A FIELD-WIDE NUMERICAL SIMULATION MODEL OF THE GEYSERS GEOTHERMAL FIELD, CALIFORNIA, USA

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Keywords: The Geysers, Case Histories, Simulation, TETRAD, Forecast.

ABSTRACT

The Geysers geothermal field is the largest developed geothermal system in the world. The total installed capacity is presently 2,056 MW although actual production in early 1994 was estimated to be only 1,200 MW(net). The inability to produce at higher generation levels is due to the significant pressure decline that has occurred within the reservoir, particularly since the mid-1980's.

In 1992, a comprehensive field-wide numerical simulation model of The Geysers field was completed, based on drilling, well-test and production data provided by four of the five major field operators. The numerical simulation model was originally developed by UNOCAL, based primarily on data from the UNOCAL-NEC-Thermal (U-N-T) lease areas, and was extended in this study to incorporate data from the other operators.

The expanded model was successfully calibrated by matching the responses of individual observation wells and changes in field-wide isobaric maps to 30 years of production history. Forecast runs were conducted using the calibrated model to calculate the reservoir response for two possible production scenarios: maintaining wellhead pressures constant at their 1991 levels and reducing wellhead pressure by up to 40 psi (0.28 MPa) over the next five years.

With the reduction in wellhead pressure, an additional 1 million lbs/hr (453 tons/hour) of steam can be produced over the next ten years; equivalent to 55 MW(net) additional power production. However, overall field production will continue to decline from the present level of approximately 20 million lbs/hr (9,100 tons/hour) to 8.5 million lbs/hr (3,850 tons/hour) by the year 2014; equivalent to a reduction in overall power production from the present level of 1,200 MW(net) to 475 MW(net).

INTRODUCTION

A field-wide reservoir modeling study of The Geysers geothermal field, located in Lake, Sonoma and Mendocino Counties, California, USA was undertaken during 1991-92 under the guidance of the Technical Advisory Committee (TAC) Industry Consortium (GeothermEx, 1992). The TAC was initially created by the California Energy Commission (CEC) during 1989 to investigate the decline in generating capacity at The Geysers and the methods available to mitigate the decline; the field-wide modeling study was undertaken as a part of these investigations.

The TAC includes representatives from both government agencies and industry while the Industry Consortium is a sub-committee of the TAC which includes representatives from steam field operators and utilities involved with The Geysers.

BACKGROUND

The Geysers geothermal field is located approximately 75 miles (120 km) north of San Francisco, California and is the largest identified and exploited geothermal reservoir in the world (figure 1). The known productive field area, as defined by the distribution of successful wells, is approximately 30 square miles (78 square km).

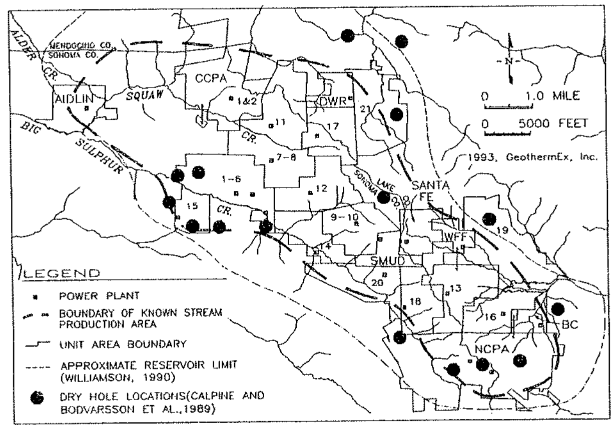

Figure 1: The Geysers geothermal field

First attempts to produce electricity from the resource came in the 1920's when steam from a few shallow wells was used to generate electricity for The Geysers Resort Hotel. In 1955, Magma Power Company obtained leases on the north side of Big Sulphur Creek and initiated a drilling program with Thermal Power Company; by 1958 sufficient wells had been drilled to supply steam to a small generating unit (Barker, Gulati, Bryan and Riedel, 1991). Pacific Gas and Electric (PG&E) then signed a contract with Magma-Thermal to provide steam to Unit No. 1, a 12 MW power plant installed in 1960.

