10/10-15-91 82(1)

LBL-31132
UC-250
Volume 1 of 2

Lawrence Berkeley Laboratory

UNIVERSITY OF CALIFORNIA

EARTH SCIENCES DIVISION

The Ahuachapán Geothermal Field, El Salvador: Exploitation Model, Performance Predictions, Economic Analysis

Volume I: Text and Main Figures

M. Ripperda, G.S. Bodvarsson, M.J. Lippmann, C. Goranson,
and P.A. Witherspoon

May 1991

Prepared for the U.S. Department of Energy under Contract Number DE-AC03-76SF00098

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

**The Anaschabán Geothermal Field, El Salvador:
Exploitation Model, Performance Predictions, Economic Analysis**

DISCLAIMER

Volume I: Text and Main Figures

This document was prepared as an account of work sponsored by the United States Government. Neither the United States Government nor any agency thereof, nor The Regents of the University of California, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by its trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof, or The Regents of the University of California. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof or The Regents of the University of California and shall not be used for advertising or product endorsement purposes.

M. Ribberds, G. P. Peterson, and P. A. Wilber

MAY 1981

This report has been reproduced directly
from the best available copy.

Available to DOE and DOE Contractors
from the Office of Scientific and Technical Information
P.O. Box 62, Oak Ridge, TN 37831
Prices available from (615) 576-8401, FTS 626-8401

Available to the public from the
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road, Springfield, VA 22161

Lawrence Berkeley Laboratory is an equal opportunity employer.

**The Ahuachapán Geothermal Field, El Salvador:
Exploitation Model, Performance Predictions, Economic Analysis**

Volume I: Text and Main Figures

by

M. Ripperda, G. S. Bodvarsson,* M. J. Lippmann,*
C. Goranson,† and P. A. Witherspoon**

*Earth Sciences Division
Lawrence Berkeley Laboratory
One Cyclotron Road
Berkeley, CA 94720

†Geothermal Consultant
1498 Aqua Vista Road
Richmond, CA 94805

Principal Investigators

Gudmundur S. Bodvarsson and Marcelo J. Lippmann

prepared for

Earth and Space Science Division
Los Alamos National Laboratory
Los Alamos, NM 87545

May 1991

This work was supported by USAID, through Contract No. 2CSH0103K1 from LANL, through the
U. S. Department of Energy Contract No. DE-AC03-76SF00098.

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

SECRET

Table of Contents

List of Figures	v
List of Tables	ix
Executive Summary	xi
Resumen Ejecutivo	xv
Acknowledgements	xix
Nomenclature	xxi
1.0 Introduction	1
2.0 General Approach to Geothermal Reservoir Modeling	3
3.0 Computer Code Description	11
4.0 Three-Dimensional Numerical Model	13
4.1 The Numerical Grid	13
4.2 Boundary Conditions	19
4.3 Initial Conditions	26
4.4 Reservoir Characteristics	28
4.4.1 Fluid Properties	28
4.4.2 Rock Properties	28
4.5 Fracture Versus Porous Media Assumptions	28
5.0 Natural State Model	31
6.0 History Matching	39
6.1 Well Treatment	39
6.2 Iteration Procedure	41
6.3 Best Model—Well Behavior	41
6.4 Best Model—General Reservoir Behavior	63

6.5 Best Model—Rock Properties	64
7.0 Field Performance Predictions	95
7.1 Well Spacing	96
7.2 Development Options	99
7.2.1 Declining Power Generation (No New Production Wells)	99
7.2.2 50 MW _e Power Production	101
7.2.3 75 MW _e Power Production	105
7.2.4 90 MW _e Power Production	111
7.3 Summary of Field Performance Predictions	111
8.0 Preliminary Economic Analysis	115
8.1 Two-Phase Pipeline and Separator Design and Cost Calculations	116
8.2 Production Development Cases Studied	117
8.2.1 Declining Power Generation	118
8.2.2 Development Program—50 MW _e	118
8.2.3 Development Program—75 MW _e	122
8.2.4 Development Program—90 MW _e	122
8.3 Discussion of Various Development Strategies	122
8.4 Conclusions of the Preliminary Economic Analysis	133
9.0 Recommendations	137
9.1 Exploitation Recommendations	137
9.1.1 Power Production—90 MW _e	137
9.1.2 Declining Generation Option	138
9.1.3 Power Production—75 MW _e	138
9.2 Recommendations on Computer Equipment	139
10.0 References	141
Appendices A—G	Volume II

List of Figures

Figure 2.1	A schematic showing the different physical and chemical processes occurring in geothermal systems.	4
Figure 2.2	General approach to reservoir evaluation.	7
Figure 4.1	Location of surface manifestations in the Ahauchapán and Chipilapa area.	14
Figure 4.2	Plan view of the grid used in the numerical simulations. Included are the locations of several surface features.	15
Figure 4.3	An expanded view of the numerical mesh in the vicinity of the wellfield (area NW of Laguna Verde, see Fig. 4.2).	16
Figure 4.4	Layer AA (in red) depicting the initial two-phase zone.	17
Figure 4.5	A cross-section running north to south showing the lithologic column and the location of the initial two-phase zone.	21
Figure 4.6	Conceptual model showing the inferred directions of fluid flow in the Ahuachapán field (from Aunzo <i>et al.</i> , 1989).	24
Figure 4.7	Low permeability flow barriers (shown by the thick lines) located near the wellfield.	25
Figure 4.8	Pressure profiles for the different aquifers.	27
Figure 5.1	Grid used by Aunzo <i>et al.</i> (1989) in their natural state model; also shown are the well locations.	32
Figure 5.2	Natural state pressure distribution (in bars) in layer A (275 masl).	35
Figure 5.3	Natural state pressure distribution (in bars) in layer B (75 masl).	36
Figure 5.4	Natural state pressure distribution (in bars) in layer C (- 375 masl).	37
Figure 6.1	Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-1.	43
Figure 6.2	Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-4.	44
Figure 6.3	Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-5.	46
Figure 6.4	Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-6.	47

Figure 6.5	Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-7.	48
Figure 6.6	Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-17.	49
Figure 6.7	Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-19.	51
Figure 6.8	Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-20.	52
Figure 6.9	Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-21.	54
Figure 6.10	Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-22.	55
Figure 6.11	Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-23.	56
Figure 6.12	Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-24.	57
Figure 6.13	Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-26.	59
Figure 6.14	Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-27.	60
Figure 6.15	Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-28.	61
Figure 6.16	Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-31.	62
Figure 6.17	Comparison between computed (solid line) and observed pressures in well AH-14 at different elevations.	65
Figure 6.18	Comparison between computed (solid line) and observed pressures in well AH-18 at different elevations.	66
Figure 6.19	Comparison between computed (solid line) and observed pressures in well AH-25 at different elevations.	67
Figure 6.20	Porosity values assigned to the two-phase zone (layer AA).	69
Figure 6.21	Porosity values assigned to layer A.	71
Figure 6.22	Contour map of the 1989 well enthalpies (in kJ/kg).	73
Figure 6.23	Comparison between computed (solid line) and observed total flow rates and average enthalpies for the entire field.	75
Figure 6.24	Computed flow rates for the surface manifestations at El Salitre and Playón de Ahuachapán.	76

Figure 6.25	Computed flow rates for the surface manifestations at Chipilapa and La Labor.	77
Figure 6.26	Estimated permeability distribution in layer AA.	79
Figure 6.27	Estimated permeability distribution in layer A.	81
Figure 6.28	Estimated permeability distribution in layer B.	83
Figure 6.29	Estimated permeability distribution in layer C.	85
Figure 6.30	Locations of high-permeability flow paths (thick lines) in layer A.	88
Figure 6.31	Locations of high-permeability flow paths (thick lines) in layer B.	89
Figure 6.32	Locations of high-permeability flow paths (thick lines) in layer C.	90
Figure 6.33	Calculated 1989 pressure distribution (in bars) in layer A.	91
Figure 6.34	Calculated 1989 pressure distribution (in bars) in layer B.	92
Figure 6.35	Calculated 1989 pressure distribution (in bars) in layer C.	93
Figure 6.36	Calculated 1989 vapor saturation (in percent) in layer A.	94
Figure 7.1	Development area for the proposed expansion of the wellfield.	97
Figure 7.2	Power generation versus time for the declining power generation option with various injection scenarios.	100
Figure 7.3	Declining Power Generation: Cases 1 (no injection) and 5 (60% injection). Projected total flow rates and average enthalpies for the entire field.	102
Figure 7.4	Time table for additional production wells required for several of the development options (injection temperature: 150°C).	103
Figure 7.5	Case 10 (50 MW _e , 60% injection at 150°C). Projected total flow rates and average enthalpy for the entire field.	104
Figure 7.6	Case 15 (75 MW _e , 60% injection at 150°C). Year 2020 temperature distribution (in °C) in layer A.	107
Figure 7.7	Case 11 (75 MW _e , no injection). Year 2020 temperature distribution (in °C) in layer A.	108
Figure 7.8	Case 15 (75 MW _e , 60% injection at 150°C). Projected flow rate and enthalpy for well AH-1.	109
Figure 7.9	Case 11 (75 MW _e , no injection). Projected flow rate and enthalpy for well AH-1.	110
Figure 7.10	Case 18 (90 MW _e , 30% injection at 150°C). Projected total flow rates and average enthalpies for the existing wells.	112

Figure 7.11	Case 18 (90 MW _e , 30% injection at 150°C). Projected total flow rates and average enthalpies for the proposed new wells.	113
Figure 8.1	Case 1 (Declining Power Generation, no injection). Total flow rate and cumulative cash flow and electrical power output.	119
Figure 8.2	Case 6 (50 MW _e , no injection). Total flow rate and cumulative number of drilled wells, cash flow and electrical power output.	120
Figure 8.3	Case 6 (50 MW _e , no injection). Location of production wells.	121
Figure 8.4	Case 10 (50 MW _e , 60% injection at 150°C). Total flow rate and cumulative number of drilled wells, cash flow and electrical power output.	123
Figure 8.5	Case 10 (50 MW _e , 60% injection at 150°C). Location of production and injection wells.	124
Figure 8.6	Case 11 (75 MW _e , no injection). Total flow rate and cumulative number of drilled wells, cash flow and electrical power output.	125
Figure 8.7	Case 11 (75 MW _e , no injection). Location of production wells.	126
Figure 8.8	Case 15 (75 MW _e , 60% injection at 150°C). Total flow rate and cumulative number of drilled wells, cash flow and electrical power output.	127
Figure 8.9	Case 15 (75 MW _e , 60% injection at 150°C). Location of production and injection wells.	128
Figure 8.10	Case 18 (90 MW _e , 30% injection at 150°C). Total flow rate and cumulative number of drilled wells, cash flow and electrical power output.	129
Figure 8.11	Case 18 (90 MW _e , 30% injection at 150°C). Location of production and injection wells.	130
Figure 8.12	Cumulative cash flow versus time for various field development scenarios.	131
Figure 8.13	Produced power output versus time for various field development scenarios.	134
Figure 8.14	Cumulative number of (production, injection and dry) wells drilled versus time for various development scenarios.	135

List of Tables

Table 4.1	Boundary conditions assigned to the computational mesh	25
Table 4.2	Formation properties held constant in all simulations	29
Table 5.1	Natural state discharge rates for major surface manifestations (from Aunzo <i>et al.</i> , 1989)	33
Table 6.1	Assigned wellbore pressures (in bars) for the liquid layers in every well	40
Table 6.2	Best model—Productivity indices used for the different wells and layers (in 10^{-12} m^3)	64
Table 7.1	Performance prediction cases studied	95
Table 7.2	Predicted year 2020 pressures in well AH-25 for Cases 11 and 15	105
Table 8.1	Assumptions used in the economic analysis	117
Table 8.2	Production development strategies investigated	118
Table 8.3	Summary of the economic calculations	132

 

Executive Summary

The Earth Sciences Division of Lawrence Berkeley Laboratory (LBL) is conducting a reservoir evaluation study of the Ahuachapán geothermal field in El Salvador. This work is being performed in cooperation with the Comisión Ejecutiva Hidroeléctrica del Río Lempa (CEL) and the Los Alamos National Laboratory (LANL) with funding from the U. S. Agency for International Development (USAID). This report describes the work done during the second year of the study (FY89-90). The first year's report included (1) the development of geological and conceptual models of the field, (2) the evaluation of the reservoir's initial thermodynamic and chemical conditions and their changes during exploitation, (3) the evaluation of interference test data and the observed reservoir pressure decline and (4) the development of a natural state model for the field.

In the present report the results of reservoir engineering studies to evaluate different production-injection scenarios for the Ahuachapán geothermal field are discussed. The purpose of the work was to evaluate possible reservoir management options to enhance as well as to maintain the productivity of the field during a 30-year period (1990-2020). The ultimate objective was to determine the feasibility of increasing the electrical power output at Ahuachapán from the current level of about 50 MW_e to the total installed capacity of 95 MW_e.

The following main conclusions reached by this study are hereby presented to CEL for its consideration and analysis:

- (1) Presently the geothermal resource at the Ahuachapán field is not being exploited in an optimal way. A proper reservoir management program that incorporates both an expansion of the present wellfield and reinjection could significantly increase the rate of steam production and, consequently, electrical generation at the field.
- (2) All reservoir management options to maintain or increase the present electrical power generation for 20 years or more show the need to expand the production area toward the southeast and east and to inject waste brines north-northeast of the present wellfield.
- (3) Reinjection of waste geothermal brines at temperatures above 150°C will be beneficial to the project. It will greatly help maintain reservoir pressures and enhance the

productivity of the field.

Injection at temperatures below 150°C may cause significant scaling problems in the injection lines and wells, and treatment of the brine will be required. Only the brine from the high-pressure separators should be reinjected to avoid possible scaling problems; the brine from the low-pressure separators could be disposed of through the existing canal. Different brine treatment and scale removal methods should be studied in the field using actual samples from Ahuachapán.

CEL should establish a reinjection monitoring program that includes the measurement of pressures, temperatures and flow rates, as well as the collection and analysis of fluid samples. This information is to be used to determine changes that injection might induce in the geothermal reservoir and to update the model of Ahuachapán.

- (4) Even if no new production wells are drilled and no reinjection is carried out, the Ahuachapán field could continue supplying steam to the power plant for the next 30 years. However, the total output will decrease with time, from about 50 MW_e in 1990 to about 38 MW_e in 2020. This case is indicated in the report as the "declining power generation" option.
- (5) With a significantly large development program (35 new wells to be drilled in the first 20 years; 17 immediately, i.e., in year zero) and by injecting 30% of the extracted geothermal fluids, it may be possible to produce sufficient steam to maintain for about 20 years full capacity (95^{*} MW_e) of the three turbogenerators in the power plant. However, at that time the low productivity of any additional development wells will make them uneconomical. Thus, after about year 20, the level of power generation will be decreasing quite rapidly (at year 30, the plant would be producing about 73 MW_e). In the report this reservoir management plan is called the "90 MW_e, 30% injection" option. The main disadvantages of this plan are the high initial investment (about 29 million U. S. dollars at year zero), and the large number of wells that will be required.
- (6) The most favorable development option for Ahuachapán is the one that maintains power production of 75 MW_e coupled with the reinjection of 60% of the extracted

* Cases were actually run at 90 MW_e to account for plant and well downtime.

fluids (the "75 MW_e, 60% injection" case). This reservoir management scenario requires the drilling of only 27 wells over the entire 30-year period (12 wells in year zero), with an initial investment of about 24 million U. S. dollars for wells, pipelines and surface installations. Out of the 27 wells, 18 are producers, 4 injectors and 5 are assumed to be unsuccessful (dry) wells. In the case of the initial 12 wells, 6 are producers, 4 are injectors and 2 are considered dry.

