estimated reservoir pore volume used in the model of 0.4 x 10^{12} ft^3. This pore volume is obviously insufficient to store even the fluid produced so far in the vapor phase. This pore volume could contain a maximum mass of 20,000 Glbs (all liquid) and a minimum of 400 Glbs (all vapor). A value of 11,100 Glbs for initial fluid mass-in-place was determined by trial and error during the early stages of the history matching process. Sixteen percent of the initial fluid mass-in-place had been produced as steam by 1987.

The initial liquid saturations assigned to the fracture domain are shown in FIGURE 3. The low liquid saturation of 1% in the Northwest Geysers was used in an attempt to match the rapid initial pressure declines in the area. This area corresponds roughly with the isotopically anomalous region described by Gunderson (1989) where produced steam is strongly enriched in oxygen-18 and moderately enriched in deuterium, and where comparison of rock and steam oxygen isotopes suggest a low water-to-rock ratio. The highest liquid saturation in the fracture domain, 25%, was assigned to the area flanking Cobb mountain where early pressure declines were slow. The general trend of decreasing initial liquid saturation from southeast to northwest is consistent with the model for the evolution of the Geysers presented by Truesdell et al (1987), where recharge in the southeast flushed through the reservoir to the northwest, and resulted in higher in-situ liquid saturation in the southeastern part of the reservoir.

In the northwestern part of the reservoir, wells encountered temperatures significantly above vapor-static saturation, typically at depths around 6,000 to 8,000 feet below sea level. Significant steam production has been observed from this high temperature zone and therefore the thermal regime is probably not conductive, but so far no liquid brine is known to have been encountered in the wells. In the model the reservoir below 8,000 feet below sea level is assigned boiling-point-depth temperatures but pressures were set to increase according to a vapor-static gradient. This thermal regime might be expected at the base of the vapor-dominated part of a low-porosity reservoir still in the process of boiling down.

The vertical component of thermal conductivity below 8000 feet below sea level was set to zero to inhibit heat transfer from the lower layers under pre-exploitation conditions.

Geometry

The limits of the Geysers reservoir in the model are based on current geological estimates by UNOCAL geologists and the lateral limits are shown in FIGURE 2 superimposed on the grid used in the model. The model was constructed with a uniform Cartesian grid covering an area of 12.1 miles by 5.7 miles with 32 by 15 square cells each 2000 feet on a side and 6 layers each 2000 feet thick. The long axis of the model was aligned northwest-southeast roughly parallel to the regional geologic strike. The grid covers an area of 44,000 acres and includes the productive acreage of U-N-T and all other operators (FIGURES 1 & 2).

The depth to the top of reservoir shown in FIGURE 4 was based on a map prepared jointly by U-N-T, GGC, NCPA, GEO, Santa Fe and DWR, and varies in elevation by as much as 6,000 feet throughout the field. In the model, areas outside the reservoir were assigned a fracture permeability two or three orders of magnitude below typical reservoir values. The complex shape of the top of the reservoir is reflected in the permeability structure.

The shape of the reservoir bottom can only be inferred from indirect observations, and is poorly defined. The consistent occurrence of steam entries to the depths reached by drilling in a particular region probably means that significant permeability extends below drilled depths in that region. Another source of information is the hypocentral distribution of microearthquakes associated with injection. This has been tentatively used to trace the path followed by liquid water in the reservoir. The base of an earthquake cluster below an injector is probably related to the depth of liquid penetration into the reservoir, and for this study this has been taken as an estimate of depth of the reservoir bottom at that location. In Units 7-8 the bottom appears to extend to 13,000 feet below sea level, but 6,000-9,000 feet below sea level is more typical for the rest of the field. Along the southwest boundary of the field microearthquake depths of 13,000-17,000 feet below sea level were observed along the Big Sulfur Creek Fault Zone but this was not interpreted as an indication of reservoir thickness but rather due to the presence of a major vertical fault zone.