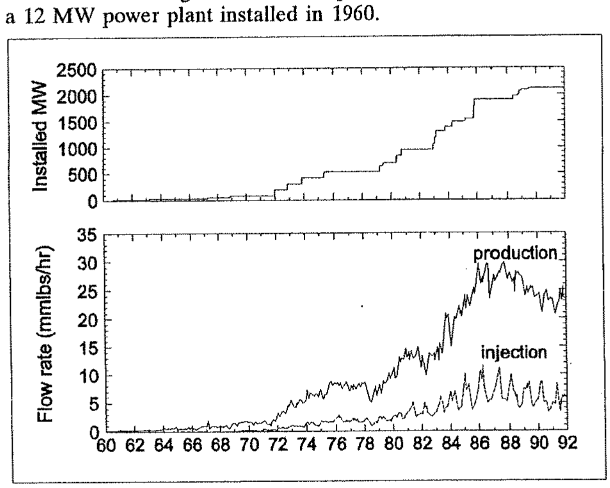

Figure 2: Development history at The Geysers

During the 1960's, the growth in generating capacity was slow (figure 2), with only 82 MW (PG&E Units 1 to 4) coming on-line by 1970. The growth rate accelerated during the 1970's when 610

MW was brought on-line and in the 1980's when an additional 1,364 MW of generating capacity was installed. The pace of development declined significantly after 1986 and the last generating unit, the Aidlin 23 MW plant was brought on-line in June 1989 to bring the total installed capacity to 2,056 MW. During the development phase, a total of 29 generating units were brought on-line, with individual capacities of between 23 and 137 MW.

No new power plants are scheduled for construction due to a combination of increasing development cost and resource risk, decreasing availability of favorable steam or power sales agreements, and problems with the performance of the developed steamfield.

The field production flow rate (figure 2) peaked at approximately 30 million lbs/hr (13,600 tons/hour) during 1986/1987 and has dropped steadily since that time to approximately 20 million lbs/hr (9,070 tons/hour). The decline in overall production flow rate was caused by a significant increase in reservoir pressure decline associated with the accelerated development of the field in the early 1980's. Well Lakoma Fame State-6 (figure 3), located in the Unit 9-10 area (figure 1), is typical of many production wells in the field; prior to 1985, the production decline rate was relatively low but increased significantly after 1985 due to the increase in overall field production.

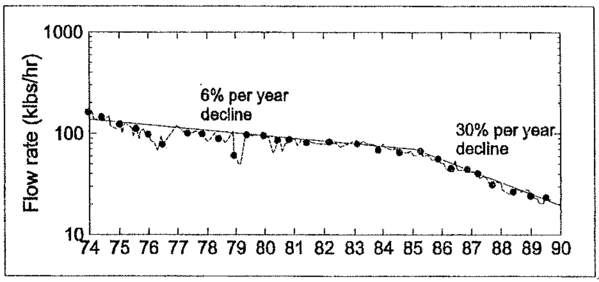

Figure 3: Well LF St.-6 monthly flow rate history

The drop in production flow rate has resulted in significant under-utilization of the installed facilities; for example, in early 1994 it was estimated that the field-wide production was approximately 1,200 MW compared to the installed capacity of 2,056 MW. With this reduction in electrical generation, the ability of The Geysers to continue to provide significant electrical generation into the future has been questioned.

MODEL DESCRIPTION

The simulation model of The Geysers on which the present model is based was developed by UNOCAL and a detailed description of the model is presented in Williamson (1990). The basic model was provided to the TAC Industry Consortium and modified to include data from other operators in the field, specifically the Northern California Power Agency (NCPA), Calpine Corporation and Central California Power Agency (CCPA), through Russian River Energy Company. The modified model was then used to match historical data and to forecast field-wide reservoir behavior under different production scenarios.

