STANFORD GEOTHERMAL PROGRAM
STANFORD UNIVERSITY
STANFORD, CALIFORNIA 94305

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PROCEEDINGS
SPECIAL PANEL ON GEOTHERMAL MODEL INTERCOMPARISON STUDY

held in conjunction with
The Code Comparison Contracts
issued by
Department of Energy
Division of Geothermal Energy
San Francisco Operations Office

at the
Sixth Annual Workshop on
Geothermal Reservoir Engineering
December 16-18, 1980

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Department of Energy
Division of Geothermal Energy

TABLE OF CONTENTS

PREFACE

The Stanford Geothermal Program hosts an annual workshop as part of its contract with the Department of Energy to develop reservoir engineering practices for accelerating the commercial development of geothermal resources. The annual workshop has two major objectives: (1) to bring together researchers active in the various scientific and engineering disciplines involved in the study of geothermal reservoirs to review progress and exchange ideas in this rapidly developing field, and (2) to summarize the effective state of the art of geothermal reservoir engineering in a form readily useful to the many government and private agencies involved in the development of geothermal resources. Each annual workshop features a panel analysis of a problem of major interest to the geothermal energy community.

The topic for panel analysis for the Sixth Annual Workshop in Geothermal Reservoir Engineering was selected in conjunction with the Department of Energy to assess the state of development and the appropriate role of geothermal reservoir simulator models in predicting geothermal reservoir performance as it affects investment decisions. The panel analysis was planned as a cohesive session with (1) an introduction on the background of the DOE decision to issue a number of contracts to determine how well existing simulator models can evaluate problems of varying complexity; (2) a report by the authors of the respective problems on how well the existing codes appear to evaluate the problems; (3) a discussion by invited panelists representing various sectors of the geothermal community to respond on how the state of art of the several simulators might meet

industry needs; and *(4)* a general discussion by all of the participants with summary reports by three selected rapporteurs.

The Stanford Geothermal Program is making the results of this panel session available as a separate report since the potential role of simulators in geothermal reservoir engineering is large, and the need to encourage further development of simulator models is apparent. The Stanford Geothermal Program hopes that these proceedings will assist in furthering the successful development of these simulator models.

Paul Kruger
Stanford Geothermal Program
March **31,** 1981

GEOTHERMAL RESERVOIR ENGINEERING CODE COMPARISON PROJECT

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Review of the need for geothermal reservoir simulators, begun at the 1978 Stanford Workshop, continues with the results of U.S. Department of Energy (DOE) contracts on comparison of computer codes. The fundamental issue is the appropriate role of simulators in major investment decisions on geothermal projects, such as the construction of a power plant at a specific reservoir.

WHAT

With this session at the 1980 Stanford Workshop, the Department of Energy responds to the geothermal industry's recommendation that reservoir simulators be evaluated and compared. Last year, DOE Headquarters' Division of Geothermal Energy budgeted for a code comparison project. In February 1980, a group of code developers met at DOE's San Francisco Operations Office to design a set of test problems. In the following papers, the designers of these problems will present the results of this Code Comparison Project.

In June, DOE requested proposals to run the problem set on commercially available geothermal reservoir simulators. In September, multiple awards were made to four offerors: Intercomp; Systems, Science and Software; GeoTrans; and Stanford Univ. Negotiations on a fifth contract were unsuccessful. Lawrence Berkeley Laboratory and the University of Auckland have also prepared solutions to the problem set. Final reports containing solutions, descriptions of the simulators, and approaches were delivered to my office in mid-November. Copies can be obtained from USDOE Technical Information Center, P.O. Box 62, Oak Ridge, TN 37830 (Final Report DOE/SF/11451-1).

DOE has not undertaken to evaluate these results, or to certify any of the reservoir simulators. Rather, the final reports were delivered to the problem designers to summarize and comment on the results. The Department supports the Stanford Workshop as the medium for the geothermal reservoir engineering community to become familiar with these results, and to determine their meaning and value.

WHY

Public funds were expended on this project for two reasons: the recommendation of geothermal industry advisors, and the mandate in the geothermal public law.

In May, 1979, the Technical Review Committee on Reservoir Engineering (Nielson, 1979) recommended to DOE that "Model comparison and validation should be a new initiative in the (Geothermal) Reservoir Engineering Program.

An attempt should be made to try all major codes on the same system and compare results with respect to output and efficiency of the code. It was suggested the codes should be run on an actual geothermal system where adequate data exists rather than a hypothetical situation. Suggested areas which could be used for code comparison include Cerro Prieto, Mexico; Wairakei, New Zealand; or Larderello, Italy. A workshop should then be held on the use and limitations of the various codes available..."

The mandate from Congress to the Department of Energy to support this effort is found in the Geothermal Research, Development and Demonstration Act of 1974 (Public Law 93-410, Sections 103(a) and 104(a)). "The specific goals shall include . . . the development of better methods for predicting the power potential and longevity of geothermal reservoirs; (and) . . . the development of reliable predictive methods and control techniques for the production of geothermal resources from reservoirs."

Don Campbell of Republic Geothermal, Lnc. has stated the fundamental need as one of establishing the confidence of consultants to banks, utilities, etc. in computer simulation as a basis for investment decisions on major geothermal projects (e.g. power plants). As you know, computer simulation is an established technique in oil and gas investment decisions.

In summary, we seek to learn what the capabilities of geothermal reservoir simulators are, and if they are reliable bases for geothermal investment decisions.

HOW

In defining how to evaluate and compare simulators, DOE turned to code developers and industry users.

A position paper was prepared for DOE Headquarters by John Pritchett (1979) of Systems, Science and Software, to describe mathematical reservoir modeling and geothermal reservoir simulators. Pritchett pointed out that reservoir simulators are tools used in the overall reservoir modelling process whose application to real fields requires considerable engineering judgment and insight. He suggested, as a first step, testing the reservoir simulators alone by setting up a suite of idealized problems designed to fully exercise the codes, thus testing the "tools" rather than the "modellers."

A comprehensive review of geothermal reservoir simulators has been published by Pinder (1979) under the DOE-LBL subsidence research program.

At the December 1979 Stanford Workshop, differences between numerical simulations and observed data at geothermal fields were discussed by Donaldson and Sorey (1979), and several limited applications were proposed. Their paper responded to the questions posed at the 1978 Workshop: whether these simulators are of any real value, and, if so, what are their best uses.

DOE then requested code developers and industry users to validate the need for a Code Comparison Project. This they did, and recommended that a set of standard problems be defined for that purpose. And, in February, 1980, the code developers met and designed the problem set.

What Next?

In my understanding, the current situation is as follows (Fig. 1):

1) Specific Reservoir and Integrated Model

At operating and developing geothermal reservoirs, field and test data has been used to derive physical properties, their distribution and change over time. These same data form the basis for conceptual model(s) of the reservoir constructed by integrating structural geology, geochemistry and reservoir engineering analyses. Reservoir management strategies (flash, pump, inject, stimulate etc.), selected by the field operator(s), define production and injection operations used to produce the reservoir.

2) Computer Simulator

Fundamental. physical processes in geothermal reservoirs have been represented by partial differential equations and assumptions. Several code developers have prepared reservoir simulators to solve these equations. A set of hypothetical reservoir problems has been designed to test the simulators.

3) Reservoir Model and Simulator

With the aid of simulator "tools", matches to actual production data may be achieved. Projections into the future, using possible reservoir management.strategies., yield.estimates of reserves, production/injection rates and reservoir lifetime. Together with extensive financial and other considerations, these results provide input to investment decisions on the reservoir.

Hopefully, the Code Comparison Project will establish that several reliable reservoir simulator "tools" are now available to the industry. The question remains of how best to engender industry and investment community confidence in the use of geothermal simulators. Perhaps acceptance of numerical simulation will evolve gradually, as more field studies are made which build a track record for the methodology.

Has DOE satisfied the concerns that led the geothermal industry to recommend that this effort be undertaken? Are consultants to major geothermal projects sufficiently confident to start using these "black boxes" for investment decisions?

If not, I invite you to define the tasks, the geothermal reservoir, and the sources of data that are needed. Will the next step be carried out by the industry, or do you recommend that DOE participate in a joint effort?

Acknowledgement

It is a pleasure to acknowledge the contributions of John Pritchett, Karsten Pruess, Michael Sorey, Michael O'Sullivan, Leland Mink and Marshall Reed in defining the code comparison project. Their concern with the relation between simulators and reservoir assessment has deepened my understanding, and increased the effectiveness of this effort.

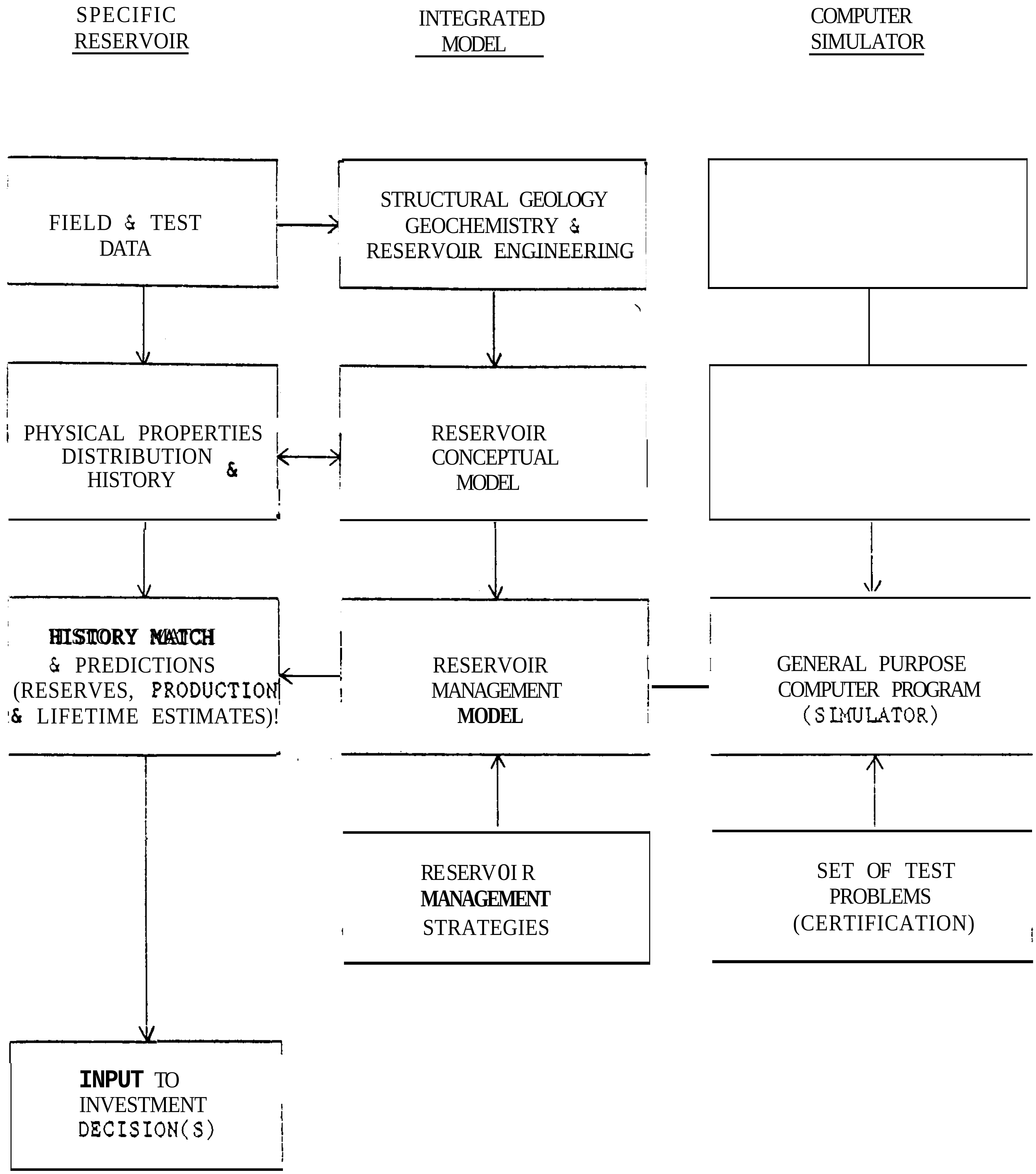


Figure 1. Design and Application of Reservoir Simulators.

References

Donaldson, Ian G., and Sorey, Michael L., "The Best Uses of Numerical Simulators", Fifth Annual Workshop on Geothermal Reservoir Engineering, Stanford Geothermal Program, Stanford Univ., Dec. 1979.

Nielson, D.L. ed., "Program Review, Geothermal Exploration and Assessment Technology Program, Including a Report of the Reservoir Engineering Technical Advisory Group", Earth Sciences Laboratory University of Utah Research Institute, Salt Lake City, Utah; Dec. 1979.

Pinder, George F. and Golder Associates, "State-of-the-Art Review of Geothermal Reservoir Modeling, Geothermal Subscience Research Management Program, Lawrence Berkeley Laboratory, LBL-9093, GSRMP-5, UC-66a, March 1979.

Pritchett, J.W., "Position Paper; Mathematical Reservoir Modeling Using Numerical Reservoir Simulators as Applied to Geothermal Systems", Aug. 1979 (unpublished).

EXHIBIT I

PROBLEM SET

The Contractor shall provide solutions to the problems included herein. Work shall be accomplished in accordance with the terms and conditions of this contract and with the Contractor's proposal submitted in response to Request for Proposal (RFP) No. DE-RP03-80SF10844.

If possible within the project budget, although not a requirement of this contract, problem set #6 will be addressed to illustrate the capabilities of the Contractor's code, but a complete solution will not,be provided.

PROBLEM STATEMENT

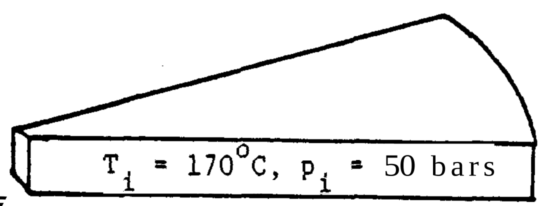
#1. 1-D Avdonin Solution

PHYSICAL DESCRIPTION

This problem involves one-dimensional, radial, steady-state flow, and unsteady heat transport in a single-phase liquid. The purpose is to test heat conduction and convection in the single-phase compressed water region.

PROBLEM SPECIFICATIONS

Water at 160°C is injected into the fringe of a geothermal reservoir of temperature 170°C. This problem looks at one well and assumes a quasi steady-state flow field is set up very rapidly. The boundary conditions for flow are: injection rate, q = 100kg/sec, specified at the well face, and pressure = 50 bars at an outer radius of 1000m. For heat transport, the temperature at the well face is 160°C and at the outer radius is 170°C. Initial temperature is 170°C everywhere in the reservoir, and the initial pressure is 50 bars. Boundary conditions and initial conditions are shown below.



at $r = r_w = 0.0$ | at $r = R = 1000m$
$T(t) = 160°C$ | $T(t) = 170°C$
$q = 100$ kg/sec | $p(t) = 50$ bars

Properties

permeability = $10^{-12}m^2$

density rock = 2500 kg/m^3

specific heat of rock = 1.0 $J/g.^oC$

thermal conductivity = 20 $W/m.^oC$

reservoir thickness = 100m

porosity = .2

Thermal properties for water

provided by modeler

specify constants: specific heat, viscosity and density of water (165^oC, 50 bars).

~~Numerical grid and time step data~~

time steps = 1.67×10^7 sec

grid spacing = 25m

OUTPUT SPECIFICATIONS

1) Temperature versus radial distance at 10^9 sec (60 time steps)

2) Take node at r = 37.5m and give solution of temperature versus time.

COMMENTS

For constant density, viscosity, and heat capacity of water, an analytical solution is available for this problem. For example, this solution is a limiting case of the problem solved by Avdonin, 1964.

Reference

Avdonin, N.A., 1964, Some formulas for calculating the temperature field of a stratum subject to thermal injection: Meft'i Gaz, v. 3, p. 37-41.

PROBLEM STATEMENT

#2. 1-D Well Test Analysis

PHYSICAL DESCRIPTION

This problem involves a set of three constant discharge, transient well test cases. Each case has 1-D radial flow to a line sink (zero radius well) in a homogeneous porous media, In Case a the fluid is single-phase liquid; in Case b the fluid is a two-phase mixture with both water and steam mobile; and in Case c the fluid changes from compressed liquid to a two-phase mixture as a flash front propogates away from the well. For each case, either an exact analytical solution (Theis solution) or an accurate semi-analytical solution is available for comparison with numerical solutions. Solutions will consist of pressure, saturation, and flowing enthalpy changes as functions of t/r^2 (time/distance squared).

PROBLEM SPECIFICATIONS

The following initial and boundary conditions and parameter values are to be used:

Specification	Case a	Case b	Case c
Initial pressure (bars)	90	30	90
Initial liquid saturation	1	.65	1
Initial temperature (^{o}C)	260	233.8 1/	300
Porosity	.20	.15	.20
Permeability ($10^{-12}m^2$)	.01	.24	.01
Thickness (m)	100	100	100
Discharge (kg/s)	14.0	16.7	14.0
Rock heat capacity ($kJ/m^{3\,o}C$)	2650	2000	2650
Rock compressibility	0	0	0
Relative permeability functions 2/	1-ph	Corey	Corey
Rock thermal conducrivity	0	0	0

1/ Saturation temperature at 30 bars

2/ $k_{rw} = [S^*]^4$, $k_{rs} = [(1-S^*)^2] \cdot [1 - (S^*)^2]$, $S^* = [(S - .3)/(.65)]$,

S = liquid saturation

NUMERICAL SOLUTIONS

Analytical results for each case indicate that solutions for pressure, saturation, and flowing enthalpy are functions of t/r . To minimize computational requirements while avoiding the significant spatial discretization errors, the following nodal arrangement should be used for each case.

$$r_n = 0.5 (\sqrt{2})^{n-1} \qquad n = 1, 26$$

Total simulation time in each case should be 1 day. For the grid specification given above, an initial time step near 10^{-4} or 10^{-5} days is suggested for accurate solutions at early times.

ONE NODE TWO-PHASE PROBLEM

To facilitate evaluation of numerical solutions for two-phase flow, an additional problem under Case b conditions should be run. It involves 1 grid block with volume = 314 m^3 and constant discharge of 16.7 kg/s for .01 days. A constant time step of 10^{-4} days should be used, and the enthalpy of the discharge fluid should be weighted according to the mobility of each fluid phase (as in Cases b and c).

OUTPUT SPECIFICATIONS

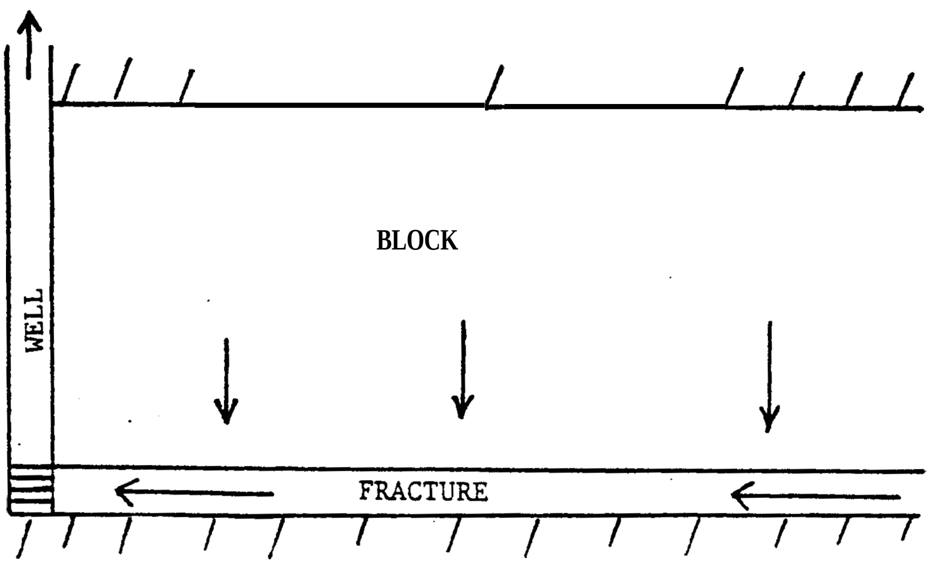
Results for each case, except for the one-node problem, should consist of plots of pressure in bars, liquid saturation (Cases b and c), and flowing enthalpy in kJ/kg (Cases b and c) as functions of log (t/r^2) in days/m^2 for nodal points at 0.5 m, 0.707 m and 1.0 m from the well. The corresponding data in tabular form should also be provided. Data covering 5 log cycles for Cases a and c, and a log cycles for Case b should be included in the plots and tabulations. Specification of the computational grid and time step variation utilized should also be procided. Results for the one-node problem should consist of plots of pressure, liquid saturation, and discharge enthalpy versus time, along with the corresponding data tabulations.

PROBLEM STATEMENT

#3. **2-D** Flow to a Well in Fracture/Block Media

PHYSICAL DESCRIPTION

. This problem represents a simplification of the general problem of well testing in fractured geothermal reservoirs. As shown in the following sketch, a well producing at constant discharge is open to a horizontal fracture of infinite lateral extent. Vertical flow in the block and radial flow in the fracture, each obeying Darcy's law,



is to be simulated. The upper boundary of the block and the lower boundary of the fracture are impermeable, and the well has a finite radius with well-bore storage.

PROBLEM SPECIFICATIONS

For application to vapor-dominated reservoirs, steam flow in the block and fracture will be simulated. Parameter specifications for two cases are listed below:

Specification	Case a	Case b
Initial-pressure (bars)	30.5	30.5
Initial liquid saturation (in block) 1/	0	.2
Initial temperature (°C) 2/	234	234
Porosity in fracture	.1	.1
Porosity in block	.1	.1
Permeability in fracture ($10^{-12}m^2$)	.3	.3
Permeability in block ($10^{-12}m^2$) 3/	,00003	.00003
Thickness of fracture	.1	.1
Thickness of block	1.0	1.0
Well discharge (kg/s)	.028	.028
Well radius (m)	.16	.16
Rock heat capacity ($kJ/m^3 {}^oC$)	2570	2570
Rock compressibility	0	0
Rock thermal conductivity	0	0

1/ Initial liquid saturation is zero in the fracture in both cases

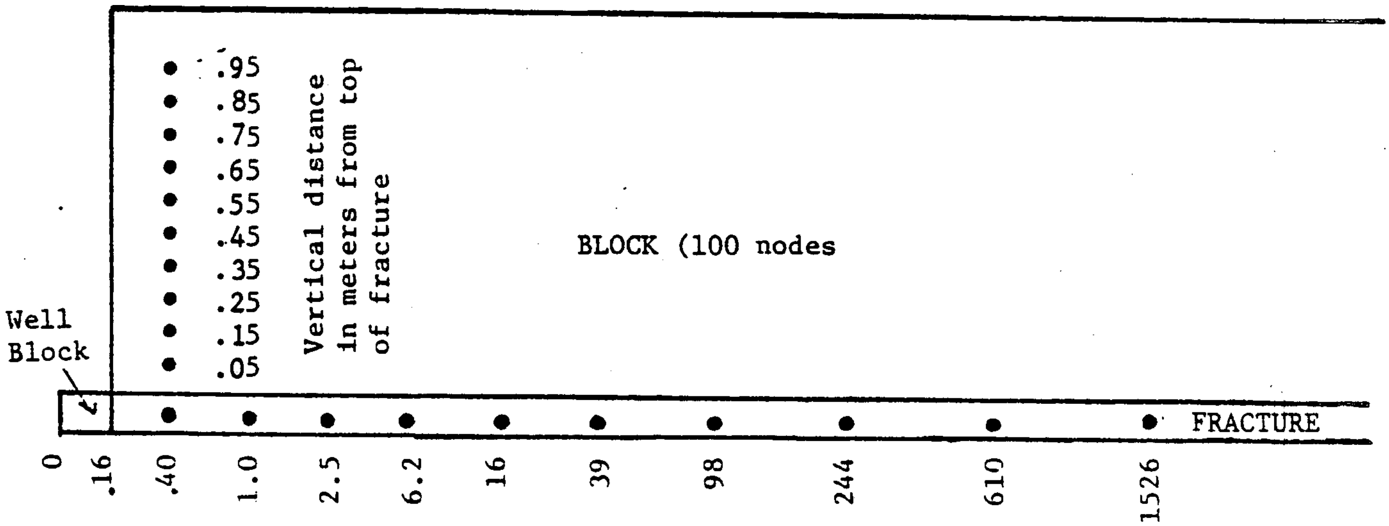
2/ Saturation temperature at 30.5 bars

3/ Horizontal permeability in block is zero in both cases

In Case a, liquid saturation is zero everywhere (no boiling). In Case b, immobile liquid boils in the blocks but not in the fracture. Relative permeability to steam is 1.0 in both cases.

NUMERICAL SOLUTION

A computational grid consisting of 1 well block, 10 logarithmically-spaced nodes in the fracture, and 100 nodes of equal vertical thickness in the block should be used. For those codes using finite difference techniques, either block-cenrered or face-centered nodai patterns could be used provided that nodal 'positions were approximately the same as those shown below. The porosity and permeability in the well block should be set to 1.0 and 30 x $10^{-12} m^2$ (or larger), respectively.



Radial distance in meters from center of well.

Total simulation time should be 10^4s or more, and to define the pressure history at the well face an initial time step of 1 s should be used. Minimum simulation time of 10^4s would be reached in about 130 time steps if a time step multiplication factor of 1.05 were used.

OUTPUT SPECIFICATIONS

Results for Cases a and b should consist of plots of pressure as a function of log (time), along with the corresponding data in tabular form. For each case, plot pressure at the well face, and pressure at a point located 2.5 m from the center line of the well and .25 m above the top of the fracture. Include a tabulation of liquid saturation versus time for this same point in the block under Case b conditions. The required data for each case should cover at least 4 log cycles in time.

PROBLEM STATEMENT

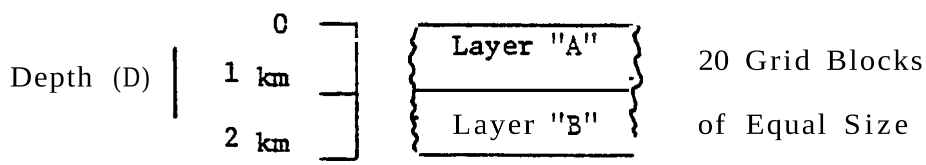
#4. Expanding 2 Phase System with Drainage

PHYSICAL DESCRIPTION

This problem involves 1-D vertical flow under both single and two phase conditions. An initially hydrostatic column of liquid is disturbed by mass withdrawal at the bottom. Boiling occurs in portions of the column, and inflow of cold water is induced at the top.

PROBLEM SPECIFICATIONS

1-D Cartesian (Vertical) Geometry



g = 9.8 m/s

Rock Properties

	Layer "A" ($0 \leq D \leq 1$ km)	Layer "B" (1 km $< D \leq 2$ km)
Grain Density (g/cm^3)	2.5	2.5
Porosity	0.15	0.25
Permeability (m^2)	5×10^{-15}	100×10^{-15}
Heat Capacity ($J/g\text{-}^{\circ}C$)	1	1
Grain Thermal Conductivity ($W/m - {}^{\circ}C$)	1	1

Relative Permeability Functions: Corey (as specified in Problem #2)

Boundary Conditions

At $D = 0$ (Surface), $P = 1.013$ Bar (~ 1 atm), $T = 10^{\circ}C$

At $D = 2$ km, see below.

Initial Conditions

$$T(D) = [10 + 280\ (D/1\ \text{km})]^{\circ}C \qquad 0 \le D \le 1\ \text{km}$$

$$= [270 + 20\ (D/1\ \text{km})]^{\circ}C \qquad 1\ \text{km} \le D \le 2\ \text{km}$$

$$P(D) = 1.013\ \text{Bar} + \int_0^D \rho g\, dD;\ \text{hydrostatic.}$$

Production Strategy

From $t = 0$, to 40 years extract fluid from the bottom of the system ($D = 2$ km) at a rate of 100 kg/s - km^2.

OUTPUT SPECIFICATIONS

Plot and Tabulate: Discharge enthalpy history of the produced fluid. Recharge rate and cumulative recharge at the surface ($D = 0$).

$P(t)$, $T(t)$ and liquid saturation $S(t)$ at $D = 0.5$, 1.0, 1.5 and 2.0 km.