This option is also the one with the highest level of constant electric power generation maintained over the entire 30-year period. It is an intermediate case between the "declining power generation" and the "90 MW_e, 30% injection" cases. Thus, in comparison with the former, it will provide a higher and continuous electrical power output over the next 30 years; compared with the latter, a smaller initial investment will be at risk if the actual resource is found to be smaller than what was assumed in these numerical simulation studies.

If this management option is selected, the electrical power output at Ahuachapán could be increased to 75 MW_e in a period of about 2 years, the time needed to complete 6 successful production wells and 4 injection wells and to construct the required pipelines and surface facilities.

The studies of the last 2 years suggest that it is feasible to locate and complete the required 18 new production wells within an area of approximately 2.5 km² situated southeast and east of the present wellfield.

For the "75 MW_e, 60% injection" option, there is enough geothermal fluid available to use the third unit installed in the power plant. CEL should adopt a system to handle the separated fluid to be used either in the third unit or in reinjection operations. On the basis of observed changes in reservoir pressure, temperature, enthalpy and fluid chemistry and the availability of hydroelectric resources, CEL could establish a management plan for the Ahuachapán field that would allow

- (a) decreasing the amount of injection and increasing electrical power generation from the third unit during the dry season, and
- (b) reducing geothermal power generation and increasing fluid reinjection during the rainy season (period of maximum hydroelectric generation) to build up pressures in

the geothermal reservoir.

- (7) The spacing between new production wells should exceed 300 m in order to reduce interference effects; the average spacing between existing producers is about 250 m.
- (8) Finally, it is strongly recommended that the geothermal reservoir engineering group at CEL acquire a computer system and its peripheral equipment. This will allow CEL (i) to develop databases on Ahuachapán and other geothermal fields, (ii) to analyze well test and monitoring data obtained in the various fields, (iii) to carry out independent reservoir prediction studies and (iv) to evaluate different reservoir management plans and procedures.

LBL will be most cooperative in transferring to CEL the database and numerical model of Ahuachapán developed during this project, as well as the required computer software for the conduct of further reservoir modeling studies.

Resumen Ejecutivo

La División de Ciencias de la Tierra del Laboratorio Lawrence Berkeley (LBL) está realizando una evaluación del yacimiento del campo geotérmico de Ahuachapán en El Salvador. Este trabajo se está efectuando en cooperación con la Comisión Ejecutiva Hidroeléctrica del Río Lempa (CEL) y el Laboratorio Nacional de Los Alamos (LANL) con fondos de la Agencia de los EUA para el Desarrollo Internacional (USAID). En este informe se describen las actividades realizadas durante el segundo año de estudios (Año Fiscal 1989-90). El informe del primer año incluyó: (1) el desarrollo de los modelos geológico y conceptual del campo, (2) la evaluación de las condiciones termodinámicas y químicas iniciales del yacimiento y de sus cambios debido a la explotación, (3) el análisis de los datos de pruebas de interferencia y de la caída de presión observada en el yacimiento y (4) el desarrollo del modelo del estado natural del campo.

En este informe se presentan los resultados de los estudios de yacimiento evaluando diferentes planes de desarrollo para incrementar y mantener la productividad del campo de Ahuachapán durante un período de 30 años (1990-2020). El objetivo principal del presente estudio fue determinar la factibilidad de aumentar el nivel de generación eléctrica en Ahuachapán de los aproximadamente 50 MW_e actuales a la capacidad total instalada de 95 MW_e.

Las conclusiones más importantes de este estudio, que se someten a la consideración y análisis de CEL, son las siguientes:

- (1) En la actualidad el recurso geotérmico del campo de Ahuachapán no está siendo explotado óptimamente. Un plan adecuado de manejo del yacimiento, que incorpore la expansión de la zona en explotación así como también la inyección de fluidos, podría incrementar en forma significativa la producción de vapor geotérmico y consecuentemente la generación de energía eléctrica del campo.
- (2) Todos los planes analizados en este estudio de manejo del yacimiento para mantener o incrementar el nivel actual de generación eléctrica por 20 años o más, indican la necesidad de extender hacia el sudeste y hacia el este la zona de pozos productores, y de inyectar las salmueras separadas al nordeste del área de producción.
- (3) La inyección de salmuera geotérmica separada, a temperaturas superiores a los 150 °C, beneficiaría al proyecto. Esta ayudaría enormemente a mantener la presión en el

yacimiento y aumentar la productividad del campo.

La inyección de salmuera con temperaturas menores de 150°C podría causar problemas serios de incrustación en las líneas de inyección y en los pozos, lo que requeriría el tratamiento de la salmuera antes de inyectarla. Para evitar estos problemas, solamente la salmuera de los separadores de alta presión deberá ser inyectada. La salmuera de los separadores de baja presión podría eliminarse utilizando el canal existente. Se sugiere estudiar diferentes métodos para tratar la salmuera y remover las incrustaciones utilizando muestras obtenidas en Ahuachapán.

CEL debería establecer un programa de monitoreo de la inyección que incluya mediciones de presión, temperatura, flujo, como así también el muestreo y análisis de fluidos. Esta información sería de utilidad en la determinación de cambios que pudieran ocurrir en el yacimiento geotérmico debido a la inyección, y en la retroalimentación del modelo de Ahuachapán.

- (4) Aún en el caso de que no se perforen pozos productores nuevos y no se implemente la inyección, el campo de Ahuachapán continuaría suministrando vapor a la planta durante los próximos 30 años. Sin embargo, la generación total va a disminuir con el tiempo, de alrededor de 50 MW_e en 1990 a cerca de 38 MW_e en el año 2020. Este plan de manejo se indica en el informe como el de la "generación declinante".
- (5) Con un programa intenso de desarrollo (perforación de 35 pozos nuevos durante los primeros 20 años; 17 inmediatamente, o sea comenzando en el año cero) y con la inyección del 30% de los fluidos extraídos, sería posible producir suficiente vapor como para mantener funcionando a los tres turbogeneradores en la planta a su capacidad total (95^{*} MW_e) por 20 años. Sin embargo todo pozo adicional de desarrollo que se construya después de ese período no será económico por su baja productividad. Después de 20 años, el nivel de generación eléctrica disminuiría rápidamente (En el año 30 la planta produciría alrededor de 73 MW_e). En el informe este plan de manejo del yacimiento se identificó como el de "90 MW_e, 30% inyección".

Las desventajas principales de este plan son la alta inversión inicial (alrededor de 29 millones de dólares en el año cero) y el elevado número de pozos que se requieren.

^{*} En los casos estudiados se consideró una generación continua de 90 MW_e y no la capacidad total instalada, tomando en cuenta posibles períodos de interrupción de la planta y de los pozos.

- (6) La opción de desarrollo más favorable para Ahuachapán es la que mantiene la generación eléctrica en 75 MW_e y considera la inyección del 60% de los fluidos producidos (el caso "75 MW_e, 60% inyección"). Este plan de manejo del yacimiento sólo requiere la perforación de 27 pozos durante los próximos 30 años (12 pozos en el año cero), con una inversión inicial de unos 24 millones de dólares para la construcción de pozos, ductos e instalaciones superficiales. Del total de 27 pozos se consideró que 18 resultarán productores, 4 inyectores y 5 fallidos. De los 12 pozos iniciales se estimó que 6 serán de producción, 4 de inyección y que 2 saldrán fallidos.

Esta opción proporciona la mayor cantidad de generación eléctrica constante durante los próximos 30 años. Este plan es un caso intermedio entre el de la "generación declinante" y el de "90 MW_e, 30% inyección". Por lo tanto comparándolo con el primero, resulta en una cantidad de electricidad generada mayor y constante. Con respecto al último, se arriesgaría una inversión inicial menor, lo que sería ventajoso en el caso que el recurso llegase a ser más pequeño que lo considerado en estos estudios de simulación numérica.

Si se opta por este plan de desarrollo, el nivel de generación eléctrica en Ahuachapán podría incrementarse a 75 MW_e en un período de unos dos años, tiempo requerido para la terminación exitosa de 6 pozos productores y 4 inyectores, y para la construcción de los ductos e instalaciones superficiales requeridos.

Los estudios de los últimos dos años sugieren la factibilidad de que los 18 pozos productores nuevos que se requieren para este plan se podrán localizar y completar al sudeste y este del campo actualmente en explotación, distribuidos en un área de aproximadamente 2.5 km².

Con este plan de "75 MW_e, 60% inyección" se dispondría de suficiente fluido geotérmico para la utilización de la tercera unidad instalada en la planta. CEL debería adoptar un sistema de manejo del agua separada para que pueda ser utilizada por la tercera unidad o para inyección. En función de los cambios que se observen en la presión, temperatura, entalpía y características químicas del yacimiento y la disponibilidad de recursos hidroeléctricos, CEL podría adoptar un plan de manejo de Ahuachapán que permita

- (a) durante la época de sequía la reducción controlada de la inyección, y el incremento del nivel de generación eléctrica de la tercera unidad y
 - (b) durante la época de lluvia (período de máxima producción hidroeléctrica) la reducción de la cantidad de electricidad generada y el aumento controlado de la inyección a fin de incrementar la presión en el yacimiento geotérmico.
- (7) La distancia entre pozos productores nuevos deberá ser mayor de 300 m a fin de reducir los efectos de interferencia; la distancia actual es de unos 250 m.
- (8) Finalmente, se recomienda ampliamente al grupo de ingeniería de yacimiento de CEL que adquiera un sistema de cómputo y el equipo periférico necesario. Esto permitiría a CEL: (i) desarrollar bancos de datos sobre Ahuachapán y otros campos, (ii) analizar datos de pruebas de pozos y de monitoreo que se obtengan de los diferentes campos, (iii) realizar estudios independientes para predecir el comportamiento futuro de los yacimientos, y (iv) evaluar diferentes planes y procedimientos de explotación de yacimientos.

El LBL está dispuesto a cooperar con CEL transfiriendo el banco de datos y el modelo numérico del campo de Ahuachapán desarrollados durante este proyecto, así como también los programas de cómputo necesarios para realizar otros estudios de modelado de yacimiento.

Acknowledgements

We appreciate the technical review and helpful suggestions by Emilio Antúnez and Alfred Truesdell. Special thanks are due to Mark Jasper for his careful production of the report.

This study would not have been possible without the cooperation of the personnel of the Comisión Ejecutiva Hidroeléctrica del Rfo Lempa. It was sponsored by the Los Alamos National Laboratory through a contract from the U. S. Agency for International Development and was also supported by the U. S. Department of Energy under Contract No. DE-AC03-76SF00098.

U

1944-1945

1944

1945

1946

1947

1948

1949

1950

1951

1952

1953

1954

1955

1956

1957

1958

1959

1960

1961

1962

1963

1964

1965

1966

1967

1968

1969

1970

1971

1972

1973

1974

1975

1976

1977

1978

1979

1980

1981

1982

1983

1984

1985

1986

1987

1988

1989

1990

Nomenclature

Symbol	Description	Units
A	area	m^2
g	acceleration due to gravity	m/s^2
k	intrinsic permeability	m^2
k_r	relative permeability	—
h	enthalpy	J/kg
P	pressure	Pa, bar
PI	productivity index	m^3
P_{wb}	flowing wellbore pressure	Pa, bar
Q	heat flux	J/s
q	mass flow rate	kg/s
S_l	liquid saturation	—
T	temperature	$^{\circ}C$
λ	thermal conductivity	W/m $^{\circ}C$
μ	dynamic viscosity	Pa · s
ρ	density	kg/m^3
σ	stress	Pa
Subscripts		
e	effective	
l	liquid	
t	total	
v	vapor	
wb	well bore	
β	vapor, liquid	
Superscripts		
s	separator	

1.0 Introduction

The Ahuachapán geothermal field in El Salvador has been producing electrical power since 1975. The power plant at the field currently generates approximately 50 MW_e, which is below its installed capacity of 95 MW_e.

This report describes reservoir engineering studies performed by Lawrence Berkeley Laboratory (LBL) in the second year of an ongoing project to determine an optimal field development plan for Ahuachapán. This work is in conjunction with Los Alamos National Laboratory (LANL) and the Comisión Ejecutiva Hidroeléctrica del Río Lempa (CEL) with funding from the U. S. Agency for International Development (USAID). The first year's report (FY88-89) concentrated on understanding the available data and the development of a conceptual model of the Ahuachapán reservoir (Aunzo *et al.*, 1989).

The current report (FY89-90) focuses on optimizing future field development at Ahuachapán. The primary objective of this work is to investigate the possibility of significantly increasing the electrical power generation over the next 30 years. Some of the questions addressed by this report are:

- (i) Will injection increase the power production at Ahuachapán?
- (ii) What is the best location for injection wells and what percentage of the produced fluids should be injected?
- (iii) Where should new production wells be located and how many wells are required for the next 30 years?
- (iv) What is the highest power production level that can be economically maintained over a 30-year period?

To address these questions, a complex three-dimensional numerical model of the field has been developed. This model is based on all of the available data, which were analyzed in the FY88-89 report. The results from this earlier report, including the geologic model, the reservoir data analysis, the conceptual and natural state models were incorporated into the current model. The model was then calibrated against 1975-89 production data, which included the reservoir pressure decline and the flow rates and enthalpies from all of the wells. The calibration (history match) involved numerous iterations in which reservoir parameters were adjusted until a

satisfactory match was obtained between calculated and observed production data.

Once the model had been calibrated, it was used to predict the future behavior of existing and new production (development) wells, as well as to study the overall reservoir response to various exploitation and injection scenarios. These different scenarios were evaluated based upon the reservoir performance, the pressure decline, returns of injected fluids and their economics.

This report describes the results of LBL's second year of Ahuachapán studies, with the text and main figures in Volume I and the supplemental figures in Volume II (Appendices A to G).

2.0 General Approach to Geothermal Reservoir Modeling

During the last decade LBL has been involved in the development of geothermal reservoir simulators and the formulation of a general approach for evaluating geothermal systems. The numerical simulation must have all of the mathematics in place to represent the physical reservoir processes. A brief discussion of some of the most important physical processes occurring in geothermal systems is given below (excerpted from Bodvarsson and Witherspoon, 1989).

Geothermal reservoirs are inherently in a dynamic state; there is a continual movement of mass and energy throughout the system. This is true in the undeveloped natural state and, of course, exploitation simply adds more transients to the dynamic nature of the reservoirs. There are a number of physical processes that contribute to the total behavior of the system: mass flow of liquid and steam, boiling and condensation, chemical reactions and mixing, conduction and convection, and changes in the state of stress. Figure 2.1 shows schematically some of these processes in an idealized geothermal system.