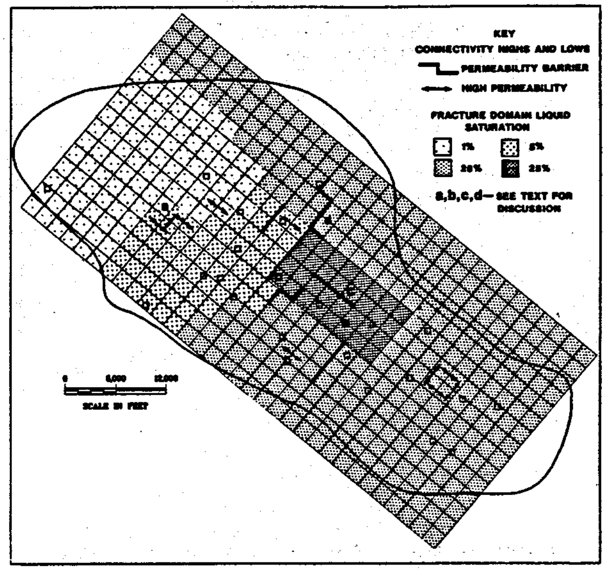

Figure 3: Liquid saturation and zones of high or low connectivity in the fracture domain.

The existence of deep reservoir in Units 7-8, southeastern Unit 14 and southeastern Unit 18 in the model had the effect of allowing injected liquids to penetrate to regions of higher temperature (up to 600 °F). Fine tuning of the shape of the reservoir bottom was carried out during history-matching by comparing those areas of the model where liquid had accumulated in the fracture domain of layers 5 and 6 (8,000-12,000 feet below sea level) towards the end of the history match period with areas where deuterium levels in the produced steam were high (FIGURE 6), indicating a contribution from injected condensate in the steam. It can be inferred from the deuterium data that injected condensate moves laterally in the liquid phase below drilled depths, presumably driven by gravity towards deeper parts of the reservoir.

Petrophysics

Knowledge of the physical properties of the Geysers reservoir was based on the results of measurements on core taken from 9 wells, on observations made while drilling, and on the interpretation of pressure transient tests.

The cores were taken within the reservoir but not within the discrete fracture zones which produce steam to the wells and therefore should be more representative of matrix domain, as defined in the double-porosity formulation, than fracture domain. The porosity data showed a decrease with depth below surface, but appeared to be even more strongly influenced by the silicic batholith commonly referred to as "the felsite" (Thompson, 1989) which underlies much of the field (FIGURE 5). A distinct decrease in porosity was observed as the felsite was approached. This decrease is thought to be due to chemical effects associated with the emplacement of the felsic intrusion. Matrix porosity values for the model were determined by estimating the elevation of each block above felsite, and then using a simple algorithm which took into account distance above felsite and depth below surface to determine porosity for all blocks considered to be inside the reservoir. The algorithm attributed a reduction of 0.2% in porosity per 1000 feet due to the proximity of felsite and 0.1% in porosity per 1000 feet due to depth of burial. Within the reservoir, matrix porosity varied between 1.2 and 4.6%, and outside the reservoir was set at 0.4%. In the Sulfur Bank and Thermal areas where the reservoir top was above sea level, matrix porosity was increased in layer 1. Fracture porosity was set at 2% for layer 1 (0-2,000 feet below level) and declined at 0.1% per 1,000 feet depth, to 1% for layer 6 (10,000-12,000 feet below sea level). There was no field data from The Geysers on fracture porosity.

Appropriate values for matrix permeability were more difficult to determine. Measurements made on selected one-inch cores of unfractured rock had values within a relatively narrow range (0.1 - 0.5 microdarcys). However microfractures dominated the permeability of four inch cores, and therefore would dominate the matrix permeability parameter applicable to the model where fracture spacing was set at 100-1,000 feet. Therefore matrix permeability was considered to be poorly constrained and was adjusted during history matching within the range 1-100 microdarcys to achieve model calibration against the measured isobaric maps.

Pruess (1985) suggested a method of estimating the vertical permeability to liquid in a vapor-dominated reservoir where the reservoir acts as a heat pipe. For a surface heat flow of 500 $mW.m^{-2}$, the method leads to a value of 5 microdarcys.