PROBLEM STATEMENT

#5. Plow in a 2-D Areal Reservoir

PHYSICAL DESCRIPTION

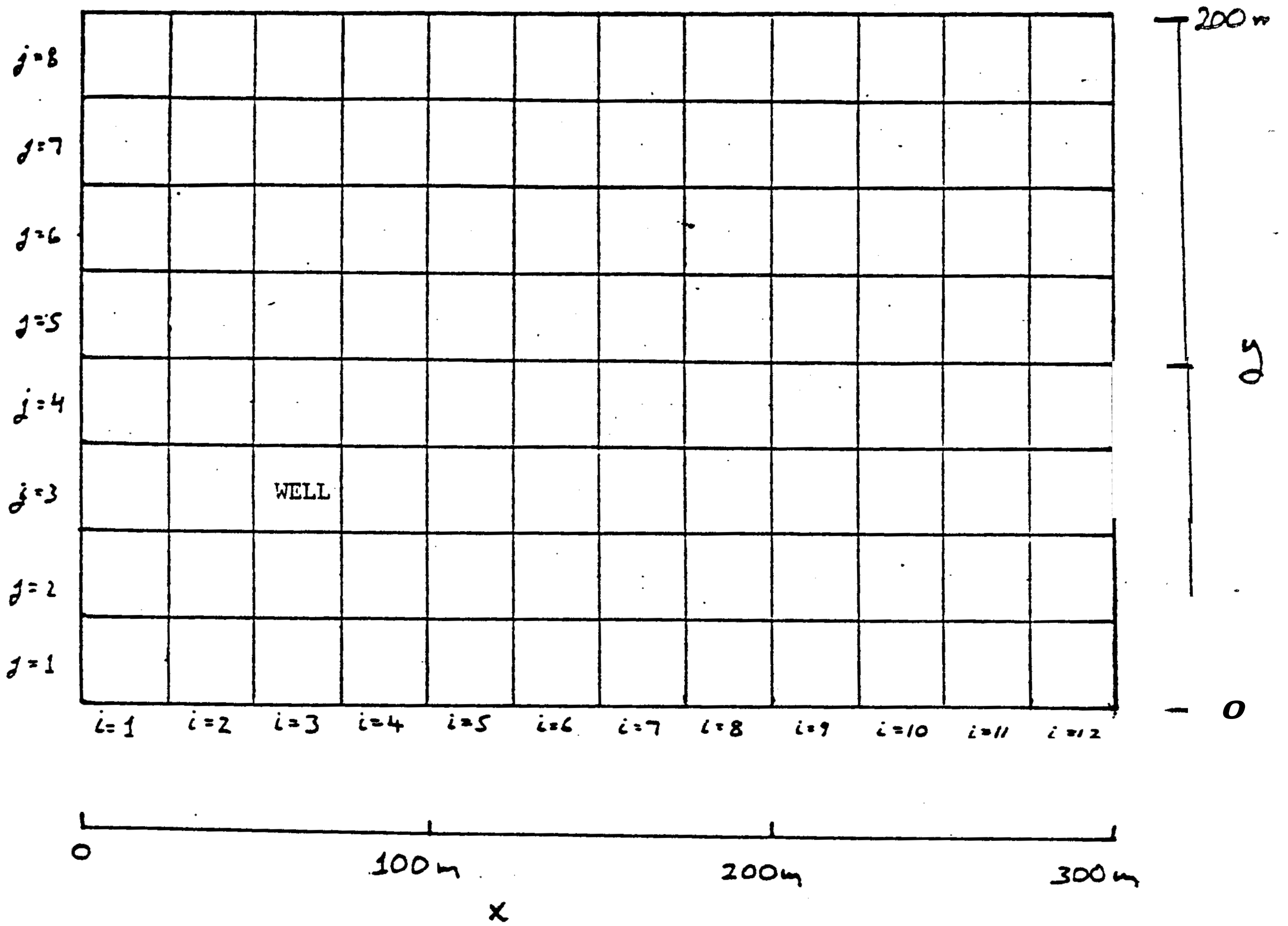
This problem involves multiphase flow in a 2-D horizontal reservoir.. Mass is produced at one point in the reservoir, and recharge is induced over one of the lateral boundaries.

PROBLEM SPECIFICATIONS

2-D Areal Geometry

Region is horizontal (gravity neglected; $g_x = g_y = 0$) and of uniform thickness; extends over $0 \leq x \leq 300$ meters, $0 \leq y \leq 200$ meters

Finite - difference zoning as indicated: 12 x 8 grid (96 zones total) of uniform size $\Delta x = \Delta y = 25$ meters.



Rock Properties (**Uniform** over Grid):

Rock Grain Density = 2.5 g/cm^3

Porosity = 0.35

Permeability ($k_x = k_y$) = $2.5 \times 10^{-14} m^2$

Heat Capacity of Rock Grain = 1 J/g ^oC

Rock Thermal Conductivity = 1 W/m ^oC

Relative Permeabilities -- Corey Equations as **in Problem** #2 with

liquid residual saturation S_{lr} = *0.3*, **gas** residual saturation S_{gr} = 0.1

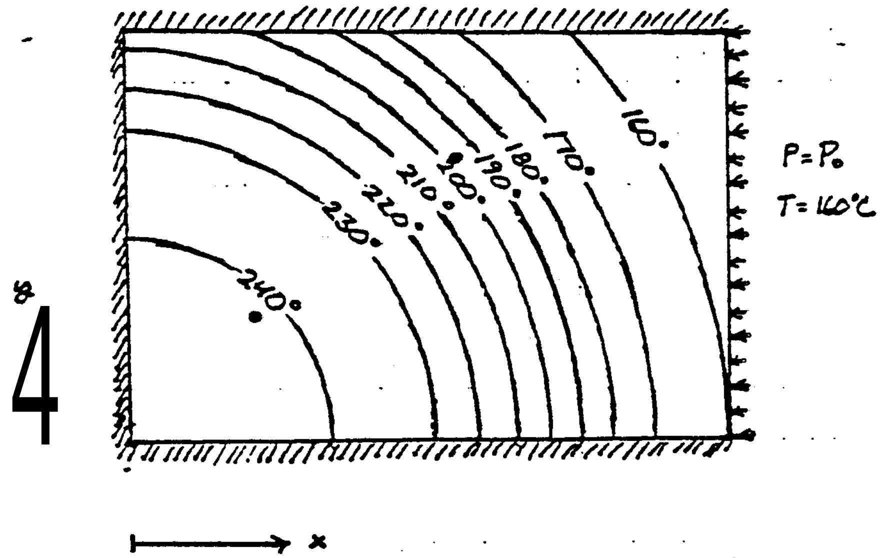
Boundary Conditions: (See Figure Below)

Impose no convection, no conduction (impermeable, insulated) along:

$y = 0m$; $y = 200m$; $x = 0m$

Maintain initial P, T along $x = 300m$, $0 \leq y \leq 200m$

($P \approx 36$ bars, $T = 160^{o}C$) ; see below



Initial Conditions:

Pressure initially uniform, and equal to saturation pressure at $240^{o}C$, plus 2.5 bars:

$$P(t = 0, 0 \leq x \leq 300m, 0 \leq y \leq 200m) =$$

$$P_{sat}(240^{o}C) + 2.5 \text{ bars}$$

Note that $P_{sat}(240^{o}C)$ 33.5 bars, so $P_{o} \approx 36$ bars

Initial temperatures for each zone are provided on the table on the next page. They are given approximately by:

$$T(t=o) = 240^{o}C \text{ for } r \leq 100m$$

$$= [240 - 160 \left(\frac{r-100m}{200m}\right)^{2} + 80 \left(\frac{r-100m}{200m}\right)^{4}]^{o}C$$

$$\text{for } 100m < r < 300m$$

$$= 160^{o}C \text{ for } r \leq 300m$$

where $r \equiv \{ \cancel{x + y}$

Initial Temperatures (^{o}C) $T_{ij}(t = o)$:

212.07	210.18	206.41	200.81	193.59	185.18	176.31	168.09	162.03	160.00	160.00	160.00	j = 8
224.92	223.16	219.54	213.95	206.41	197.16	186.79	176.31	167.13	161.12	160.00	160.00	j = 7
234.31	232.93	229.92	224.92	217.70	208.29	197.16	185.18	173.71	164.58	160.11	160.00	j = 6
239.31	238.62	236.74	232.93	226.64	217.70	206.41	193.59	180.56	169.11	161.54	160.00	j = 5
240.00	240.00	239.77	237.76	232.93	224.92	213.95	200.81	186.79	173.71	163.85	160.00	j = 4
240.00	240.00	WELL 240.00	239.77	236.74	229.92	219.54	206.41	191.85	177.68	166.22	160.26	j = 3
240.00	240.00	240.00	240.00	238.62	232.93	223.16	210.18	195.36	180.56	168.09	160.77	j = 2
240.00	240.00	240.00	240.00	239.31	234.31	224.92	212.07	197.16	182.06	169.11	161.12	j = 1
		i = 3	i = 4								i = 12	

Production Strategy for Case A

A fully-penetrating production well is located at x = 62.5m, y = 62.5m (at the center of zone i=3, j=3). Starting at t=o, it produces fluid at the constant rate of 0.05 kilograms/sec-meter of thickness. The well radius is 15 cm and no skin effect is present.

Production Strategy for Case B

A production well is present, identical to Case A. In addition, an injection well is located at x = 162.5m, y = 137.5m, at the center of tone i=7, j=6. The well is fully penetrating, has no skin effect, and is of radius 15 cm. The injection well is inoperative until $t = 1$ year (3.1536×10^7 sec). Thereafter, it begins injecting water at $T = 80^\circ$C at a rate of 0.03 kilograms/sec-meter of thickness.

OUTPUT SPECIFICATIONS

In both cases, the time domain of interest is

$0 \leq t \leq 10$ years (3.1536×10^8 sec).

For cases A & E, plot and tabulate:

(1) Pressure history in zones i=3, j=3 and i=7, j=6.

(2) Temperature history in zones i=3, j=3.

(3) History of discharge (flowing) enthalpy in zone i=3, j-3.

(4) Variation with time of total mass of steam in the system per meter of thickness.

Optional (for those with subgrid well model):

(5) What is the sandface pressure history for the production well in cases A & B?

(6) What is the sandface pressure history for the injection well in Case B?

(7) What is the sandface steam saturation history at the production well in cases A & B?

PROBLEM STATEMENT

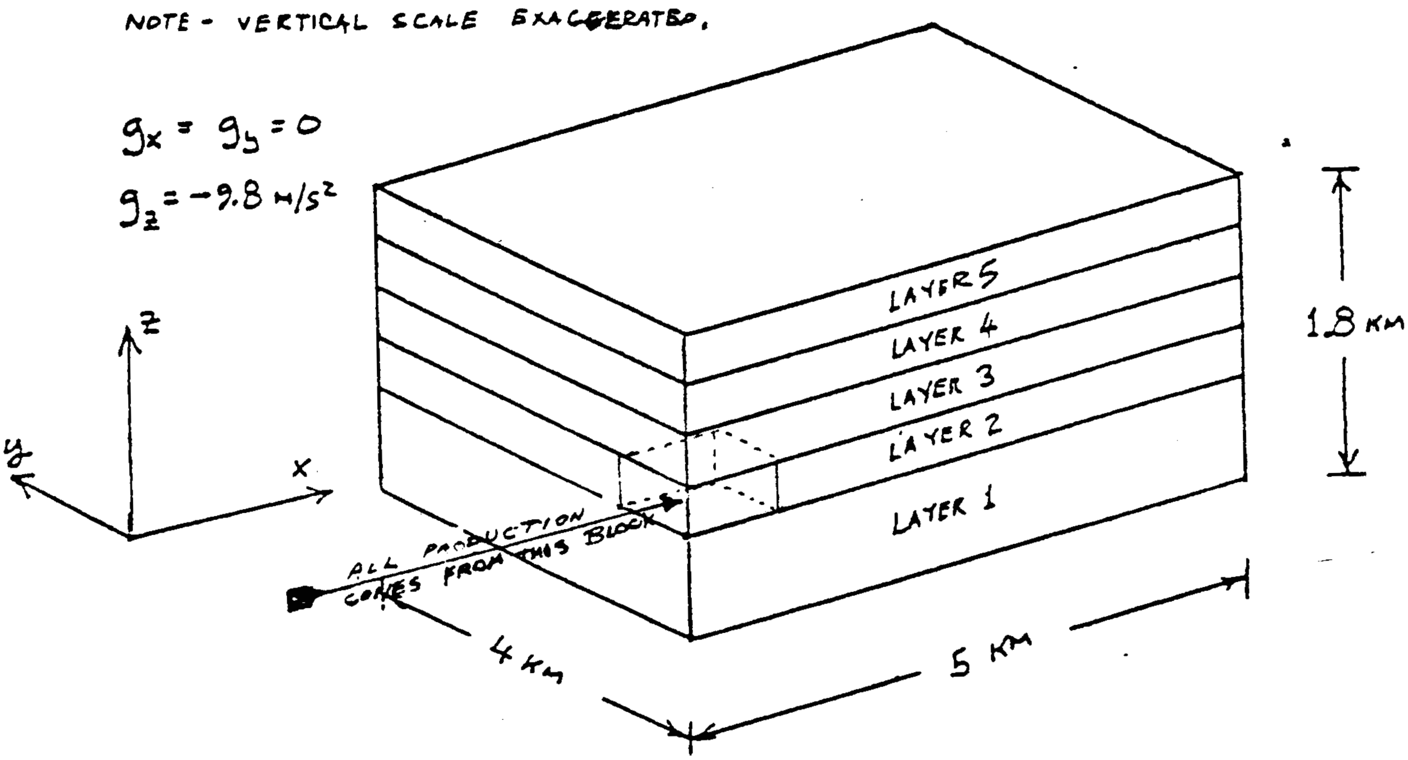
16. Flow in a 3-D Reservoir.

PHYSICAL DESCRIPTION

This **problem involves flow within a 3-D system, with production from one corner grid block, and constant pressure upper and lower surfaces. The flow is initially single phase liquid, except in one layer where an immobile steam phase exists.**

PROBLEM SPECIFICATIONS

3-D geometry, five layer



LAYER THICKNESSES:
LAYER 1, 0.6 KM
LAYERS 2-5, 0.3 KM EACH

GRID: 5 x 5 x 5
(Horizontal, uniform, 5 zones each direction)

Rock Properties

	Layer 1	Layer 2	Layer 3	Layer 4	Layer 5
Grain Density (g/cm^3)	2.5	2.5	2.5	2.5	2.5
Porosity	0.2	0.25	0.25	0.25	0.2
x-Permeability (m^2)	100×10^{-15}	200×10^{-15}	200×10^{-15}	200×10^{-15}	100×10^{-15}
y-Permeability (m^2)	100×10^{-15}	200×10^{-15}	200×10^{-15}	200×10^{-15}	100×10^{-15}
z-Permeability (m^2)	2×10^{-15}	50×10^{-15}	50×10^{-15}	50×10^{-15}	2×10^{-15}
Heat Capacity ($J/g\text{-}^oC$)	1	1	1	1	1
Rock Therm. Cond. ($w/m\text{-}^oC$)	1	1	1	1	1

Relative Permeability: Corey equations as in Problem #2, except:

S_{lr} (liquid residual)	0.3	0.3	0.3	0.3	0.3
S_{gr} (gas residual)	0.1	0.1	0.1	0.1	0.1

Initial Conditions

Temperature:

Layers 1-4, 280^oC everywhere

Layer 5, 160^oC

Pressure:

Layer 4: $P_4^o = P_{sat}\,(280^oC) \approx 64$ Bars

(Steam saturation) $S_s^o = 0.1$ (steam initially immobile)

Layer 5: $P_5^o = P_4^o - (1470\ m^2/s^2) \times (\rho_4^o\text{-liq} + \rho_5^o)$

Layer 3: $P_3^o = P_4^o + (1470\ m^2/s^2) \times (\rho_4^o\text{-liq} + \rho_3^o)$

Layer 2: $P_2^o = P_3^o + (1470\ m^2/s^2) \times (\rho_3^o + \rho_2^o)$

Layer 1: $P_1^o = P_2^o + (1470\ m\ /s\ ) \times (\rho_2^o + 2\rho_1^o)$

Where $\rho_4^o\text{-liq}$ = liquid density in Layer 4

These initial conditions (P^o, ρ^o, S_s^o) are functions of z only. Layers 1, 2, 3 and 5 are initially single-phase liquid; layer 4 is initially 2-phase with an immobile steam phase. The pressure distribution is liquid-hydrostatic throughout at zero time.

Boundary conditions

At z = 1.5 km (top surface), maintain $P_{top} = P_5^o - (1470\ m^2/s^2) \times \rho_5^o$ and T = 100°C.

At z = 0, maintain $P_{bottom} = P_1^o + (2940\ m^2/s^2) \times \rho_1^o$ and T = 280°C.

Along planes at x = 0 and y = 0, impose symmetry conditions.

Treat plane at y = 4 km as impermeable and insulated.

Along plane at x = 5 km, maintain initial distributions of P, T, S_s.

Production Strategy

All production is taken from a single corner cell (i=1, j=1, k=2).

$0 < t < 2$ years,	Q(t) = 1000 kg/s
2 years $< t \leq 4$ years,	Q(t) = 2500 kg/s
4 years $< t \leq 6$ years,	Q(t) = 4000 kg/s
$t > 6$ years,	Q(t) = 6000 kg/s

OUTPUT SPECIFICATIONS

For a total production time of 10 years, plot and tabulate:

Discharge enthalpy history.

Histories of P, T, S_s at x = y = o for each layer.

THE DOE CODE COMPARISON STUDY: SUMMARY OF RESULTS FOR PROBLEM 1

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INTRODUCTION

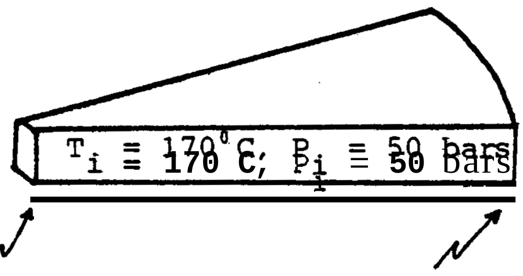
The steps in developing a numerical model consist of different levels of error elimination, The first step is to compile the program to remove FORTRAN errors. Next, the numerical solution is compared with analytical solutions to remove logic errors in solving the equation. Numerical solutions are compared with laboratory and field observations to remove logic errors in equations describing the physics. Finally, It is good programming practice to include mass and energy balances as checks that the model is working properly.

Problem 1 satisfies the second step. That is, it is a problem for which there exists an analytical solution. Computed results from the numerical models are therefore compared with the exact analytical results.

PROBLEM DESCRIPTION

This problem involves one-dimensional, radial, steady-state flow and unsteady heat transport in a single-phase liquid. The purpose is to test heat conduction and convection in the single-phase compressed water region.

Water at 160°C is injected into the fringe of a geothermal reservoir of temperature 170°C. This problem looks at one well and assumes a quasi steady-state flow field is set up very repidly. The boundary conditions for flow are: injection rate, q = 10kg/s, specified at the well face, and pressure = 50 bars at an outer radius of 1000 m. For heat transport, the temperature at the well face is 160°C and at the outer radius is 170°C. Initial temperature is 170°C everywhere in the reservoir, and the initial pressure is 50 bars. These boundary and initial conditions are shown in Figure 1. Reservoir properties are given in Table 1.



at $r = r_w = 0.0$	at $r = R = 1000$ m
$T(t) = 160^{\circ}C$	$T(t) = 170^{\circ}C$
$q = 10$ kg/sec	$p(t) = 50$ bars

Figure 1. Boundary and initial conditions for Problem 1.

Table 1. Reservoir properties and output specifications for Problem 1.

Properties

Permeability = $10^{-12} m^2$
density rock = 2500 kg/m^3
specific heat of rock = 1.0 J/g $^{\circ}C$
thermal conductivity = 20 W/m $^{\circ}C$
reservoir thickness = 100m
porosity = .2

Thermal properties for Water

provided by modeler
specify constants: specific heat, viscosity and density of water (165°C, 50 bars)

Numerical Grid and Time Step Data

time steps = 1.67×10^7 sec
grid spacing = 25m

Output Slsecifications

1) Temperature versus radial distance at 10^9 sec (60 time steps)

2) Take node at r = 37.5m and give solution of temperature versus time

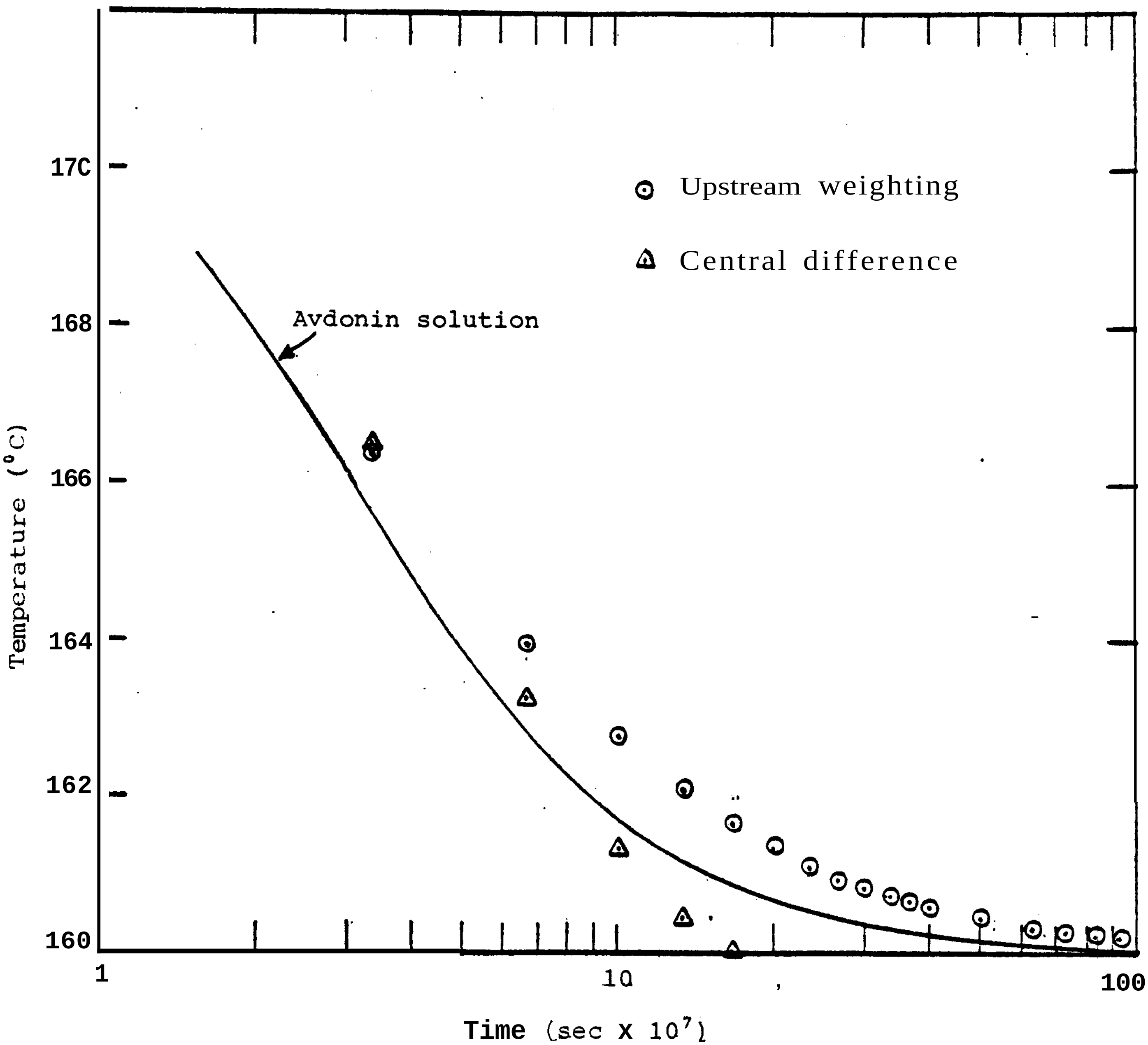


Figure 2. **Problem 1, calculated results for node 2 at 37.5 m from injection well.**

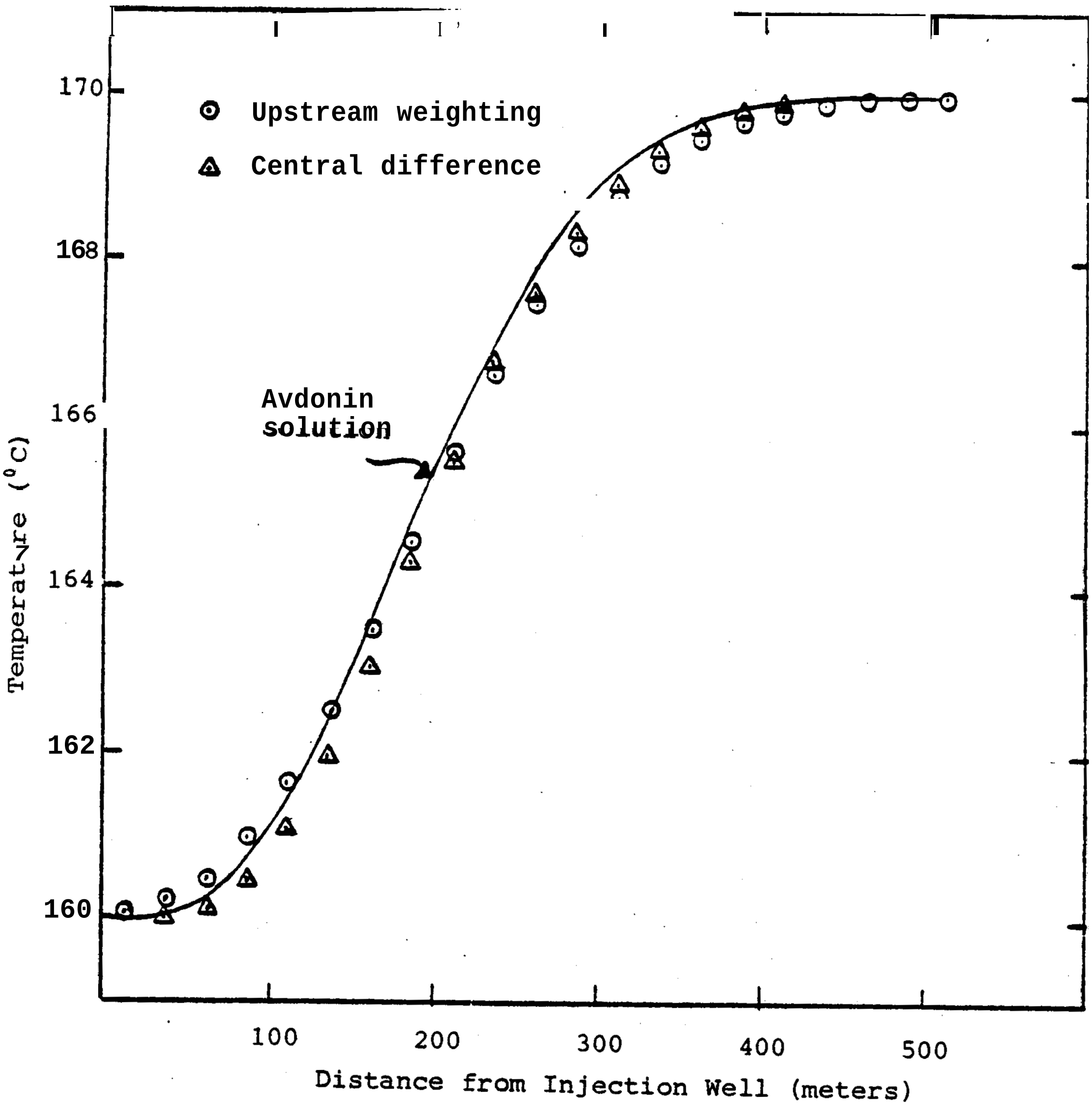


Figure 3. Problem 1, calculated results.ut time = 10^9 **sec.**

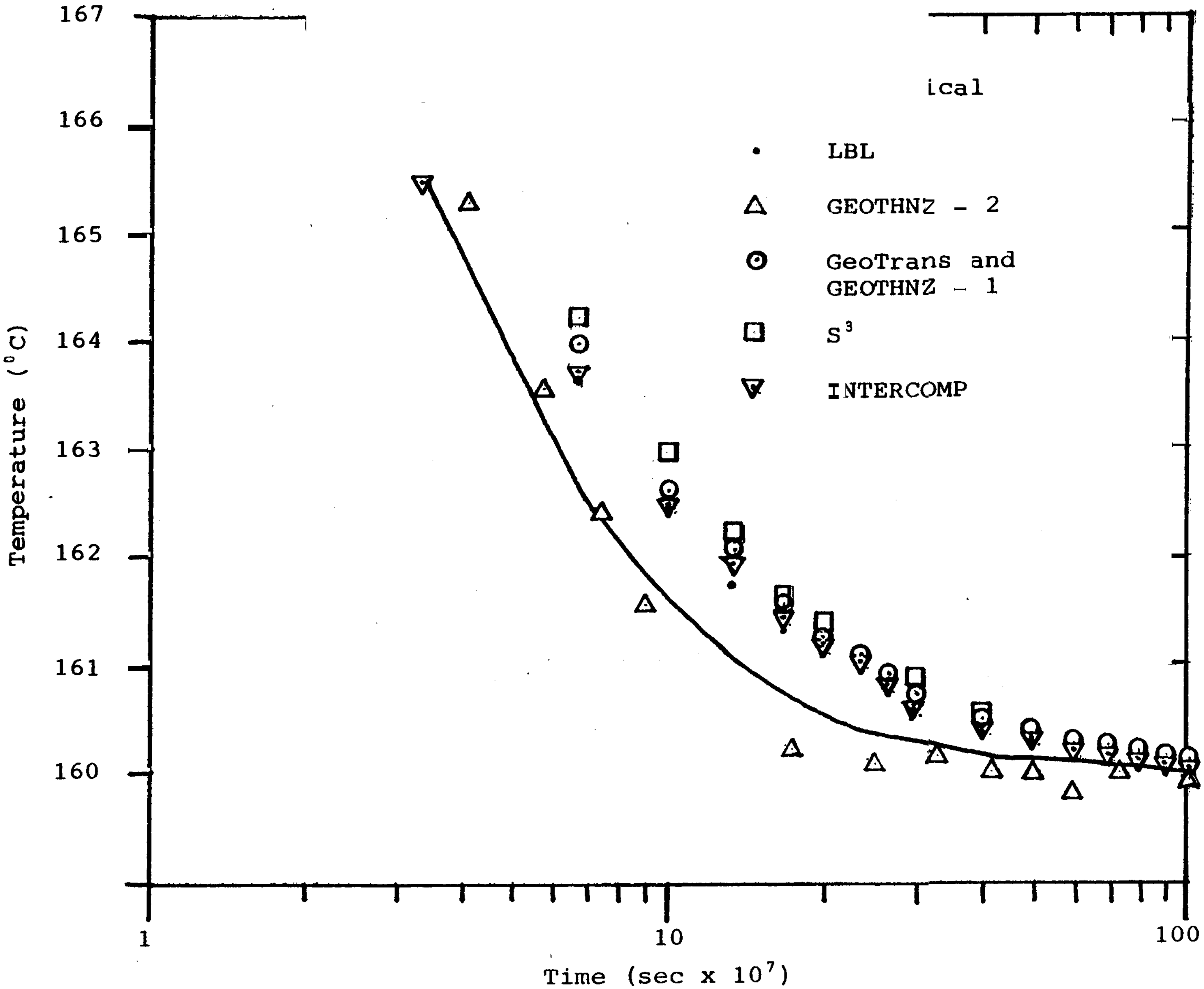


Figure 4. Problem 1, calculated results for node 2 at 37.5 m from injection well for all participants