The mass flow rate of reservoir fluids depends on the combined effects of the driving forces of pressure gradient and gravity. For a two phase fluid, Darcy's law can be written as:*

$$q_l + q_v = -kA \left[\frac{k_{rl}}{\mu_l} \rho_l (\nabla P - \rho_l g) + \frac{k_{rv}}{\mu_v} \rho_v (\nabla P - \rho_v g) \right] \quad (2.1)$$

The extension of Darcy's law to multiphase flow is achieved by introducing two terms inside the brackets, one for the flow of liquid and one for the simultaneous flow of vapor. The relative permeability terms k_{rl} for the liquid and k_{rv} for the vapor phase, are function of their respective saturations in the pore space.

Boiling and condensation continually occur in two-phase hot water reservoirs. These processes are very important because of the large difference in the enthalpies of liquid water and saturated steam; the latent heat of vaporization for temperatures exceeding about 200°C varies from 1.0 to 1.9 MJ/kg. In such a process, the rock acts as a buffer providing heat during boiling and absorbing heat during condensation. These processes are also important when transport of dissolved solids and non-condensable gases must be considered. Phase changes alter the chemical

*Symbols are defined in the Nomenclature.

Figure 2.1 A schematic showing the different physical and chemical processes occurring in geothermal systems.

equilibrium, often resulting in precipitation or dissolution of minerals. Truesdell *et al.* (1984) have reported that boiling in the vicinity of wells at the Cerro Prieto field in Mexico has produced precipitation of quartz and calcite with a drastic reduction in permeability, and hence, well productivity.

The mixing of fluids of different composition is another example of a geochemical process that should be considered in understanding fluid flow patterns within the reservoir. For example, the recharge of colder fluids from shallower surrounding regions may be indicated by changes in chloride and silica concentrations (Grant *et al.*, 1982; Tomasson and Halldorsson, 1981).

Heat transfer in geothermal systems is controlled by conduction and convection. The Fourier law, which is exactly analogous to Darcy's law, expresses the conductive heat flux as a function of the temperature gradient,

$$Q = \lambda A \nabla T \quad (2.2)$$

The convective heat flux due to fluid movement is given by:

$$Q = q_l h_l + q_v h_v \quad (2.3)$$

In general, convection is the dominant mode of heat transfer in the permeable zones of the reservoir, while conduction prevails in the caprock and surrounding low permeability confining layers.

Finally, the state of stress within the geothermal reservoir can change during exploitation due to the decline in fluid pressures within the pore spaces. A change in the stress condition of the system can result in a mechanical response of the rock mass according to the effective stress law. In one dimension, this law is written as:

$$\sigma_e = \sigma_t - P \quad (2.4)$$

where σ_e is the effective stress, σ_t is the total stress on the system, and P is the pore pressure. Since the total stress remains constant, a decrease in pore pressure causes the effective stress on the rock skeleton to increase, and the physical effect is for the pore volume to decrease under the increased load. This may result in compaction that propagates all the way to the land surface (see Fig. 2.1). For example, fluid pressures in the Wairakei field in New Zealand have decreased by tens of bars and the land surface has subsided in some areas by over 5 meters (Allis, 1982). Another source of stress change can occur when the geothermal reservoir is in an area of active tectonism. The Krafla geothermal field in Iceland has undergone significant changes in the elevation of the ground surface as a result of the inflation and deflation of a magma chamber located a few kilometers beneath the field (Bjornsson *et al.*, 1979).

In the case of Ahuachapán, the physical processes that must be considered in the reservoir evaluation include multi-phase mass flow, boiling, condensation and convective and conductive heat transfer. Transport of minerals and precipitation induced by phase changes has not been established as an important process at Ahuachapán. Precipitation of minerals because of injection of spent brine was not found to be significant during the 1978–82 reinjection period. It should be noted, however, that the brine was never allowed to supersaturate, as it was injected at a temperature in excess of 150 °C (Einarsson *et al.*, 1976).

Mixing of fluid with different chemical signatures is certainly occurring at Ahuachapán, as described in our last year's report (Aunzo *et al.*, 1989). The chemical concentrations are relatively low and do not significantly affect the thermodynamic properties of the brine or cause significant mineral precipitation. Future work should, however, consider the results of various tracer tests at the site as these are very important in the final design of the injection scheme. Subsidence has not been reported at Ahuachapán, thus the inclusion of stress changes in the model is not required.

The basic approach to modeling a geothermal reservoir that is employed by LBL and others as described by Bodvarsson *et al.* (1986), is briefly summarized below. 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. 2.2). It must be in agreement with the observed reservoir thermodynamic and chemical conditions (pressure, temperature and salinity distributions, both areally and vertically), available pressure transient data and the exploitation history (well flow rate decline and reservoir pressure drawdown). When a single model has been developed that is consistent with all of these data, it should provide the best possible predictive capabilities, given the limitation of the database and inaccuracies in individual data sets. A good conceptual model of the field is the most important starting point for 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 the data on the chemistry of the produced fluids. 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 a numerical model

ESD-9109-0155

Figure 2.2 General approach to reservoir evaluation.

that is a simplified version of the conceptual model. The numerical model must include all the essential features of the field, such as major faults, main geological units, upflow and discharge areas and proper reservoir processes. This "natural state" model is developed using trial and error procedures until it matches the spatial distribution of temperatures and pressures. When fully developed, the natural state model will allow the determination of the rate of fluid and heat recharge and discharge, 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 tests (especially long-term interference tests), the flow rate and pressure decline histories and enthalpy changes. This merging of multidisciplinary 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, a process which generally requires several 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 important parameters that affect the performance prediction. Usually, these parameters are the permeability and porosity distributions, the temperature distribution and the assumed nature of the reservoir boundaries (e.g., 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 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.

In our studies of Ahuachapán we have followed the basic approach described above. In our last year's work (Aunzo *et al.*, 1989) a conceptual model of the field was developed based upon geological and geochemical models, detailed studies of the major aquifers and feed zones and the initial thermodynamic conditions. The primary reservoir properties were determined from individual well tests, interference test data and the long-term reservoir pressure drawdown. Detailed analysis of the reservoir temperature decline was conducted and explained in terms of boiling, cold water recharge and returns of cooler injected fluids. All of this information was integrated

into a preliminary natural state model of the reservoir. During the second year this work was continued with the development of a comprehensive three-dimensional model and its calibration against the natural state conditions and the temporal changes in flow rates, pressures and temperatures observed during the active exploitation history of Ahuachapán.

 

3.0 Computer Code Description

The computer code MULKOM (Pruess, 1988) was used in the Ahuachapán simulations. MULKOM is an acronym for "multicomponent model," a computer program for simulating the flow of multicomponent, multiphase fluids in porous or naturally fractured reservoirs. The numerical approach in MULKOM is based on the integral finite difference method, which permits simulation of one-, two- or three-dimensional systems. This formulation easily handles both regular and irregular grid block geometries. The difference equations are formulated fully implicitly. All mass and energy balance equations are solved simultaneously, using Newton-Raphson iteration and a direct solution technique.

4.0 Three-Dimensional Numerical Model

Because of the complex thermodynamic and geologic conditions of the Ahuachapán system, it was decided that a fully three-dimensional model of the field was necessary. The important components of the model include the computational grid, the rock and fluid properties and the initial and boundary conditions.

4.1 The Numerical Grid

A three-dimensional grid with four horizontal layers was used for the modeling. A multi-layered model was necessary because most of the wells have several feedzones and a relatively shallow two-phase zone provides a significant fraction of the produced fluids. Also, much of the recharge to the system flows through a deep lithologic unit, the Older Agglomerates (Aunzo *et al.*, 1989). The grid was developed considering various factors, including the:

- locations of the natural reservoir boundaries,
- locations of the hot and cold fluid recharge sources,
- locations of surface manifestations, such as El Salitre and the various hot springs,
- location and size of the initial reservoir two-phase zone,
- locations of the wells and their feedzones,
- three-dimensional temperature distributions.

A map of the Ahuachapán area, including the field and surface thermal manifestations is shown in Fig. 4.1. A plan view of one of the grid layers is shown in Fig. 4.2. The grid extends from El Salitre in the north to a location about two kilometers south of the Laguna Verde volcano. An expanded view of the computational mesh, in the vicinity of the wellfield, is shown in Fig. 4.3.

The same areal grid is used for layers A, B and C. The initial two-phase zone is represented by the upper layer AA (Fig. 4.4), which covers most of the existing wellfield. The total length of the grid is 14,500 m (in the north-south direction), its width is 8000 m, and its thickness is 1000 m. The AA, A and B layers comprise the Ahuachapán Andesites and are assigned thicknesses of 30, 150 and 250 m, respectively. The lower C layer represents the Older Agglomerates and is

Figure 4.1 Location of surface manifestations in the Ahuachapán and Chipilapa area.

Figure 4.2 Plan view of the grid used in the numerical simulations. Included are the locations of several surface features.

Figure 4.3 An expanded view of the numerical mesh in the vicinity of the wellfield (area NW of Laguna Verde, see Fig. 4.2).

Figure 4.4 Layer AA (in red) depicting the initial two-phase zone.

assigned a thickness of 550 m. A geologic cross-section of the field running north to south, with the vertical mesh dimensions and lithologic units, is shown in Fig. 4.5.

One of the powerful aspects of the integral finite difference method is its ability to handle irregularly shaped grid blocks. This allows each well to be placed in a separate grid element, while minimizing the number of required elements. In developing the grid, the surface locations of the wells and springs were used as nodal points for their respective grid elements (Figs. 4.3 and 4.4). After the nodal points had been located, interfaces were generated by the OGRE preprocessor program (Weres and Schroeder, 1978), using perpendicular bisectors on lines connecting neighboring nodal points.

4.2 Boundary Conditions

The geology of the system and the temperature and geochemical distributions prior to exploitation indicate that the upflow region is southeast of the field, in the vicinity of the Laguna Verde volcano. The location of this upflow zone with respect to the geothermal field and surface manifestations is shown in Fig. 4.2. In the natural state, the recharge rate and temperature were determined to be 225 kg/s and 255°C, respectively (Aunzo *et al.*, 1989). The geochemical data (Aunzo *et al.*, 1989) seems to imply inflow of the geothermal fluid from the west, which is inconsistent with all other relevant information. It is believed that the observed chemical gradients are due to dilution within the wellfield area. The geothermal source fluid enters Ahuachapán from the southeast. Most of the recharge undergoes dilution as it sweeps through the field, but some of it flows undiluted south of the main wellfield and into the western part of the field. The high Na-K-Ca temperatures (260°C) and chloride concentrations (8600 ppm) in the western region indicate, therefore, the geothermal source temperatures and salinity, although the recharge area is at considerable distance from this part of the field. A conceptual model of the recharge flow paths and faults controlling fluid flow in and around the reservoir is shown in Fig. 4.6.

The present geothermal reservoir at Ahuachapán is found below about 400 masl and is associated with the Ahuachapán Andesites and Older Agglomerates. The caprock is formed by a mostly impermeable layer between the Ahuachapán Andesites and Young Agglomerates (Fig. 4.5). Barriers to flow are believed to exist north and west of the present wellfield (Fig. 4.7). The northern barrier is indicated by the much lower temperatures found in wells AH-11 and AH-12; these wells are also affected by cold water influx (see Fig. 4.6). The western barrier is inferred from the pressure and temperature data from wells AH-17, AH-8 and AH-15. The initial

XBL 8910-7808

Figure 4.5 A cross-section running north to south showing the lithologic column and the location of the initial two-phase zone.

Figure 4.6 Conceptual model showing the inferred directions of fluid flow in the Ahuachapán field (from Aunzo *et al.*, 1989).

Figure 4.7 Low permeability flow barriers (shown by the thick lines) located near the wellfield.

temperatures in wells AH-17 and AH-8 are on the order of 220°C, while the temperature in AH-15 is about 120°C. Well AH-15 is located only a few hundred meters from AH-17 and AH-8 (Fig. 4.7).

These flow barriers correspond roughly with the locations of faults 1, 2a, 3 and 11 (Fig. 4.6) identified in last year's report (Aunzo *et al.*, 1989). The computer code is formulated so that the permeability across a barrier can be specified to be very low [0.01 millidarcies (md) for these faults], while the permeability in the nodes along the barrier is not changed. Thus, there is fluid flow in the reservoir region between the sealing faults and the edge of the mesh.

The central part of the present wellfield is located in a horst structure that has about 50 m of uplift (Fig. 4.5). This shallower structure allowed a two-phase zone to develop over most of the region between wells AH-23 and AH-17 before exploitation (Fig. 4.4). North and west of this structure, much cooler fluid is found. The hottest temperatures reported in the field were in well AH-14, east of the wellfield. Wells AH-18 and AH-32, which are south of the uplifted region, are also hotter than most of the other wells, but the reservoir is deeper there and these wells did not penetrate a shallow two-phase zone.

The boundary conditions used in the simulations are listed in Table 4.1 for each side (A-F) of the mesh (see Fig. 4.2).

Table 4.1 Boundary conditions assigned to the computational mesh

A (south)	infinite	D (west)	closed
B (east)	infinite	E (north)	infinite
C (north)	closed	F (west)	closed

Infinite boundary conditions were used in parts of the mesh because they are more conservative than constant pressure boundaries. A constant pressure boundary is equivalent to having an unlimited source of fluid and heat at a finite distance from the reservoir. An infinite boundary condition is represented by extending the grid beyond the distance reached by the pressure disturbance created by the exploitation. This does not require an excessive number of nodes, because the element size can be rapidly increased with distance from the wellfield. The total grid extended about 30 km from the wellfield toward the south, north and east. This is probably a more realistic boundary condition, because as the pressure drawdown envelope extends outward with time, any new recharge must travel a larger distance. The nodes south of boundary A were

assumed to have an initial temperature of 260°C and a pressure of 49.2 bars at an elevation of 75 masl. (Note that in this report all pressures are given in bars absolute.) The temperatures in the nodes east of boundary B range from 260°C in the south to 160°C as far north as El Salitre. The elements north of boundary E represent the Regional Saturated Aquifer and are connected only to the A layer. The fluid in these elements is assumed to have a temperature of 75°C and a pressure of 36 bars at an elevation of 275 masl.

4.3 Initial Conditions

Determining the appropriate initial and boundary conditions is critical to properly model a geothermal system. As a minimum requirement, it is necessary to specify the distribution of temperature, pressure and vapor saturation throughout the reservoir before exploitation. It may also be desirable to consider other parameters that would further constrain the model. Such parameters might include the concentrations of noncondensable gases and dissolved solids. In the present study only water was considered in order to limit computational costs.

It is also necessary to know the natural fluid and heat recharge and discharge from the system, as well as the pressure and temperature conditions at its boundaries. The most reliable and consistent method for obtaining initial conditions is to develop a model of the natural state of the field. This assures that the initial conditions are stable and self-consistent. It also provides first-order estimates for the vertical and horizontal permeability and the fluid and heat flow through the reservoir. A natural state model of Ahuachapán was developed in the first year of this project (Aunzo *et al.*, 1989) using a coarse three layer 3-D mesh. This model was refined and improved in the present study as a result of the changes required to match the exploitation history. The initial and boundary conditions that were the result of the new natural state model are described briefly here. The natural state model is discussed in detail in a later section.