The assignment of fracture domain permeability in the model was based on observations made during drilling and to a limited extent, on the interpretation of pressure transient data. Steam entries were recorded during drilling as pressure increases in the air compressor line to the drill string. The relative size of a pressure increase can be used as an approximate measure of the productivity of a steam entry. UNOCAL's experience with Temperature-Pressure-Spinner surveys has verified that this is a reasonable approximation. For the model, it was

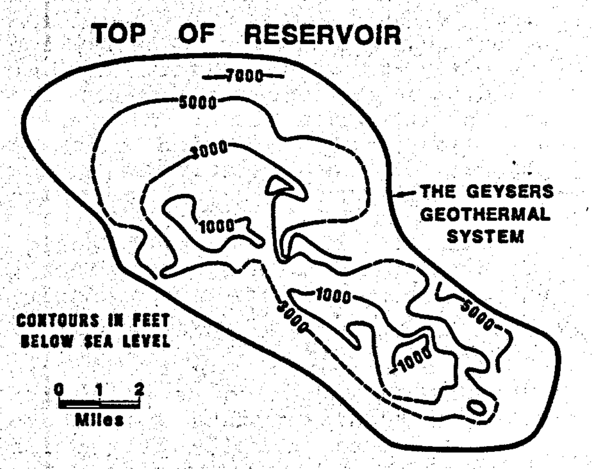

Figure 4: Top of steam reservoir.

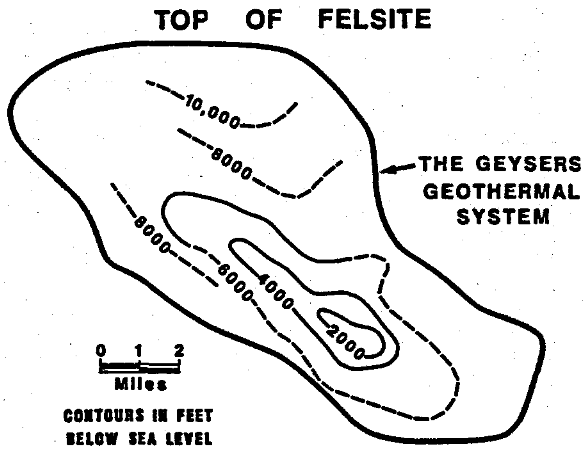

Figure 5: Top of felsite.

assumed that this productivity distribution based on steam entries, after correction for wellbore effects and reservoir pressure, could be used as a qualitative guide to fracture domain permeability.

A back-pressure equation constant was calculated for each well, assuming an exponent of 0.75, and using orifice test flow rates and pressures, and appropriate reservoir pressures. This value for the well was then distributed between each steam entry encountered by the well, weighted according to steam entry magnitude. The location of each steam entry relative to the blocks of the model was known, and the values for all steam entries within each grid block were summed. The probability of encountering steam in a grid block is also related to the footage drilled through that block, so a correction was made to account for this by dividing by the number of drilled feet passing through a block. The result was then used to assign fracture permeability in a relative sense for the blocks in the model for which drilling data was available. A smoothing algorithm was used to assign starting values to all other blocks, which were then modified as necessary during the history match.

Some constraints on fracture permeability can also be made from pressure transient data which have been collected annually from wells throughout U-N-T's leaseholds. The permeability-thickness (kh) product calculated from the data used in the preparation of the 1985 isobaric map were typically in the range 50,000 to 1,000,000 millidarcy-feet. Assuming a reservoir thickness of 10,000 feet, the kh data imply that the permeability of the fracture system typically lies in the range 5-100 millidarcys. This compares with a range of about 3-140 millidarcys used in the model for horizontal fracture permeability and 4-200 millidarcys for vertical fracture permeability.

The frequency of occurrence of steam entries was used as a qualitative guide to the fracture spacing and therefore to the matrix-fracture shape