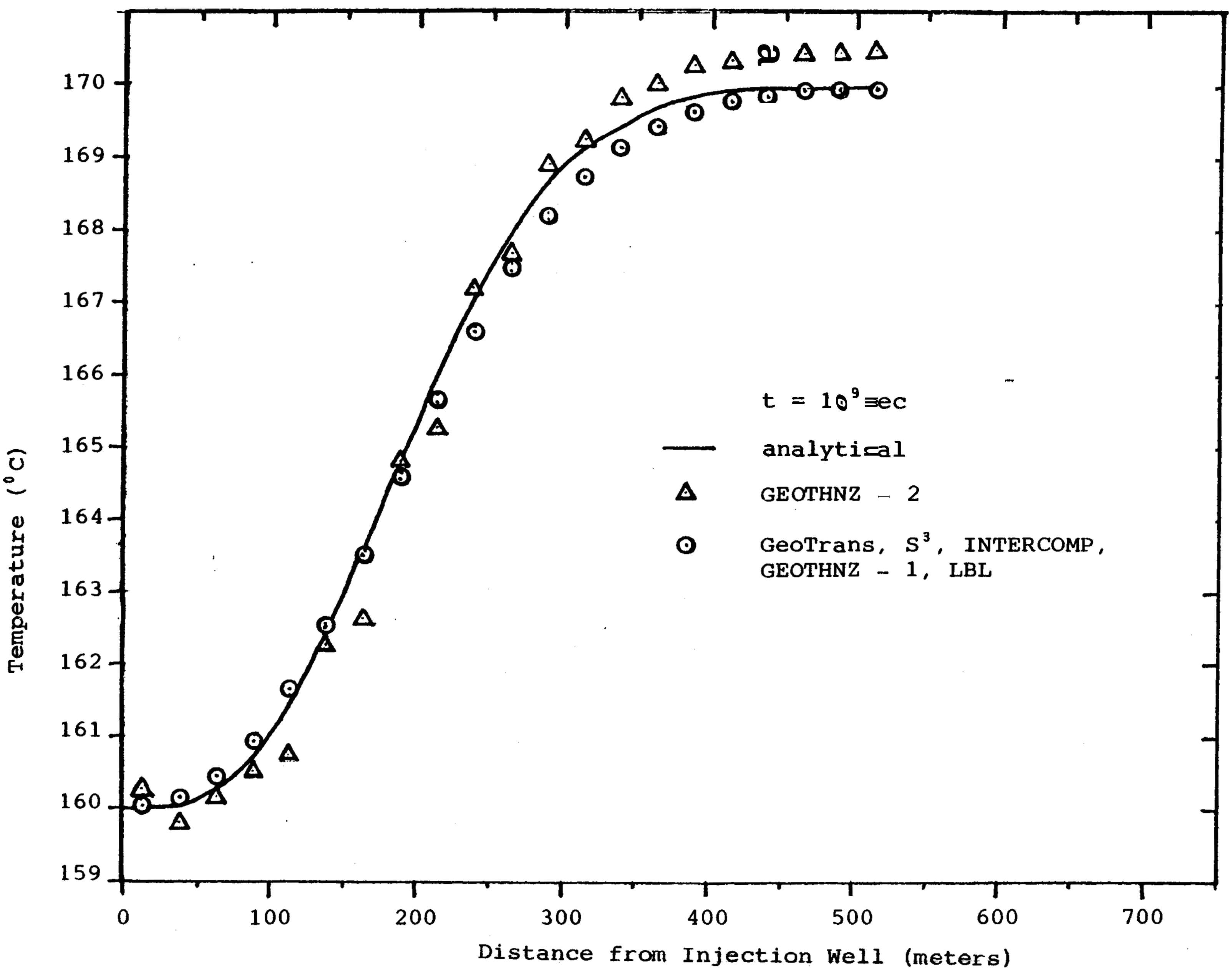


Figure 5. Problem 1, calculated results at time = 10^9 sec for all participants

GENERAL DISCUSSION

For constant density, viscosity, and heat capacity of water, an analytical solution is available for this problem. For example, this solution is a limiting case for the problem solved by Avdonin **(1964)**.

This problem offers little difficulty in solution. The grid spacing specified leads to numerical dispersion if upstream weighting is used. To see how significant the numerical dispersion could be, the problem was run twice - once with upstream weighting and once with midpoint weighting (central difference).

The results of this problem are shown in Figures 2 and 3. In the model the specific heat, viscosity and density of water for 165°C and 50 bars are **0.44425 x** 10^8 ergs/g-°C, 0.001636 g/cm-s, and 0.90893 g/cm^3, respectively. Both Figure **2** (temperature vs time at 37.5m) and Figure 3 (temperature vs distance at 10^9 sec) show the effects of the coarse grid spacing. The upstream-weighting results show numerical dispersion, whereas the central-difference results show an overshoot.

COMPARISON OF RESULTS

Figures **4** and 5 show the simulated results of GeoTrans, S^3, **LBL**, INTERCOMP, and two results from a code called GEOTHNZ. As may be seen all results compare favorably (within the range of the thermodynamic parameters used in each code and within machine error), except the second results for GEOTHNZ. For these results, the thermal boundary condition at the outer radius **was** specified **as** 170.5°C. Also, central difference was used for both the space and time approximations. These differences in input specifications easily account for the differences in results.

CONCLUSION

The numerical solutions compare well with the Avdonin analytical solution. Thus, it appears that the simulators are solving the equations properly.

REFERENCE

Avdonin, N.A., 1964, Some formulas for calculating the temperature field of a stratum subject to thermal injection: Neft'i Gaz, **Vol.** 3, p. **37-41**.

THE D.O.E. CODE COMPARISON PROJECT: SUMMARY OF RESULTS FOR PROBLEM 2 - RADIAL FLOW TO A WELL UNDER SINGLE AND TWO-PHASE CONDITIONS

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INTRODUCTION

Problem 2 involves a set of four constant-discharge, transient well test cases. Three of the cases involve one-dimensional radial flow to a line sink (zero-radius well) in a homogeneous porous media. In case A the reservoir fluid remains single-phase liquid; in case B the fluid remains a two-phase mixture with both steam and water mobile; in case C the fluid changes from compressed liquid to a two-phase mixture as a flash-front propogates away from the well. An additional problem was run under the initial conditions used in case B, involving only one grid block with discharge but no inflow. In each of these cases analytical or semi-analytical solutions for pressure, saturation, and flowing enthalpy as functions of time/distance squared (t/r^2) are available for comparison with the numerical results.

PROBLEM SPECIFICATIONS

The initial and boundary conditions specified for this problem are listed below.

Specification	Case A	Case B	Case C
Initial pressure (bars)	90	30	90
Initial temperature ($^{\circ}C$)	260	233.8	300
Initial liquid saturation	1	0.65	1
Porosity	0.2	0.15	0.2
Permeability ($10^{-12} m^2$)	0.01	0.24	0.01
Thickness (m)	100	100	100
Discharge (kg/s)	14.0	16.7	14.0
Rock heat capacity ($kJ/m^3\ ^{\circ}C$)	2650	2000	2650
Rock compressibility	0	0	0
Rock thermal conductivity	0	0	0

Relative permeability functions, based on the Corey equations, were used as indicated below.

$$k_{rl} = (S^*)^4$$

$$k_{rv} = ((1-S^*)^2).(1-(S^*)^2)$$

$$S^* = (S-0.3)/\ 0.65$$

where S = liquid saturation.

To minimize computational requirements while avoiding significant spacial discreetization errors, the following nodal arrangement was suggested for each radial-flow case.

$$r_n = 0.5\ m(2)^{\frac{n-1}{2}},\ n=1,26$$

For these cases a total simulation time of 1 day and an initial time step of 10^{-5} days were specified. In the one-node problem under case B conditions, a volume of 314 m^3 and 100 time steps of 10^{-4} days each were called for, with the enthalpy of the discharged fluid weighted according to the mobility of each phase.

The desired output for cases A, B, and C included pressure (in bars), liquid saturation, and flowing enthalpy (in kJ/kg) histories as functions of t/r^2 (in days/m^2) for nodal points at 0.5 m, 0.707m, and 1.0m from the well. For the one-node problem, pressure, saturation, and flowing enthalpy in the block versus time were required.

RESULTS

Case A

For this case the exponential integral solution of Theis (1935) is available for comparison. Results plotted in figure 1 show excellent agreement for each simulator solution. The fluid remains an isothermal compressed liquid as reservoir pressures remain above the saturation pressure of 47 bars during the l-day simulation period.

One-node Problem

Results for the one-node problem are plotted in figure **2.** The expected change in pressure (ΔP) and saturation (AS) per time step (At) can be hand-calculated from the equations shown in figure 2, which can be obtained from simultaneous solutions to the mass and energy balance equations as presented by Grant and Sorey (1979) and Sorey, Grant, and Bradford (1980), where

Q = discharge
V = block volume
ϕ = porosity
c_e = effective two-phase compressibility
ρ_f = density of flowing fluid mixture
ρ_w = density of water (liquid phase)

The value of $\Delta P/\Delta t$ changes with time as c_e and ρ_f vary; calculations of $\Delta P/\Delta t$ were made at **t** = 0 and **t** = 70 x 10^{-4} days. All the numerical results are in good agreement with the analytically-determined values for $\Delta S/\Delta t$ (which remain nearly constant) and $\Delta P/\Delta t$. Corresponding hand-calculations for changes in flowing enthalpy were not carried out. Simulator results for flowing enthalpy are self-consistent and show the characteristic rise in enthalpy to a stable value observed for radial flow to wells in two-phase reservoirs (Sorey, Grant, and Bradford, 1980).

Case B

For case B, involving radial flow with mobile liquid and steam, a semi-analytical similarity solution involving numerical integration of ordinary differential equations (O'Sullivan and Pruess, 1980) is available for comparison with numerical solutions. Results shown in figure **3** are in reasonable agreement; additional runs using the SHAFT79 simulator indicate that the numerical solutions would match the semi-analytical solution even better **if** a finer grid were used near the well. The scatter among the different results is probably due mainly to minor variations in the thermodynamic relationships used in each code. Numerical results for pressure, saturation, and flowing enthalpy at each of the three nodal distances listed previously as functions of t/r^2 are essentially identical, in agreement with the similarity solution.

Case C

Case C involves the propogation of a flash front away from the well. The initial reservoir pressure is approximately 5 bars above the saturation pressure of 86 bars for $T=300^oC$ so boiling occurs near the well soon after discharge commences and extends to a distance of about 10 m after 1 day. In several respects, this case is more difficult to accurately simulate than are the other cases in Problem 2 and consequently deviations of the numerical results from the semi-analytical solution are somewhat greater in this case as shown in figure 4. Numerical solutions are sensitive to nodal spacing and some improvement in the comparison with the analytical solution would result if a finer grid near the well were used. In this case also, the choice of a logarithmically-spaced grid causes the numerical solution at large values of t/r^2 to oscillate. This is most noticeable in the plot of flowing enthalpy. Using a grid with equally-spaced nodal increments near the well greatly reduces the size of the oscillations, but does not improve the fit with the analytical solution at large t/r^2. In spite of these numerical difficulties, results from each simulator are roughly the same, and the level of agreement with the analytical result indicates that these numerical simulators can adequately handle the flashing-front problem.

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Grant, M.A., and Sorey, M.L.,1979, The compressibility and hydraulic diffusivity of a water-steam flow, Water Resources Research, vol. 15, No. 3, pp. 684-686.

O'Sullivan, M.J., and Pruess, K., 1980, Analysis of injection testing of geothermal reservoirs; Geothermal Resources Council, Transactions, vol. 4, pp. 401-404.

Sorey, M.L., Grant, M.A., and Bradford, E., 1980, Nonlinear effects in two-phase flow to wells in geothermal reservoirs, Water Resources Research, vol. 16, No. 4, pp.767-777.

Theis, C. V., 1935, The relation between the lowering of the piezometric surface and the rate and duration of discharge of a well using groundwater storage; Trans. Amer. Geophysical Union, Vol. 16, pp. 519-524.

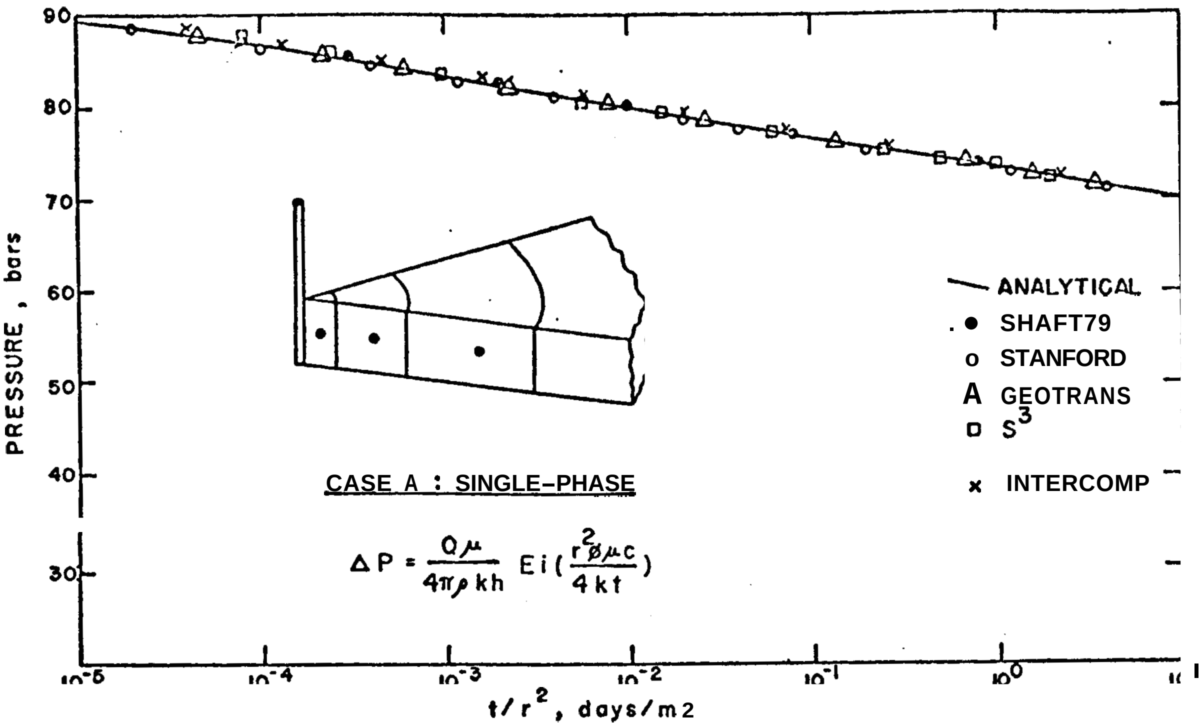


Figure 1. Solutions to Problem 2, case A.

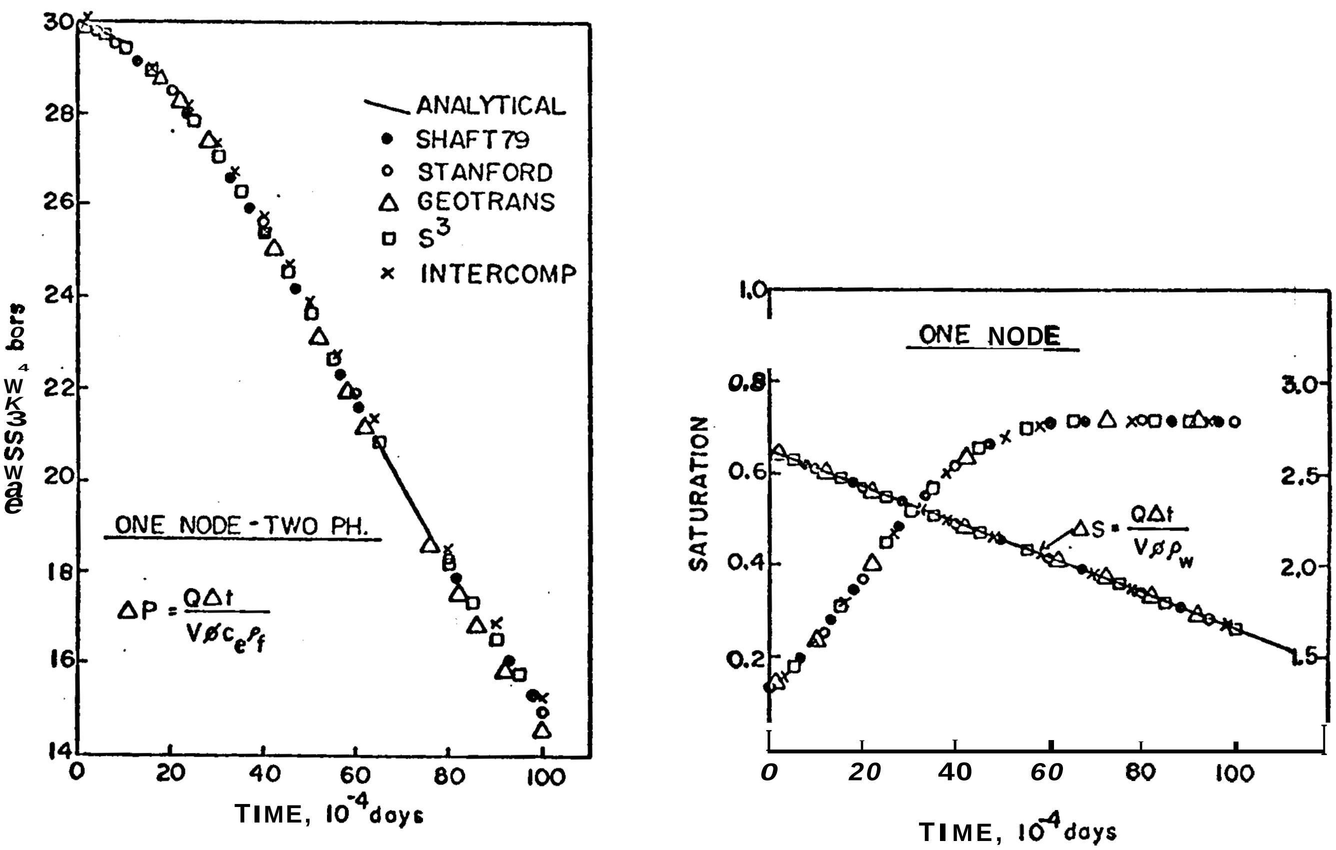


Figure 2. Solutions to Problem 2, me-node case.

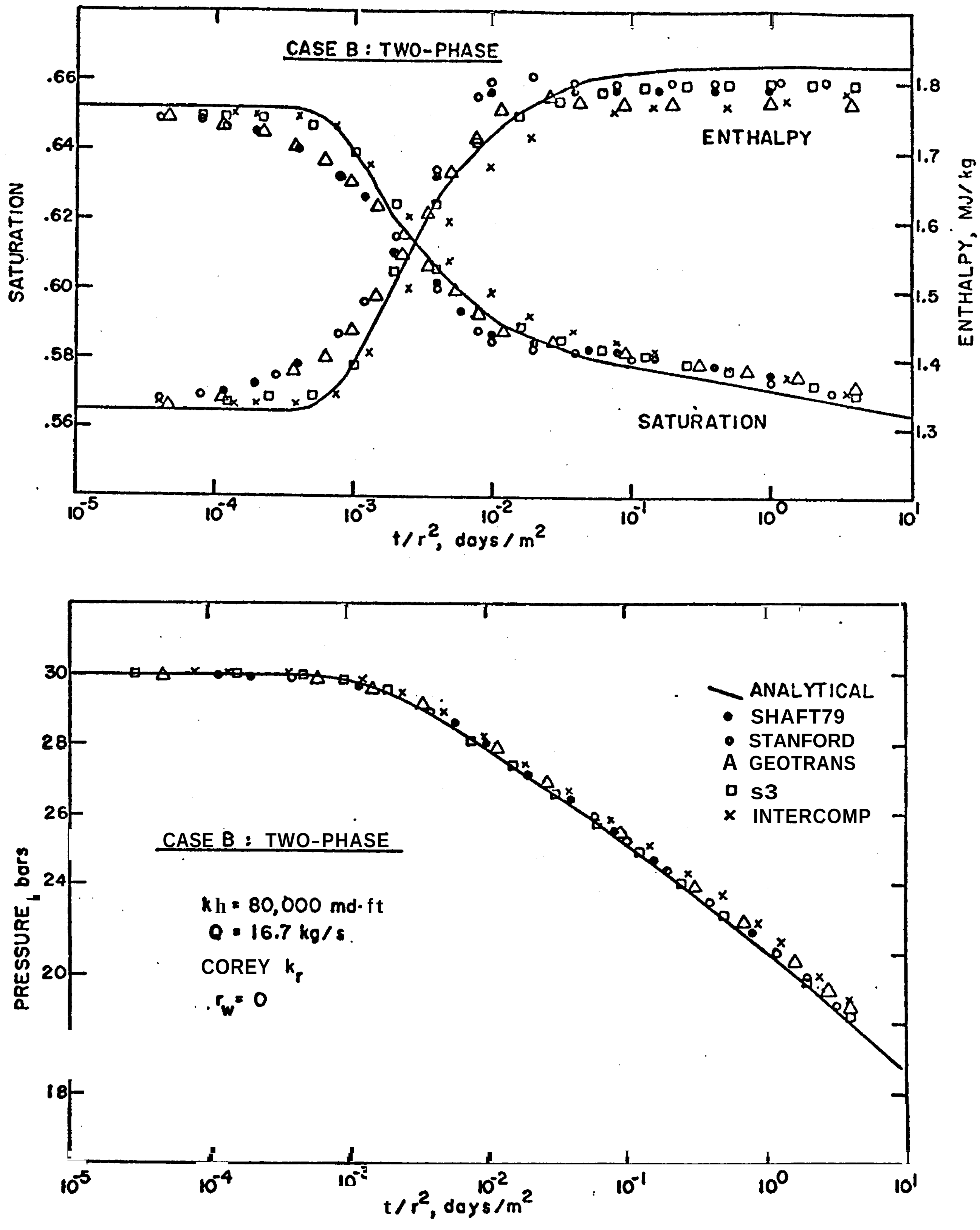
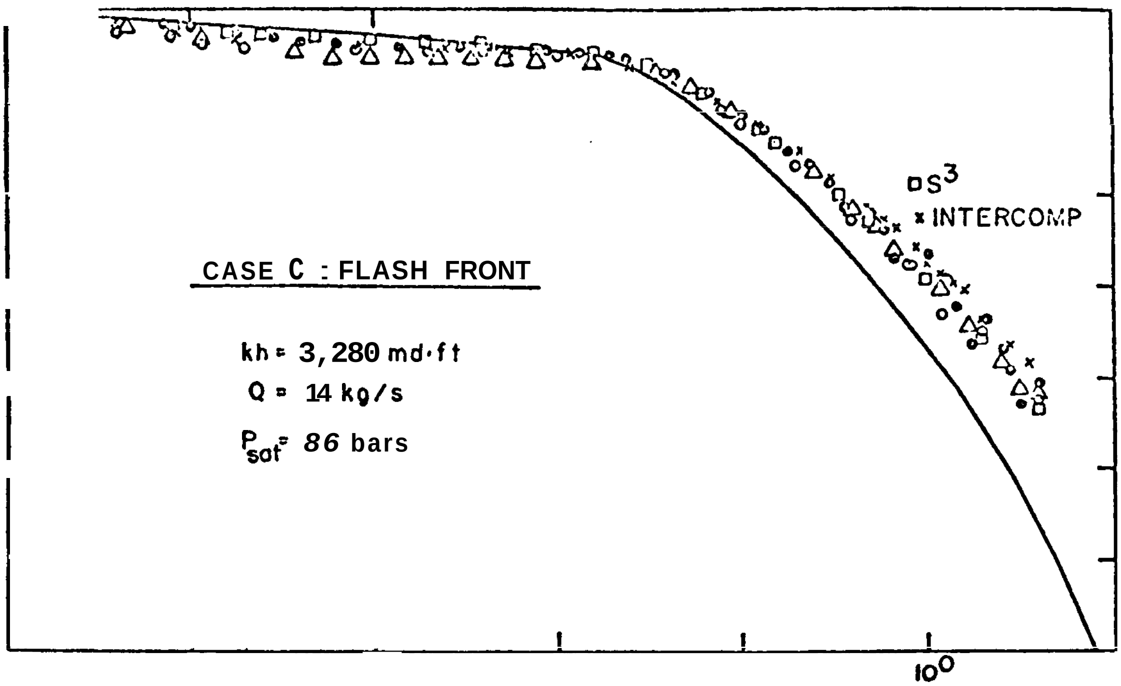
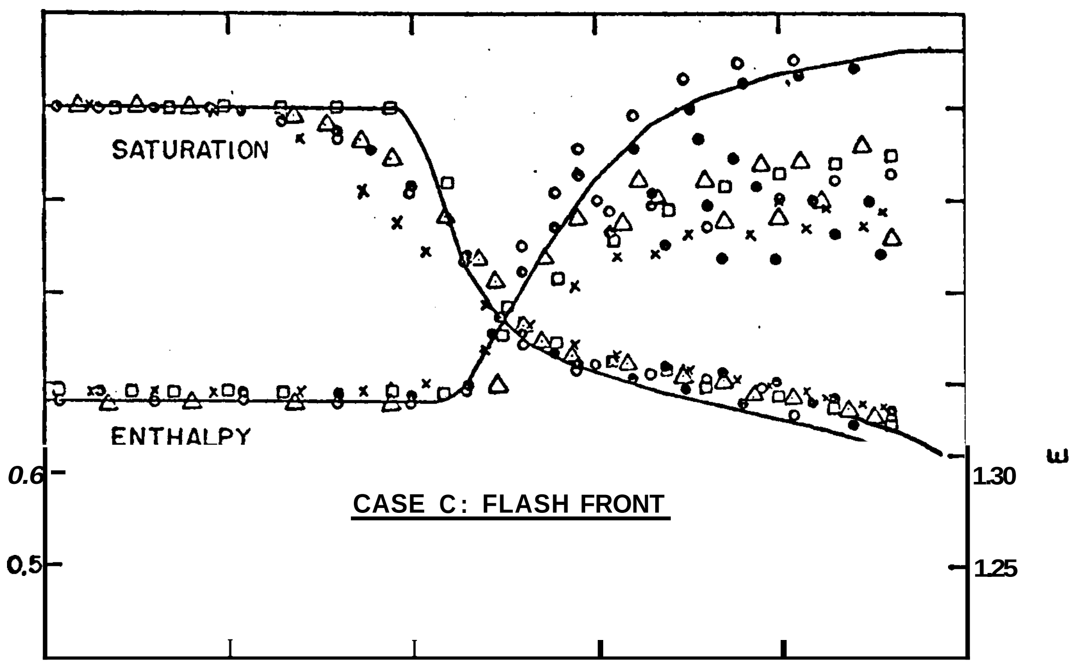


Figure 3. Solutions to Problem 2, ,case B.



CASE C : FLASH FRONT
kh = 3,280 md·ft
Q = 14 kg/s
P_{sat} = 86 bars
□ S³
× INTERCOMP
10⁰



SATURATION
ENTHALPY
CASE C: FLASH FRONT
0.6
0.5
1.30
1.25
ω

D.O.E. Code Comparison - Problem 3
"2-D Flow to a Well in Fracture/Block Media"

A.F. Moench, U.S.G.S.