The pressures and temperatures in the different aquifers prior to exploitation, reported in last year's report (Aunzo *et al.*, 1989), were determined by studying well logs from the years 1968 to 1975. The pressure was approximately 31 bars at 275 masl throughout the geothermal reservoir (Saline Aquifer), varying hydrostatically with depth. The shallower Regional Saturated Aquifer and near-surface Shallow Aquifer had significantly higher hydraulic potentials (see Fig. 4.8), implying that the reservoir is mostly sealed by a caprock at approximately 350 to 400 masl. The hydraulic potential in the Regional Saturated Aquifer is about 5 bars higher than in the Saline Aquifer.

XBL 891-7436

Figure 4.8. Pressure profiles for the different aquifers.

Because of the complexity of the system the temperature varies significantly throughout the reservoir, both horizontally and vertically. There is both hot and cold water recharging the reservoir and feeding the several hot springs. There are also large variations of permeability throughout the reservoir because of the presence of faults (Figs 4.5 and 4.6). These faults channel the flow and can cause large temperature gradients over relatively short distances.

The pressure throughout the reservoir prior to 1975 was about 48 bars at an elevation of 75 masl. This depth corresponds to the middle of the B layer in the simulation model (Fig. 4.5). In 1975, the temperatures at this depth ranged from nearly 250°C around wells AH-32 and AH-18 in the southern region of the reservoir, to about 140°C in well AH-12 just north of the reservoir (locations of the wells are shown in Figs. 4.3 and 4.6). The temperatures in the reservoir increase from north to south and from west to east. This is consistent with the hot recharge coming from the southeast and the cooler boundaries located north and west of the reservoir.

4.4 Reservoir Characteristics

The physical characteristics of the reservoir must be known, or reasonably approximated, prior to performing the history matching and performance prediction calculations. The rock and fluid properties were determined from the geologic model and various analyses described in Aunzo *et al.* (1989) report. Here, we will summarize some of the analyses and how the results are applied to the current work.

4.4.1 Fluid Properties

The fluid is approximated to be pure water and all of its properties are based on the steam tables given by the International Formulation Committee (1967). This appears to be a good approximation as the Ahuachapán geothermal fluid contains fairly small amounts of dissolved solids (TDS $\approx$ 18,000 ppm) and noncondensable gases (0.2% by mass in the steam) (Sigvaldason and Cuellar, 1970).

4.4.2 Rock Properties

For our purposes, the most important rock property is the permeability. Various permeability measurements have been conducted at Ahuachapán, including injectivity, drawdown, build-up and interference tests. The analyses and results were described in last year's report (Aunzo *et al.*, 1989). The interference tests were determined to be the most useful and showed an average

reservoir transmissivity of 25 darcy-meters (Dm).

Little information is available regarding the effective porosity of the fracture network at Ahuachapán. Porosity measurements of cores indicate that the matrix porosity varies between about 8 and 30% (Larios, 1983). We used porosity values in the range of 10 to 25% for the Ahuachapán Andesites and 10% for the Older Agglomerates.

Relative permeability strongly influences the computed production well flowing enthalpies. There is extensive literature on gas-oil and oil-water relative permeabilities, but steam-water relative permeabilities are poorly known. We used a linear function to represent the relative permeabilities. The liquid relative permeability increases linearly between 0 and 1 as the liquid saturation varies between an irreducible saturation ($S_l = 0.5$) and a fully mobile saturation ($S_l = 1.0$). The high value for the irreducible liquid saturation is believed to be reasonable because the liquid is held in the matrix by capillary forces, while the vapor is free to move in the fractures. The vapor relative permeability was then assumed to be equal to one minus the liquid relative permeability, so that the sum of relative permeabilities always equals unity (Pruess *et al.*, 1983).

Other reservoir rock properties have little impact on the modeling results. The parameters are listed in Table 4.2.

Table 4.2 Formation properties held constant in all simulations

Rock density:	2650 kg/m ³
Heat capacity:	1000 J/kg°C
Thermal conductivity:	2.0 W/m°C
Rock compressibility:	zero
Relative permeabilities:	$k_{rl} = \frac{S_l - 0.50}{0.50}$
	$k_{rv} = 1.0 - k_{rl}$

4.5 Fracture Versus Porous Media Assumptions

Flow through the Ahuachapán reservoir is primarily fracture-controlled, while most of the fluid and energy are stored in the matrix blocks (Aunzo *et al.*, 1989). This type of a system can best be modeled using double-porosity techniques, where most of the flow takes place in the

high-permeability fractures which are recharged with mass and heat from the low-permeability matrix. For various reasons, however, it was decided to develop a simpler, porous medium model in this work. One of the main reasons being the cost and time involved in developing a three-dimensional fracture-porous medium model. We also believe that it is always beneficial to use a simple model in the beginning, in order to understand the general characteristics of a geothermal system and identify the shortcomings of the model for future work. As will be shown in later sections, the present porous medium model is capable of reproducing almost all of the physical behavior of the reservoir observed at Ahuachapán. We believe that the most serious drawback of our porous medium model is its inability to accurately model cold-water recharge into the system, whether due to injection or from the surrounding colder aquifers. This is because direct flow paths along fractures may cause breakthrough times to be much shorter than in porous medium systems. Tracer tests would allow this question to be addressed directly.

5.0 Natural State Model

In geothermal systems there is a continuous flow of fluids, heat and chemical species. Developing a natural state model is an important step in simulating the behavior of these systems. A natural state model of a geothermal field is one that matches the observed thermodynamic conditions of the resource prior to exploitation. This is achieved by balancing the fluid mass and heat recharge to the system with fluid mass and heat losses from the system. The heat and mass recharge is usually unknown, but by using trial-and-error procedures one can estimate it from natural state modeling, as well as determine the coarse permeability structure of the system. This type of model provides the necessary stable initial thermodynamic conditions for the subsequent exploitation modeling.

The parameter values that are matched with the natural state model are the mass and energy outflows from the surface manifestations and the temperatures and pressures measured by static well logs prior to exploitation. The parameters that are adjusted during the iteration procedure are the vertical and horizontal permeabilities, recharge rates and temperatures and the productivity indices of the outflow elements in the computational mesh. The conceptual model will control how the numerical grid is arranged in all three dimensions, although in the design of the grid due consideration must also be given to the various exploitation plans that will be investigated later. The results of available pressure transient tests will give the first "guess" of the permeability distribution in the system, but permeabilities may be significantly changed during the trial-and-error iteration process in order to match observed temperatures and pressures. Permeability is the only rock property adjusted during natural state modeling; thermal conductivities are generally left unchanged. Other rock properties, such as porosity and heat capacity, have no effect on steady state flow behavior. The outflows are matched with productivity indices rather than assigning them constant rates. This allows their flow rates to decrease with time as the reservoir pressure declines during the exploitation phase.

The natural state model developed here is a refinement and extension of last year's work (Aunzo *et al.*, 1989); the mesh that was used by these authors is shown in Fig. 5.1. The areal discretization of the mesh has been made finer for the present study (see Fig. 4.2). Also, a thin fourth layer has been added over the wellfield area to represent the initial two-phase reservoir

Figure 5.1 Grid blocks used by Aunzo *et al.* (1989) in their natural state model; also shown are the well locations.

zone, as discussed previously.

The results from last year's report were used as the input for the current natural state model. The initial pressures and temperatures for layers A, B and C were taken from the final conditions from last year's simulations. Since the two-phase zone (layer AA) was not included in the first model, its initial temperatures and pressures were estimated. The pressure was obtained by assuming hydrostatic pressure conditions above the A layer. The temperature was then assigned to be slightly less than the saturation temperature, so that initially the vapor saturation was zero everywhere. Letting the vapor saturation start out as zero provides another control parameter in the matching process. The two-phase zone will develop only if the heat flow/mass flow ratio through the reservoir is correct. If the heat flow is too low, then no boiling will occur and the reservoir will be fully liquid saturated. If the heat flow is too high, then the vapor cap will be thicker and more extensive than what is observed. The two-phase zone may also develop a vapor saturation that is too high, causing the pressure conditions to become vapor-static rather than hydrostatic with depth.

Table 5.1 Natural state discharge rates for major surface manifestations
(From Aunzo *et al.*, 1989)

Manifestation	Flow (kg/s)	MW _t
Cerro Blanco	4.95	5.08
El Sauce & San José	3.35	3.37
Playón de Ahuachapán	20.51	18.72
Agua Shuca	2.18	1.85
Chipilapa	3.54	3.19
La Labor	29.16	27.76
El Salitre	170.47	169.36

The natural state discharge rates for the various manifestations were determined in last year's work and are listed in Table 5.1. A constant 225 kg/s influx of 255°C water was assigned to a source located in the Laguna Verde volcano area (Fig. 4.2), while the outflow rates were all matched as part of the iteration procedure by varying the individual productivity indices and reservoir permeability values. The final natural state pressure distributions are shown in Figs.

5.2-5.4. The pressure contours are not shown for the AA layer (two-phase zone), because the pressures are fairly constant throughout this layer, around 25 bars. Temperature profiles with depth for the various wells are given in Volume II (Appendix A). The two-phase zone developed throughout the AA layer showed vapor saturations in the range of 5 to 30%. Several elements in the A layer also experienced a small degree of boiling. The elements in the A layer containing wells AH-6, AH-26 and AH-17 had vapor saturations of 1 to 5%.

The modifications in the rock properties for the new natural state model mostly involved the vertical permeabilities and the introduction of several high-permeability pathways (faults). The conceptual model for the fluid flow, including faults, determined by last year's work (Aunzo *et al.*, 1989) is shown in Fig. 4.6. None of these faults or inferred flow paths were incorporated into last year's natural state numerical model. Instead, for simplicity's sake, average permeabilities were used over large areas. Although this approach worked well in matching the temperatures for the coarse three-layer mesh, it did not allow sufficient boiling to occur for the formation of a two-phase zone. Thus, in our new model high-permeability zones were introduced corresponding to faults 6 and 10 (Fig. 4.6) to channel the hot recharge fluid more directly into the reservoir. The vertical permeability was also increased from about 5 md to several hundred millidarcies throughout much of the reservoir to increase the upward heat flow. These changes caused sufficient boiling to create a two-phase zone in the appropriate location, while still matching the observed temperature and pressure profiles.

XBL 8910-7814

Figure 5.2 Natural state pressure distribution (in bars) in layer A (275 masl).

XBL 8910-7815

Figure 5.3 Natural state pressure distribution (in bars) in layer B (75 masl).

XBL 8910-7816

Figure 5.4 Natural state pressure distribution (in bars) in layer C (- 375 masl).

6.0 History Matching

The primary data used for the history match of the Ahuachapán wells are the mass flow rate, flowing enthalpy and static pressure data. The flow rate and enthalpy data are compiled from monthly CEL production records and the pressure data are taken from shut-in pressure logs. Fluid production from the field began on August 27, 1968, when well AH-1 was flowed for the first time. Fluid extraction increased in the following years as new wells were completed and tested. Large scale exploitation started in June 1975, when the first 30 MW_e generator came on line. A second 30 MW_e unit started in July 1976 and a third one (35 MW_e) in November 1980. For the history match, we neglected the fluid mass extracted prior to June 1975 during the flow testing period.

6.1 Well Treatment

In the model, fluid flow into a well is allowed through all layers in which the well has feed-zones. For example, well AH-26 has feedzones in the two-phase zone and in the lower liquid zone. The fluid flow into a well from each layer is not prescribed. Instead it is calculated based on a productivity index (PI), fluid mobility and the difference between the wellbore and local reservoir pressures. Outflows from the manifestations are also calculated based on productivity indices, to realistically model the decline in outflow due to reservoir pressure drawdown. The PI can be expressed mathematically as:

$$q = \sum_{\beta=1}^n \frac{k_{r\beta}}{\mu_{\beta}} \rho_{\beta} \text{PI} (P_{\beta} - P_{wb}) \quad (6.1)$$

Here $k_{r\beta}$ is the relative permeability of the β phase (vapor or liquid), μ_{β} is the dynamic viscosity, ρ_{β} is the fluid density, PI is the productivity index, P_{β} is the pressure in the well element, and P_{wb} is the flowing wellbore pressure at the feedzone. Note that Equation (6.1) basically represents Darcy's law, with the productivity index primarily denoting the geometric parameters of the well feed.

The PI and wellbore pressure are input parameters to the model. The wellbore pressure can be estimated from flowing pressure surveys. For the liquid layers (layers B and C in the model),

a constant wellbore pressure is assigned. These pressures are listed in Table 6.1. Determining the appropriate wellbore pressures to be used for the shallower two-phase zones is more difficult, because of the large change in wellbore pressure that occurs with a phase change. An empirical equation was used to calculate the wellbore pressure at every timestep. This equation is dependent on the reservoir pressure and the flowing enthalpy. The PI is adjusted during the history match procedure to fit the initial flow rate data. The best values obtained for the PI's will be listed with the results from the history match.

Table 6.1 Assigned wellbore pressures (in bars) for the liquid layers in every well

(Pressures are only shown for wells with feedzones in these layers.)

Well	Layer B	Layer C
AH-1	—	—
AH-4	—	60
AH-5	25	—
AH-6	—	—
AH-7	21	—
AH-17	—	—
AH-19	—	—
AH-20	20	—
AH-21	20	—
AH-22	—	—
AH-23	24	—
AH-24	24	—
AH-26	21	—
AH-27	24	—
AH-28	22	—
AH-31	22	—

The enthalpy of the fluid produced from each layer is calculated using the definition of flowing enthalpy:

$$h = \frac{\frac{k_{rl}\rho_l h_l}{\mu_l} + \frac{k_{rv}\rho_v h_v}{\mu_v}}{\frac{k_{rl}\rho_l}{\mu_l} + \frac{k_{rv}\rho_v}{\mu_v}} \quad (6.2)$$

In Equation (6.2) h_l and h_v denote the saturated enthalpies of liquid and vapor, respectively. The

total flowing enthalpy from a well is simply the mass-weighted average enthalpy from all contributing layers.

6.2 Iteration Procedure

Numerous iterations were necessary to obtain reasonable matches with the observed well flow rates and enthalpies. The parameters that were adjusted during the iteration process were:

- (1) productivity indices,
- (2) permeabilities, and
- (3) porosities

Although the effects of these parameters are coupled, each of them affects the flow rates and enthalpies in a different way. The productivity index most strongly affects the well flow rate at relatively early times; consequently, we use this parameter to fix the initial rate from a layer. The permeability primarily controls the flow rate decline with time, but also affects the enthalpy transients. Lower permeabilities cause the enthalpy to increase with time. The porosity has very little effect on the flow rate, but has a relatively strong effect on the enthalpy, especially when porosities are low (Bodvarsson *et al.*, 1980). Because the porosities are relatively high at Ahuachapán (8 to 30%), they had only a limited effect on the enthalpy transients.

As mentioned previously, the calibration of the model against well flow rates, enthalpies and observed pressure decline started after a coarse match was obtained with the natural thermodynamic conditions of the field. The calibration with the production history required many changes in the permeability distribution, especially within the reservoir and in the region south of it. This in turn required recalibration of the natural state calculations and vice versa. Any changes to the permeability distribution which were made during the history match procedure had to be compatible with the natural state model. Thus, these changes had to be incorporated into the natural state model during every iteration.