The model is presently running on the TETRAD reservoir simulator and uses a "double porosity" formulation to account for the presence of fractures and low permeability matrix blocks in the reservoir. The wells are assumed to be completed within the fracture network while the matrix blocks provide the bulk of the reservoir storage capacity. The model does not include recharge but relies on storage in the matrix blocks to maintain production.

Model Geometry

The basic layout of the model in terms of overall area and grid block layout was not changed from the original UNOCAL model. The overall area covered is 69 square miles (180 square kms), which includes all the presently developed areas of the field (figure 4). The model is split vertically into six 2,000 foot (610 m) layers, with the top of the upper layer corresponding to mean sea level (msl). Each layer contains 32 by 15 square cells each 2000 feet (610 m) on a side, giving a total of 5,760 grid blocks; 2,880 matrix blocks and 2,880 fracture blocks. The long axis of the model is aligned northwest-southeast; roughly parallel to the regional geologic strike.

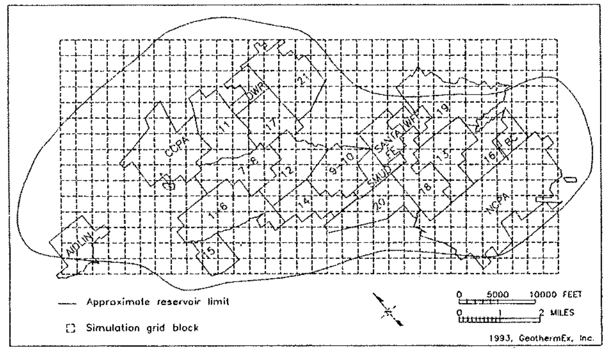

Figure 4: Simulation model grid block layout

The depth to the top of the reservoir was defined by a map prepared jointly by the field operators and it varies in elevation by as much as 6,000 feet (1,830 m) throughout the field. The shape of the reservoir bottom can only be inferred from indirect observations and is therefore poorly defined. Information that has been used by the operators to help define the bottom of the reservoir includes:

- depth of steam entries;
- hypocentral distribution of microearthquakes that are associated with injection;
- history-matching: comparing those areas of the model where liquid accumulated in the fracture domains of layers 5 and 6 (-8,000 to -12,000 feet msl; -2,440 to -3,660 m msl) with areas where deuterium levels in the produced steam are high, indicating a contribution from injected condensate in the steam.

The extent of the productive reservoir in the original model was based on the approximate reservoir limits established by UNOCAL geologists (figure 1). Additional information on reservoir extent is provided by the location of dry holes (Bodvarsson, Gaulke and Ripperda, 1989 and data provided by Calpine) and the area of known steam production (figure 1). Figure 1 shows that the productive boundary is not well defined in the SE of the field, where the West Ford Flat (WFF) development and the East Ford Flat (Unit 19) areas are located.

In the original UNOCAL model, both the West Ford Flat and East Ford Flat areas were assumed to have low permeability as no significant data were available in these areas at the time the model was developed. With the success of the West Ford Flat development, which started production in December 1988, it is apparent that the reservoir extends further to the east than was previously represented in the model. Hence, the reservoir geometry and matrix permeabilities were modified to include these areas for the present study.

Petrophysics

The important petrophysical properties required for the model include: matrix and fracture porosity, matrix and fracture permeability, fracture spacing, relative permeability and capillary pressure.

Matrix porosities used within the model vary from between 1.2% to 4.6% within the reservoir to 0.4% outside the reservoir. The data available to UNOCAL also suggested that the matrix porosity decreases with depth from the surface and is strongly influenced by the proximity of the felsite, which underlies much of the field (Gunderson, 1990).

Fracture porosity has not been well defined by available field data and is therefore used as a variable for matching the measured pressure data.

Matrix permeability values are also not well defined but are believed to be very low (in the micro-darcy range).

For the fracture domain, permeability values were assigned based on observations during drilling and also on the interpretation of pressure transient data. The permeability values in the fractures range from 3 to 140 millidarcies for horizontal permeability and 4 to 200 millidarcies for vertical permeability.