INTRODUCTION

This problem represents a simplification of the general problem of well testing in fractured geothermal reservoirs. The reservoir is idealized as a horizontal fissure of infinite lateral extent bounded on one side by a block of finite thickness. Steam flows vertically from the block to the fissure and thence radially to a well where it discharges to the atmosphere.

PROBLEM SPECIFICATION

Figure 1 shows the geometry of the reservoir and a suggested mesh design. The upper boundary of the block and the lower boundary of the fissure are impermeable. The flow of steam in the fissure and block obeys Darcy's law. The well has a finite radius and discharges steam at a constant rate.

Two cases are considered. In Case a, liquid saturation is zero everywhere. In Case b, liquid water partially saturates the block but not the fissure. The relative permeability to steam is 1.0 and the relative permeability to liquid water is 0.0. Rock compresfibility and thermal conductivity are zero. The remaining parameters are listed in Table 1.

A computational grid consisting of one well block, ten logarithmically-spaced nodes in the fissure, and ten equally spaced nodes in the block, as partially illustrated in figure 1, is suggested. The node in the fissure furthest from the well block will be located a distance of about 1½ km from the well if the spacing from one node to the next is increased by a factor of 2.5. A large fictional permeability at least 100x the permeability of the fissure should be assigned to the well block node. Total simulation time should be 10^4 seconds and the initial time step should be 1 second. A time step multiplication factor of 1.05 is suggested. This would result in achieving the required simulation time in about 130 time steps.

Results for Cases a and b should consist of plots of pressure as a function of the logarithm of time, along with the corresponding data in tabular form. Pressure at the well face and at a point in the block located 2.5 m from the center line of the well and 0.25 m from the top of the fissure should be presented. Also, for Case b liquid saturation versus time for the above specified point in the block should be tabulated.

COMPARISON OF RESULTS

Figures 2a and 2b show the results obtained by tbe various participants for the single phase flow of steam (Case A). The solid lines represent the results deemed by this author to be most accurate. This conclusion is based in part upon comparisons with an analytical solution and in part upon comparisons with yet another finite-difference model designed specifically for this problem. Pressure declines in the block are about the same for all the participants but there is considerable discrepancy in the pressure declines at the well face. Upon discussing the results with several of the participants it was found that these discrepancies were due Primarily to the manner in which the transmissive characteristic was obtained for the flow between the well block node, which was assigned a very large permeability, and the node in the fissure adjacent to the well block node. In all but the results obtained by LBL and S^3 this procedure effectively increased the well diameter so that computed pressure drawdowns were less than they should have been[1]. Results obtained by Stanford are in error for the additional reason that the wrong well radius was specified.

Figures 3a and 3b show the results obtained when immobile liquid water is present in the block (Case B). As in Case A the solid lines represent the results deemed by this author to be most accurate. Pressure declines in the block are nearly the same for all participants. Unfortunately the parameters defined in the problem were such that little change occurred in the specified block node so a good test of the code is not possible at this location. As in case A there is considerable discrepancy in the pressure declines at the well face. In the case of Geo Trans2 and New Zealand this can be attributed to permeabilities in the vicinity of the well block node as in Case A. The discrepancy is enhanced in Intercomp's results because of unduly large time steps early in the simulation and in Stanford's results because of recognized errors in the thermodynamics at the saturated steam-superheated steam interface.

Figure 4 shows the changes in saturations that occur in the block in Case B. Differences in the results can be attributed to the reasons already given for discrepancies in figures 3a and 3b.

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[1]After the Workshop Geo Trans submitted revised results, correcting this error, which agree closely with S^3 and LBL.

[2]Ibid.

CONCLUSIONS

The results presented in figures 2-4 show considerable variations from one participant to another. It was found that these variations could be explained by operator errors and misunderstanding of the specified problem. Unfortunately the problem was not posed in a manner which eliminated ambiguity. Variations obtained by the different participants were not due to errors inherent in any of the computer codes.

Table 1

Specification	Case a	Case b
Initial pressure (bars)	30.5	30.5
Initial liquid saturation in block 1/	0	.2
Initial temperature (°C) 2/	234.8	234.8
Porosity in fracture	.1	.1
Porosity in block	.1	.1
Permeability in fracture ($10^{-12}m^2$)	.3	.3
Permeability in block ($10^{-12}m^2$) 3/	.00003	.00003
Thickness of fracture (m)	.1	.1
Thickness of block (m)	1.0	1.0
Well discharge (kg/s)	.028	.028
Well radius (m)	.16	.16
Rock heat capacity ($kJ/m^{3\circ}C$)	2570.	2570.

1/ Initial liquid saturation is zero in the fracture in both cases

2/ Saturation temperature at 30.5 bars,

3/ Horizontal permeability in block is zero in both cases.

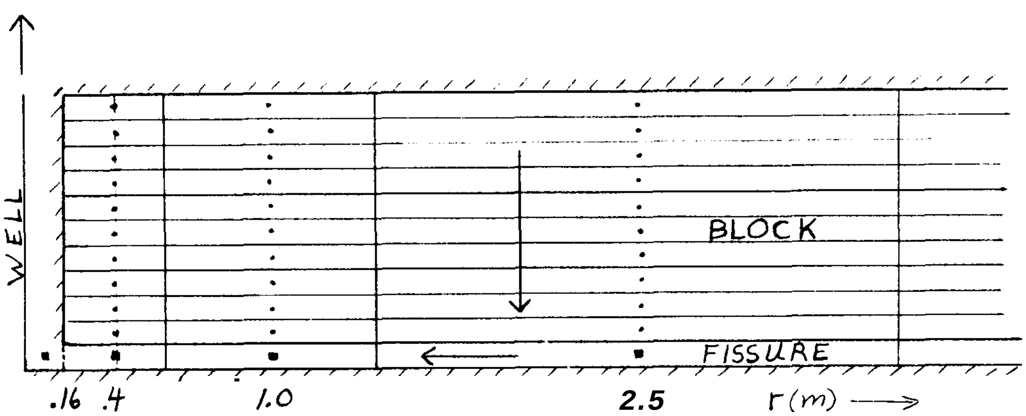

Figure 1. Reservoir geometry and possible mesh design

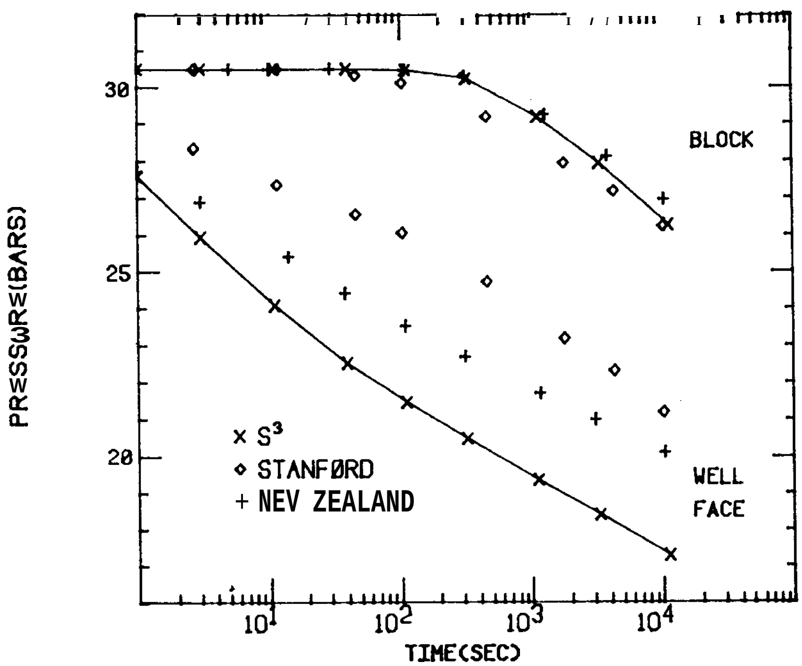

Figure 2a.--Pressure versus time at well face and in reservoir block for Case A.

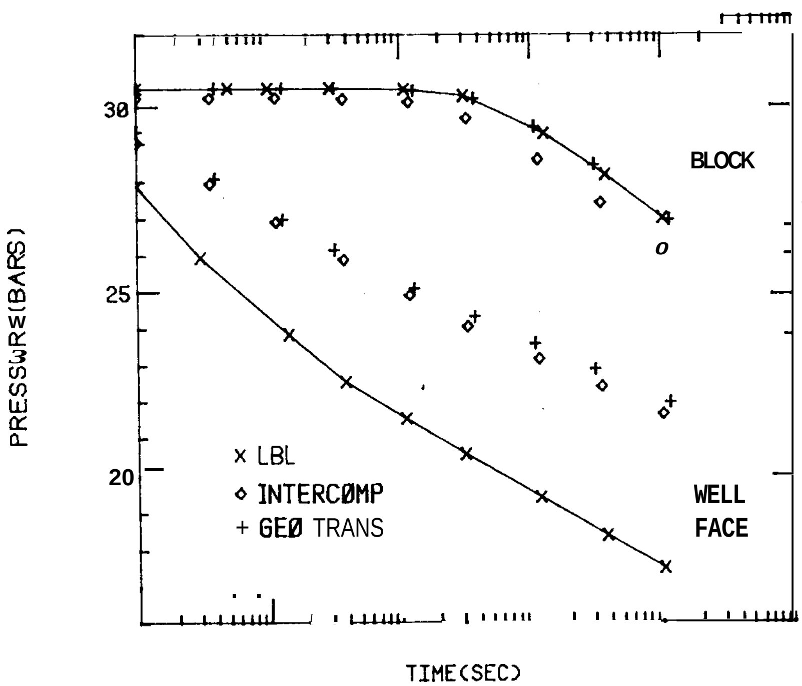

Figure 2b.--Pressure versus time at well face and in reservoir block for Case A.

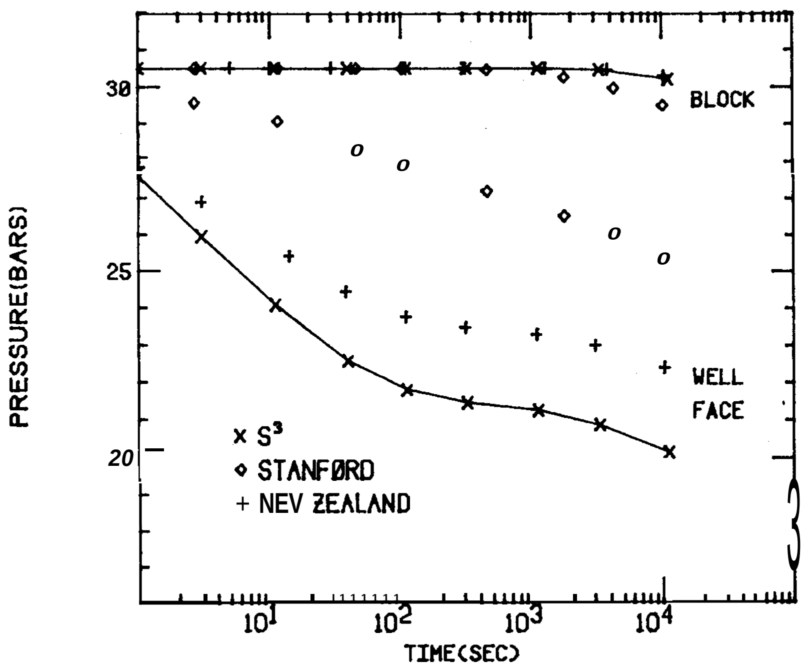

Figure 3a.--Pressure versus time at well face and in reservoir block for Case B.

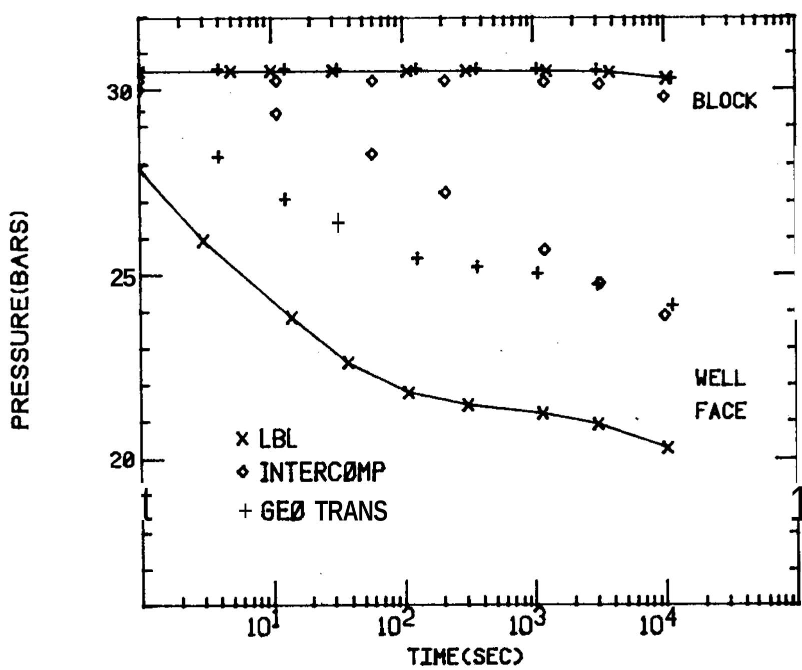

Figure 3b.--Pressure versus time at well face and in reservoir block for Case B.

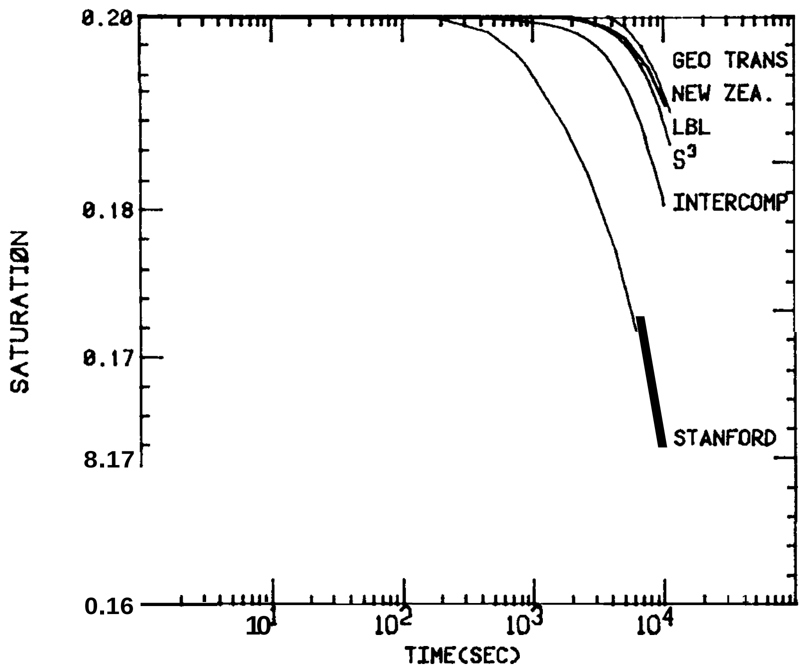

Figure 4.--Saturation versus time in reservoir block for Case B.

THE D.O.E. CODE COMPAFUSON STUDY:

SUMMARY OF RESULTS FOR PROBLEM 4 -

EXPANDING TWO-PHASE SYSTEM WITH DRAINAGE

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INTRODUCTION

The reservoir in this problem consists of two layers each 1km thick with the top layer less permeable than the bottom (detailed properties are given in Table 1). The initial temperature in the reservoir drops linearly from 310°C at the bottom of the reservoir to 290°C at the interface between the two layers and then drops more steeply, but still linearly to 10°C at the ground surface. The initial pressure distribution is the hydrostatic profile corresponding to this temperature distribution.

The reservoir is produced at the bottom of the system at a rate of 100kg/s.km^2. It is assumed that the system and the production are uniform in the horizontal directions so that flow occurs in the vertical direction only.

A calculation grid of *20* equal sized blocks is specified and results are required for a **40** year period.

The anticipated behavior of the reservoir is that a boiling zone will develop near the top of the more permeable layer and spread downwards, also spreading a short distance into the upper layer. As the pressure drops in the lower layer, down flow through the top layer and recharge at the ground surface will be induced.

DIFFICULTIES

The vertical flow of a boiling fluid driven by a combination of gravity and production related pressure gradients is one of the most difficult flow problems for a numerical simulator to handle. Initially the pressure in the reservoir increases rapidly with depth. After production begins the slope of the pressure profile decreases and a liquid/vapor counter-flow develops after about one year when the reservoir starts boiling. That is, water flows downwards to the production well while steam rises and recondenses at a higher level. The numerical analysis required to simulate these physical processes is quite complex. Separate treatment of the vapor flow **and** the liquid flow is required with upstream weighting of pressure gradient terms in opposite directions for each phase.

At a more elementary level this problem also tests the ability of simulators to handle vigorous boiling (several nodes changing from liquid to two-phase) and the implementation of a constant pressure, constant temperature recharge condition at the ground surface.

RESULTS

The pressure profiles given in Figure 1 show the processes involved clearly. The flow in the top layer does not change very significantly with time and at a rate of approximately $30 kg/s.km^2$ is not sufficient to supply all the production. Therefore the fluid from the bottom layer is progressively mined. The steeper part of the pressure profile in the lower layer corresponds to the boiling zone. At about 30 years this extends throughout the lower layer and after about 37 years the liquid saturation has dropped sufficiently to inhibit the flow of water and then the pressure gradient steepens to induce an adequate additional downward flow of steam. The steam flow-rate profiles given in Figure 2 show the upward flow of steam changing to a later downward flow at around 37 years.

COMPARISON OF RESULTS

A selection of the required results for problem four are shown in Figures 3,4,5 and 6. The surface recharge results shown in Figure 3 all agree well except for those of Intercomp. Even the Intercomp results are not significantly different. The surface recharge rate is very strongly dependent on the viscosity of water and other parameters at temperatures close to the recharge temperature of 10^oC. Therefore, the differences between Intercomp's results and the other results could be explained by minor inaccuracies in their low temperature thermodynamic properties of water. A more detailed comparison of temperatures and pressures at nodes near the surface would be required to fully explain the differences. The production enthalpies shown in Figure 4 are all similar except for those submitted by Intercomp. Their results predict a later rise in the enthalpy, that is a later boiling of the production node. This result is to be expected because of their higher surface recharge rate. Since more cold water flows into the Intercomp reservoir it takes longer for the bottom layer to completely boil.

The pressure and saturation histories at various depths shown in Figures 5 and 6 all agree well (with Intercomp results showing some variation).

CONCLUSIONS

All the simulators compared in this study came through the severe test represented by problem four very well.. Clearly they are capable of handling the counter-flow of steam and water, the expansion of a boiling zone and the vertical drainage of cold surface water into a reservoir. As all these processes occur in real geothermal reservoirs such as Wairakei, the results for this problem have considerable practical significance. The simulators tested all appear to be satisfactory tools for analyzing models of this type of geothermal reservoir.

TABLE 1. RESERVOIR PROPERTIES

	Top Layer	Bottom Layer
Porosity	0.15	0.25
Permeability ($10^{-15}m^2$)	5.0	100.0
Rock density (kg/m^3)	2500.	2500.
Rock heat capacity (kJ/kg.K)	1.0	1.0
Thermal conductivity (W/m.K)	1.0	1.0

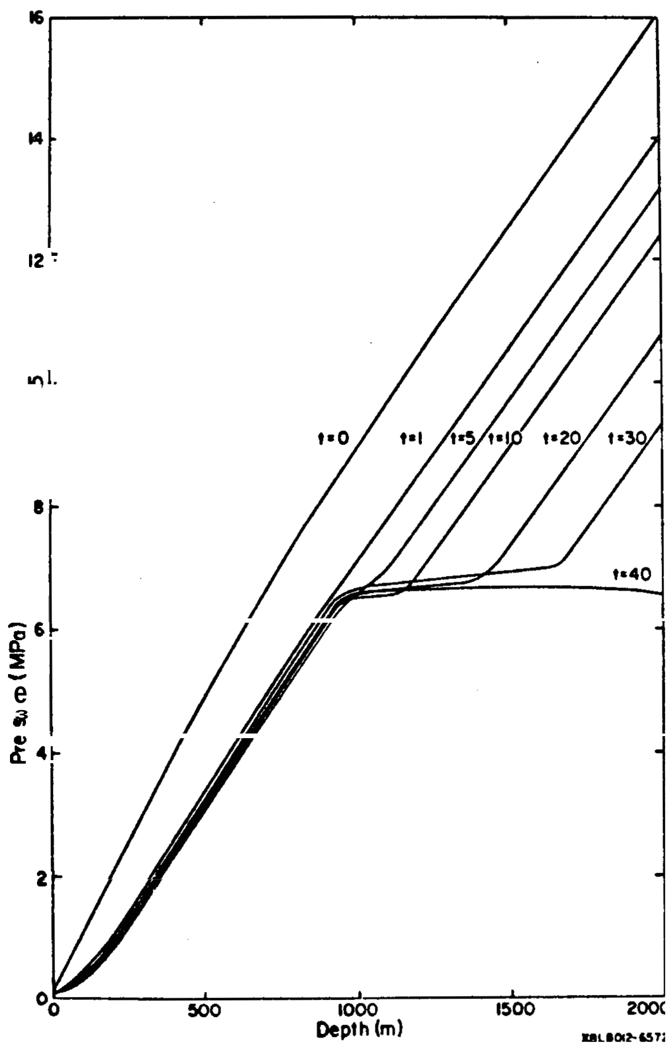

Figure 1. Pressure profiles in the reservoir at various times.

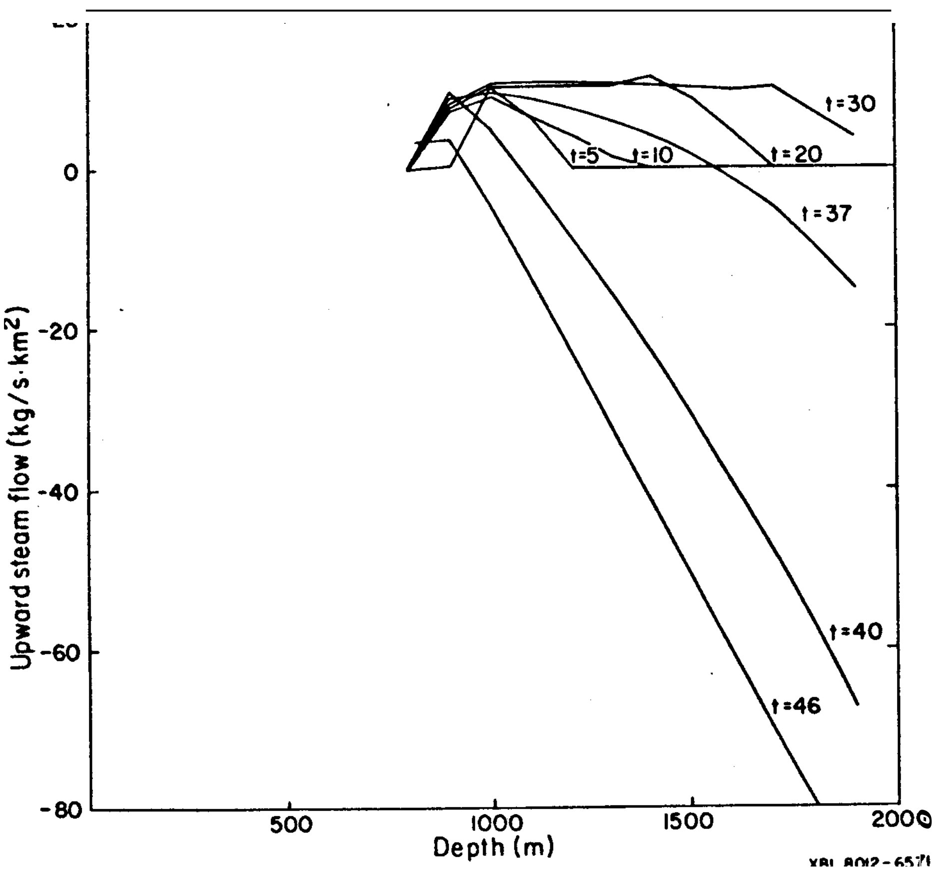

Figure 2. Steam flow in the reservoir at various times.

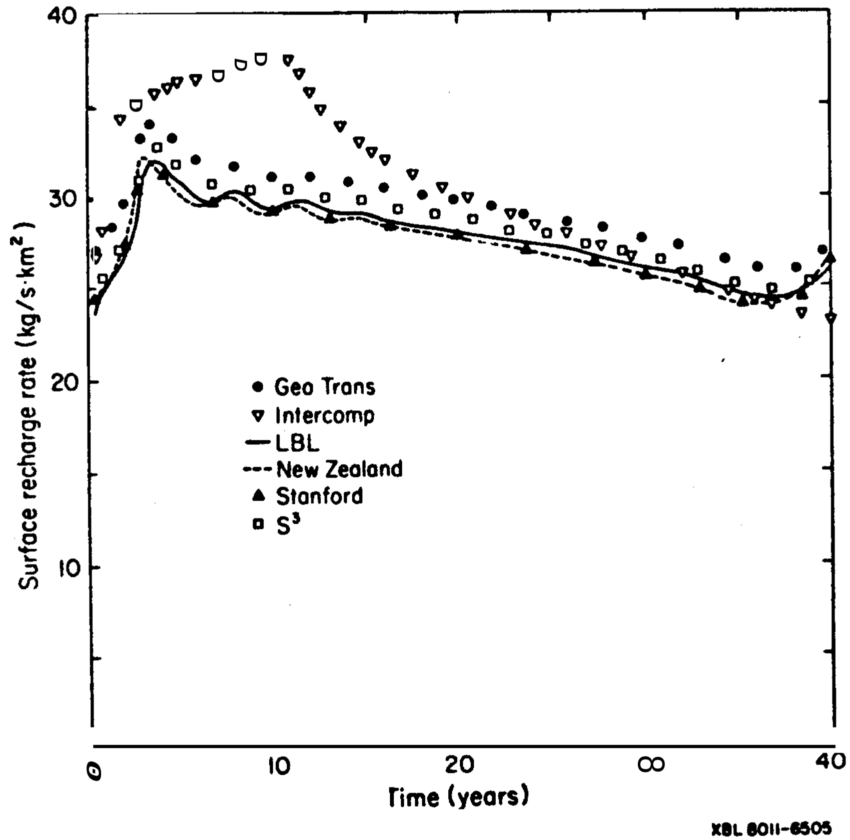

Figure 3. Surface recharge rate.

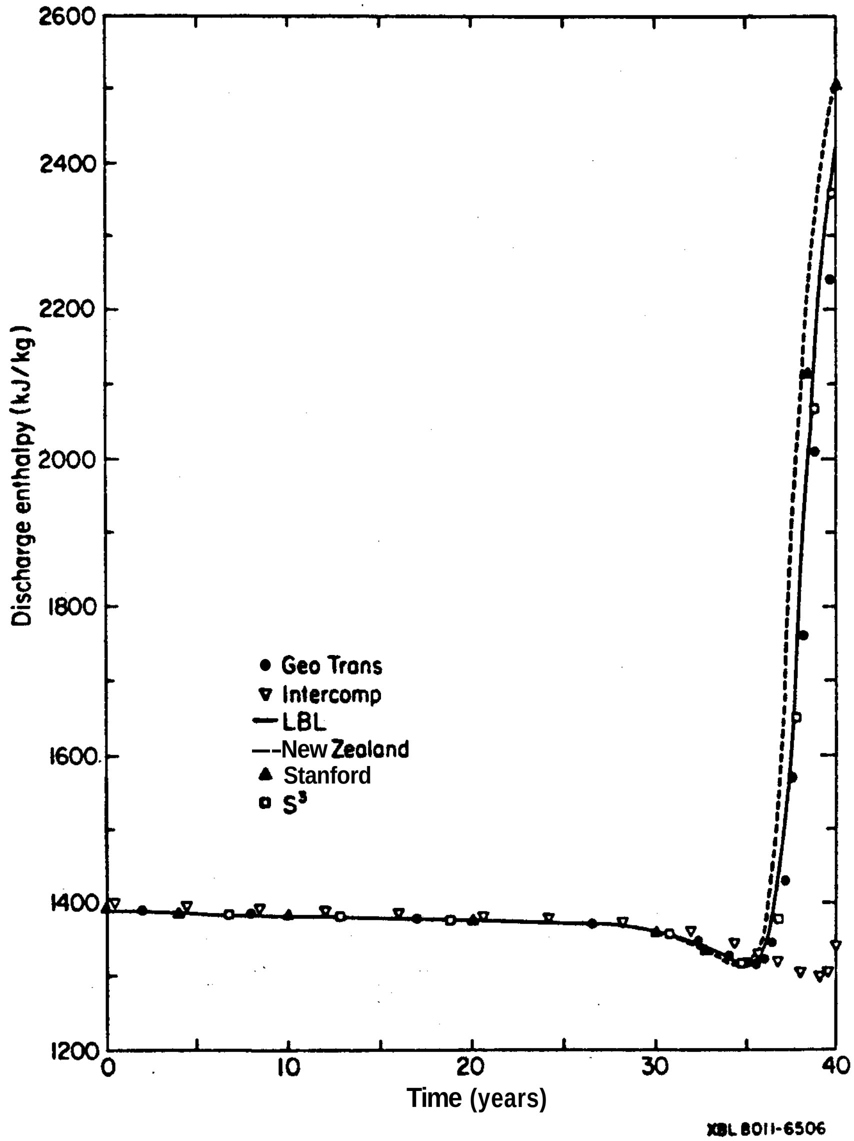

Figure 4. Production enthalpy.