6.3 Best Model—Well Behavior

After numerous iterations, the matches with well data shown in Figs. 6.1–6.16 were obtained. The solid circles denote the actual field measurements and the calculated values are shown by the lines. Note that the scales are the same for all the wells to allow direct comparisons. Most of the emphasis was placed upon obtaining a reasonable match with the most recent well data, so that future predictions would be more reliable. In almost all cases there is good

agreement with the recent data, and in most instances the calculated and observed flow rates and enthalpies agree well over the entire exploitation period. Below, we will discuss the individual history matches for all the existing wells.

Well AH-1 (Fig. 6.1)

Well AH-1 began commercial production in 1975 at a rate of about 90 kg/s. It had a flowrate decline of about 5 kg/s/year from 1977 to 1984, and a decline of only about 1 kg/s/year from 1984 to 1989. This stabilization in flowrate is probably because of the leveling off of the reservoir pressure decline after about 1984 (e.g., Fig. 6.17). The enthalpy has declined slightly, from about 950 to 900 kJ/kg. Spinner surveys suggest that the major feedzone is within the two-phase zone (Aunzo *et al.*, 1989). However, since the enthalpy decreases with time, the true location of the major feedzone is probably deeper; other wells producing from the two-phase zone have enthalpies that increase with time. The production from this well was assigned to the A layer at an elevation of 275 masl (a depth of 525 m). This is just below the initial two-phase zone, so the cooling is probably caused by boiling effects (Steingrímsson *et al.*, 1989). The calculated flow rate and enthalpy closely match the observed data for the entire exploitation period.

Well AH-4 (Fig. 6.2)

Well AH-4 originally produced from the shallow two-phase zone and a deeper liquid zone. Around 1981, boiling had increased the reservoir vapor saturation near this well and the fluid production from the shallow feed became predominately steam. This raised the enthalpy to about 1800 kJ/kg, but caused a corresponding decrease in the flow rate, from approximately 100 to 50 kg/s. A subsequent workover (1982) probably plugged the deep feedzone (C. Escobar, personal communication, 1989), leaving a flowrate of about 25 kg/s with an enthalpy of 1000 kJ/kg. The well was abandoned in 1985.

The general flow rate decline and enthalpy trend were matched closely for this well. The rise in enthalpy and decrease in production observed during 1982 were matched by turning off the production from the C layer, mimicking the plugging of the deeper feedzone.

AH-1

Figure 6.1 Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-1.

AH-4

Figure 6.2 Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-4.

Well AH-5 (Fig. 6.3)

Well AH-5 produced the lowest enthalpy fluid in the field, about 850 to 900 kJ/kg. An attempt to match this low flowing enthalpy was made by lowering the permeability between this well and the higher enthalpy wells such as AH-6 and AH-20. The permeability was also increased between this well and the cooler water recharge from the north and from the injection area around wells AH-29 and AH-2. The fact that the enthalpy calculated by the model was still about 950 kJ/kg indicates that the porous media assumption does not adequately predict the direct cold water migration for this particular well. Some of the discrepancy in the enthalpy may be caused by wellbore heat losses.

Well AH-6 (Fig. 6.4)

Well AH-6, which is located near well AH-1, also had a flow rate decline of about 5 kg/s/year until 1984, when it stabilized at about 1 kg/s/year. The enthalpy increased from 1200 kJ/kg in 1976, to 2200 kJ/kg in 1985, after which it has remained relatively stable. The model matched the flow rate decline very well, but the computed enthalpy rise is too rapid. This is probably because production from a well element is always assigned to the center of the node. In the case of well AH-6, the AA layer is slightly too shallow (375 masl) compared to the actual depth of the feedzone, so that the boiling in the model occurs too soon. However, this provided the best overall match, because when increased production was assigned to the A layer (275 masl), the final flowing enthalpy was too low.

Well AH-7 (Fig. 6.5)

The flow rate from well AH-7 declined slowly from 1978 to 1983, and then stabilized at about 40 kg/s. The reason for the relatively small rate decrease is that this well is located toward the southern edge of the field, near the hot water recharge area. The results calculated by the model matched both the flow rate decline and enthalpy very well.

Well AH-17 (Fig. 6.6)

Well AH-17 is the only one in the field producing dry steam. This is interesting considering that it was used as an injection well until 1981. It indicates that the strongest injection effects are related to pressure maintenance rather than reservoir cooling.

AH-5

Figure 6.3 Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-5.

AH-6

Figure 6.4 Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-6.

AH-7

Figure 6.5 Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-7.

AH-17

Figure 6.6 Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-17.

The model could not sustain the observed flow rate (15–20 kg/s) at such a high vapor saturation. Increasing the horizontal permeability around this well to 2 darcies helped, but was not sufficient. The vertical permeability for this well element was set at 5 md and the nearby elements were assigned vertical permeabilities of 100 to 500 md. When the vertical permeabilities were increased above these values, the enthalpy fell below 2600 kJ/kg. The flow rate could be matched at lower enthalpy values, but it was considered more important to match the enthalpy.

This well probably intercepts very shallow permeable faults or fractures, so that the flow behavior cannot be properly matched with a porous medium model. Although the final computed flow rate is too low for this well, the slope of the calculated flow rate decline agrees well with that observed during the last four years of its production history. The flowing enthalpy is correctly matched over the entire production period.

Well AH-19 (Fig. 6.7)

There is an initial decrease in the flow rate from well AH-19 due to short-term boiling which affects the reservoir effective permeability (relative permeability effects). The model slightly overpredicts this rate decline and the recovery is several months too slow. However, this is to be expected given the large volume of the well elements in the model. Overall, both the enthalpy and flow rate are properly matched for this well. Production in this well comes only from the liquid zone (layer A) because the two-phase zone was cased off.

Well AH-20 (Fig. 6.8)

Well AH-20 is the nearest production well to AH-5, which is interesting because AH-20 is a high-enthalpy well (up to 1400 kJ/kg), while AH-5 is the production well with the lowest enthalpy in the field. As mentioned above, this required low permeabilities (50 md) to be assigned between these two wells. The flow rate from well AH-20 decreased from about 65 kg/s in 1976 to 50 kg/s in 1982 (a decline of approximately 2 kg/s/year), while the enthalpy increased from 1000 to 1400 kJ/kg. The enthalpy calculated by the model does not increase as much as that observed, but overall the model performance is reasonably good. The drop in enthalpy and small decrease in flow rate after 1982 were probably caused by the workover performed that year. The well had a small increase in production rate after being shut-in for a time in 1986.

AH-19

Figure 6.7 Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-19.

AH-20

Figure 6.8 Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-20.

Well AH-21 (Fig. 6.9)

Well AH-21 is located in the middle of the field and seems to respond strongly to production from other wells. The model has a flow rate schedule that brings the wells on line in four groups, rather than continuously. To stop and restart the model for each new well would greatly increase the complexity of the modeling process. The model has large variations in flow rate behavior whenever a new group of wells is brought on line, but matches the average flow rate and flowing enthalpy very well.

Well AH-22 (Fig. 6.10)

Well AH-22 shares a fluid transmission line with AH-23 and AH-19. AH-19 was brought on line in 1984, causing an increase in wellhead pressures in AH-22 and AH-23 (C. Escobar, personal communication, 1989). The increase caused the flow rates from wells AH-22 and AH-23 to decrease suddenly. As it is not trivial to include these surface facility effects in the model, we matched the enthalpy behavior over the entire production history and matched the flow rate as if there had been no change in 1984. It was felt that this satisfactorily represented the reservoir conditions and also helped offset the slightly low production rates calculated for wells AH-21 and AH-20.

Well AH-23 (Fig. 6.11)

Because of the changes in the surface facilities mentioned above, well AH-23 also had a sudden change in behavior in 1984. The flow rate dropped to 30 kg/s and the enthalpy increased from about 1000 to 1400 kJ/kg as some production out of its liquid feedzone was lost. We did not change the productivity of the liquid layer in the model to match this, but rather, we concentrated on matching the final conditions. This caused the early flow rate to be too low and the early enthalpy to be too high. The flow rate and enthalpy of AH-23 have been almost constant since 1985.

Well AH-24 (Fig. 6.12)

AH-24 is located near three high-enthalpy wells (AH-6, AH-17 and AH-26) but its enthalpy is only about 1000 kJ/kg. This is because of the very low productivity of its shallow two-phase feedzone. The flow rate has declined by only 2 kg/s/year since 1983, while the enthalpy has been fairly constant at about 1000 kJ/kg.

AH-21

Figure 6.9 Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-21.

AH-22

Figure 6.10 Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-22.

AH-23

Figure 6.11 Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-23.

AH-24

Figure 6.12 Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-24.

Well AH-26 (Fig. 6.13)

The enthalpy of the fluids produced by well AH-26 increased from about 1300 kJ/kg to about 1600 kJ/kg in 1979 when well AH-24 came on line. The model shows very sudden increases in enthalpy in 1977, 1979 and 1981 corresponding to the times when wells AH-6, AH-24 and AH-17 were brought on line, respectively. The average enthalpy for this well shows a slight decrease from 1700 to 1500 kJ/kg between 1980 and 1989. This is due to cooling caused by boiling. The production is a mixture of fluids from the two-phase zone (layer AA) and the liquid zone (layer B). In the model, the fraction produced from each layer does not change over the production history. The model correctly matches the flow rate decline and the enthalpy behavior, including the initial 1977–80 boiling period in the two-phase zone.

Well AH-27 (Fig. 6.14)

Well AH-27 is located as far south as AH-19, but some of its production is from the two-phase zone, as indicated by its relatively high enthalpy (1100 to 1200 kJ/kg). AH-27 had a flow rate decline of approximately 10 kg/s/year between the years 1981 and 1984. This was matched by locating within the model a lower permeability zone in the A layer in the region between this well and AH-32 and AH-18. This contrast in permeabilities was necessary for the model to match the initial enthalpy decrease and the subsequent rise to 1200 kJ/kg around 1984. The lower permeability zone also allowed the model to match the lower natural state A layer temperatures in wells AH-32 and AH-18.

Well AH-28 (Fig. 6.15)

Well AH-28 is located next to AH-27 and also has a very steep initial flow rate decline. However, the rate levels off after 1983. The initial fast decline occurs because of the lower permeability zone in layer A south of well AH-27. The leveling off was matched by assigning a high permeability (300 md) to fault 6 (Fig. 4.6), which resulted in stabilized flow rate after 1983.

Well AH-31 (Fig. 6.16)

Well AH-31 is located south of AH-27, but did not show the same high flow rate decline. This is because the major feedzone for AH-31 is several hundred meters deeper than in AH-27 and AH-28. Thus, it is not affected by the lower permeable zone in the A layer (see above). The flow rate and enthalpy stay fairly constant at about 75 kg/s and 900 kJ/kg, respectively. The flow

AH-26

Figure 6.13 Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-26.

Figure 6.14 Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-27.

AH-28

Figure 6.15 Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-28.

AH-31

Figure 6.16 Comparison between computed (solid line) and observed flow rates and enthalpies for well AH-31.

rate is supported by recharge along fault 7 (Fig. 4.6). This fault is only assigned higher permeabilities in the B and C layers to match the flow rate declines in wells AH-27, AH-28 and AH-31.

6.4 Best Model—General Reservoir Behavior

In general, the decline in well flow rate at Ahuachapán is mostly due to reservoir pressure drawdown. The pressure has decreased by approximately 15 bars since 1975, with a corresponding decline in flow rate per well. The current well spacing is only about 250 m, resulting in very significant interference between wells.

The other major contributing factor to the flow rate decline is mobility effects, caused by changes in reservoir vapor saturation. Because the density of vapor is about two orders of magnitude lower than that of liquid, flow rate declines generally accompany increases in vapor saturation. Therefore, when a well is put on line and boiling starts in its vicinity, the enthalpy rises and the flow rate declines. By the end of 1985, most of the Ahuachapán wells had reached quasi-steady conditions, with fairly constant enthalpies and minor flow rate declines.

Because the Ahuachapán wells are fed by fractures that have small volumes, flow rate and enthalpy transients recorded after opening a well tend to be of short duration. However, the well elements in the model are rather large, so the computed transients are much longer. But after a few months, the observed and calculated values agree reasonably well.

The productivity indices used in the model for the different wells and layers are given in Table 6.2. This parameter cannot be directly related to any field data. However, the calculated values are generally higher for the better wells than for the less productive ones. Also note, that a considerably higher productivity index is required for the steam zone than for the liquid zones.

Matching the reservoir pressure decline is just as important as matching the flow rates and enthalpies. This assures that the proper amount of recharge is entering the reservoir. The most accurate pressure histories are from observation wells. We have data from several such wells including AH-25, which is within the present wellfield and from AH-14 and AH-18, which are located just outside of it (see Fig. 4.6). Figures 6.17–6.19 show the measured and calculated pressures in these three observation wells for depths where data are available. By 1989 the drawdown is about 15 bars in well AH-25, 10 bars in AH-18 and 7 bars in AH-14. The lower drawdown in AH-14 reflects the larger distance and lower permeability between it and the producing wellfield. Note that the pressure in wells AH-25 and AH-18 has not changed significantly since

Table 6.2 Best model—Productivity indices used for the different wells and layers (in 10^{-12} m^3)

Well	Layer AA	Layer A	Layer B	Layer C
AH-1	0.	40.	0.	0.
AH-4	145.	0.	0.	.4
AH-5	0.	0.	4.5	0.
AH-6	100.	2.5	0.	0.
AH-7	0.	2.5	1.4	0.
AH-17	300.	0.	.05	0.
AH-19	0.	30.	0.	0.
AH-20	40.	0.	5.	0.
AH-21	0.	40.	2.	0.
AH-22	25.	20.	0.	0.
AH-23	65.	0.	3.8	0.
AH-24	0.	12.	2.2	0.
AH-26	80.	0.	1.4	0.
AH-27	30.5	2.8	6.3	0.
AH-28	0.	32.	1.4	0.
AH-31	0.	0.	8.7	0.

1984. This implies that a near-equilibrium has been established between the current production levels and the recharge.

6.5 Best Model—Rock Properties

The porosity values assigned to the top two layers in the model are shown in Figs. 6.20 and 6.21. Note that on the basis of well behavior it is not possible to estimate the porosity of the liquid zones, as these layers always remain single phase (no enthalpy transients). The liquid zones were assigned porosities of 15% within the known reservoir and 10% around the boundaries. The porosity in the vapor zone (layers A and AA) was estimated to vary between 10 and 20%.

A contour map of the 1989 well enthalpies is shown in Fig. 6.22. The highest enthalpies are found in wells AH-6, AH-17 and AH-26, which are within or near the horst structure identified in the geologic model (see Fig. 4.6). Most of the high-enthalpy production comes from a band of wells located in the north-central (shallowest) portion of the field.

br: AH14 Pressure Trend

Figure 6.17 Comparison between computed (solid line) and observed pressures in well AH-14 at different elevations.

AH18 Pressure Trend

Figure 6.18 Comparison between computed (solid line) and observed pressures in well AH-18 at different elevations.

AH25 Pressure Trend

Figure 6.19 Comparison between computed (solid line) and observed pressures in well AH-25 at different elevations.

Figure 6.20 Porosity values assigned to the two-phase zone (layer AA).

Figure 6.21 Porosity values assigned to layer A.