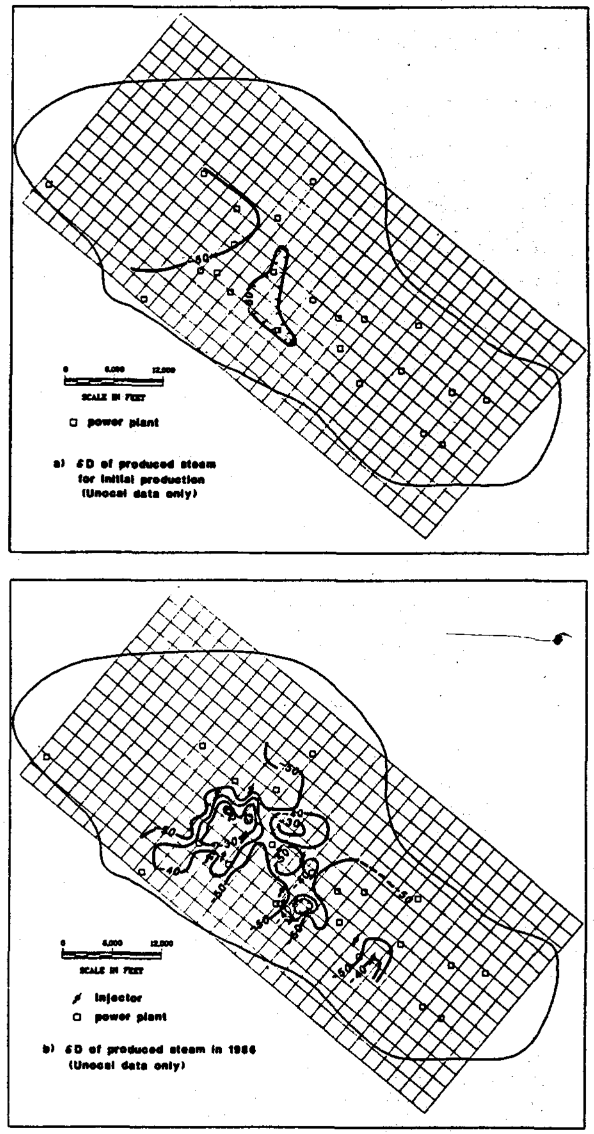

Figure 6 Deuterium levels in produced steam.
a) Initial production.
b) Production in 1986.
Contours are in per mil relative to SMOW.

factor (σ) by dividing the cumulative footage drilled in a block by the number of steam entries encountered in the block. This result was used to assign the σ-values to blocks in the model in a relative sense. Typical values used in the model corresponded to fracture spacings of 160 to 600 feet, consistent with estimates made by UNOCAL geologists.

The absolute magnitudes of fracture permeability and shape factor were then modified during the history-match. Enthalpy was not monitored consistently throughout the history match period and therefore the model could not be calibrated for the distinct thermal effects of k_m and σ on steam production from the matrix.

Structure

During the history-matching process it was necessary to introduce permeability barriers and zones of enhanced permeability (FIGURE 3) in the model to match the observed pressure response, and in all cases but one there was supporting geological evidence. For example, on the western Ottoboni Ridge (high connectivity zone "a" in FIGURE 3) there was strong evidence for low angle fractures connecting steam entries between wells. In Unit 14, (zone "b") a mapped surface expression of the Big Sulfur Creek Fault Zone coincided with a well-defined linear zone of very large steam entries in a group of wells. An example of a permeability barrier is "c" in FIGURE 3, where the northeastern edge of the reservoir is down-dropped by a major fault which offsets the lithology in this area.

The case of a barrier with no clear geologic basis occurs in the zone between Unit 17 and NEGU where a 200 psi pressure change was observed over a horizontal distance of 2,000 feet in the 1987 isobaric map ("d" in FIGURE 3).

HISTORY MATCH

Reservoir pressures have been determined periodically at The Geysers using pressure buildup techniques. Comparison of this data with simulated fracture domain pressures over the past 20 years was the chosen method of model calibration. Isobaric maps adjusted to mean sea level for the years 1966, 1969, 1972, 1975, 1977, 1981, 1984, 1985, 1986, and 1987 were compared against simulated fracture domain pressures taken from the layer with the highest permeability for each cell, and extrapolated to mean sea level.

The following procedure was adopted for the model calibration process:

- Set starting values for all model parameters, utilizing drilling data and geological models to establish relative values for fracture permeability, fracture spacing and matrix porosity. Set liquid saturation in the matrix at a high value (95%) and fracture liquid saturation at a low value (5%). Set matrix permeability at a uniform value.

- By trial and error, adjust liquid saturation and change fracture and matrix permeability by constant factors until pressures at the end of the history match are within the range of measured values. The relative permeability curves used in the simulation for both matrix and fracture domains allowed up to 30% immobile liquid.

- Change matrix permeability to improve the match.

- Change fracture permeability, shape factor (fracture spacing), as far as possible only in blocks for which drilling data are absent, to improve the match.

- Add zones of high or low connectivity consistent with the geological model, and locally increase or decrease liquid saturation in the fracture domain to improve the match.