Estimates of the fracture spacing were based primarily on the frequency of occurrence of steam entries, with typical values of between 160 feet (49 m) and 600 feet (183 m).

Definition of the petrophysical properties in the areas outside the U-N-T area were based on data made available by the other operators for this study. Estimates of fracture spacing in individual blocks were provided by the operators, based on interpretation of drilling logs, while initial estimates of fracture permeability were provided based on results of pressure transient tests.

The relative permeability relationships used in the model, which control the relative flows of steam and water between blocks, are based on UNOCAL's own experience but are similar to the Grant relative permeability curves. The residual water saturation is assumed to be 30% while the residual steam saturation is 0%.

Thermodynamics

In general, over most of The Geysers field, an initial reservoir pressure of approximately 514 psia (3.54 MPa.a) was encountered and the vertical pressure gradients were vapor-static. Temperatures do not vary significantly from saturation conditions (470°F; 243°C), except in the NW area of the field where reservoir temperatures greater than 500°F (260°C) have been measured at depths ranging from -6,000 feet (-1,830 m) to -8,000 feet (-2,440 m) msl; well above vapor-static saturation conditions.

Within the upper four layers of the model, including the NW sector of the field, the thermodynamic conditions were set to saturation conditions corresponding to 514 psia (3.54 MPa.a). In layers 5 and 6, temperatures were set to boiling-point-for depth conditions and pressures were increased according to a vapor static gradient. The pore space in layers 5 and 6 was therefore filled with superheated steam (liquid saturation = 0). The vertical component of thermal conductivity below -8,000 feet msl (-2,440 m msl) was also set to zero to inhibit heat transfer from the lower layers under pre-exploitation conditions.

From simple mass balance considerations, it is known that The Geysers reservoir must contain liquid water in order to have maintained its productivity since 1960. The fracture domain liquid saturations in the original UNOCAL model varied from 1% in the NW Geysers up to 25% in the vicinity of Cobb Mountain, where pressure declines have been relatively low. There is a general decrease in liquid saturation from the SE to the NW. The matrix domain liquid saturation in layers 1 to 4 was initially set to a constant value of 83% in the original UNOCAL model.

The thermodynamic conditions from the original UNOCAL model were used as the initial conditions for the present study but it was necessary to make some changes in order to match the available observation well pressure histories and the overall field isobaric maps.

HISTORY MATCHING

The UNOCAL model included detailed production data from the U-N-T lease areas and generalized production data from the lease areas of the other operators. Detailed production data, provided by NCPA, Calpine and CCPA for the individual wells in their lease areas, were incorporated into the expanded model while the generalized production data were maintained in the Santa Fe lease area.

The locations of production zones of individual wells were based on actual drilling profiles and discussions with each operator regarding production depths. For wells that produced from more than one layer of the model, it was assumed that the production blocks were stacked vertically. Due to the relatively large size of the grid blocks, this assumption is probably reasonable although the majority of the wells are deviated.

Specifying injection well locations was difficult due to the close proximity of production and injection wells in the field relative to the coarseness of the simulation grid. The injection wells were therefore located in layers 4 to 6 of the model even though the actual completion depths may be shallower. This approach has been justified by the assumption that the injected water sinks toward the bottom of the reservoir due to gravitational effects.

Isobaric maps from 1987 to 1991 were provided by UNOCAL for use in calibrating the model; these maps were then modified based on data received from the other operators. The isobaric maps, which had a datum of mean sea level, were then compared with the simulated fracture pressure distributions in layers 1, 2 and 3 of the model after correcting to msl. The different layers were included as the production depth changes across the field; generally shallower to the SE and deeper towards the north although shallow steam is also found over a significant area along the NW/SE axis of the field.

Pressure data were also provided from a number of observation wells with relatively long pressure histories. The data from these wells were also matched to provide further calibration of the model.