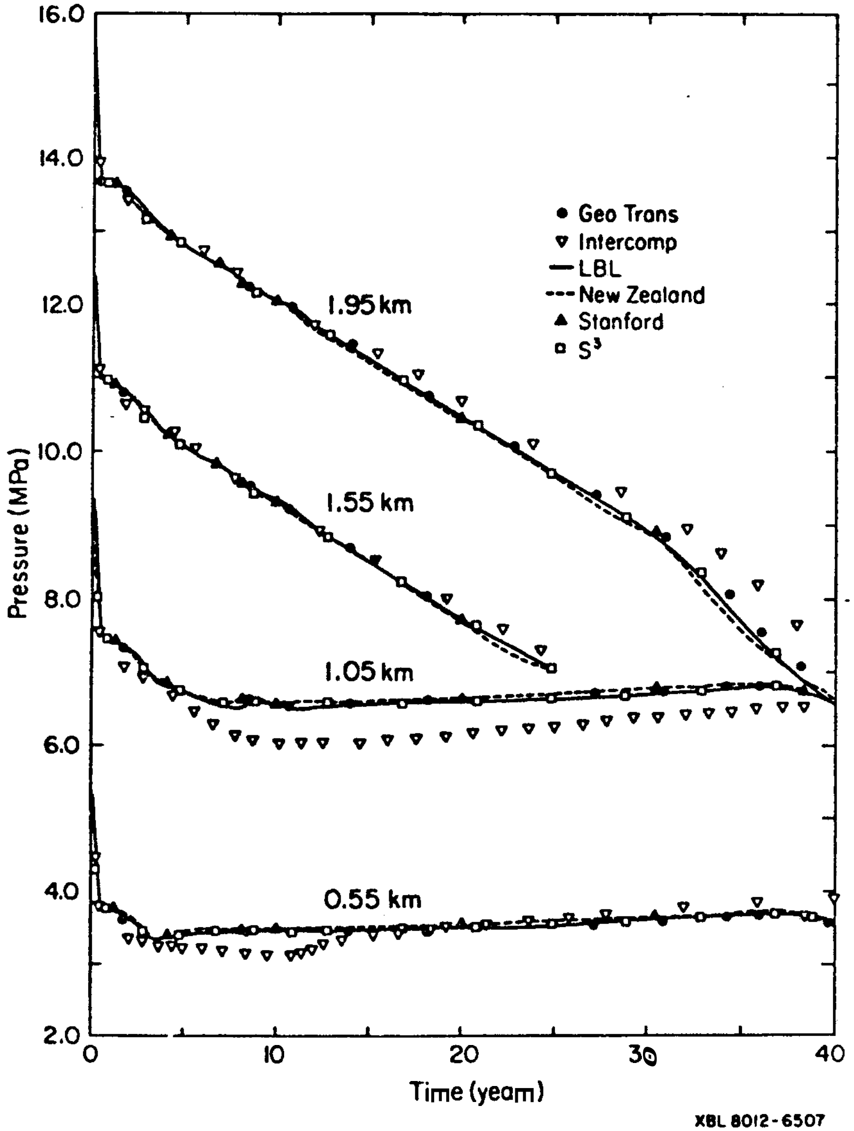

Figure 5. Pressure histories at various depths

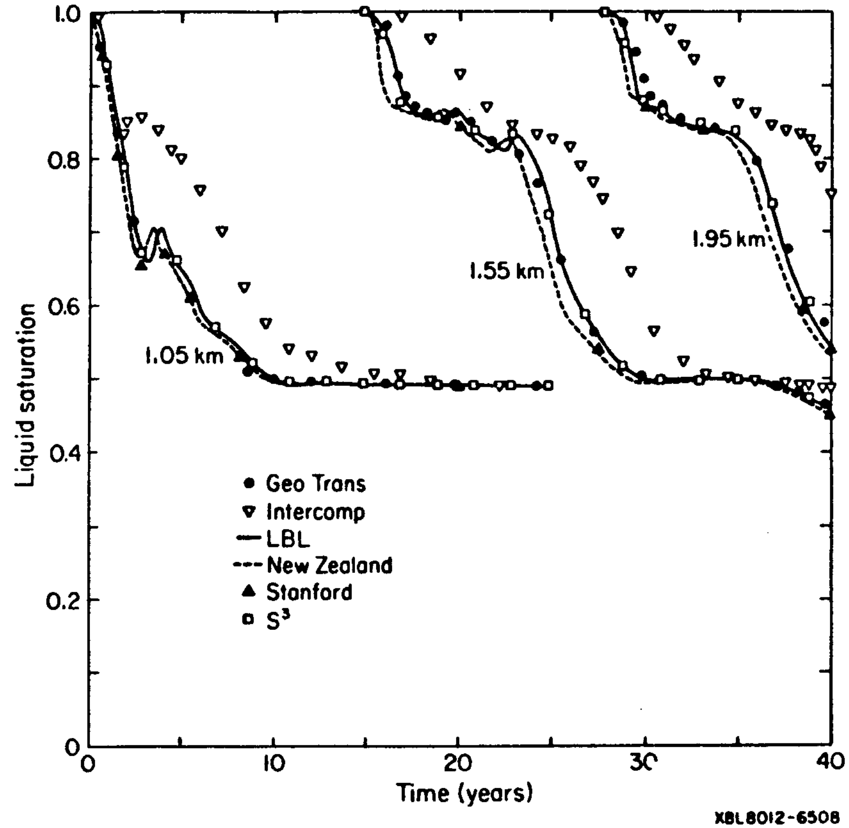

Figure 6. Liquid saturation histories at various depths.

THE DOE CODE COMPARISON PROJECT:

-SUMMARY OF RESULTS FOR PROBLEM 5-

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INTRODUCTION

Problem 5 is a two-dimensional areal case involving both single-phase (water) and two-phase (water/steam) flow in a system in which lateral cold-water recharge occurs; the initial temperature distribution is non-uniform. Thus, convective heat transfer and water/steam phase transitions play important roles. The first case (Problem 5A) considers the effect of a single production well; the second (5B) treats the combined effects of fluid production and reinjection.

PROBLEM DESCRIPTION

Consider a horizontal region extending over $0 \leq x \leq 300$ meters, $0 \leq y \leq 200$ meters (see Figure 1). The rock properties within the region are uniform (see Table 1). Initially, temperatures are distributed in a non-uniform manner. For $r \leq 100$ meters, the initial temperature is 240°C ($r^2 = x^2 + y^2$). For $r \geq 300$ meters, the initial temperature is 160°C. For intermediate values of r, the initial temperature varies smoothly between 160°C and 240°C according to:

$$T = (240°C) - (160°C)\,\nu^2 + (80°C)\,\nu^4 ; \quad \nu = \frac{r - 100\text{ m}}{200\text{ m}}$$

The initial pressure in the system is uniform, and is sufficient to maintain an all-liquid state throughout. The initial pressure (P_0) is taken to be equal to the water/steam saturation pressure associated with a temperature of 240°C (P_{sat} (240°C) = 33.48 bars according to the ASME Steam Tables), plus 2.5 bars. Thus, the initial pressure (P_0) is about 36 bars, so that a pressure drop of at least 2.5 bars will be required to cause boiling in the region within r = 100 meters, and even more pressure decline will be required to cause phase changes at greater radii. The boundaries along x = 0, along y = 0, and along y = 200 meters are all taken as impermeable and insulated. Along x = 300 meters, the pressure and temperature are maintained at their initial values (T = 160°C, $P = P_0 \approx 36$ bars), so that recharge fluid may enter the system.

The first case (Problem 5A) involves a single production well located at x = 62.5 meters, y = 62.5 meters which starts producing fluid at zero time at a constant rate of 50 grams per second per meter of thickness. In Problem 5B, in addition to the production well, an injection well is located at x = 162.5 m, y = 137.5 m. Starting at t = 1 year, this well injects fluid at a temperature of 80°C at a constant rate of 30 grams per second per meter of thickness (60 percent of the production rate). In both cases, the time domain of interest is $0 \leq t \leq 10$ years. The problem is to be subdivided, for numerical purposes, into 8 x 12 = 96 square zones measuring 25 meters on a side, as indicated in Figure 1. The time-step to be used is left to the discretion of the engineer.

THE NUMERICAL CALCULATIONS

Six different organizations used five different numerical reservoir simulators to solve this problem during the DOE Code Comparison Project. Geotrans, Inc., Intercomp, and Lawrence Berkeley Laboratory (LBL), Systems, Science and Software (S-Cubed) and the University of Auckland in New Zealand each used their own internally-developed simulators. In addition, Stanford University undertook the problem using the University of Auckland's simulator. In all of these calculations, the prescribed spatial zoning was employed. The time-resolution employed by the various investigators varied significantly, however, as shown in Table 2. Intercomp used by far the crudest time-resolution ($\Delta t \approx 4$ months), followed by Geotrans ($\Delta t \approx 6$ weeks), LBL ($\Delta t \approx 5$ weeks), S-Cubed ($\Delta t \approx 18$ days), the University of Auckland ($\Delta t \approx 4$ days) and Stanford University ($\Delta t \approx 2$ days). The very small time-steps used by the last two groups were required for computational stability by the University of Auckland simulator. As will be seen, the crude time-step used by Intercomp adversely influenced accuracy at early times.

EFFECTS OF THE SATURATION CURVE

At very early times, the pressure in the production well-block (zone i = 3, j = 3 centered at x = 62.5 m, y = 62.5 m) drops very rapidly in response to production. Very quickly, pressures in this zone reach saturation conditions. Thereafter, the well-block pressure drops more slowly, accompanied by a decline in temperature and the evolution of steam. Thus, the temperature and pressure histories in the production well-block may be cross-correlated; the resulting relationship between pressure and temperature coincides with the water/steam saturation curve $P_{sat}(T)$.

Results of this type are shown in Figure 2, along with data points taken from the ASME Steam Tables. Figure 2 illustrates the accuracy of the fit to the water/steam saturation curve employed by each simulator. Both the LBL and S-Cubed codes use interpolation between tabulated steam-table points to establish $P_{sat}(T)$; the other three simulators use analytic fits. Thus, the LBL and S-Cubed saturation curves are essentially exact. The Intercomp code uses a fit that is high by about 0.2 bar in the vicinity of 240°C; the University of Auckland simulator is high by 0.5 bar. The Geotrans fit is worst of all in this vicinity, being high by a full bar.

The prescribed description of Problem 5 entailed a value for P_0 (the initial system pressure, and the boundary pressure to be maintained along x = 300 meters) which exceeds the saturation pressure for 240°C by 2.5 bars, as discussed above. Unfortunately, these instructions were interpreted differently by the various groups, as illustrated in Table 3. The true value for P_{sat} (240°C) from the ASME Steam Tables is 33.48 bars, so that ideally P_0 should be 35.98 bars ($\approx$ 36.0 bars). In the cases of LBL and S-Cubed, who employ exact phase-line fits, no difficulties arose. Both the Stanford and University of Auckland groups used an initial pressure (P_0) of 36.52 bars; this value was chosen so as to maintain the relationship [$P_0 = P_{sat}$ + 2.5 bars] in spite of the fact that the saturation curve used by the University of Auckland's simulator is about one-half bar high at T = 240°C. Both Intercomp and Geotrans, however, interpreted the problem specifications to mean that P_0 should be 36 bars, and made no attempt to correct for deviations in their saturation curve fits from steam table values. In the case of Intercomp, this meant that P_0 exceeded P_{sat} by 2.3 bars, or 92 percent of the intended pressure difference. In the Geotrans case, P_0 exceeded P_{sat} by only 1.5 bars, or only 60 percent of the intended excess. This error produced substantial deviations between the Geotrans calculations and those of the other groups. Due to the smaller restraining pressure, the two-phase region in the Geotrans results was both larger and more persistant than in the other calculations, as will be seen.*

TOTAL STEAM-IN-PLACE

Figures 3 and 4 show the time-histories of the total mass of steam in the system for Problems 5A and 5B as predicted by each calculation. These calculated results fall into three groups. The LBL and S-Cubed calculations are virtually identical. The Intercomp results indicate a slightly greater steam mass, probably due to the fact that the boundary pressure exceeded saturation pressure by 2.3 bars instead of 2.5. The Stanford University/University of Auckland calculations predict higher steam quantities, particularly for Problem 5A; typically, from 5 to 15 percent higher than LBL and S-Cubed. Stanford and the University of Auckland used the correct restraining pressures; possible reasons for the deviation between LBL/S-Cubed and Stanford/U. Auckland will be discussed later.

* Since these calculations were made, Geotrans has corrected their saturation curve fit so that, were they to repeat the calculations, they would obtain correct results.

Finally, as discussed earlier, the Geotrans calculations vastly overpredicted the steam mass (by a factor of as much as 1.6). The differences in results between Problems 5A and 5B arise, of course, from the onset of injection at t = 1 year in the latter case. This causes pressures to rise and boiling to be suppressed.

CALCULATED PRESSURE HISTORIES

Figures 5 and 6 show the calculated pressure histories in the production well-block (i=3, j=3) for the two cases (5A, 5B); Figures 7 and 8 are the corresponding pressure histories in the injection well-block (i=7, j=6). Recall that no injection takes place in Problem 5A. These results are plotted as pressure difference from the initial pressure (P_0) for each calculation. In both cases (5A and 5B), the pressure in the production well-block first drops very rapidly to the saturation pressure; this occurs virtually instantaneously on the time-scale of these plots. Then, the fluid in the well-block begins to boil. Pressures continue to decline, but much more slowly. In Problem 5A, the production well-block remains two-phase until $t \approx 2.8$ years. At this time, sufficient cold water has been drawn into the well-block to cause all the steam to condense. Once single-phase conditions again prevail, the lower resistance to flow permits pressures to recover somewhat, in spite of continued production. In Problem 5B, the pressure increase induced by the onset of injection at t = 1 year causes the production well-block to revert to single-phase conditions shortly thereafter.

The pressure histories calculated by LBL and S-Cubed are essentially indistinguishable. Those computed by Intercomp generally agree with LBL and S-Cubed except at early times ($t < 1$ year or so). This early disagreement is probably due to the poor temporal resolution of the Intercomp calculation; a four-month time step is too long to accurately resolve the very rapid pressure changes that occur during the first part of the problem. The Geotrans results differ substantially from Intercomp, LBL and S-Cubed for the first several years of history for reasons discussed above, but at late times all four calculations (Geotrans, Intercomp, LBL and S-Cubed) are in reasonably good agreement. The computations of Stanford University and the University of Auckland (both using the latter's simulator), on the other hand, exhibit late time pressure disturbances that are 5 to 10 percent greater than those predicted by the other groups. The reasons for this discrepancy are not known for certain. It is not unlikely, however, that they arise from the constitutive description of the fluid employed, in particular the viscosity. Darcy's law states that, all else being equal, the pressure gradient required to maintain a given fluid mass flow rate will increase in proportion to the fluid's kinematic viscosity. Thus, one would expect that if viscosities were about 5 percent too high, predicted pressure drops would be approximately 5 percent high as well. In this connection, it is worthy of note that the experimental tolerances reported in the ASME Steam Tables for the kinematic viscosities of saturated water and steam in the vicinity of 240°C are typically ± 2 to 3 percent. Furthermore, if the viscosities used by the University of Auckland's simulator were slightly high, the exaggerated pressure drop which would then result would tend to cause more boiling and a greater mass of steam in the system as a whole. This is indeed observed, as was shown in Figures 3 and 4.

RESULTS FOR HEAT TRANSFER

Figures 9 and 10 illustrate the calculated temperature histories for Problems 5A, 5B; Figures 11 and 12 show the evolution with time of the enthalpy of the produced fluid. For early times (t < 2.8 years for Problem 5A, < 1 year for Problem 5B), the production well-block is two-phase so that the temperature history is correlated with the pressure history. At late times, the invasion of the production area by colder fluid causes the well-block temperature to decline. This effect is particularly pronounced for Problem 5B which involves the injection of cold (80°C) water in a nearby well. Similar trends may be observed in the discharge enthalpy histories (Figures 11 and 12). The results of all the calculations are in excellent agreement, except that at early times ($t \lesssim 3$ years for Problem 5A, < 2 years for 5B) the Geotrans results exhibit lower temperatures and-higher discharge enthalpies than the others. Since the Geotrans calculation produced excessive steam, the steam-phase mobility was enhanced so that a greater proportion of high-enthalpy steam entered the production well. The presence of this excessive steam, furthermore, reduced the overall mobility of the water/steam mixture as a whole, causing a greater well-block pressure drop; since, for two-phase flow, pressure and temperature are correlated by the saturation curve $P_{sat}(T)$, the well-block temperatures were correspondingly reduced relative to the other calculations. At late times, however, it is noteworthy that the Geotrans results for both temperature and discharge enthalpy agree with the others.

CONCLUSIONS

The results obtained from four of the five simulators are in excellent agreement for Problem 5. The fifth simulation (that of Geotrans) deviates from the others due only to an unfortunate combination of a misunderstanding concerning the definition of the problem and a somewhat inaccurate fit to the water/steam saturation curve in the vicinity of 240°C; the disagreement does not arise from any fundamental flaw in the Geotrans simulator. As noted earlier, since these calculation were performed, Geotrans has improved their saturation curve fit; there is every reason to believe that a repeat calculation would agree with the other results, particularly in view of the good performance of the Geotrans simulator on the other problems in the DOE Problem Set.

TABLE 1

ROCK PROPERTIES FOR PROBLEM 5

DENSITY OF ROCK GRAIN MATERIAL = 2500 KG/M^3

POROSITY = 0.35

PERMEABILITY = 2.5 X 10^{-14} M^2 (≈ 25 MILLIDARCIES)

ROCK GRAIN HEAT CAPACITY = 1 JOULE/GRAM-°C

ROCK GRAIN THERMAL CONDUCTIVITY = 1 WATT/M-°C

RELATIVE PERMEABILITY DATA:

$$\left.\begin{aligned} R_L &= 1 \\ R_S &= 0 \end{aligned}\right\} \quad \text{FOR } 0 \leq S \leq 0.1$$

$$\left.\begin{aligned} R_L &= Z^4 \\ R_S &= (1-Z^2)(1-Z)^2 \end{aligned}\right\} \quad \text{FOR } 0.1 \leq S \leq 0.7$$

$$\left.\begin{aligned} R_L &= 0 \\ R_S &= 1 \end{aligned}\right\} \quad \text{FOR } 0.7 \leq S \leq 1$$

S IS STEAM SATURATION

R_L IS RELATIVE PERMEABILITY TO LIQUID WATER

R_S IS RELATIVE PERMEABILITY TO STEAM

$Z = (0.7 - S)/0.6$

TABLE 2

PROBLEM 5 TEMPORAL RESOLUTION

	CASE "A" (CYCLES/YEAR)		CASE "B" (CYCLES/YEAR)	
	MEAN	MINIMUM	MEAN	MINIMUM
GEOTRANS	8	NR	8	NR
INTERCOMP	3.2	3.0	3.9	3.0
LBL	NR	10	NR	10
S-CUBED	21	20	21	20
STANFORD	225"	183"	205"	183"
U. AUCKLAND	NR	90"	NR	90"

"NR" = NOT REPORTED

* SMALL TIME STEPS REQUIRED FOR COMPUTATIONAL STABILITY

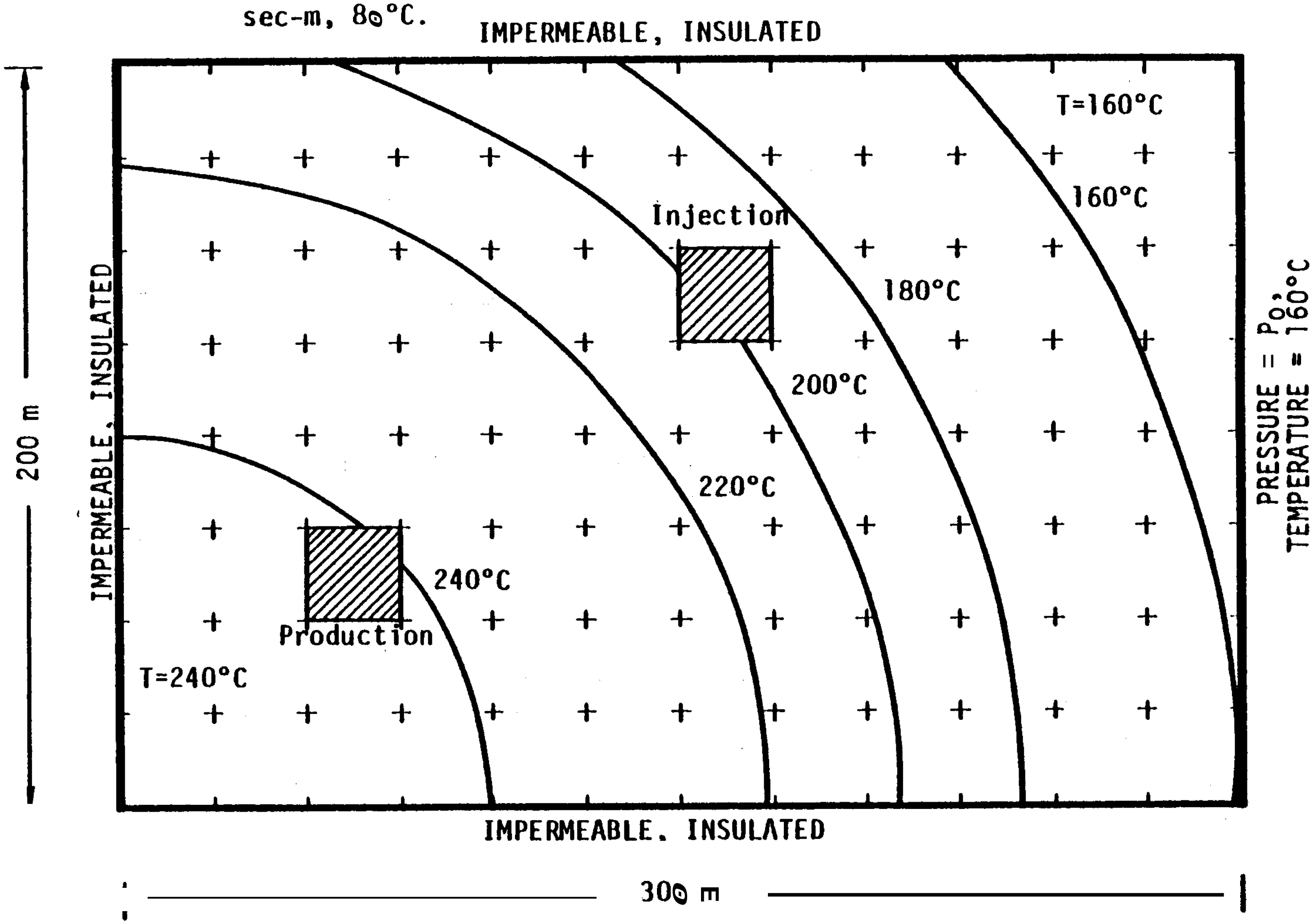
TABLE 3

PROBLEM 5 PRESSURE VALUES

	(Initial and Boundary Pressure)	P_{SAT}(240°C) (Boiling Pressure in Central Region)	$P_O - P_{SAT}$
GEOTRANS	36.00 Bars	34.50 Bars	1.50 Bars
INTERCOMP	35 99 Bars	33.70 Bars	2.29 Bars
LBL	36 00 Bars	33.48 Bars	2.52 Bars
S-CUBED	35 98 Bars	33.48 Bars	2.50 Bars
STANFORD	36.52 Bars	34.02 Bars	2.50 Bars
U. AUCKLAND	36.52 Bars	34.02 Bars	2.50 Bars

Case A: No Injection, Production 50 gram/sec-m.

Case B: Production 50 gram/sec-m. Injection for Time $\geq$ 1 Year, 30 gram/sec-m, 80°C.



Initial Pressure = Boundary Pressure = P_0 = P_{sat}(240°C) + 5 Bars ≈ 36 Bars

FIGURE 1. PROBLEM 5 GEOMETRY

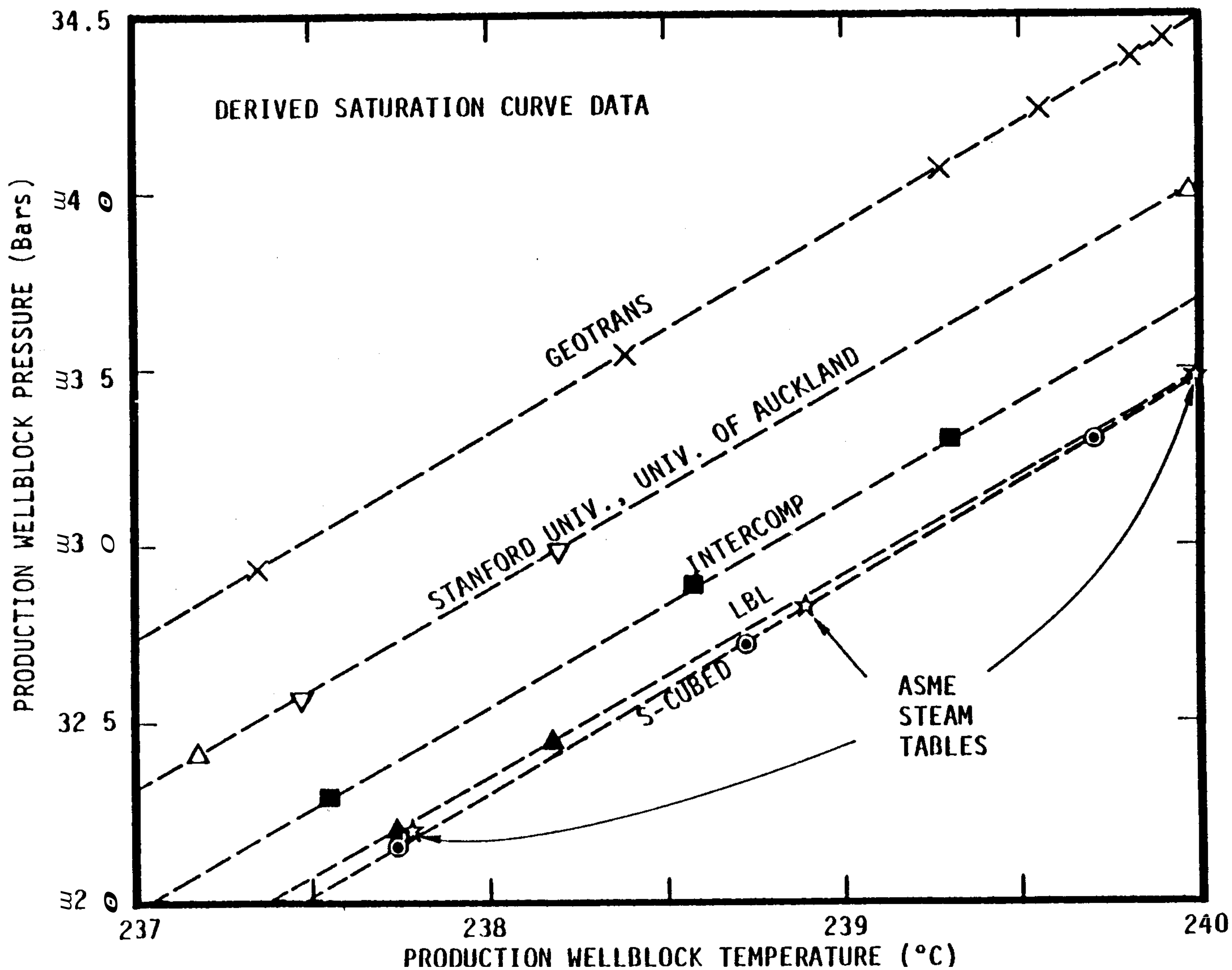


FIGURE 2. EARLY-TIME CORRELATION BETWEEN WELL-BLOCK PRESSURE AND TEMPERATURE.