Although this describes the general sequence followed, it was necessary to iterate over the last three steps to achieve a satisfactory pressure match. A liquid saturation for the matrix domain of 82% was determined from the second step.

FIGURE 7 shows simulated and measured isobaric maps for 1987. In FIGURE 8, the Pressure versus Cumulative Production curves are shown for both historical and simulated data for the period 1966 - 1987. The most significant deviation (1984) is due largely to the inadequacy of the historical data in the higher pressure marginal areas of the field, where there was a lack of UNOCAL pressure observations. The most significant discrepancies in the pressure matches on U-N-T leaseholds are listed below. Pressures are discussed as "simulated" relative to "observed".

1985: Unit 7-8 (south) > 20 psi high and Units 1-6 (east) > 30 psi high.

1984: Up to 50 psi low on peripheral areas in north, west and south but pressure data was lacking in these areas when the 1984 isobaric map was made and the high pressure gradients between the 400 and 500 psi contours are now considered to be unrealistic extrapolations of the existing data at that time. Units 1-6 (east) was 30 psi high.

1981: Units 1-6 (east) and Units 7-8 (west) 50 psi high and Unit 12 and Units 9-10 (northwest) 30-50 psi low.

1977: Units 1-6 (south) 30-50 psi high, Unit 12 20-30 psi low and Unit 17 10-20 psi low.

1975: Unit 7-8 (east) 50 psi low, Unit 9-10 20-40 psi low.

1972: Units 7-8 (west & east) 20 psi low. Units 1-6 (centre) 40 psi high

1969: Units 1-6 (centre) > 20 psi high.

During the period of the history match 433 Glbs of liquid water were injected into the reservoir model and by 1987 liquid water covered more than 1,100 acres on the bottom of the reservoir in the Units 1-8 area, and parts of Units 14 and 18. The mass of liquid water accumulated in these lower layers of the model is greater than 80 Glbs or 18% of the cumulative total injected. Temperatures in the fracture domain dropped by up to 140 F° in layer 6 and 220 F° in layer 5, and pressures below injectors in the northwestern part of the field exceeded pre-exploitation values by as much as 600 psi, due to the accumulation of liquid in the fracture domain in layers 5 and 6.

Temperatures in the rock matrix were lowered by up to 10 F° in layer 6 and up to 14 F° in layer 5 beneath injectors. Since the effective fracture spacing in these blocks was 700-800 feet the rate of heat transfer from matrix to fracture domain was slow and differences in temperature between matrix and fracture domains of up to 200°F were developed.

Patterns in the isotopic composition of produced steam throughout the field have been interpreted as evidence for the movement of injected condensate. It was concluded that injectate moves in the liquid phase for 3,000 to 4,000 feet horizontally in the deep reservoir below drilled depths, and that local barriers to movement could be inferred. During the history match of the model, permeabilities in layers 5 and 6 were adjusted to match the zones where produced steam was enriched in deuterium (FIGURE 6), with the areas of liquid water accumulation in the fracture domain of layers 5 and 6.

Three features of the model important in converting injected liquid to steam are not well-constrained:

The first is the effective fracture spacing. The matrix-to-fracture mass flow in the double-porosity formulation includes a term containing the product of matrix permeability (k_m) and matrix-to-fracture shape factor(σ). The shape factor σ is related to fracture spacing which is the parameter dominating the rate of heat transfer from rock matrix to injected liquid. Injected liquid was thought to move along the fractures, being heated principally by thermal conduction from the rock to the fracture face. A simple analytical solution to this phenomenon was used to demonstrate that a fracture spacing range of the order of 10's to 100's of feet has a major effect on the ability of injected liquid to mine heat from the rock within a 30-year period. The fractures which act as pathways for injected liquid may not be the same ones which produce steam into the wells, and therefore the steam entry distribution may not be an appropriate guide to fracture-spacing required to model the injection process. In addition, injectate flows downwards under gravity below drilled depths, and the fracture distribution at these depths has not been determined.

The second parameter which is poorly-constrained is the bulk volume of the fracture domain, which determines how much heat is stored in the vicinity of fractures and is therefore readily transferred to fluids within the fracture domain. A value of 30% was used for the reservoir graywacke implying conceptually that the fracture network penetrates about a third of the bulk volume. A value of 20% was assigned to felsite, which is considered to be less well-penetrated by fractures.