The production data were entered into the model and runs were made for the total 30 year field history. The calculated pressure changes in the field and for individual wells were then compared with the measured data and this process was repeated until reasonable matches were obtained. During the matching process, the main parameters that were modified included: fracture permeability, initial matrix water saturation and matrix permeability. Localized changes were also made to the initial fracture liquid saturation and some zones of high or low connectivity were added to the model in order to match the observation well pressure data. These changes were required to either increase the storage of initial water within the reservoir or to change the extent of the reservoir response to changes in production in various parts of the field.

Observation Well Pressure Data

Observation well pressure data from a number of wells were provided by the operators involved with this project for matching. By matching individual well data, it is possible to show that the shape of the pressure response curves are being matched as well as the overall pressure change.

Well 1862-1 is an observation well located in the northern corner of the Unit 13 area (figure 1); the measured and simulated pressure responses are shown in figure 5. From 1982 to 1989, the simulated pressures closely follow the measured data in terms of both pressure decline rate and the overall change in pressure. In mid-1989, the measured pressure decline reduces and the pressures continue to decline at a lesser rate until the end of the measured history. The simulated pressure history shows similar characteristics but slightly overstates the current reservoir pressure in this well. This is probably due to the relative coarseness of the grid blocks, although the overall match is considered to be very reasonable.

The reduction in pressure decline rate that occurred in late-1989 and 1990 is probably associated with additional pressure support from the new injection strategy initiated in late 1989 by both Calpine and NCPA. In an attempt to alleviate the pressure decline in the low pressure area bordering the Unit 13, Unit 18 and NCPA areas (figure 1), injection was relocated to provide more direct pressure support.

The reduction in pressure decline rate was reproduced in model by creating a preferential path between well 1862-1 and the new injection area by increasing the transmissivity of blocks connecting the two areas fivefold. The existence of a high permeability N-S path is consistent with the results from tracer tests conducted by Calpine and NCPA (Adams, Beall, Enedy and Hirtz, 1991).

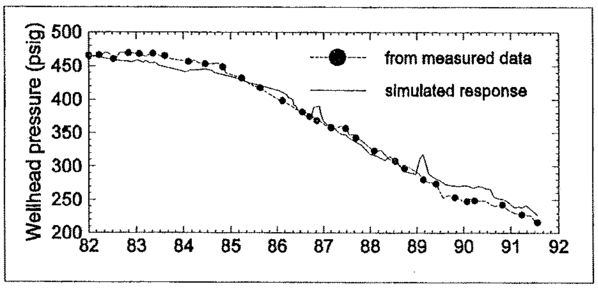

Figure 5: Well 1862-1 pressure history

April 1991 Field-wide Isobaric Maps

When the simulation model was first run to match the field-wide pressure data, it was found that in some areas the reservoir pressures recovered in response to the decline in overall production flow rate since 1987 (figure 2). However, the measured data show that in spite of the reduction in production, reservoir pressures have continued to decline or, in the best case, to stabilize. Hence, in order to match the 1991 pressure contour data (figure 6), it was necessary to adjust the initial matrix water saturation which had been set to a constant value of 83% in the original UNOCAL model.

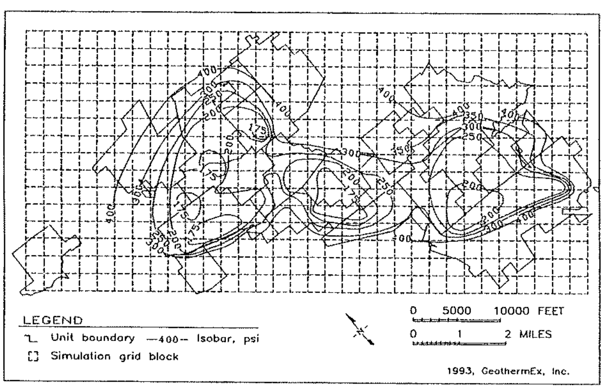

Figure 6: Measured pressure contours, April 1991

In layer 1, the initial matrix water saturation was increased to between 86% and 95%, except for a small area in the vicinity of the SMUD lease (figure 1) where it was set to between 71% and 75%. In layers 2 and 3, the main production layers, it was necessary to modify the initial matrix water saturation distribution significantly and values between 55% and 90% were used in various parts of the field. In layer 4, the initial matrix water saturation was set to a constant value of 70%. With these changes it was possible to obtain reasonable matches to the field-wide isobaric map for April 1991 (figure 6); the simulated isobaric map for layer 2, corrected to the same datum (msl) as the measured data, is shown in figure 7.