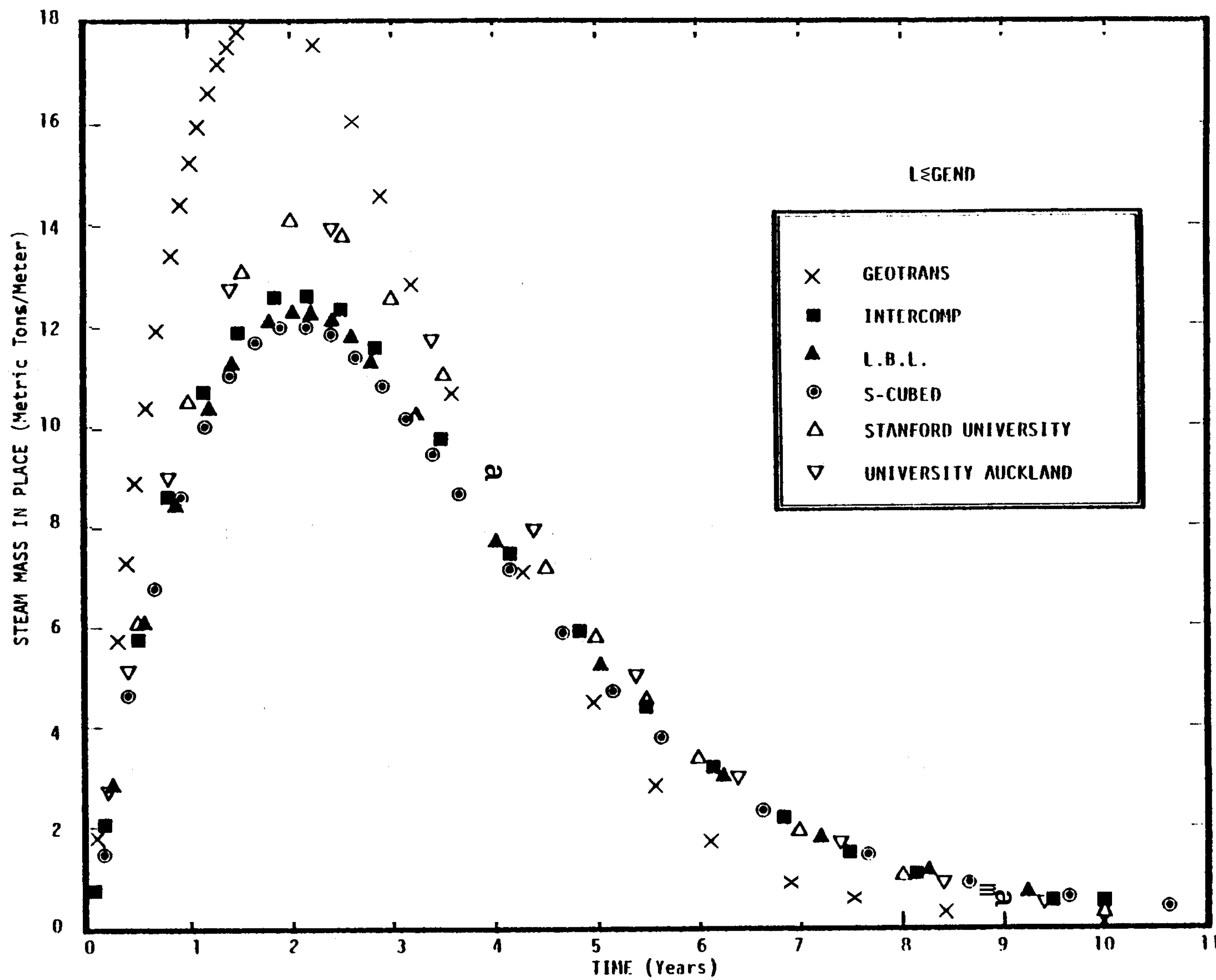


FIGURE 3. HISTORY OF TOTAL STEAM-IN-PLACE PER UNIT THICKNESS -- PROBLEM 5A.

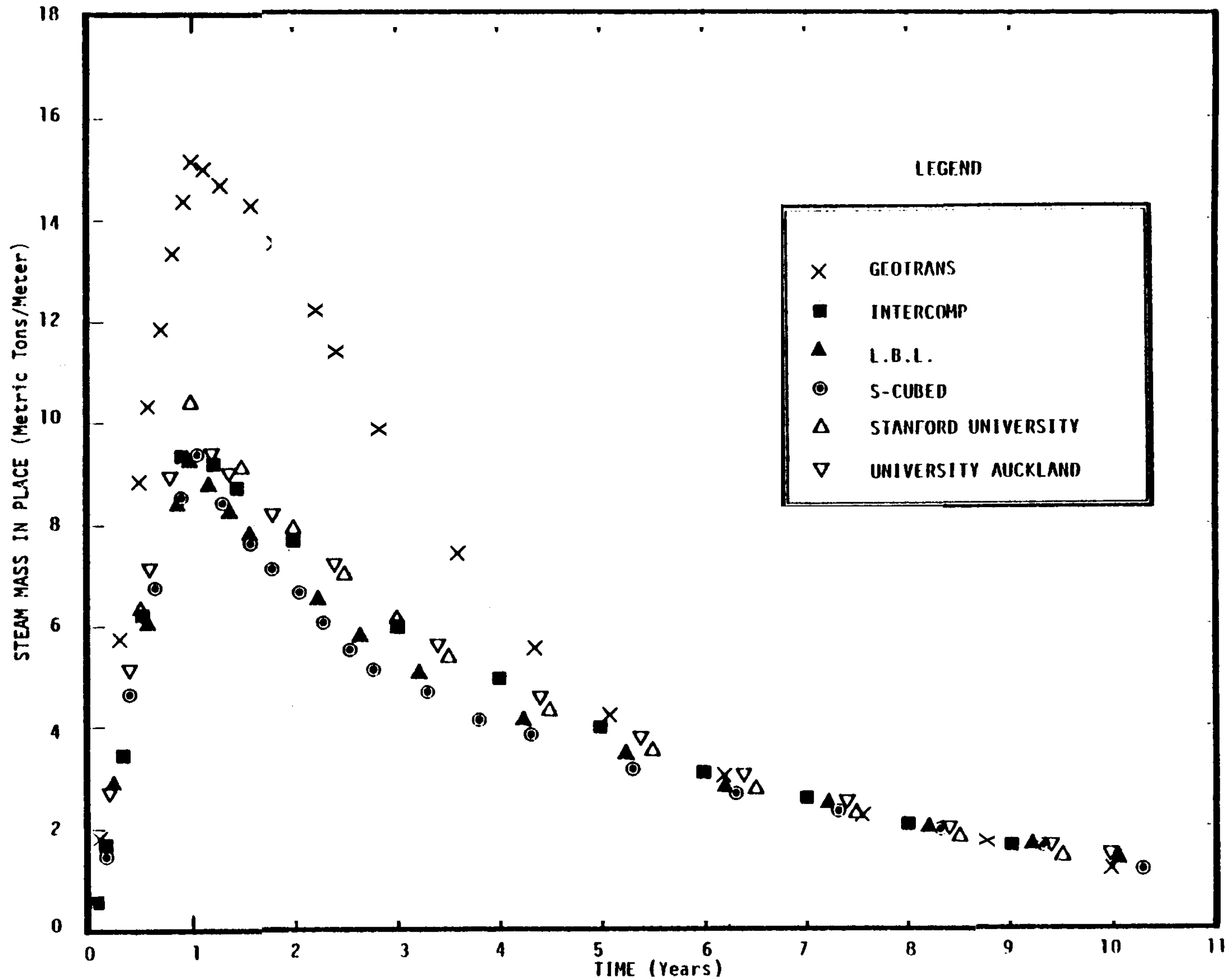


FIGURE 4. HISTORY OF TOTAL STEAM-IN-PLACE PER UNIT THICKNESS -- PROBLEM 5B.

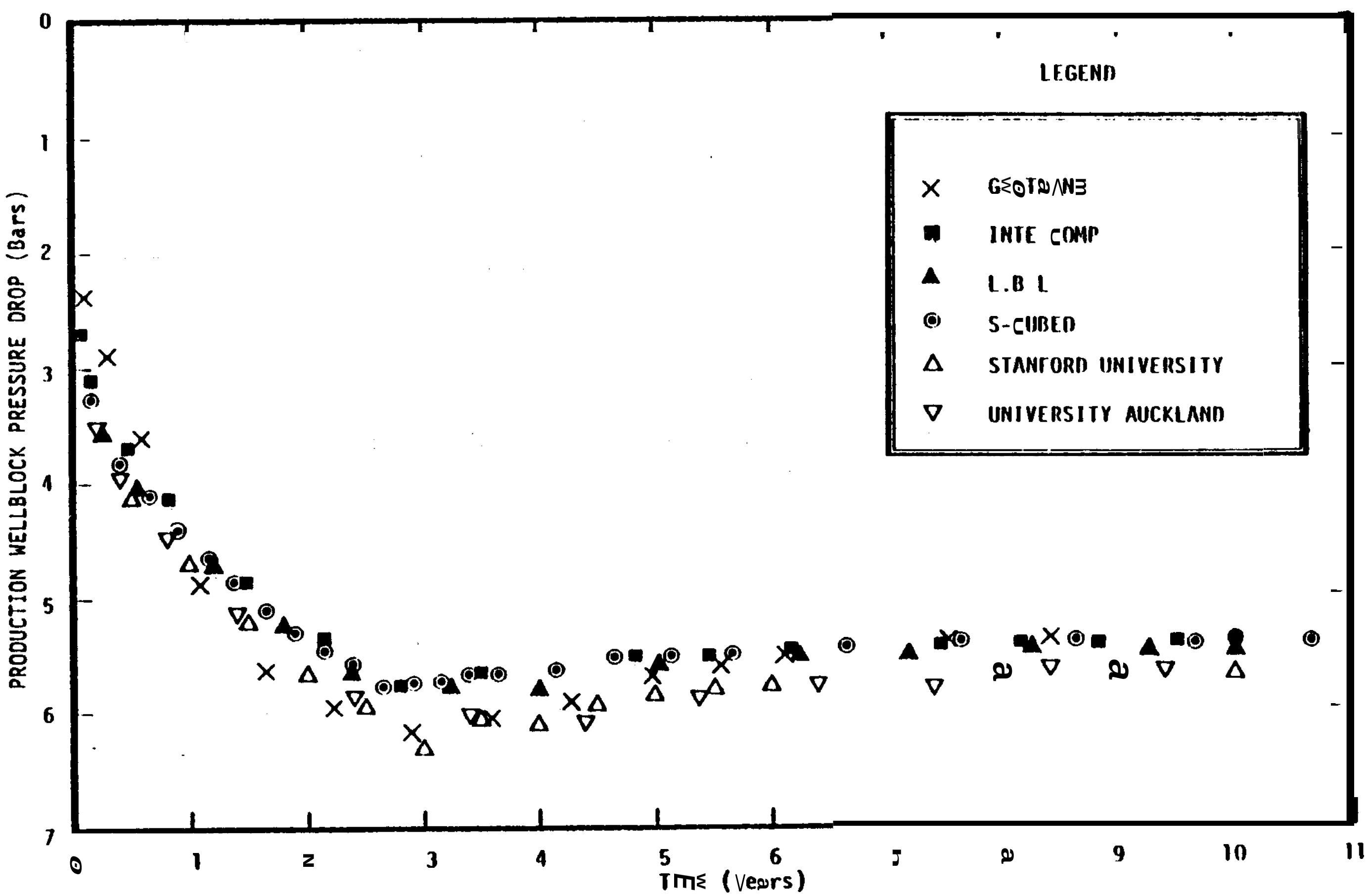


FIGURE 5. PRESSURE HISTORY IN PRODUCTION WELL-BLOCK -- PROBLEM 5A.

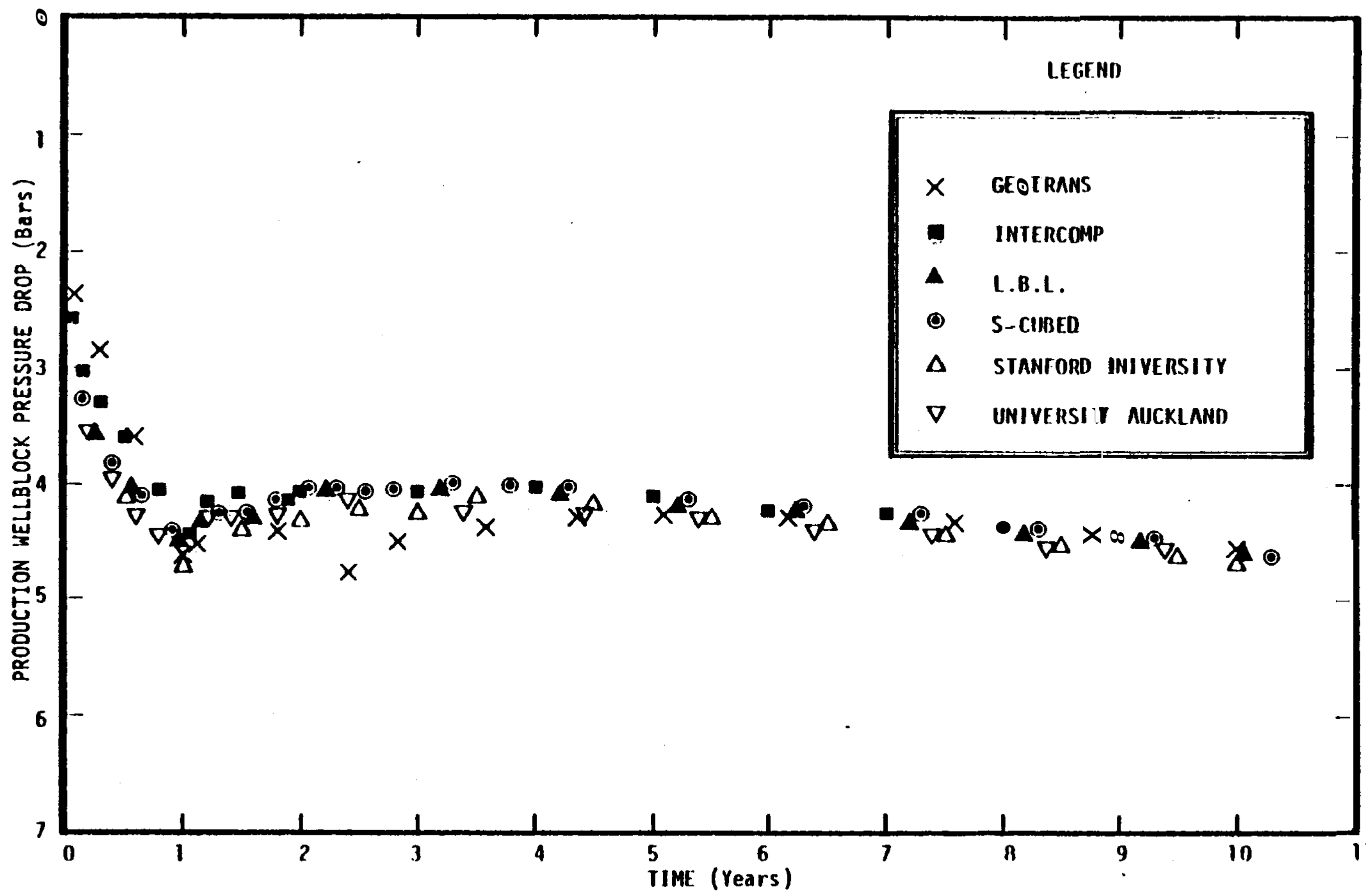


FIGURE 6. PRESSURE HISTORY IN PRODUCTION WELL-BLOCK -- PROBLEM 5B.

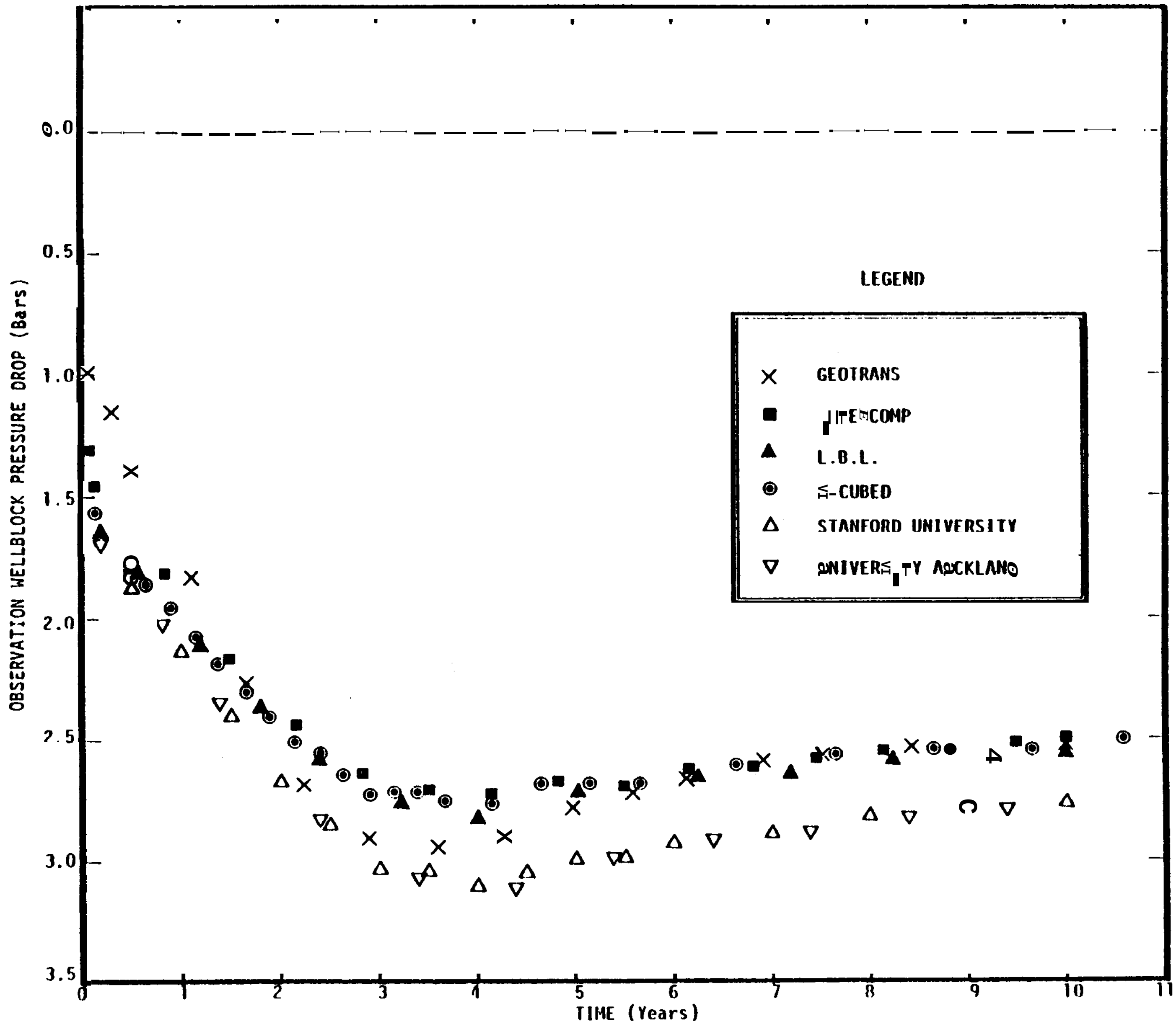


FIGURE 7. PRESSURE HISTORY IN OBSERVATION WELL-BLOCK -- PROBLEM 5A.

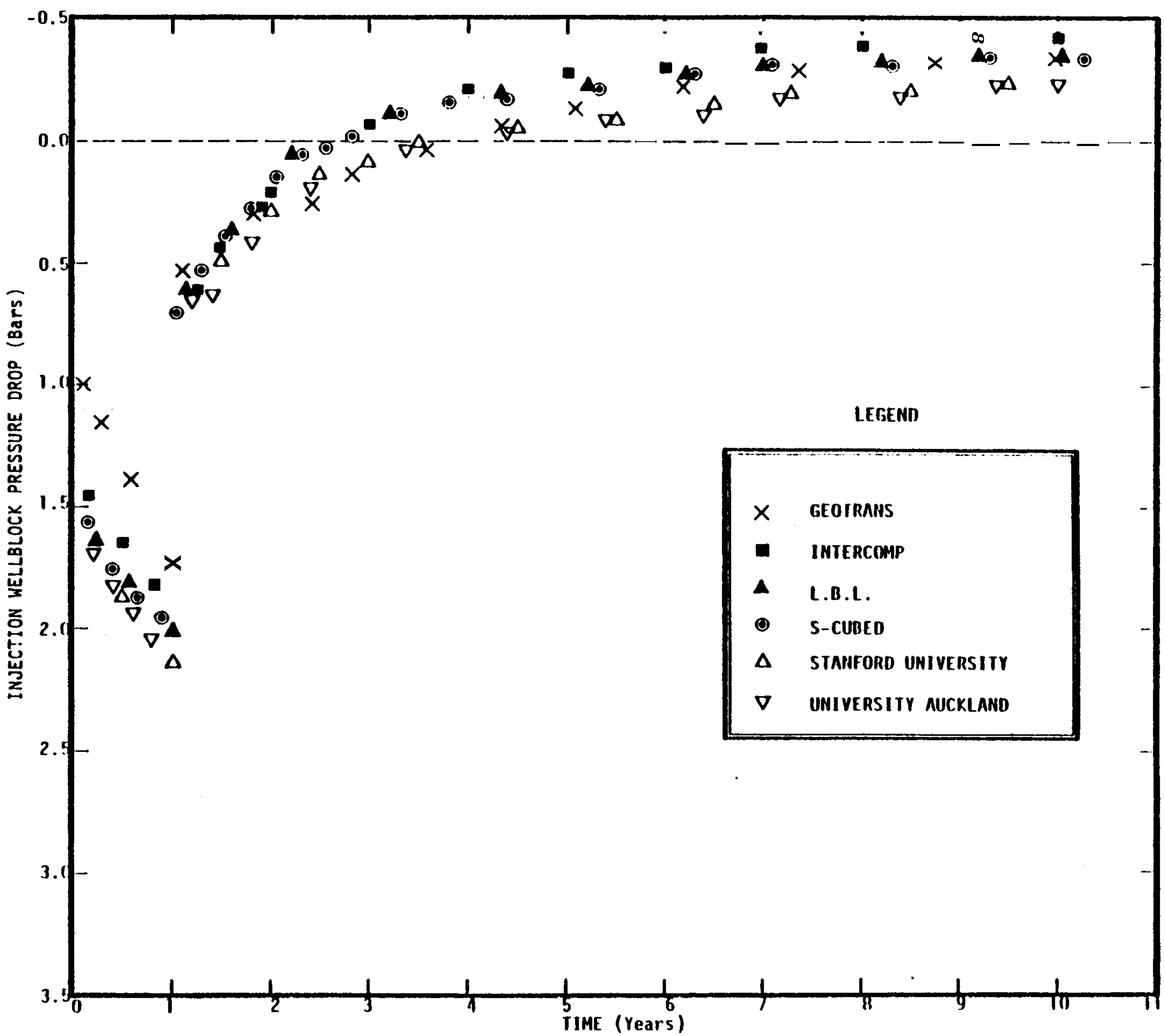


FIGURE 8. PRESSURE HISTORY IN INJECTION WELL-BLOCK -- PROBLEM 5B.