Figure 6.22 Contour map of the 1989 well enthalpies (in kJ/kg).

The 1989 calculated total flow rate and average enthalpy for all the wells are approximately 600 kg/s and 1100 kJ/kg, respectively (Fig. 6.23). Between 1978 and 1989, the total production from the field varied between about 400 and 800 kg/s. The model matched the average flow rate quite well. It also matched the general enthalpy trend, including the rise to 1200 kJ/kg in 1981 and the decrease to the 1989 value of approximately 1100 kJ/kg.

The calculated surface manifestations' discharge histories are shown in Figs. 6.24 and 6.25. The flow from Playón de Ahuachapán, near wells AH-6, AH-7, AH-17 and AH-24 (Figs. 4.2 and 4.3) had declined to almost zero by 1982. The geothermal fluid contribution to the outflow at El Salitre decreased from approximately 175 kg/s prior to exploitation to 50 kg/s in 1989. We do not have accurate measurements of the surface manifestations' output to match against, but our results are consistent with the general trends that have been reported (Aunzo *et al.*, 1989).

The final permeability distributions determined by the history matching process are shown in Figs. 6.26–6.29. It can be seen that the permeability values within the wellfield for the A, B and C layers are fairly similar to those determined by the natural state model (about 100 md; Aunzo *et al.*, 1989). The permeability in the vapor cap is estimated to range between 1 and 1.5 darcies, which is much higher than the average values for the lower layers. However, because the vapor cap is so thin (30 m) its transmissivity (permeability-thickness) is comparable to those of the other layers (around 30 Dm). The high permeabilities in the vapor cap were necessary to support the large amounts of production from high-enthalpy wells such as AH-6, AH-17 and AH-26. With lower permeabilities, the steam mobility is too low and the reservoir pressures in the well elements decrease too rapidly, because of the low density of steam. When the vertical permeabilities were made higher to supply more recharge to the high-enthalpy wells, the enthalpy was too low because of insufficient boiling.

The uniform transmissivities that were estimated during the natural state modeling (10 Dm) for the area south of the current wellfield, turned out to be too low. For that area, Aunzo *et al.* (1989) had assigned a permeability of 10 md. The same value was used here to model the natural state, with the exception of several high-permeability fault zones. Along the strike of the faults permeabilities of 300 to 400 md were assigned. The permeabilities in the direction perpendicular to the faults (10 md) were not changed. The computed pressures still declined too quickly in that area, so the permeabilities of the elements not associated with major faults were increased to 150 md. The existence of higher permeabilities southeast of the wellfield appears reasonable. It is not unexpected that the region nearest the volcano would have more faults and fractures, and

History Match

Figure 6.23 Comparison between computed (solid line) and observed total flow rates and average enthalpies for the entire field.

Figure 6.24 Computed flow rates for the surface manifestations at El Salitre and Playón de Ahuachapán.

Figure 6.25 Computed flow rates for the surface manifestations at Chipilapa and La Labor.

Figure 6.26 Estimated permeability distribution in layer AA.

Figure 6.27 Estimated permeability distribution in layer A.

Figure 6.28 Estimated permeability distribution in layer B.

Figure 6.29 Estimated permeability distribution in layer C.

hence, higher permeabilities. The locations of the high-permeability flow paths that were incorporated into the model are shown in Figs. 6.30–6.32.

Contour maps of the computed pressure distribution in the different layers at the end of the history match (1989) are shown in Figs. 6.33–6.35. Comparing these to the initial pressures (see Figs. 5.2–5.4) shows that the reservoir pressure has declined by about 16 bars within the wellfield. The pressure has declined by an estimated 8 bars in all the layers as far north as El Salitre. The pressure decline at the northern edge of the field is much more pronounced than at the southern edge, which is to be expected given that the fluid recharge is from the southeast.

It can be seen that in 1989 the two-phase zone had grown deeper and also laterally to cover an area much larger than originally. In the A layer the two-phase zone now extends over most of the wellfield, with saturations as high as 30% north of well AH-32 (Fig 6.36). The vapor saturation is around 80 to 90% throughout the AA layer. The pressure drop is highest in the AA layer (approximately 18 bars), even though the permeabilities are highest there. That is because in the two-phase zone the liquid reserves are low (high vapor saturation and low density) in the vicinity of the wells and the fluid must flow from greater distances. The pressure drop is smaller (10–12 bars) in the C layer because there is little production from that depth. Also, the vertical permeabilities are lower in the Older Agglomerates (C layer) than in the Ahuachapán Andesites (AA, A and B layers).

Figure 6.30 Locations of high-permeability flow paths (thick lines) in layer A.

XBL 914-739

Figure 6.31 Locations of high-permeability flow paths (thick lines) in layer B.

Figure 6.32 Locations of high-permeability flow paths (thick lines) in layer C.

XBL 8910-7817
T.I.D. Illus.88

Figure 6.33 Calculated 1989 pressure distribution (in bars) in layer A.

XBL 8910-7818

Figure 6.34 Calculated 1989 pressure distribution (in bars) in layer B.

XBL 8910-7819
T.I.D. Ilius.88

Figure 6.35 Calculated 1989 pressure distribution (in bars) in layer C.

Figure 6.36 Calculated 1989 vapor saturation (in percent) in layer A.

7.0 Field Performance Predictions

From the production history match we obtained a model for the Ahuachapán field that can be used to predict the response of the reservoir and individual wells to various exploitation schemes. The primary interest of CEL is to determine the maximum electrical power generation levels that can be economically maintained over a suitable time period. We have run numerous cases that range from letting the field continue in its present state, to drilling enough wells to bring the power generation up to the full 95 MW_e capacity. It should be noted that the full power plant capacity cases were actually run at 90 MW_e to allow for plant and well downtime. Also, because the generation of 90 MW_e requires the full use of the low-pressure separators, only 30% of the produced fluids are available for high-temperature (>150°C) reinjection. The cases are summarized in Table 7.1.

Table 7.1 Performance prediction cases studied

Case	Power Generation	Percent Injection	Injection Temperature
1	declining	0	—
2	declining	30	100°C
3	declining	60	100°C
4	declining	30	150°C
5	declining	60	150°C
6	50 MW _e	0	—
7	50 MW _e	30	100°C
8	50 MW _e	60	100°C
9	50 MW _e	30	150°C
10	50 MW _e	60	150°C
11	75 MW _e	0	—
12	75 MW _e	30	100°C
13	75 MW _e	60	100°C
14	75 MW _e	30	150°C
15	75 MW _e	60	150°C
16	90 MW _e	0	—
17	90 MW _e	30	100°C
18	90 MW _e	30	150°C

When running a case that specifies a given power generation level, the numerical code (MULKOM) automatically adds new wells as required. The wells are added at given locations and in a pre-established order. When specifying a fixed level of MW_e to be produced, one must consider the steam rate at the separator rather than the total flow rate. The steam rate at the separator (q_s) can be estimated assuming iso-enthalpic expansion,

$$q_s = q_t \frac{h - h_l^s}{h_v^s - h_l^s} \quad (7.1)$$

where q_t is the total flow rate and h is the fluid enthalpy from the well, h_l^s and h_v^s are the liquid and steam enthalpies, respectively, at separator conditions (about 6 bars). For example, a 75 MW_e power production requires approximately 165 kg/s of steam, assuming a power plant conversion of 2.2 kg/s of steam per MW_e . The steam rate from each producing well is then added up until 165 kg/s are reached. The remaining wells are left shut-in until the total steam rate declines below 165 kg/s.

The amount of injection listed in Table 7.1 is based on a percentage of the extracted fluids. For example, the field currently produces approximately 550 kg/s of steam and brine. Thus an injection amount of 30% would be 165 kg/s. The injection temperature is either 100 or 150°C, depending on whether or not the low-pressure steam is used in the plant.

The development area for the proposed new production wells is southeast and east of the current wellfield (Fig. 7.1). This area is closest to the hot fluid recharge and is the best location from a reservoir management perspective. The total surface area of this region is approximately 2.5 km², or about three times the size of the current wellfield. The proposed location for the new injection wells is north-northeast of the current wellfield (Fig. 7.1). In the model, the new (hypothetical) production and injection wells were assumed to be completed in layers A and B.

7.1 Well Spacing

The well spacing in the current field is approximately 250 m. It was found in our simulation studies that when the well spacing in the new region fell below 350 m, the productivity of any new wells was very low. For example, the 90 MW_e case with 30% injection (Case 18) requires that 24 new production wells be drilled by the year 2008, resulting in a well spacing of 350 m. Because of limited recharge and declining reservoir pressures, the flow rates of wells added after that year is only about 20 kg/s. Assuming an enthalpy of 1000 kJ/kg, this is about 1.5 MW_e per well.

Figure 7.1 Development area for the proposed expansion of the wellfield.

The region near AH-32 is the first area drilled in all of the assumed development options. This is to take advantage of the fact that this well has already been completed. Once a fluid transmission line has been built connecting AH-32 with the main wellfield, the new wells can feed into the same pipeline. This minimizes the amount of pipeline that must be constructed initially. The drilling pattern for the new wells is such that the spacing is approximately 400 m for the first 10 wells. The spacing approaches 350 m as additional production wells are added. (The expanded production wellfield is shown by the red areas in Fig. 7.1.) Note that in the model more than one well was assigned to some of the larger elements for the cases where more than 18 new production wells were needed. This situation only occurred in the later part of the 30-year development period.

In all cases that considered injection, three or four injectors (located in the blue areas shown in Fig. 7.1) were assumed to be available in 1990. In the model, the total mass reinjected was equally distributed between these wells.

7.2 Development Options

The list of cases in Table 7.1 was selected to cover the range of possible field development schemes. Some cases will turn out to be significantly more attractive than others, while some may be completely impractical. Here, we will describe in detail several cases selected as being representative of the various development options that were analyzed. A complete set of figures with the projected flow rates, enthalpies, power generation and year 2020 temperature distribution are given in Volume II for Cases 1, 6, 10, 11, 15 and 18.

7.2.1 Declining Power Generation (No New Production Wells)

Cases 1–5 consider what would happen if no further field development occurs, i.e., the field is just run in its current state without drilling new production wells. The electrical power output (in MW_e) for various injection amounts and temperatures are shown in Fig. 7.2. For the case with no injection (Case 1), the power production declines from 50 MW_e in 1990 to 38 MW_e in the year 2020. Injection has a strong effect on maintaining power generation at higher levels. In Case 5 (60% injection at 150°C) the field is still producing at about 46 MW_e in the year 2020. This decline in power production is less than half of the decline for the case without injection (Case 1). Injection, however, does have an adverse effect on the produced fluid enthalpy. The mass-weighted average enthalpy in the year 2020 is 1040 kJ/kg for Case 1 and 940 kJ/kg for Case

XBL 914-6707

Figure 7.2 Power generation versus time for the declining power generation option with various injection scenarios.

5 (Fig. 7.3). To a degree this is due to the partial quenching of the two highest enthalpy wells, AH-6 and AH-17, and also due to the higher reservoir pressures from injection. In fact, the temperature is actually 4°C higher in the element of the mesh containing well AH-17 for the case with 60% injection than for the case with no injection. In the element with well AH-25, the pressure at 275 masl for Case 5 is about 2 bars higher in the year 2020 than for Case 1. The higher pressures reduce the amount of boiling, resulting in lower enthalpies and higher temperatures and well flow rates.

7.2.2 50 MW_e Power Production

A more interesting and perhaps realistic scenario is that of maintaining the field at a specified power generation level. Of particular interest in all of these cases is the number of new production wells which will have to be drilled, and the time at which they will be needed. Cases 6–10 all consider a constant 50 MW_e output, which is merely maintaining the current power production until the year 2020. As discussed above, the computer model automatically adds new wells when the total steam rate at the separators falls below a specified level. Thus, for 50 MW_e, a new well is added when the total steam rate is less than 110 kg/sec. All of the cases require only four or five new wells over the next 30 years to maintain 50 MW_e. For Cases 6 and 10, the time table for new production wells is shown in Fig. 7.4. This small number of additional wells is rather surprising. However, as previously noted, the reservoir pressure decline has been very small over the last five years (1984–89), suggesting that the amount of natural recharge is close to the current rate of fluid withdrawal (i.e., quasi-steady state flow conditions).

Injection does not make much difference to the total number of wells required; it is five for the case with no injection and four for the case with 60% injection (Cases 6 and 10, Fig. 7.4). However, it is very important to note when those additional wells are needed. Looking at the two extreme cases, i.e., no injection (Case 6) and 60% injection at 150°C (Case 10), we find that initially both require a new well to reach 50 MW_e. For Case 6 a second well is required after six years, while for Case 10, another well is not needed until after eight years. The pressure support and increased flow rates due to injection more than compensate for the associated decrease in enthalpy (Fig. 7.5). The field requires a third and fourth well for Case 6 after 13 and 22 years, respectively, a fourth well is not required for Case 10 until after 27 years (Fig. 7.4). An economic comparison of these cases is discussed in a later section.

Figure 7.3 Declining Power Generation; Cases 1 (no injection) and 5 (60% injection). Projected total flow rates and average enthalpies for the entire field.

XBL 913-386

Figure 7.4 Time table for additional production wells required for several of the development options (injection temperature: 150°C).

Figure 7.5 Case 10 (50 MW_e, 60% injection at 150°C). Projected total flow rates and average enthalpy for the entire field.

7.2.3 75 MW_e Power Production

In Cases 11–15 (75 MW_e), we produce 50% more power than in Cases 6–10 (50 MW_e), but require up to 24 additional wells (Fig. 7.4) instead of a maximum of five. The drastic increase in the number of wells is caused by the disturbance of the present near-equilibrium existing between recharge and production. Even with this larger number of wells, 75MW_e is still feasible, especially with injection.

The effects of injection are much more evident at this level of power production. For the case with no injection (Case 11) 24 new wells are needed after 28 years (Fig. 7.4). After that time the power production begins to fall below 75 MW_e. In all cases that were considered it was decided to stop adding new wells when the well spacing became less than 350 m. Only 18 new wells are needed when there is injection of 150°C water at 60% of the production rate (Case 15). If the injection temperature is changed to 100°C, but still kept at a 60% rate (Case 13), then 22 new wells are required, due to greater reservoir cooling. Cases 11 and 15 are evaluated in the Preliminary Economic Analysis Section.

It is interesting to compare in detail the reservoir temperatures and pressures between the cases with and without injection. Table 7.2 gives the year 2020 pressures in the element containing well AH-25 for Cases 11 and 15.

Table 7.2 Predicted year 2020 pressures in well AH-25 for Cases 11 and 15

Elevation (masl)	Layer	Pressure (bars)	
		Case 15 (60% Injection)	Case 11 (Without Injection)
375	AA	8.1	8.4
275	A	12.3	9.1
75	B	29.3	26.2
-325	C	63.7	61.7

With injection, the pressures are about 3 bars higher in the A and B layers, however, the pressure is actually 0.3 bars lower in the top vapor zone. This is because the vapor zone is partially quenched and the flowing enthalpies are lower (see Appendices E and F). Because the mobility for liquid is much higher than that for steam, the flow rates out of the vapor zone are higher when the enthalpies are lower (i.e., large increase in water production). Consequently, this

larger mass extraction results in lower local pressures.