Although a reasonable overall match to the measured data was obtained, the model calculated higher pressures than measured in the central UNOCAL area. This is probably due to the large grid blocks in the model which may allow excessive return of injection water from the deeper layers and/or too much recharge from the matrix blocks to the fractures.

In the West Ford Flat area, the calculated pressures are lower than observed by approximately 25 psi (0.17 MPa) to 50 psi (0.34 MPa). This is probably due to the proximity of the low permeability boundary blocks. Initial matrix water saturations of up to 90% were defined in this area to provide additional water reserves but this was not sufficient to maintain reservoir pressure; hence, the model results suggest that recharge may be occurring in the SE Geysers area. This is consistent with geochemical data (Truesdell, Haizlip, Box and D'Amore, 1987) which suggests that recharge from the SE flushed through the reservoir towards the NW.

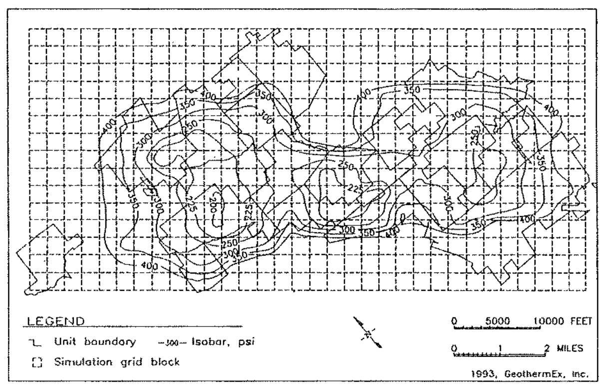

Figure 7: Calculated pressure contours (layer 2)

FORECAST RUN RESULTS

After the history matching was successfully completed, the field-wide model was used to forecast future field performance under two scenarios; the first run considered lowering wellhead pressures over the next five years by up to 40 psi (0.28 MPa) but not below a minimum wellhead pressure of 70 psia (0.48 MPa.a) while the second assumed that wellhead pressures would remain constant at present levels. The ability to drop wellhead pressure from the present levels will depend on retrofitting of the present Geysers power plants to accept lower pressure steam to the gas ejectors. Modifications to the turbines may also be necessary to improve efficiency at lower pressures.

The other main assumptions used in the forecast runs were:

- No infill-drilling in the UNOCAL, CCPA and NCPA leaseholds.
- Infill-drilling of new wells to maintain power production in the Calpine lease areas. The number of future wells drilled, their locations and expected production rates were provided by Calpine.
- No development of the East Ford Flat (Unit 19) area.

For both forecast runs, the percentage of produced fluid that was injected was maintained constant at 25%; similar to the present injection percentage. The model did not consider the possibility that with declining production to a plant, the amount of injection water available from the cooling tower would drop below 25%. The possibility of enhanced injection was also not considered as the present model is not adequately detailed to provide information on the localized effects of injection. It is likely that the model will show improvement in overall reserve levels due to enhanced injection but would not be able to provide more detailed information on the effect of injection on nearby wells.

Due to the field-wide nature of the model and the overlap of grid blocks with area boundaries, only the steam forecasts for the entire Geysers field from the two scenarios are presented (figure 8). The increases in flow rate that occur during the period 1992 to 1999 for Case 1 are caused by the reductions in wellhead pressure.