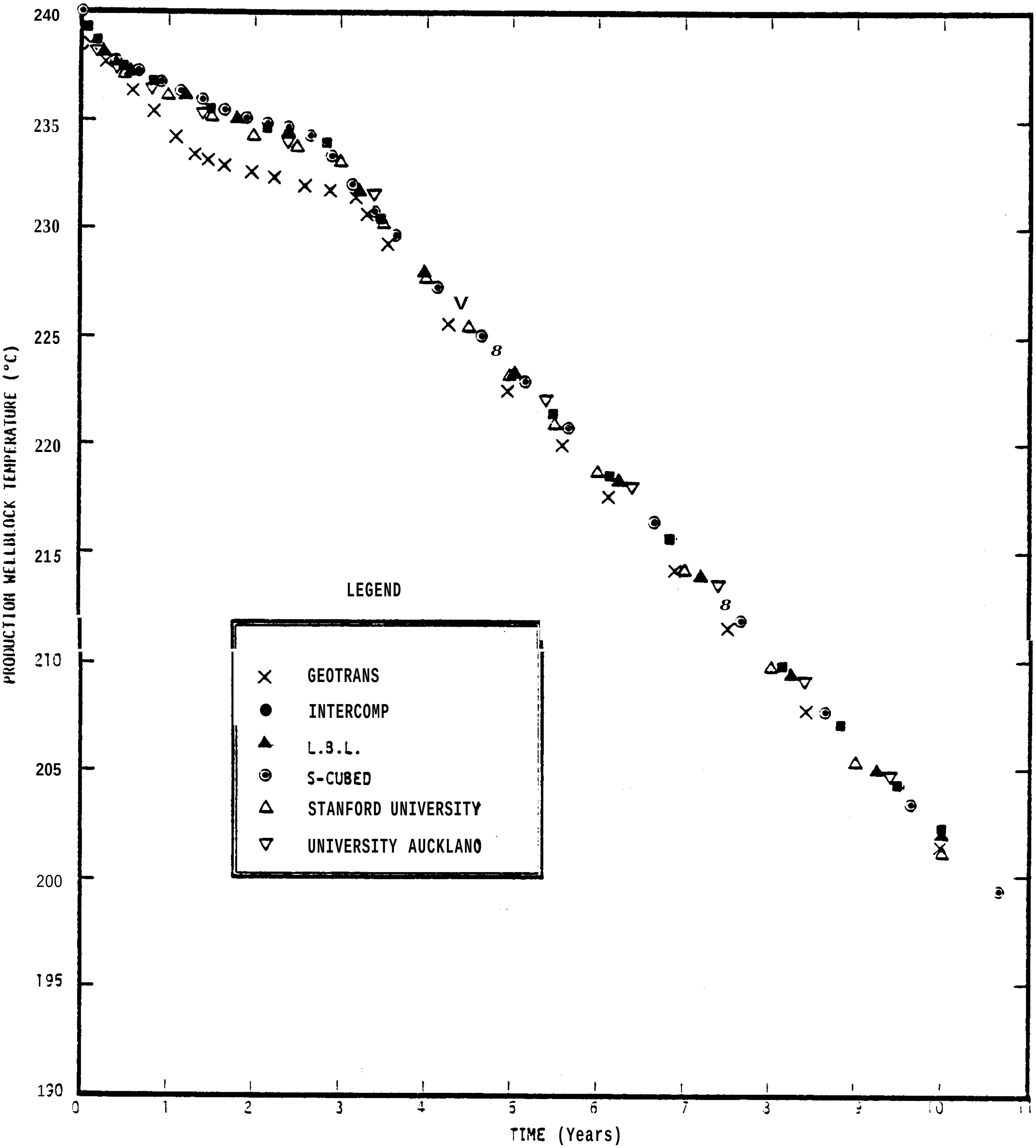


FIGURE 9. PRODUCTION WELL-BLOCK TEMPERATURE HISTORY -- PROBLEM 5A,

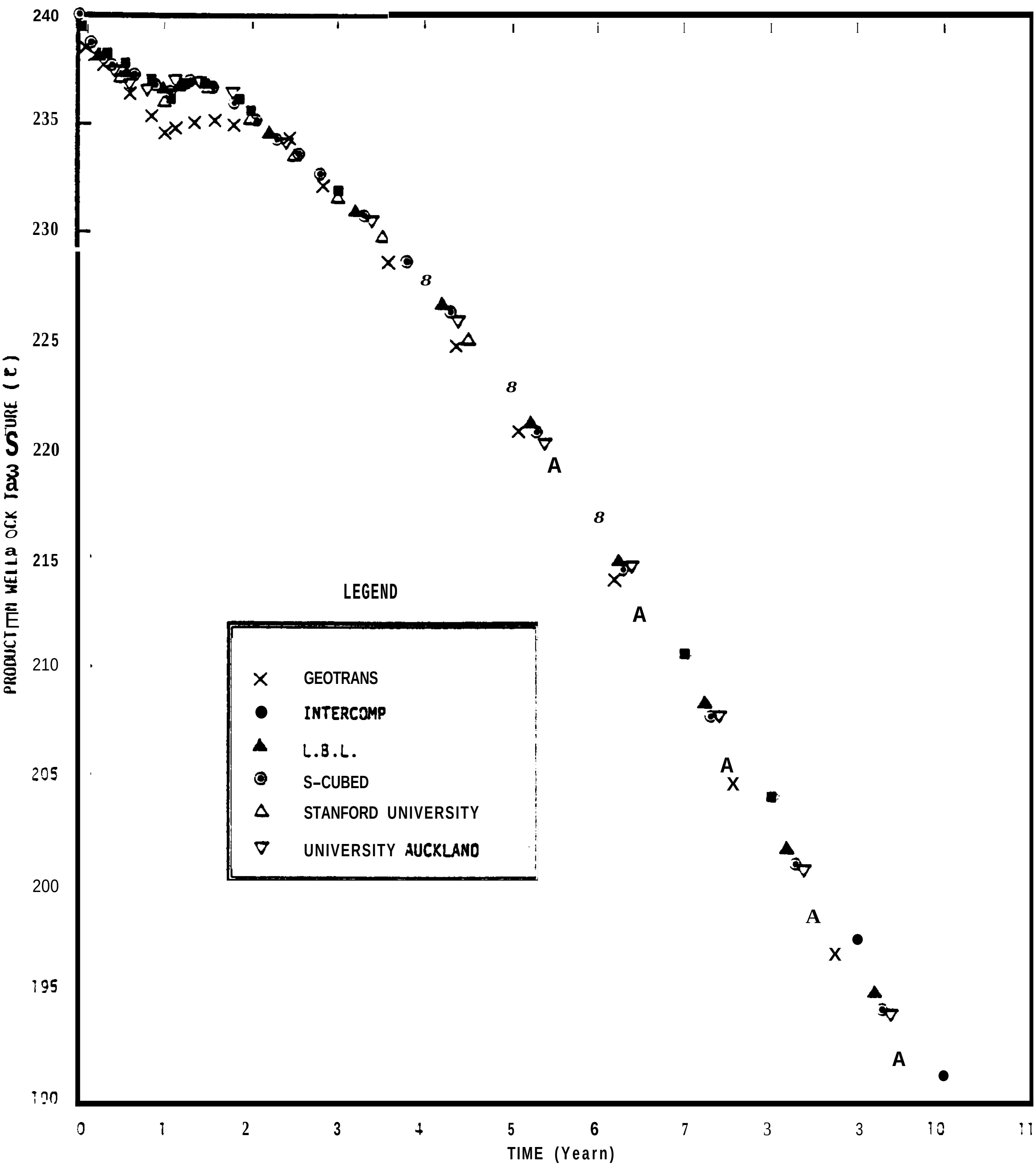


FIGURE 10. PRODUCTION WELL-BLOCK TEMPERATURE HISTORY -- PROBLEM 5B

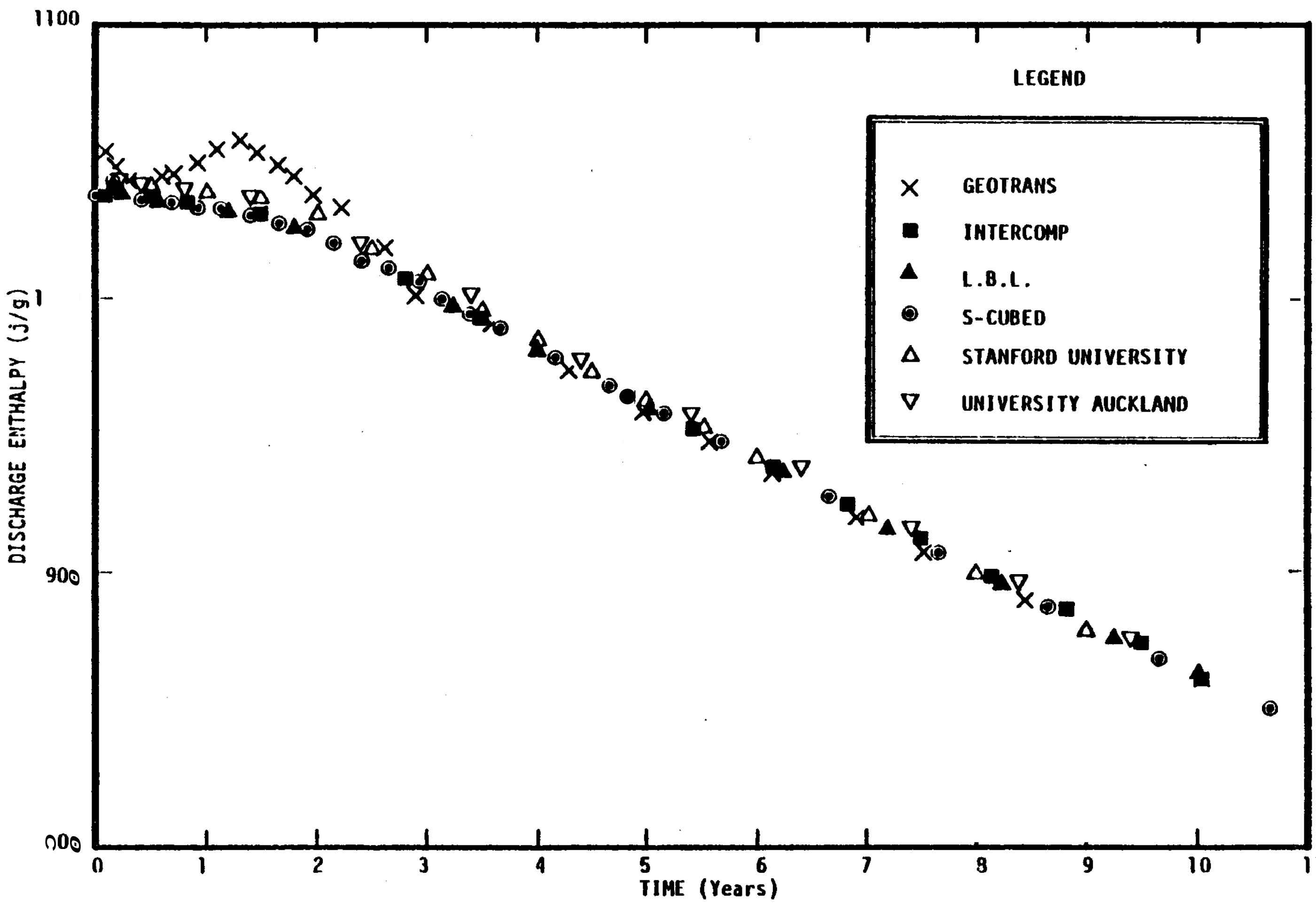


FIGURE 11. PRODUCTION WELL DISCHARGE ENTHALPY HISTORY -- PROBLEM 5A.

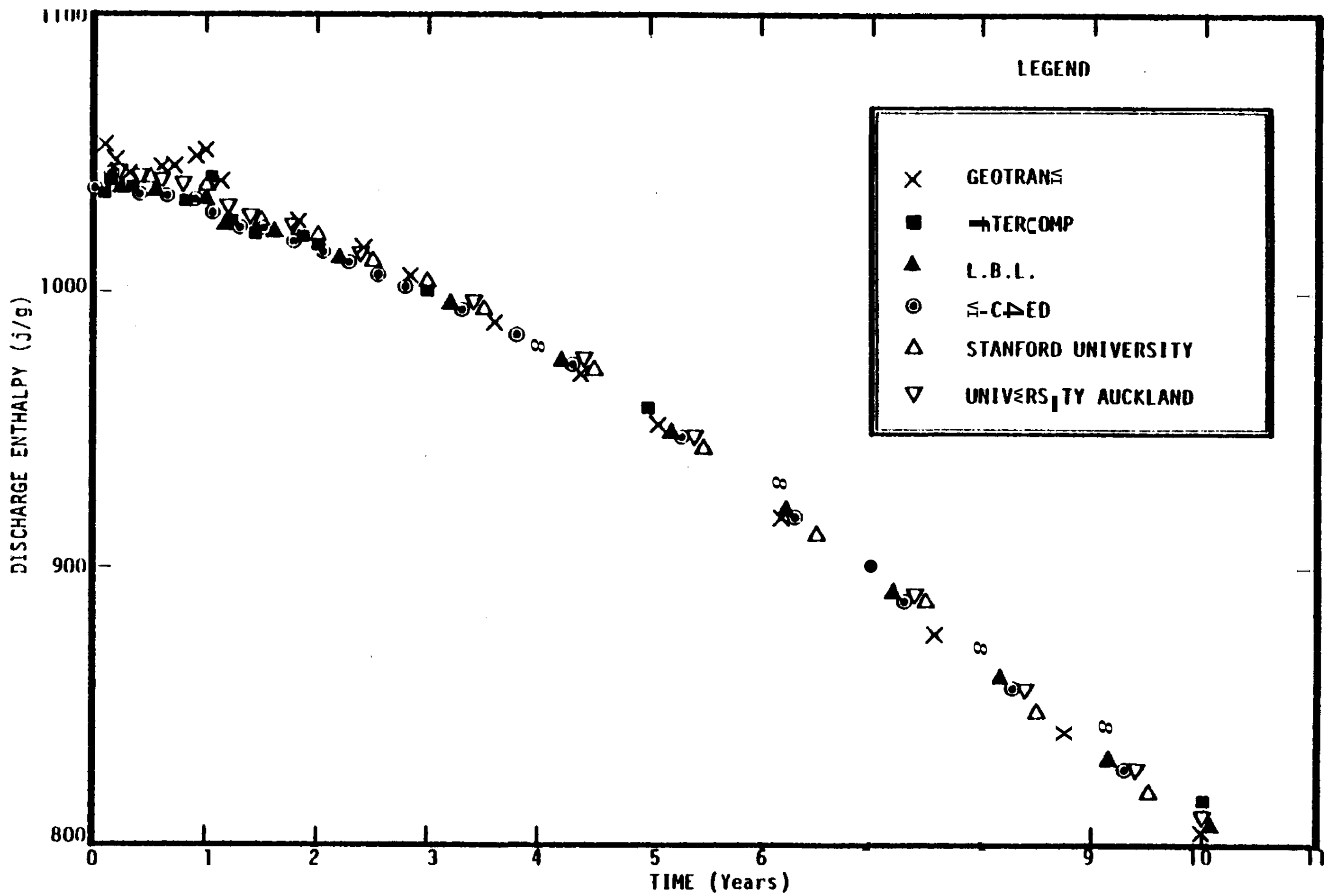


FIGURE 12. PRODUCTION WELL DISCHARGE ENTHALPY HISTORY -- PROBLEM 5B.

DOE-PROJECT ON GEOTHERMAL RESERVOIR ENGINEERING
COMPUTER CODE COMPARISON AND VALIDATION

-EVALUATION OF RESULTS FOR PROBLEM 6-

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INTKODUCTION

Problem 6 is a reservoir-wide problem, and the only one in tne set which involves three-dimensional flow. The reservoir is of "Wairakei-type," with single-phase liquid at depth, overlain by a two-phase zone with immobile steam, and capped off with a zone of colder single-phase water. Production occurs from a well field with completion intervals below the two-phase zone. Parameters are chosen in such a way that boiling in the well field and two-phase flow commence after a certain period of production.

Although the problen is schenatic in nature, it is nonetheless a prototype of field-wide studies which would be undertaken to examine alternative reservoir developnent plans. Typical questions to be addressed by this type of problem would include: at what depth should the wells be completed? what flowrates can be sustained for what length of time by a well field of given areal extension? what is the evolution of downhole pressures and discharge enthalpies?

Problen 6 is probably the most difficult one in the set for numerical sinulators, due to its three-dimensional nature and the occurrence of phase transitions with subsequent two-phase flow, including gravitationally induced steam/water counterflow.

PROBLEM DESCKIPTION

The reservoir is a parallelepiped of 4 x 5 km^2 areal extent and 1.8 km thickness. Figure 1 shows the geometric design of the system, and the zoning to be used in the simulation. Tables 1 through 4 give the complete specifications of all parameters. Fornation properties vary somewhat with depth, and there is a large contrast between horizontal and vertical permeability. The lower 2/3 of the reservoir is initially filled with liquid water at 280 ^{o}C temperature. This is overlain by a two-phase region, also at 280 ^{o}C, which has an immobile steam saturation of 10% by volume. Overlying this is a layer of colder water at T = 160 ^{o}C. The entire reservoir is gravitationally equilibrated, so that initially there is no fluid flow. The process to be simulated is production from a specified subregion at depth. Production rates increase with time in such a way that boiling in the wellblock and two-phase flow is initiated. In the process, temperatures and pressures are kept to their initial values at the upper and lower boundaries, and at the surface at x = 5 km. The other three reservoir faces are closed ("no flow").

GENERAL DESCKIPTION OF KESERVOIR EVOLUTION

The evolution of the reservoir in response to production can be described as follows. As a consequence of production, pressures drop in the wellblock, so that horizontal and vertical flow towards the wellblock is initiated. Downflow from the two-phase zone gives rise to boiling and increasing vapor saturation. As the pressure decline spreads to the margins of the field, water recharge is initiated. One consequence of this is the occurrence of several phase transitions to single-phase Conditions in the two-phase layer. The production rates for the first few years are such (small) that pressures in the wellblock stabilize, resulting in an approximately steady flow pattern. The increase in production rate after four years can not be readily sustained for the given permeabilities. Thus, large pressure drops occur in the grid block which represents the well field, as well as in adjacent grid blocks. This causes several phase transitions to two-phase conditions, and subsequent boiling. This is accompanied by a decline in temperatures and pressures, as well as a buildup of vapor saturation. Steam/water counterflow occurs as steam rises from the shallow two-phase layer, whereas water flows downward towards the production well. Conditions again approach a steady flow until the imposed increase in production rate after six years causes a rapid catastrophic decline of pressures in the production region, thus terminating the problem. This is unfortunate, as somewhat smaller production rates and a longer reservoir life would have allowed a more extensive comparison of simulated results.

COMPARISON OF RESULTS

Figures 2-4 show the simulated time evolutions of some of the more sensitive parameters. It is apparent that there is excellent agreement between the results of S^3, Geotrans, and LBL; whereas Intercomp's calculation is somewhat off. A conspicuous feature of Intercomp's results is that pressures below the well block (in layer 1) do not decline at all in the course of production, which gives rise to more water influx into the well block. As a consequence, well block pressures remain higher, particularly after five years, and vapor saturation and discharge enthalpy remain lower. The deviations become larger after the increase of production rate after six years. The nature of the discrepancies suggests sone error in the problem definition rather than an error in Intercomp's simulator. It appears that the lower boundary conditions or the permeability below the well block had not been properly specified.

The quality of agreement between the calcuations of S^3, Geotrans, and LBL is quite remarkable, particularly in view of the significant differences in methodology used in the simulators. S^3 and Geotrans use a finite difference method, whereas LBL's simulator employs an integral finite difference method. The primary dependent variables are, respectively, energy and pressure (S^3), pressure and enthalpy (Geotrans), and energy and density (LBL). Geotrans uses an analytical approximation for thermophysical properties of water substance, whereas S^3 and LBL employ a tabular equation of state.

CONCLUSION

Three of the four simulators used in computing a difficult three-dimensional problem show excellent quantitative agreement. This demonstrates that numerical simulators are capable of producing accurate results for field-wide reservoir depletion problems, involving phase transitions, gravitationally induced steam/water counterflow, and recharge.

Table 1: Rock properties.

	Layer 1	Layer 2	Layer 3	Layer 4	Layer 5
Grain Density (g/cm^3)	2.5	2.5	2.5	2.5	2.5
Porosity	0.2	0.25	0.25	0.25	0.2
x-Permeability (m^2)	100×10^{-15}	200×10^{-15}	200×10^{-15}	200×10^{-15}	100×10^{-15}
y-Permeability (m^2)	100×10^{-15}	200×10^{-15}	200×10^{-15}	200×10^{-15}	100×10^{-15}
z-Permeability (m^2)	2×10^{-15}	50×10^{-15}	50×10^{-15}	50×10^{-15}	2×10^{-15}
Heat Capacity (J/g-°C)	1	1	1	1	1
Rock Therm. Cond.(w/m-°C)	1	1	1	1	1
Relative Permeability: Corey equations as in Problem #2, except:					
S_{lr} (liquid residual.)	0.3	0.3	0.3	0.3	0.3
S_{gr} (gas residual)	0.1	0.1	0.1	0.1	0.1

Table 2: Initial conditions.

Temperature:

Layers 1-4, 280°C everywhere

Layer 5, 160°C

Pressure:

Layer 4: $P_4^o = P_{sat}\ (280°C) \approx 64$ Bars

(Steam saturation) $S_s^o = 0.1$ (steam initially immobile)

Layer 5: $P_5^o = P_4^o - (1470\ m^2/s^2) \times (\rho_4^o\text{-liq} + \rho_5^o)$

Layer 3: $P_3^o = P_4^o + (1470\ m^2/s^2) \times (\rho_4^o\text{-liq} + \rho_3^o)$

Layer 2: $P_2^o = P_3^o + (1470\ m^2/s^2) \times (\rho_3^o + \rho_2^o)$

Layer 1: $P_1^o = P_2^o + (1470\ m\ /s\ ) \times (\rho_2^o + 2\rho_1^o)$

Where ρ_4^o-liq = liquid density in Layer 4

These initial conditions (P^o, ρ^o, S_s^o) are functions of z only. Layers 1, 2, 3 and 5 are initially single-phase liquid; layer 4 is initially 2-phase with an immobile steam phase. The pressure distribution is liquid-hydrostatic throughout at zero time.

Table 3: Boundary conditions.

At z = 1.5 km (top surface), maintain $P_{top} = P_5^o - (1470\ m^2/s^2) \times \rho_5^o$ and T = 100°C.

At z = 0, maintain $P_{bottom} = P_1^o + (2940\ m^2/s^2) \times \rho_1^o$ and T = 280°C.

Along planes at x = 0 and y = 0, impose symmetry conditions.

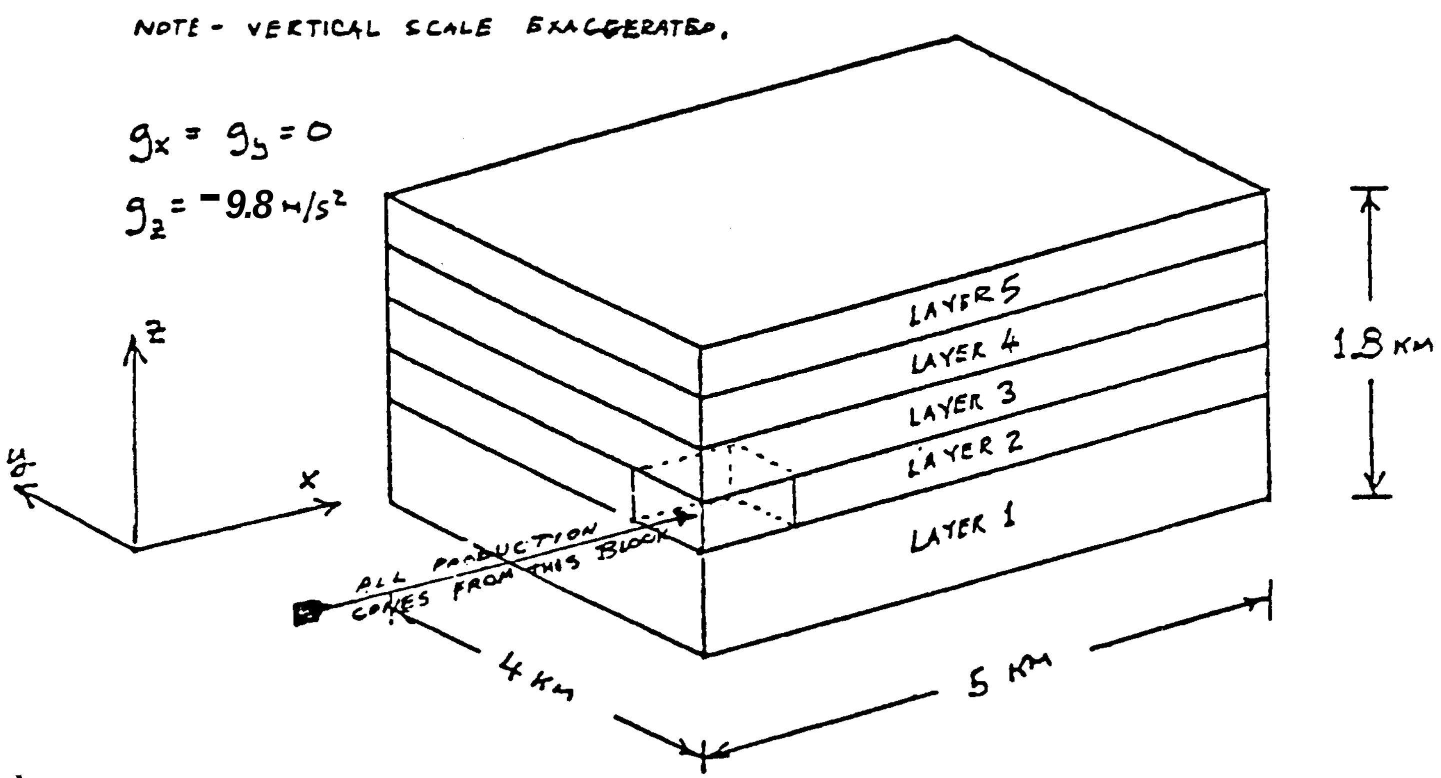
Treat plane at y = 4 km as impermeable and insulated.

Along plane at x = 5 km, maintain initial distributions of P, T, S_s.

Table 4: Production strategy.

All production is taken from a single corner cell (i=1, j=1, k=2).

0 < t < 2 years,	Q(t) = 1000 kg/s
2 years < t ≤ 4 years,	Q(t) = 2500 kg/s
4 years < t ≤ 6 years,	Q(t) = 4000 kg/s
t > 6 years,	Q(t) = 6000 kg/s



LAYER THICKNESSES:
AYER 1, 0.6 KM
LAYERS 2-5, 0.3 KM EACH

GRID: 5 x 5 x 5
(Horizontal, uniform, 5 zones each direction)

Figure 1: Geometry of the reservoir and mesh design.

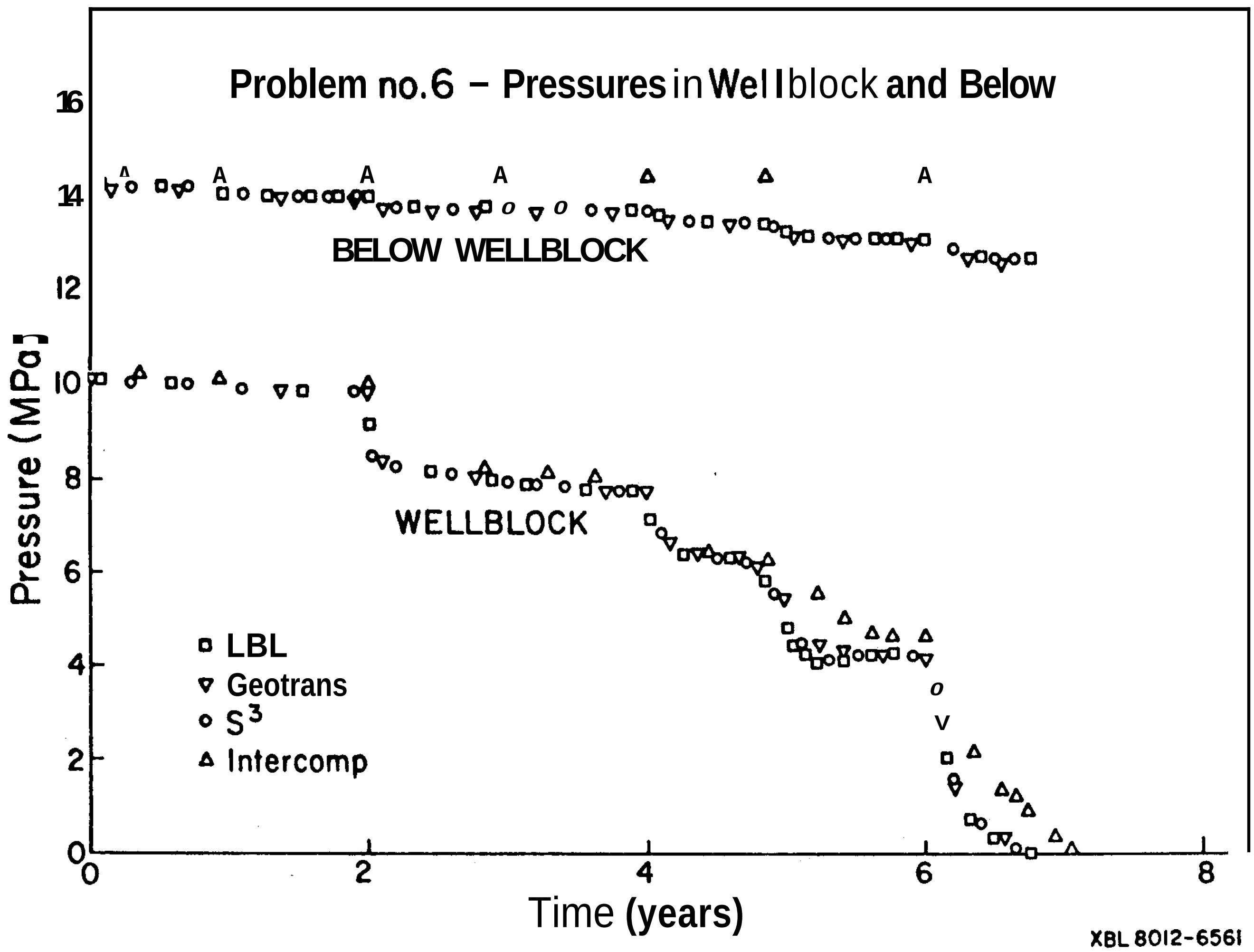


Figure 2: Time dependence of selected pressures.

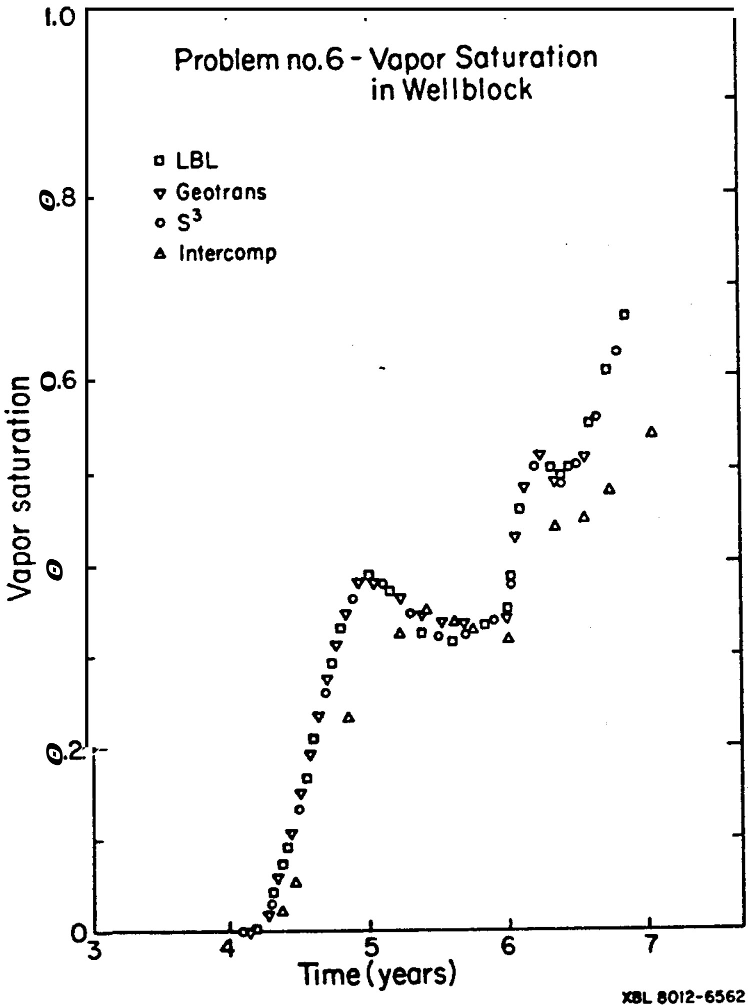


Figure 3: Evolution of vapor saturation in well block.

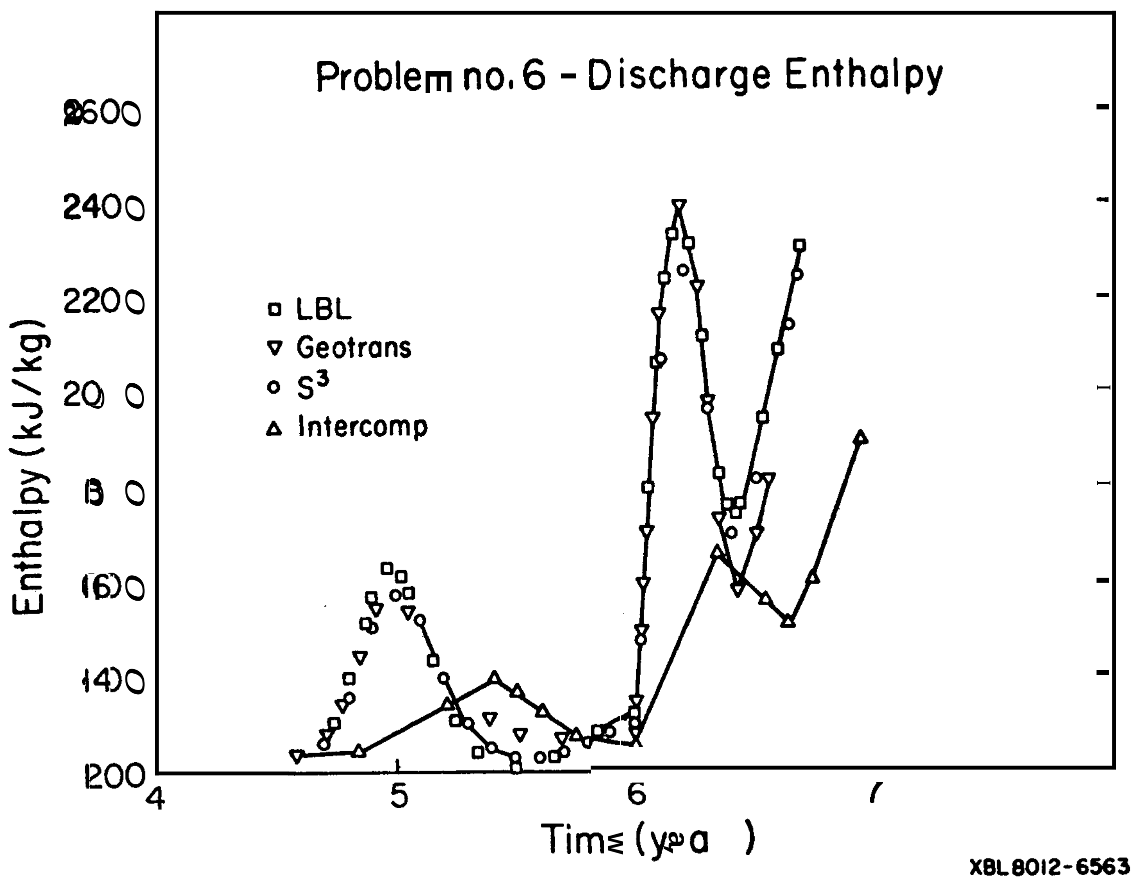


Figure 4: Discharge enthalpy history.