The third feature of the model affecting its response to injection was the superheated zone from 8,000 feet to 12,000 feet below sea level in

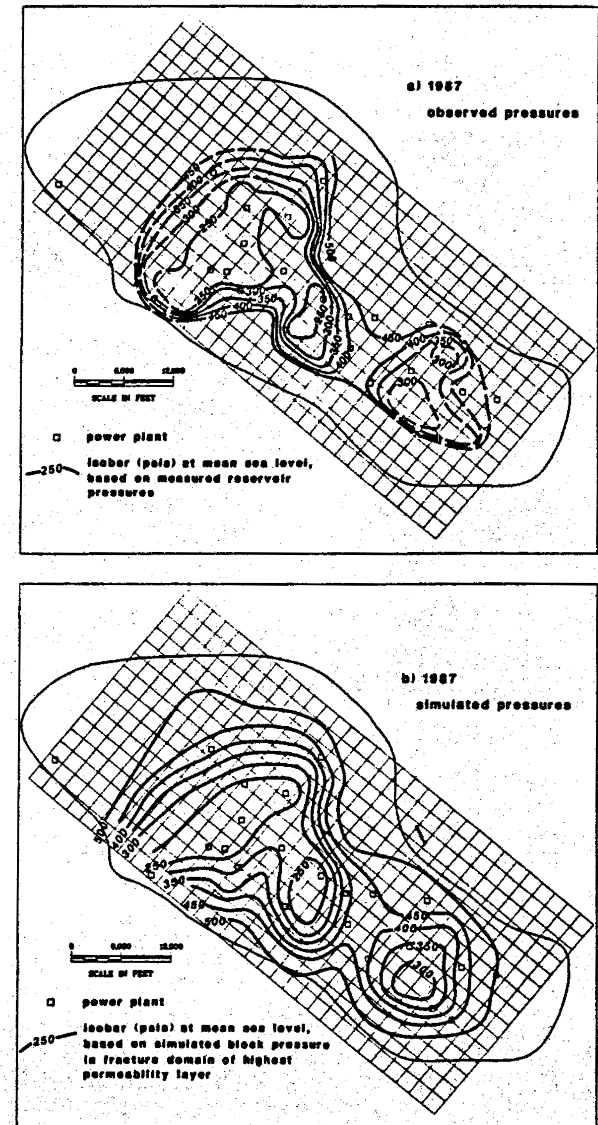

Figure 7: Observed and simulated reservoir pressures
a) observed
b) simulated
Contours are in psia at mean sea level.

the model. The effect was significant in zones where the vertical permeability of the fracture domain was high enough to allow injected liquid to flow downwards under gravity, and steam to flow upwards after flashing. The existence of such zones in the model had the effect of raising reservoir pressure 10 to 30 psi by 1987 where injection took place near regions of high vertical permeability, as in Units 7-8. The temperatures and permeabilities at depths below 8,000 feet subsea in this area and in the Southeast Geysers were speculative.

FORECAST

In the forecasting mode, the deliverability of each well on U-N-T leaseholds was constrained by requiring the well to produce at a fixed wellhead pressure. The deliverability of each well was calibrated against flowrates and wellhead pressures measured in August 1987 and wellhead pressures were then fixed at these values throughout the forecasting period. The effects of lowering wellhead pressure are not considered in this paper, but have been described elsewhere (Barker et al.,1989). Production from non-U-N-T leaseholds was estimated, and bottomhole-pressure-constrained "superwells" were created for each block producing steam outside U-N-T leaseholds. The decline rates of these "superwells" were adjusted to be similar to estimated values in 1987, and thereafter declined in response to declining reservoir pressure.
The rate of water injection into the model was automatically adjusted after each time step of the forecast to be 24% of produced steam.