Comparing the results of the two scenarios (figure 8), the reduction in wellhead pressure provides a gain in flow rate of nearly 1 million lbs/hr (453 tons/hour), corresponding to additional generation of approximately 55 MW(net), over the next 10 years. Most of this gain occurs as a result of the UNOCAL leases moving to variable pressure operation (VPO) during October 1991 but there are continued gains during the 1992 to 1999 period when wellhead pressures are further reduced. Beyond the year 2000, the improvement in steam flow rate is maintained at a lower though still significant level. By 2014, the field-wide steam production has declined to 8.5 million lbs/hr (3,850 tons/hour), compared with the present flow rate of approximately 20 million lbs/hr (9,070 tons/hour). The decline in flow rate calculated for Case 1 can be fitted reasonably accurately by an average harmonic decline rate of 9%.

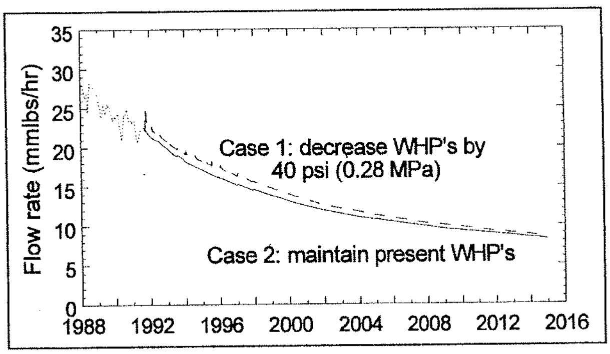

Figure 8: Fieldwide forecasts of steam production

Based on a conversion to MW(net) of 18,000 lbs/hr (8.16 tons/hour) per MW(net), which is believed to be a reasonable conversion factor based on data supplied by PG&E and Calpine, the model results show that by the year 2000, the power output from the field will be approximately 800 MW(net) and by the year 2014, the end of the forecast runs, the output will have dropped further to 475 MW(net).

The model results also show that by 2007, reservoir pressures will have declined by approximately 50 psi (0.35 MPa) in the NW area of the field and by 75 psi (0.52 MPa) to 125 psi (0.86 MPa) in the central and SE areas of the field, respectively, when compared with the 1991 pressure contours (figure 5). The higher pressure declines in the SE may be due in part to the impact of the low permeability boundaries in this area. If there is significant recharge in the West Ford Flat and East Ford Flat (Unit 19) areas, then the model results are probably conservative.

CONCLUSIONS

The field-wide model of The Geysers geothermal field was successfully calibrated against 30 years of available production and pressure data, with reasonable matches being obtained to pressure data measured in individual observation wells and to the overall field isobaric maps. The production data used in the calibration process were provided by four of the operators at The Geysers who control the majority of the productive area.

After calibrating the model, it was used to forecast future field behavior, assuming that wellhead pressures will reduce by 40 psi (0.28 MPa) over the next five years. A further run was also made assuming that wellhead pressures will be maintained at their present levels. It was found that by reducing wellhead pressure, an additional one million pounds per hour (453 tons/hour) could be produced over the next ten years; this is equivalent to 55 MW(net) additional production.

The forecast runs also indicated that over the next 15 years, pressures in the field will decline by between 50 psi (0.35 MPa) and 125 psi (0.86 MPa), with the highest pressure drop occurring in the SE. It is felt, however, that the pressure drop in the SE may have been over-predicted due to the proximity of low permeability boundary blocks. There is some evidence that recharge may be occurring in this area and this is not included in the present model. In terms of production flow rate, it is estimated that the total flow rate will decline from the present level of approximately 20 million lbs/hr (9,070 tons/hour) to 8.5 million lbs/hr (3,850 tons/hour) by 2014. This is equivalent to a reduction in overall field power potential from the present level of approximately 1,200 MW (net) to 475 MW(net).

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ACKNOWLEDGEMENTS

The authors are grateful to the Technical Advisory Committee Industry Consortium for permission to publish this paper. The work described was undertaken with support from the California Energy Commission, who provided the primary funding through a grant to Lake and Sonoma Counties, and from the Technical Advisory Committee Industry Consortium who provided additional funding. We are very grateful to the field operators who participated in the project and provided the necessary data and support. We would also like to thank the staff at UNOCAL for providing the software for running the field model and for continuing to provide support during the project.