The differences in pressure are much larger towards the northeast, close to the injection locations. Near well AH-29, the pressures at 275 masl are 14.3 bars with injection and 9.3 bars without it, and the temperature is about 20°C lower due to injection-induced cooling. The effects of injection are much less pronounced in the Older Agglomerates (Layer C). The temperatures at -325 masl in the element corresponding to well AH-29 are approximately 241°C with and without injection (Cases 15 and 11, respectively). There is only a 1.6 bar pressure difference at this depth.

The effect of injection on the high-enthalpy wells, such as AH-17 and AH-6, can best be seen by looking at the individual flowrates and enthalpies (Appendices E and F). Injection causes the flowrates of these wells to more than double, from about 10 kg/s to about 25 kg/s each, while the flowing enthalpy is reduced by half. This results in about the same power production for these two wells (about 3 MW_e), with and without injection.

Although injection causes the enthalpy to decrease, it does not cause cooling in most of the reservoir. There are steep temperature gradients near the injection wells (Fig. 7.6). For example, when the field produces 75 MW_e, the temperatures are about the same between the cases with and without injection for all the wells south of AH-6 and AH-24 (Figs. 7.6 and 7.7). The enthalpy decreases are due primarily to the pressure support, as the injection maintains the pressure above saturation.

Injection has a large effect on the flowrates of the low-enthalpy wells located in the northern part of the field. For example, with injection, well AH-1 has a flowrate of about 40 kg/s after 30 years (Fig. 7.8) and only 15 kg/s with no injection (Fig. 7.9). The injection causes the enthalpy to decrease from approximately 870 to 800 kJ/kg. As one moves further to the south, injection has less effect. In well AH-7, the difference in flowrate is only about 5 kg/s and the difference in enthalpy is about 50 kJ/kg (see Appendices E and F).

The production from the step-out wells to the southeast interferes almost immediately with wells AH-19, AH-28 and AH-31. These wells show a decline of 20 to 50% in the year 1990 when the new step-out wells are put on line (Appendices E and F).

XBL 8911-7831A

Figure 7.6 Case 15 (75 MW_e, 60% injection at 150°C). Year 2020 temperature distribution (in °C) in layer A.

XBL 8911-7827A

Figure 7.7 Case 11 (75 MW_e, no injection). Year 2020 temperature distribution (in °C) in layer A.

Figure 7.8 Case 15 (75 MW_e, 60% injection at 150°C). Projected flow rate and enthalpy for well AH-1.

Figure 7.9 Case 11 (75 MW_e, no injection). Projected flow rate and enthalpy for well AH-1.

7.2.4 90 MW_e Power Production

The final set of cases involve running the three power plants at their full capacity of 95 MW_e. A nominal value of 90 MW_e was considered for calculating steam requirements to account for occasional downtime of the power plant and wells. The design of the power plants is such that about 30% of the produced fluids would be available for reinjection at this production level. With 30% injection (Case 18), the field can maintain 90 MW_e with 24 new producers until about the year 2010 (Fig. 7.4). At that point, the well spacing would be about 350 m and the productivity of any additional well would be too low to justify further drilling. The final power production in the year 2020 is 73 MW_e. With no injection and a maximum of 24 new wells (Case 16), the field can only maintain 90 MW_e until the year 2005. The final generation capacity with no injection is 62 MW_e.

The pressure drawdown is obviously greater for the 90 MW_e cases than for the other ones. The year 2020 pressure and temperature contours with 30% injection at 150°C (Case 18) are given in Appendix G. The predicted AH-25 pressures in the year 2020 are approximately 8, 11, 28 and 62 bars at 365, 275, 75 and -325 masl, respectively. This is a total pressure drawdown of approximately 20 bars since the beginning of production (1975).

The production behavior of the existing wellfield and of the proposed step-out area is shown in Figs. 7.10 and 7.11. In 1990, the existing wellfield produces approximately 550 kg/s at an average enthalpy of 1060 kJ/kg. Over the 30 year simulated production period, this rate declines to 250 kg/s, while the enthalpy stays fairly constant. The wells in the step-out area begin producing about 500 kg/s at an enthalpy of about 1100 kJ/kg. The production from the new area increases to about 700 kg/s in 2020, while initially the enthalpy increases to approximately 1200 kJ/kg before declining to around 1000 kJ/kg. The power production from the existing field decreases by a factor of 2.5, to approximately 20 MW_e. On the other hand, the production from the new area increases from 45 MW_e to nearly to 70 MW_e after all 24 new wells are drilled. Then, between the years 2010 and 2020, with no new wells added, the power generation from the new area drops to almost 50 MW_e and to about 73 MW_e for the entire field (see Appendix G).

7.3 Summary of Field Performance Predictions

The best fit model indicates that hot fluid recharge to the field originates from the vicinity of the Laguna Verde volcano to the southeast. The model corroborates the location of barriers to flow identified in the conceptual flow model given in last year's report (Aunzo *et al.*, 1989).

Figure 7.10 Case 18 (90 MW_e, 30% injection at 150°C). Projected total flow rates and average enthalpies for the existing wells.

Figure 7.11 Case 18 (90 MW_e, 30% injection at 150°C). Projected total flow rates and average enthalpies for the proposed new wells.

There is a barrier immediately west of the field and a leaky barrier to the north. Some cold water recharge (in the range of 30 to 60 kg/s) enters the field from the north and from the southwest. In the exploitation model several of the faults identified in the conceptual flow model (Fig. 4.6) had to be considered as highly conductive flow paths. In particular, faults 6, 8 and 10 were major conduits for recharge. Fault 6 was extended much farther to the southeast, to the edge of the volcano.

The three-dimensional exploitation model discussed in Section 6 was utilized to investigate the effects of different production-injection scenarios and to determine the level of power generation that can be sustained for 30 years. The basic reinjection options were zero, 30 and 60% of the produced fluids. The four major production scenarios involved:

- 1) drilling no new wells (declining generation rate)
- 2) maintaining 50 MW_e
- 3) maintaining 75 MW_e
- 4) maintaining 90 MW_e

The results indicate that the field can support 50 MW_e with injection north-northeast of the present wellfield and by adding only four or five new production wells. An electrical power generation of 90 MW_e cannot be maintained over a 30 year period (assuming 30% injection), but only for approximately 20 years. After that time, the productivity of any new well is too low to be economical. The field can maintain a 75 MW_e level of generation by injecting 60% of the produced fluids back into the reservoir and drilling 18 new wells to the southeast and east of the current wellfield.

8.0 Preliminary Economic Analysis

The cost of future alternate development strategies at the Ahuachapán geothermal field was studied to determine the economics of power production at various output levels. A number of cases were studied, ranging from letting the fluid production continue to decline without drilling any additional wells (the "declining power generation" case) to drilling enough new wells to bring the power generation up to the full installed capacity at Ahuachapán (95 MW_e). The effects of reinjection on each of these development strategies—by way of three or four injection wells located north-northeast of the present wellfield—was also investigated.

The economic analysis includes estimated costs for production and injection wells, pipelines, separation facilities, power plant operating conditions, and estimates for power sales and field development cost escalation rates. The cost, and therefore the economic impact, of power plant equipment was not included in the analysis because equipment for generating 95 MW_e of electrical power is in place at this time. The effects of land acquisition costs, taxes, interest, engineering and development costs, equipment acquisition, management overhead and costs, etc., were also not considered.

The analysis utilized predicted well flow rates and assumed locations for production and (for some cases) injection wells from the Field Performance Prediction section. Pipeline sizes were calculated assuming that large-diameter two-phase lines would extend from the power plant to areas central to the new production wells to be drilled in the southeast and east quadrants of the known geothermal area. Two-phase pipelines from the individual wells were then tied into these large-diameter pipelines (termed "trunk lines"). The time when wells were drilled and pipelines built were discretized in five-year increments to reflect an ordered field development program to simplify the economic calculations and to assist in the representation of the economic comparisons.

The production and injection wells, pipelines, separation facilities, operating costs, and cash flows from power sales were used as input to a computer program to determine the cumulative cash flow versus time, using the inflation rate on costs and sales with an assumed plant operating factor. Comparison of the various development strategies was made with the cumulative cash flow versus time and on a net present value (NPV) calculation. The NPV calculation

used a 10% return factor and represents the amount of money that would be needed as an investment in year zero to achieve the yearly cash flows that the project generates. Additional economic comparison methods are available, but since the cost of the power plant is neglected in this study, the number of available comparison methods is thereby reduced.

8.1 Two-Phase Pipeline and Separator Design and Cost Calculations

The homogeneous two-phase flow method was used to determine the size of the two-phase pipelines. The steam-water tables were digitized and fifth-order polynomials fitted to the pressure, temperature, and enthalpy data to allow iterative calculations to be performed on a personal computer. The pipelines were divided into 100-m lengths for the purpose of making pressure drop calculations. The pipeline size was adjusted to maintain the two-phase flow conditions in an annular regime. The Baker (1954) method was used to determine the pipeline flow conditions. The pipe sizes were further adjusted to limit the wellhead pressures to below 8.5 bars with a steam-water separator inlet pressure of 5.7 bars. The estimated length of the pipelines was increased by 25% to account for terrain and thermal expansion loops. The pipeline sizes are approximate, and no design safety factors are included. The sizes vary for each well and for the main trunk lines, depending on the flow rate and length of line (e.g., a 1500-m-long line carrying 250 kg/s requires a 30-in.-diameter line; a 1000-m-long line with a 40-kg/s flow rate requires a 16-in. line, etc.).

The cost of the pipelines was estimated as $\$685 \times d^2$ per km, where d is the pipeline diameter in inches. For example, the cost of a 30-in.-diameter pipeline is \$620,000/km (all costs are in U.S. dollars). The costs are based on data from available handbooks and experience in other geothermal fields. However, it should be noted that most of the pipeline costs are small when compared to the well costs. The pipeline costs are included only to provide a more accurate comparison of the various development strategies.

The separator equipment sizes were designed using a combination of methods from Bangma (1961) and Lazalde-Crabtree (1984). The steam-water separator size was calculated for a design flow rate of 250 kg/s with an inlet pressure of 5.7 bars and an enthalpy of 1000 kJ/kg. This requires a separator with a 30-in.-diameter two-phase inlet and steam line outlet with a separator 10 m high and 2.5 m in diameter. The cost of the separator was estimated to be \$250,000 in year zero based on vessel quotation and estimated associated costs f.o.b. Houston, Texas. For some of the development cases two separators are required. There has been no

attempt at this time to determine what existing surface installations can be used for the various development strategies investigated in this study. Several of the cases show that the total mass flow rate will change with time and existing pipelines and separation facilities may be used in conjunction with the new wells to be drilled and required pipelines. The actual development strategy and the field behavior over time will determine the best use of the available facilities.

Several assumptions are used in the economic analysis (Table 8.1) and are based on experience and conversations with personnel involved with the Ahuachapán project (G. Cuellar and C. Escobar, personal communications, 1989). Additional assumptions were made for inflation and operating factors.

Table 8.1 Assumptions used in the economic analysis

Well costs	\$1000/m per well (\$1,500,000 per well)
Pipeline cost	$\$685 \times d^2$ per km, (d = diameter, inches)
Well dry hole ratio	1 : 4 (one out of four wells drilled are dry)
Inflation rate on costs	5%
Inflation rate on sales	5%
Operating factor	85% (plant operates 85% of the year)
Power sales rate	\$0.035 per kW-hr
Operating costs	\$0.015 per kW-hr

8.2 Production Development Cases Studied

Several power production development strategies were studied to determine the economics of future reservoir development. The cases studied (Table 8.2) include different levels of power generation with and without injection of 150°C separated water. We also considered the case of allowing the field to decline with the existing wells that are in place without injection or the drilling of make-up wells. The injection temperature of 150°C was considered appropriate for several reasons, including (a) past experience, (b) the need to inject at higher temperatures to reduce well scaling from silica deposition, (c) thermal breakthrough considerations and (d) the availability of injection fluid during long-term production. The power outputs are all estimated nominal power outputs. No correction to actual net power output has been used in these analyses.

Table 8.2 Production development strategies investigated

Cases (see Section 7.2)	Observations
Declining power generation (Case 1)	No new wells/no injection
50 MW _e , No injection (Case 6)	—
50 MW _e , 60% injection (Case 10)*	—
75 MW _e , No injection (Case 11)	—
75 MW _e , 60% injected (Case 15)*	—
90 MW _e [#] , 30% injection (Case 18)*	No new wells drilled after year 20

* Injection temperature: 150°C

[#] A nominal value of 90 MW_e, instead of 95 MW_e was considered for calculating steam requirements to account for occasional downtime of the power plant and wells.

8.2.1 Declining Power Generation

No injection (Case 1): This case was studied to determine the cash flows and net present value (NPV) of the cash flows if one allows the field to decline using the existing wellfield as it is at this time (1990). No injection takes place and no make-up wells are drilled. Figure 8.1 shows the flowrate from the existing field, the cumulative cash flow (CCF) and the cumulative energy produced as a function of time. (Note that here and in subsequent figures showing cumulative energy produced, the 85% plant operating factor—see Table 8.1—has been taken into consideration.) The cumulative power output (CPO) slope decreases with time due to the reduced plant output. The NPV of the plant cash flow is \$82,000,000.

8.2.2 Development Program—50 MW_e

No injection (Case 6): This case has 50 MW_e of power production with make-up wells drilled in the southeast and east quadrants (termed “new wellfield” in the figures). Figure 8.2 shows the field flowrate, cumulative number of wells drilled (CNW), the CCF and the CPO. A total of seven wells are drilled to meet the power output requirements over a 30-year period (two wells drilled are assumed to be dry). At late time the existing and new fields supply equal amounts of fluid to the plant. The NPV of the cash flow is \$100,000,000. Figure 8.3 shows the location and the year the successful wells are drilled. The dry holes (meaning mechanically damaged, low permeability, etc.) are not shown in the figure, but have been included in the plot of cumulative number of wells drilled and are considered in the cost analysis.

Figure 8.1 Case 1 (Declining Power Generation, no injection). Total flow rate and cumulative cash flow and electrical power output.

Figure 8.2 Case 6 (50 MW_e, no injection). Total flow rate and cumulative number of drilled wells, cash flow and electrical power output.

Figure 8.3 Case 6 (50 MW_e, no injection). Location of production wells.

60% injection (Case 10): This case has 50 MW_e of power produced with additional wells drilled for production and three wells drilled for injection. Figure 8.4 shows the various data plots. Most of the fluid is produced from the existing well field. A total of nine wells are drilled including two dry holes and three injection wells that are drilled in the northern portion of the field. The NPV of the cash flows is \$94,000,000, which is somewhat less than the 50 MW_e case with no injection (see above) due mainly to the cost of the injection wells (the injection wells are drilled in year zero). Figure 8.5 shows the location of the successful wells and the year they are drilled.

8.2.3 Development Program—75 MW_e

No injection (Case 11): This case considers a nominal 75 MW_e of produced power. Figure 8.6 shows the pertinent information. The total well field flow rate drops with time due to increasing produced enthalpy. Drilling of a total of 30 new wells (six dry holes are included) is required over a 30-year period. The NPV of the cash flows is \$130,000,000. Figure 8.7 shows the locations of the production wells that are needed to meet the power output requirements.