A 20-year forecast for one scenario at The Geysers is summarized in FIGURE 9. This scenario involved no future drilling, and U-N-T decline rates were initially high at 12%/yr and reduced to 6%/yr in 6 years, with production rates dropping from 1987 levels by 50% in 10 years. By 2008, most of the producing areas in the older Units of the West Geysers were predicted to be around 150 psia whereas the South Geysers was typically 180-190 psia at

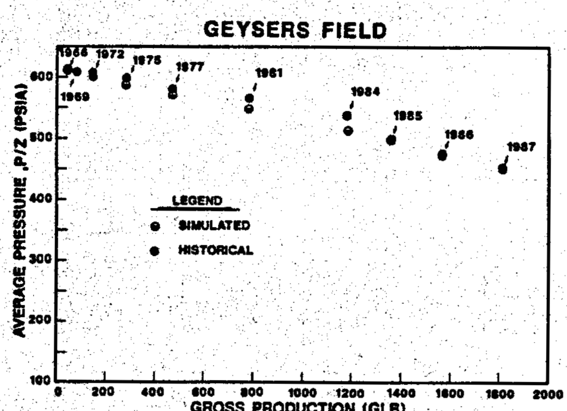

Figure 8: Average pressure versus cumulative production.

sea level.

The validity of the model as a predictive tool, at least for short term projections, is demonstrated in FIGURE 10, where the steam deliverability from U-N-T leaseholds is compared with a model forecast starting in September, 1987. For this forecast, newly drilled wells were added at the appropriate times and wellhead pressures on all U-N-T wells were adjusted monthly to reflect actual operating conditions.

The thermal energy present in the Geysers reservoir model was 43 x 10^{15} BTU's, assuming reference temperatures for each layer corresponding to saturation temperatures in a vapor-static pressure regime where the pressure at mean sea level is 150 psia. This corresponds to more than 25 times the amount of heat required to flash the roughly 2,000 Glbs of steam produced by 1988 from the Geysers reservoir. The forecast projected that only 14% of the initial thermal energy would have been depleted by 2010.

The initial fluid mass-in-place in the Geysers reservoir was more difficult to estimate principally due to a lack of knowledge of liquid water saturation in the rock pores and fractures. The model had approximately 11,100 Glbs initial fluid mass-in-place contained within a pore volume of 0.4 x 10^{12} cu ft, 64% of which was within the matrix domain. The model predicted 12% net fluid mass depletion by 1987 and 31% net fluid mass depletion by 2010.

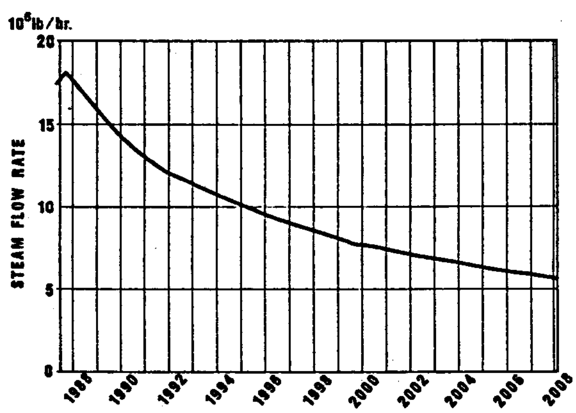

Figure 9: 20 year forecast.

CONCLUSIONS

It has been demonstrated that a model consistent with our current understanding of the geology of The Geysers can simulate the pressure and production history of the field over the past 30 years. The deliverability predictions of the model for the period 9/87 to 9/89 have been validated after comparison with observed production for U-N-T leaseholds.

The model predicted that, if no wells had been drilled since 1988, by the year 2000 U-N-T deliverability would drop below 8 million lbs/hr and by the year 2010 to around 6 million lbs/hr. By that time 43% of the initial fluid mass-in-place would have been produced, and 14% of the initial "usable" heat extracted.

The initial fluid mass-in-place is an important parameter for long-term predictions, but was difficult to constrain with existing data.

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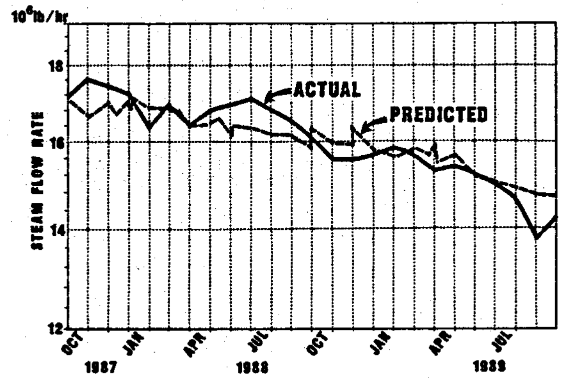

Figure 10. Predicted and observed production from U-N-T leases 1987-1989