60% injection (Case 15): Figure 8.8 shows the summary information for this development scenario. A total of 27 new wells are needed over the 30-year period (five wells are dry holes). The NPV of \$128,000,000 is somewhat less than in Case 11 due to the four successful (one injection well is assumed to be unsuccessful) injection wells that are drilled in year zero. Figure 8.9 shows the location of the successful wells drilled to meet the project requirements.

8.2.4 Development Program—90 MW_e

30% injection (Case 18): This was the only 90 MW_e case investigated. Figure 8.10 shows the pertinent information. For this case wells are drilled to year 20 and the field flow rate declines during years 20–30. The CPO shows a decreasing slope versus time reflecting the declining power output in later years. A total of 35 wells are drilled. The NPV of the cash flows is \$141,000,000. The location of the successful wells is shown in Fig. 8.11.

8.3 Discussion of Various Development Strategies

Figure 8.12 shows the cumulative cash flow versus time for the various development scenarios for which economic aspects were studied. The 90 MW_e case shows the largest cumulative cash flow and the declining power generation (no wells drilled) case shows the lowest. The

Figure 8.4 Case 10 (50 MW_e, 60% injection at 150°C). Total flow rate and cumulative number of drilled wells, cash flow and electrical power output.

Figure 8.5 Case 10 (50 MW_e, 60% injection at 150°C). Location of production and injection wells.

Figure 8.6 Case 11 (75 MW_e, no injection). Total flow rate and cumulative number of drilled wells, cash flow and electrical power output.

Figure 8.7 Case 11 (75 MW_e, no injection). Location of production wells.

Figure 8.8 Case 15 (75 MW_e, 60% injection at 150°C). Total flow rate and cumulative number of drilled wells, cash flow and electrical power output.

Figure 8.9 Case 15 (75 MW_e, 60% injection at 150°C). Location of production and injection wells.

Figure 8.10 Case 18 (90 MW_e, 30% injection at 150°C). Total flow rate and cumulative number of drilled wells, cash flow and electrical power output.

Figure 8.11 Case 18 (90 MW_e, 30% injection at 150°C). Location of production and injection wells.

Figure 8.12 Cumulative cash flow versus time for various field development scenarios.

75 MW_e cases with and without injection show approximately similar cash flows versus time at levels somewhat below the 90 MW_e cash flow. The 50 MW_e cases with and without injection also show similar cash flows with respect to each other, with cash flows notably less than the 75 and 90 MW_e cases. The reason for the similarity of the cash flows for the cases with and without injection is that, for the cases with injection, a greater amount of cash needs to be invested in year zero because of the injection wells. However, a smaller number of production wells are required during the project life for the cases with injection when compared to the those without injection.

Table 8.3 summarizes the economic and developmental information, including the total number of new wells required in each of the cases analyzed. The main difference between the various cases is the amount of investment required in year zero, due to the number of wells drilled at the beginning of the project.

Table 8.3 Summary of the economic calculations

Case	Number of New Wells				NPV [†]	Year Zero Investment [†]	Cumulative Cash Flow [†]
	Prod.	Inject.	Dry	Total			
Declining Power Gen.	0	0	0	0	82	0	360
50 MW _e No injection	5	0	2	7	100	3	489
50 MW _e 60% injection.	4	3	2	9	94	8	503
75 MW _e [#] No injection	24	0	6	30	130	15	685
75 MW _e 60% injection.	18	4	5	27	128	24	704
90 MW _e [#] 30% injection.	24	4	7	35	141	29	731

[†]Millions of US dollars

* Injection temperature: 150°C

[#]For these cases the targeted power generation is not possible for the entire 30-year period

Figure 8.13 gives the produced electrical output for the various cases as a function of time. This plot shows the reduction in output versus time for the declining power generation and the 90 MW_e with 30% injection cases. The other cases show constant power output over the 30-year project period.

Figure 8.14 shows the cumulative number of new wells (including production, injection, and dry wells) drilled for all but the case of declining power generation (no drilling is assumed). From the graphs given in Figs. 8.12 and 8.14 one concludes that the total number of wells drilled have a direct influence on the cash flow as a function of time.

8.4 Conclusions of the Preliminary Economic Analysis

As noted in Table 8.3 the difference between all the cases studied is small in terms of NPV but large in terms of the number of new wells drilled and the year zero investment. In this analysis this early investment is the main controlling factor on the NPV and in turn is governed by the number of wells needed initially to meet the production requirements and, for the cases with injection, the injection well requirements. From a NPV standpoint, each of the cases are justified for development because the project cash flow can easily cover the cost of development. From the standpoint of the number of new wells needed there is a large difference between the 50, 75, and 90 MW_e cases. This therefore leads to the conclusion that the magnitude of the development to be undertaken should be based on the confidence in the resource size and the ability of the resource to behave as the reservoir simulation has indicated.

The main reason that the economics indicate that each development case is warranted is that the cost of purchase and installation of the power plant is not included. This allows for the cost of the wells to easily be met by the cash flows. If the plants were not already in place, then a rate of return economic analysis (and other additional economic analyses) could then be performed. In any case, confidence in the reservoir size and reservoir simulation studies will always enter into the evaluation of development strategies.

Figure 8.13 Produced power output versus time for various field development scenarios.

Figure 8.14 Cumulative number of (production, injection and dry) wells drilled versus time for various development scenarios.

THE UNIVERSITY OF CHICAGO

 
CHICAGO, ILL. 60637
U.S.A.

 

9.0 Recommendations

9.1 Exploitation Recommendations

A total of 18 reservoir exploitation schemes (Table 7.1) were investigated. The four basic cases included maintaining power production at 50 MW_e, increasing it to 75 MW_e and 90 MW_e, or letting it decline naturally without drilling additional wells. The permutations of these basic schemes involved reinjecting the spent brine at different rates and temperatures. As discussed in Section 7, in all cases reinjection was beneficial. Our results indicate that the preferred option is to increase the power generation level to 75 MW_e, while injecting 60% of the produced fluids. Below we briefly describe some of the major reservoir exploitation schemes that were studied.

9.1.1 Power Production—90 MW_e

The 90 MW_e option brings the power production up to the installed capacity (minus 5 MW_e for plant and well downtime) using all three power plant units. Our results show that this is not a favorable option for several reasons, including the high number of wells required, the large initial cost, possible injection problems, and the larger risk of unsuccessful well drilling.

Because this option involves running the low pressure double flash unit, there is less spent brine available for injection and the brine is at a lower temperature. Approximately 30% of the produced fluids can be reinjected at a temperature of about 150°C. Injecting lower temperature brines may result in significant scaling problems in the injection lines and wells, and treatment of the brine will be required. Another problem with low injection temperatures is the greater degree of reservoir cooling.

Approximately 10 new production wells will be needed initially to increase the power production to 90 MW_e. The estimated initial cost for these wells as well as for the injection wells, dry holes, pipelines and surface facilities is 29 million dollars (see Table 8.3).

Our simulation predictions indicate that a total of 24 new production wells will be required over the first 20 years to maintain 90 MW_e (see Fig. 7.4). This appears to be the largest number of new wells that can produce at rates that are economical. The number of wells is limited by the size of the proposed wellfield expansion area and the amount of geothermal fluids recharging the

expansion area. Thus, after approximately 20 years, the electrical power production from the field would begin to decline below 90 MW_e.

9.1.2 Declining Generation Option

This scenario is not acceptable because the field will be producing power at a level far below its potential capacity. With no development drilling or injection, the power generation is projected to decline to approximately 38 MW_e by the year 2020 (see Fig. 8.13). Because the present large investment in power plants and surface facilities, it is most economical to produce the field at the highest level that the reservoir can support.

9.1.3 Power Production—75 MW_e

Our results indicate that 75 MW_e is the highest electrical power production level that can be maintained continuously over the 30-year period (1990–2020). Injecting 60% of the produced fluids at 150°C provides strong pressure support and decreases the number of new production wells by 33% (from 24 to 18, see Fig. 7.4). This option requires six new production wells in the first years and a total of 18 new production wells over the 30-year life of the project.

The 75 MW_e with 60% injection (at 150°C) case is considered the most favorable since it provides the greatest amount of power over the longest time period. The initial investment is considerably less than that for the 90 MW_e schemes, 24 million compared to 29 million dollars (see Table 8.3). After the initial drilling program to bring the field up to 75 MW_e, including the completion of the injection wells, the drilling requirements are less than one well every two years. The risk involved in this scenario is also much lower than with the 90 MW_e case, because of the smaller number of new wells that are required and because the changes from the current operations are less drastic.

The new production wells should be located southeast and east of the current wellfield (see Fig. 7.1). The injection wells should be completed north-northeast of the current wellfield to provide pressure support to the reservoir while not interfering with the natural hot fluid recharge. The injection should also help decrease the natural cold water influx coming from the north. The well spacing of the new production wells should not be any smaller than about 300 m.

9.2 Recommendations on Computer Equipment

It is extremely important that the reservoir engineering methodology developed for the Ahuachapán project be transferred to CEL personnel. Under a proposed work plan, LBL would transfer the comprehensive Ahuachapán data base to CEL along with the necessary software to manipulate and plot the data. CEL engineers and technicians will be trained to manage and expand the data bank as new information becomes available. LBL will also provide copies of various computer codes used in the analysis, including wellbore models, programs for analyzing well testing data and for reservoir simulation.

It will be very beneficial for CEL to conduct independent reservoir modeling studies in the future. This will require a computer dedicated to the storage of the reservoir engineering data base and to perform the numerical simulations. Computer design has advanced to a point where large-scale simulations may now be carried out on scientific workstations that fit under a desk and that cost less than about 40,000 dollars. A number of companies manufacture such stations, including Sun, IBM, DEC and Solbourne. The simulations performed at LBL for this report were all run on a Solbourne 502 series workstation.

The minimum requirements for running a simulation code such as MULKOM are a virtual memory machine with 16 megabytes of RAM. The speed of the machine should be at least 12 MIPS and 2 MFLOPS. At this speed, a full 3-D model of the field takes several hours to run. Thus, two or three iterations may be performed in a working day. The hard disk drive should have at least 600 megabytes to store the data base, the simulation results and all of the working files used by several engineers and technicians.

The necessary peripherals include a 19-in. monitor, either color or black and white, several user terminals (preferably VT-100 style), and at least one graphics terminal. The computer will have to be ordered with enough ports for all of the terminals. A laser printer that is capable of producing both text and graphics (such as an Apple postscript laser printer) will be required. The final necessary piece of equipment is a tape drive for transferring data and performing system backups. Exabyte style tape drives have the largest capacity, but quarter-inch streaming drives are also acceptable. An useful but optional feature on the workstation would be a PC emulator with a floppy disk drive.

10.0 References

- Allis, R. G., 1982. Comparison of Subsidence at Wairakei, Broadlands and Kawerau Fields, New Zealand, Proc. Eighth Workshop Geothermal Reservoir Engineering, Stanford, CA, Report SGP-TR-60, 183-188.
- Aunzo, Z., G. S. Bodvarsson, C. Laky, M. J. Lippmann, B. Steingrimsen, A. H. Truesdell and P. A. Witherspoon, 1989. The Ahuachapán Geothermal Field, El Salvador—Reservoir Analysis, Lawrence Berkeley Laboratory Report, LBL-26612.
- Baker, O., 1954. Design of Pipelines for the Simultaneous Flow of Oil and Gas, *Oil and Gas Journal*, 53, 185.
- Bangma, P., 1961. The Development and Performance of a Steam-Water Separator for Use on Geothermal Bores, Proc. U. N. Conference on New Sources of Energy, Rome, Italy, v. 3, p. 60.
- Bjornsson, A., G. Johnsen, S. Sigurdsson, G. Thorbergsson and E. Tryggvason, 1979. Rifting of the Plate Boundary in North Iceland 1975-78, *J. Geophys. Res.*, 84, 3029-3038.
- Bodvarsson, G. S. and P. A. Witherspoon, 1989. Geothermal Reservoir Engineering— Part I, *Geothermal Science and Technology*, 2 (1), 1-68, LBL-26881.
- Bodvarsson, G. S., M. J. O'Sullivan and C. F. Tsang, 1980. The Sensitivity of Geothermal Reservoir Behavior to Relative Permeability Parameters, Proc. Sixth Workshop Geothermal Reservoir Engineering, Stanford, CA, report SGP-TR-50, 224-237, LBL-15341.
- Bodvarsson, G. S., K. Pruess and M. J. Lippmann, 1986. Modeling of Geothermal Systems, *J. Pet. Eng.*, 38 (10), 1007-1021, LBL-18268.
- Einarsson, S. S., A. Vides R. and G. Cuellar, 1976. Disposal of Geothermal Waste Water by Reinjection, Proc. Second U. N. Symp. Development and Use Geothermal Resources, San Francisco, CA, U. S. Government Printing Office, 1349-1363.
- Grant, M. A., I. G. Donaldson and P. F. Bixley, 1982. *Geothermal Reservoir Engineering*, Academic Press, 369 p.
- International Formulation Committee, 1967. A Formulation of the Thermodynamic Properties of Ordinary Water Substance, IFC Secretariat, Düsseldorf, Germany.
- Larios, D., 1983. Estudio de la Permeabilidad, Porosidad y Densidad de las Rocas del Campo Geotérmico de Ahuachapán, CEL Internal Report.
- Lazalde-Crabtree, H., 1984. Design Approach of Steam-Water Separators and Steam Dryers for Geothermal Applications, *Geotherm. Resour. Coun. Bull.*, 13 (9) 11-20.
- Pruess, K., 1988. SHAFT, MULKOM, TOUGH: A Set of Numerical Simulators for Multiphase Fluid and Heat Flow, *Geotermia, Rev. Mex. Geoenergía*, 4 (1), 185-202, LBL-24430.

- Pruess, K., G. S. Bodvarsson and V. Stefansson, 1983. Analysis of Production Data from the Krafla Geothermal Field, Iceland, Proc. Ninth Workshop Geothermal Reservoir Engineering, Stanford, CA, report SGP-TR-74, 345-350, LBL-17145.
- Sigvaldason, G. E. and G. Cuellar, 1970. Geochemistry of the Ahuachapán Thermal Area, El Salvador, *Geothermics, Special Issue*, 2 (2), 1392-1399.
- Steingrímsson, B., G. S. Bodvarsson, G. Cuellar and C. Escobar, 1989. Changes in Thermodynamic Conditions of The Ahuachapán Reservoir Due to Production and Injection, Proc. Fourteenth Workshop Geothermal Reservoir Engineering, Stanford, CA, Report SGP-TR-122, 279-286, LBL-26871.
- Tomasson, J. and G. K. Halldorsson, 1981. The Cooling of the Selfoss Geothermal Area, S-Iceland, *Geother. Resour. Coun. Trans.*, 5, 209-212.
- Truesdell, A. H., F. D'Amore and D. Nieva, 1984. The Effects of Localized Aquifer Boiling on Fluid Production at Cerro Prieto, *Geother. Resour. Coun. Trans.*, 8, 223-229.
- Weres, O. and R. C. Schroeder, 1978. Documentation for Program OGRE, Lawrence Berkeley Laboratory Report, LBL-7060.