COMMENTS ON SIMULATOR VALIDATION STUDY

by C. W. Morris and D. A. Campbell

Because of the dependence of the geothermal industry on the prediction of the resource performance with little or no production history, the validity of the reservoir engineering estimates, including the reservoir simulation work, is very important. Investors, utilities, government agencies, and other outside parties, therefore, must have confidence that the geothermal simulator can accurately solve the energy and flow equations necessary to describe the physical processes. This is analogous to the use of "black oil" simulators in the petroleum industry;[1] Our experience has shown that many consultants, particularly those who are non-users of geothermal simulators, are reluctant to accept the simulator results. Even when they agree that the model "set-up" is a reasonable representation of a field as known at the time, they commonly limit their endorsement because of uncertainty that the physics of reservoir and well operations are properly replicated.

The studies presented at this workshop clearly indicated that these simulators can solve a wide variety of geothermal problems, using different numerical methods, and arrive at the same results. It must, therefore, be concluded that these computer codes can describe the physical processes as well as we now understand them.

The validity of the geothermal reservoir simulator calculations should not be confused with the accuracy of the reservoir performance predictions since the computer code is only one of many "tools" used by the engineer. A reasonable reservoir model and an accurate description to the reservoir parameters by the engineer are required to achieve good performance predictions. Parametric and sensitivity studies are properly part of any reservoir simulation work. Outside parties must evaluate these phases of reservoir engineering independent of the simulation physics.

Assuming that the reservoir model and input parameters reflect the true reservoir conditions, the reservoir simulation results can be accepted as valid by the outside parties involved in geothermal development. The added advantage of the simulator approach over the consultant's "guess" is that the input is clearly documented for evaluation by others and the results can be modified in a logical manner as experience and knowledge of the resource increases. The complexity of the reservoir simulation effort can also increase with knowledge.

We wish to congratulate the DOE/San Francisco and the contract participants for a job well done. This complex study was accomplished in a timely fashion to support a recognized need of the geothermal industry.

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1. A. S. Odeh, "Comparison of Solutions to e Three-Dimensional Black-Oil Reservoir Simulation Problem," JPT, January 1981, Vol. 33, No. 1, p.13.

Panelist's Remarks on Intercomparison of Reservoir Models
Sixth Stanford Geothermal Program Workshop
December 17, 1980

by

Evan Hughes and Vasel Roberts
Electric Power Research Institute

The presentations made in this session have shown that simulators are capable of calculating reservoir performance with reasonable agreement among the models. Beyond such confirmation of modeling capability, additional effort in four areas is needed:

- sensitivity of results to errors in the physical data
- accurate physical data for use in the models
- estimates of probabilities and/or levels of confidence associated with production capacity, temperature and pressure profiles, and reservoir life
- verification of models by comparison with reservoir production data

From our perspective in conducting a geothermal research program for the electric utility industry we have formulated some informal criteria for reservoir simulation models. These constitute a "model of a model," i.e., some expectations of what a reservoir model should do in order to meet the needs of electric utilities engaged in geothermal power development. To develop the model of the model four questions are addressed.

First, what should a reservoir model be to a geothermal utility? In one respect it is no different than any other type of model. It is a device that will allow one to visualize what the product. looks like and how it works prior to commitment. While this particular tool is generally used directly by resource companies and reservoir engineering consultants and may be foreign to the utility itself, it can contribute to the utility decision making process if results relevant to risk assessment are presented with clarity. It is expected that the results from reservoir modeling will make the decision process somewhat easier to the extent that the model is a vehicle for understanding what happens in the reservoir and how this relates to investment risks associated with reliance on the reservoir for the generation of electricity.

Second, how should a reservoir model be packaged, or developed as a product for utility use? It should be understandable by engineers and managers who are not specialists in geothermal or petroleum reservoir engineering. Also, it should be transferable for use on computers and by people other than the particular computing machine and staff that developed the model.

Third, what should the reservoir model do for the utility? Here are some specific capabilities of a useful model. It should be capable of calculating the production of a whole geothermal field over a 30 year life from data based on early tests or production of a well or wells on a limited portion of the field. It should estimate the limits of off-design production conditions that may arise and assign probabilities to different off-design conditions. It should be capable of accepting and using new data that become available as the field is developed and operated. Such data can be used to confirm the model and to improve predictions in two ways: (1) greater confidence and (2) narrower range of probable outcomes.

In addition to the above capabilities, and related to them, a reservoir model should generate the following information for reservoir risk assessments relevant to the decisions on whether and how to build geothermal power plants: curves showing the probabilities associated with the capability of a reservoir to support various levels of generating capacity; life of a reservoir as a function of generating capacity being supported, indicating the confidence levels of various life versus capacity curves; probability of precipitous decline in production as a function of capacity; identification of detectible changes that would precede or be associated with such a decline; production rate, temperature, pressure and, perhaps chemistry versus time, capacity and well spacing; and, finally, identification and quantification of reservoir risk associated with development of the first power generating unit at a reservoir and with development of subsequent units at the same reservoir.

Fourth, what is the validity of the reservoir model? The model should be verified as to usefulness in performing calculations of interest. The types of results listed above are those of value for power plant commitment decisions, generation expansion plans, and geothermal power plant design considerations. In addition a reservoir model should, of course, be verified by comparison with field experiments and actual operating experience.

The results presented in this workshop suggest that the models agree reasonably well in calculations for the theoretical problems posed. Also, the problems posed are of types that have practical relevance, especially those that involve calculating a production history from parameters whose value could be inferred from measurements made early in the development of a reservoir. What is needed beyond this are calculations that reveal how sensitive the results are to variations in the values of dominant parameters, some probabilities assigned to various possible production histories, good physical data to put into the models, verification of the calculations through comparison to field results, and the development of models that are easy to understand, use and transfer to other users.

SESSION VII

Model Intermparison Study (Panel)
(Opening Remarks of N. K. Barrett of
Corroon & Black of Pennsylvania, Inc.)

I want to express my thanks to our Stanford University hosts for this opportunity to participate here as a panelist. In order to achieve a realistic perspective of geothermal resource insurance needs, I do welcome this perspective of the current state of the geothermal art.

The INA - C&B Geothermal Resource Insurance Program is a very potent financial tool which has keen designed to stimulate private sector financing of geothermal projects. In our opinion, such private funding of geothermal projects will more than offset the expected reduction in government funding alluded to by Mr. Robert Grey in his opening remarks yesterday.

In order to underwrite each geothermal project, the insurance underwriters must obtain a fair assessment of the expected nature and longevity of the resource involved -- then tailor their insurance coverages to protect against the unexpected. Underwriters are leaning heavily upon the expertise of the geothermal engineers of their potential clients for their initial technical perspective of each geothermal project. This is ultimately followed by technical confirmation by a qualified geothermal engineering consultant retained by the underwriters involved.

Such geothermal engineers will be relied upon by the underwriters for decisions concerning the use of numerical code reservoir simulators. It seems likely that in many cases numerical reservoir modeling may be combined with the economic modeling of such projects as an aid in fairly assessing "the realm of the expected".

The INA - C&B Geothermal Resource Insurance Program is designed to insure the long-term availability of the resource at the needed quantity and quality level established for the project during the simulation modeling and sampling period. Insurance is afforded not only against loss arising out of project termination because of resource inadequacy, but also against loss resulting from project capability reduction. Coverages are offered for a noncancellable policy period encanpassing the project construction period plus an operational period of up to seven (7) years.

I. DIRECT USE OF GEOTHERMAL RESOURCE (Electricity Generation Plant)

A. The Expediting Phase (Plant Construction Period):

Coverage for the Expediting Phase will go into effect after completion of the reservoir exploration process and will remain in effect until the commencement of the normal commercial operations. Inception of such insurance coverage occurs only after confirmation of the resource reserve capacity sufficient to operate the proposed geothermal power plant at a specified level of efficiency. In the unlikely event that the proposed project must be scaled down or terminated due to inadequacy of the resource, the policy indemnifies the Insured for the financial loss resulting therefran.

1. COVERAGE: During Field Development and Facilities Construction Period.

2. INSUREDS: Any persons or entities having a financial interest in the Electricity Generation Project.

3. INDEMNIFICATION in the event of:

   a. Project Termination Prior To Project Completion -- payment of the sunk costs of the project as of the date of termination.

   b. Project Capability Reduction (inability to achieve the project's target capability -- with subsequent commercial operations at the reduced capability) -- payment of agreed amounts to assure continuation of debt service and payment of the fixed costs.

B. The Operational Phase (Up to Seven Years):

Coverage for the Operational Phase will go into effect at the time of the official commencement of commercial operations. Project termination due to inadequacy of the resource is covered as in the Expediting Phase. Coverage for loss of earnings (business interruption) due to inadequacy or scale-down of the geothermal resource is also available.

1. COVERAGE: During Commercial Operations (Maximum of Seven Years)

2. INSUREDS: Any persons or entities having a financial interest in the geothermal project.

3. INDEMNIFICATION in the event of:

   a. Project Termination -- the payment of the unamortized sunk costs of the Insured as of the date of termination.

b. Project Capability Reduction, (Inability to continue production at the commencement capability level -- with subsequent continuation of operations at the reduced capability level) -- payment of an agreed amount per day.

NOTE: A self-insured retention of not more than 10% is negotiated for each Geothermal Resource Insurance Program.

11. DIRECT USE OF GEOTHERMAL **RESOURCE**
(Space Heating, Agriculture, Aquaculture, Greenhouses, Alcohol Production, Food Processing, Health Spas, etc.)

A. THE "RETROFIT" INSURANCE CONCEPT (One Direct-Use Example):

1. **INSUREDS**: Any persons or entities having a financial interest in the geothermal project.

2. COVERAGE PERIOD -- The Construction Period plus an agreed number of operational years (a maximum of seven operational years).

3. INDEMNIFICATION -- the Insured's Loss resulting from the Geothermal Resource Inadequacy Hazard.

4. "The Insured's Loss" means the total of the following munts:

(1) The actual cost, including the cost of installation, of an alternatively fueled steam boiler sufficient to produce the degree level and quantity of heat required in the geothermal project specifications.

(2) The actual cost of the alternative fuel required to produce the heat necessary to meet the geothermal project specifications.

B. OTHER INSURANCE CONCEPTS:

This INA - C&B Geothermal Resource Insurance Program can be tailored to meet the particular financial needs of each specific geothermal project.

The aforementioned Geothermal Resource Insurance Programs are being underwritten by INA Underwriters Insurance Company, 1221 Avenue of the Americas, New York, New York 10020. Negotiations and underwriting liaison are being conducted by Corroon & Black of Pennsylvania, Inc. who have been designated by the INA as their sole Managing Agency for *this* type of insurance.

I repeat that this expediting of private sector financing of geothermal projects will, in *our* opinion, more than offset the expected curtailment of government funding. Thank you.

SOME GENERAL COMMENTS ON THE DOE CODE COMPARISON PROJECT

J. W. Pritchett
Systems, Science and Software
P. O. Box 1620
La Jolla, CA 92038

The basic purpose of the DOE Code Comparison Project was to attempt to increase the confidence of the financial community in predictions and assessments made by reservoir engineers as regards the performance of geothermal fields. Numerous issues are relevant to this question of confidence, not all of them technical. It should be recognized that this DOE project was directed at only one of these issues: the accuracy and reliability of numerical geothermal reservoir simulation computer programs, or "simulators".

Numerical reservoir simulators are only one of many tools available to an engineer when he attempts to make a prediction. Typically, the engineer proceeds roughly as follows. He starts with a body of measured facts concerning the system in question. These facts might include such things as the results of surface resistivity surveys, gravity anomoly measurements, drilling logs, laboratory tests of core samples, downhole temperature measurements, the results of pressure transient tests in completed wells, downhole static pressure measurements, discharge enthalpy measurements, chemical analyses of reservoir fluids and rock matrix material, and so forth. If the field has already been partially developed, he may have a significant production history at his disposal. All of these data are likely to vary in accuracy, reliability, and relevance.

Based on whatever facts are available to him, he constructs a preliminary conceptual picture, or "model", of the field. Since the actual density of measurements in the field is always very low, considerable guesswork is always involved at this stage. Typical components of this preliminary conceptual "model" will include his best guesses concerning questions such as:

- What kind of a field is it? (Single-phase hot water? Two-phase liquid-dominated? Vapor-dominated?)

- Where are the major permeable zones and how far do they extend?

- Where are the barriers to flow? Is the field a single unified system, or is it really a collection of relatively isolated aquifers?

- What is the subsurface temperature distribution? How large is the anomoly?

- Are there major fractures present which serve as fluid conduits? If so, where are they?

- Where are the major natural recharge paths? What is the source of recharge fluids? Is there significant connection with the shallow groundwater system?

If the conceptual model is simple enough, analytic tools may be adequate (such as "lumped parameter" models, homogeneous radial single-phase aquifer solutions, and the like). For more complex systems, however, the engineer may be forced to employ a numerical simulator. He quantifies his conceptual model, assigning spatial distributions of such quantities as porosity, permeability, fluid pressure, temperature, enthalpy, and the like, and also supplies appropriate boundary conditions to the domain of space under study. He provides all of this information to the computer program (the "simulator"), and observes the computed results.

Almost invariably, the reservoir response computed by the simulator based on the preliminary conceptual model will differ in important ways from the actual observed behavior of the system. Accordingly, the engineer revises the model in such a way as to minimize such discrepancies. This iterative process is likely to be quite lengthy and involve numerous computer runs before a satisfactory match is obtained. At this stage, the engineer is now ready to use the simulator, in connection with his final conceptual model, to make predictions of future performance. Not infrequently, particularly for relatively undeveloped systems, two or more different conceptual models will account adequately for all known historical data, but will result in markedly different future predictions. Under these circumstances, the engineer cannot make a definite prediction. He can, however, by using the simulator, devise a program of experimental measurements capable of discriminating among the various competing models. Clearly, in the absence of experimental facts, numerical reservoir simulation is useless. On the other hand, as more and more data become available, predictions become more precise.

If numerical reservoir simulation is employed as a key element in a prediction of future performance, the question of the accuracy of the simulator itself becomes an issue of legitimate concern. Several large-scale general-purpose simulation programs now exist which are capable of treating geothermal reservoirs. All were developed within the last seven or eight years. The Department of Energy consequently desired to test several such simulators to determine which (if any) are capable of producing accurate results. Originally, it was suggested that these tests be carried out in a manner something like the following. A particular geothermal field would be selected which has a substantial production history. A partial data set would be assembled, including all available early exploration measurements, early development-phase data, and the first part of the production history. Then, the Department of Energy would provide this partial data set to a number of independent research groups, each with its own numerical simulator. Based upon the partial data set, each group would employ its simulator in an attempt to "predict" the remainder of the history of the field (which is in reality known, but is presumably concealed by DOE). Each simulator would then be judged on the basis of the accuracy of this "prediction".

There are at least two serious shortcomings to this approach. First, the geothermal industry is at present quite small; the number of fields with sufficient history is so limited that completely concealing the later history of such a field would probably prove impossible. Furthermore, "inside" knowledge concerning the "unknown" late-time data is likely to be non-uniformly distributed among the various research groups involved. Accordingly, it would probably prove impossible to devise a test of this type which would be even-handed.

The second shortcoming is even more fundamental; a testing procedure of this type does not really test the numerical simulators themselves as much as it tests the insight, engineering judgement, and good luck of the engineers in the research groups using the simulators. A group with a relatively inaccurate numerical simulator but with a good conceptual "model" of the reservoir will probably make better predictions than a group with a better simulator but a flawed conceptual picture of the system. Stated differently, even if the simulators themselves were in fact identical, the various independent groups would almost certainly produce predictions that differ one from another in varying degrees.

Considerations such as the above led to the approach employed in the DOE Code Comparison Project. To test the various simulators (instead of the engineers), a set of hypothetical problems was selected. These problems were specified completely a priori, so that no engineering judgement whatever is required to define them. The problem set was chosen subject to several constraints. First, it seemed desirable that some of the problems possess known exact analytic solutions (or at least approximate solutions) so that the absolute accuracy of the simulators could be independently assessed (Problems 1 and 2 fall into this category). Unfortunately, many problems of geothermal interest, particularly those involving multi-dimensional multi-phase flow, do not have analytic solutions (if they did, there would be no need for numerical simulators). A wide range of space and time scales was considered, from effects of individual wells (Problems 1-3) to field-wide studies (Problems 4-6) and from short-term pressure transients (Problem 2) to the entire history of a field during depletion (Problems 4, 6). Emphasis was placed on multi-phase flow of water/steam mixtures (Problems 2-6);

the effects of formation heterogeneity were also included (Problems 4, 6, and particularly Problem 3). One-dimensional (Problems 1, 2, 4), two-dimensional (Problems 3, 5) and fully three-dimensional (Problem 6) cases were considered.

On the other hand, all of the problems in the set were computationally small in scope. For uniformity, the spatial zoning was prescribed for all of the problems; for several, the computational time-step was also specified in advance. Grid sizes ranged from 20 zones (Problem 4) to 125 zones (Problem 6). It should be noted that a typical field application of a numerical resevoir simulator usually involves at least several hundred computational zones, and often several thousand are required. Crude zoning was prescribed for two reasons. First, it was desired to maximize both the number of participants in the project and the number of different problems which could be accomodated within the confines of a limited budget. Second, it seemed desirable to emphasize the effects of numerical truncation errors on the computed results.

The results of the project clearly demonstrate that the various simulators involved are indeed adequate. The extent of the agreement among these calculations performed by different groups using independently-developed numerical simulators which employ markedly different mathematical techniques is very reassuring. Such minor discrepancies as do exist are traceable to misunderstandings about problem definition, small variations in the description of water/steam properties such as saturation pressure and viscosity, and such matters as variations in the time-step size chosen by the various groups, rather than to fundamental flaws in the simulators themselves.

Thus, it would seem that the particular concern which motivated this project -- the accuracy of existing numerical geothermal reservoir simulation programs -- has been laid to rest, at least as regards the group of simulators involved. Furthermore, these results may be used as benchmarks by the developers of other programs. Of course, the fundamental issue -- that of the confidence of the financial community in reservoir engineering predictions -- has not been resolved, but an important first step has been taken. It should be noted that the use of numerical reservoir simulation to make practical performance predictions with significant financial relevance is not unique to geothermal development. This same basic approach has been an accepted practice in the petroleum industry for many years. Presumably, the apparent confidence in numerical simulation methods as applied to oil and gas reservoirs arises from a substantial record of successful performance of these techniques in that industry.

Should the Department of Energy decide to pursue the matter further, considerations such as the above suggest that further competitive calculations among various groups would not be particularly productive. What is lacking in the geothermal area is a significant record of successful predictions for real geothermal systems. This does not mean that those attempts at describing real systems which have been made have been failures; indeed, several quite successful simulations of geothermal field performance have been published in the open literature. The difficulty is simply that there are very few geothermal fields presently in production. Furthermore, in the United States, the developers of such fields as exist typically regard all relevant field data as proprietary information, so that much of the publically-available data on case histories of real geothermal systems comes from foreign projects. Nonetheless, at the present time a substantial body of relevant information is available for several geothermal systems, both within the U.S. and abroad. As time goes on, this body of case-study information will grow.

In order to develop confidence within the financial community in reservoir engineering predictions in general and the application of numerical simulation techniques in particular, it seems that the most productive course would be to encourage the application of these techniques to several real situations for which an adequate data base is available or obtainable. There is no need, however, to employ the competitive approach used in the present Code Comparison Project; indeed, such a diffusion of effort would probably be counterproductive. If a number of research teams were each allowed to concentrate fully upon a particular system, rather than divide their attention in a more cursory fashion over several different systems, more adequate simulation results would undoubtedly occur.

Response to Model Intercomparison Study

by H. Dykstra

The results obtained from the several reservoir simulation models that were used in the study showed very good agreement for the most part. The close agreement indicates that the modellers have done an adequate job in analyzing the physics and in programming the mathematics for computer calculations. This is very encouraging in that it means that one does not have to be as much concerned with the computer model as one does in getting an adequate description of the geothermal reservoir. The latter point forms a basis for determining when a model could be used.

A reservoir simulation model can be thought of as having two purposes. One would be to determine which reservoir and fluid parameters are important in order to obtain an adequate description of a particular reservoir. For example, in a fractured reservoir, the porosity of the rock matrix may be unimportant. A second purpose, and much more important one, is to make a prediction of future performance, such as flow rate, enthalpy, water temperature, and pressure decline. This information is then used in the design of a power plant and in making an economic evaluation of the overall project.

In order to make such a prediction with any degree of confidence it is necessary to have an adequate description of the geothermal reservoir, and this requires a considerable amount of time and effort. Two or three wells will in general not provide sufficient information on which to base a prediction. Five to ten wells may be needed along with well test data and interference test data in order to provide a picture of the reservoir, A computer simulation model can be of help in making an evaluation, or prediction, but it should be kept as simple as possible consistent with the amount of data available.

RAPPORTEUR REPORT ON PANEL RESPONSE TO MODEL INTERCOMPARISON STUDY

G. A. Frye, Division Engineer
Geothermal Resources Division
Aminoil USA, Inc.
Santa Rosa, California

During the panel discussion, several consensus opinions developed. All panelists concurred that the model intercomparison study was a proper and necessary effort for the Department of Energy to support. The results from the problem sets indicate there exists a group of good coders and smart mathematicians. Most results were comparable which satisfied the first part of the original task. Unfortunately, the second part of the original task, code efficiency, was deleted for a reported inability of the model intercomparison advisory committee to agree on criteria for code efficiency.

The models are valid for calculations but do not necessarily yield the right answers. Needs of potential users of geothermal reservoir models require multiple runs. An example would be parameter study to produce an error bound or various sensitivity studies to estimate levels of certainty. The need for multiple runs increases the potential user's concern for model effic ency.

Several technical uncertainties were mentioned. These included the proper means of defining the well bore radius, weighted mean versus upstream weighting of parameters, computed enthalpies as an assessment of mode validity, and matching parameters if initial pressure near saturation.

Most panelists concurred that ultimately model results would be a tool for investment decisions, i.e. build a power plant. Models should be a vehicle for understanding the reservoir. If so, then modeling results once understood and accepted as valid, should lead to expedited development of geothermal resources.

RAPPORTEUR'S SUMMARY

by

George F. Pinder
Department of Civil Engineering
Princeton, New Jersey

1.0 INTRODUCTION

On Wednesday, December 17, 1980, a session of the sixth Workshop on Geothermal Reservoir Engineering entitled "Model Inter-comparison Study" was held at Tresidder Union at Stanford University. The session was chaired by M, S, Gulati. The program consisted of an introduction by M. W, Molloy, a description of the performance of each of four models on a series of problems, a brief panel presentation and, to close the session, an open discussion, The objectives of the model comparison were stated by M. W. Molloy as

1) to test existing geothermal models on a standard set of problems

2) to compare their output [accuracy][†] and efficiency

The motivation for this project came from the Department of Energy (DOE) congressional mandate and more specifically from a recommendation of the Geothermal Division advisory committee.

2.0 MODEL COMPARISON

Six problems were considered by each of the four groups involved in the project (Intercomp, Geotrans, Stanford University, Systems, Science and Software, Lawrence Berkeley Laboratory and a New Zealand group), Not all problems were attempted by all participating groups, No efforts were made to formally measure the accuracy of the various simulations nor were there any attempts to determine the relative efficiency of the various models, While the discretization parameters eg. Δx, Δt) were specified in some problems, this was not universally the case. Thus, the comparisons of the resulting simulations were primarly qualitative, rather than quantitative,

At the time of this writing, all of the written reports on the performance of each code on each problem were not available to the rapporteur, Thus, my comments are necessarily rather general and based on'ly on information presented by the author of each test problem. (J. Mercer, M, Sorey, A. Moench, M, O'Sullivan, J. Pritchett and K. Pruess).

On the whole, the various codes were able to provide a solution qualitatively similar to the known or anticipated physical behavior. When unexpected results were encountered they were generally attributed to errors in input, interpretation or grid-size selection rather than

[†] square bracketed comments are rapporteur's interpretation.

any fundamental problems in the simulators themselves. The reader interested in detailed comparisons of the solutions is referred to the accompanying papers in this volume devoted to t is topic.

3.0 PANEL DISCUSSION

The five member panel assembled to discuss the comparison study was made up of individuals representing different e ements of the geothermal community. The members and their affiliati ns follow: C. Morris (Republic Geothermal, field developer), Mr. Hughes (EPRI, Utility), N. Barrett (Corroon and Black, insurance, finance), J. Pritchett (Systems, Science, Software, technical) and H. Dykstra (Consultant, consulting firm). There was no representative from the academic community.

Each panel member was invited to make a brief opening statement. The most germane comments, as perceived by this rapporteur, follow:

<u>C. Morris</u>:

- the reported model results demonstrate that the models are mathematically sound.
- the models cannot be considered accurate, however, unless one considers the assumptions inherent in the models and the sensitivity of the various parameters.
- in supporting this model comparison, DOE has responded rapidly to a relevant industry problem.

<u>Mr. Hughes</u>:

- reservoir models should provide

  1) a decision tool

  2) a description of the behavior of the reservoir

  3) an assessment of project risk

- reservoir models should exhibit the following attributes:

  1) they should be understandable and transferable to others

  2) they should make use of and improve with more field information

  3) they should be probability based, i.e. they should provide probability estimtes of reservoir behavior

  4) they should provide production information as a function of time

- model verification is a two-step procedure

  1) demonstrate that the model is computationally sound
  2) determine its accuracy through a comparison with field information

N. Barrett:

- the limited use of geothermal by utilities is due to the lack of geothermal insurance
- utilities cannot assume risk and must have protection from losses incurred either in the development period or from an inability to provide a contracted level of power availability
- utilities rely on geothermal engineers and geologis s to develop, evaluate and confirm technical data
- cutbacks in funding by DOE will be taken up by private industry

J. Pritchett:

- meaningful model results are dependent upon accurate field data input and engineering interpretation
- the objective of this comparison, however, was to demonstrate the veracity of the mathematical apparatus; this was achieved.

H. Dykstra:

- the comparison documented herein demonstrates that the mode s are mathematically sound
- the principal problem is reservoir definition
- there are three levels of sophistication that have been employed historically in conducting reservoir analysis

  1) guess at answer
  2) employ analytical models
  3) employ relaxation [an early form of numerical ana ysis used in conjunction with finite difference approx mations]

- the basic engineering problem is the number of we ls to be put in before making a major financial commitment to a field.

4.0 GENERAL DISCUSSION

While there was spirited discussion from the floor, relatively few distinct topics were considered. The most relevant, from the rapporteurs perspective, follows:

- model efficiency is important because models are becoming more complicated and therefore costly to implement.
- model efficiency is critical to the use of Monte Carlo methods of risk assessment.
- models can and should be used to Drovide insight into the physical system [the goethermal reservoi 1
- a large number of runs are normally required in analyzing a typical field problem
- models can be used to determine the sensitiv ty of reservoir projections on field parameter accuracy
- there is a lack of consultants who can use the existing computer codes to analyze a field problem
- while some participants felt the models now should be applied to a real field situation, others thought this would only test the ability of the geothermal engineer rather than the simulator

5.0 RAPPORTEUR'S EVALUATION

The stated goals of the project constitute a useful contribution to the geothermal community. Numerical solution of the equations describing geothermal reservoir behavior is difficult and the accuracy of the codes cannot be readily determined. This code comparison demonstrated the general credibility of the models for the selected problems.

The model problems were, for the most part, carefully conceived and the resulting computer solutions conscientiously evaluated. While a qualitative comparison of accuracy was presented at the workshop, a quantitative statement is also needed. This is readily provided for problems with known solutions through one of the generally accepted mathematical norms. It is unfortunate indeed that program efficiency was not documented. The geothermal community would like to know which algorithm leads naturally to a more cost-effective simulator.

The panel presentation was very interesting. It provided an interesting perspective on the role of models in the geothermal community. I feel the addition of an academic panel member would have provided a viewpoint quite different from those presented. The general discussion was lively, relevant and a worthwhile element of the program.

In summary, the code comparison project and the subsequent presentation of the results was well conceived and executed. Extensions beyond this level of effort probably would be of limited benefit. The question of simulator efficiency remains unanswered.

GFP:dh

A REVIEW OF THE PANEL SESSION ON NUMERICAL MODEL COMPARISONS

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As one of the authors of the set of test problems used to compare various geothermal reservoir simulators, as discussed by Sorey (this volume), I feel that the general reaction of the panel members and the workshop audience to the issue of simulator validation was favorable. That is, each of the codes tested gave valid results for these test problems which involved analysis of typical multiphase flow problems in geothermal reservoirs. This clearly was a necessary step toward developing confidence in the use of numerical simulators for reservoir engineering purposes.

Most of the discussion during this session of the workshop, however, concerned additional considerations involved in making valid and useful applications of these codes to modeling specific geothermal fields, and in using the codes for parameter sensitivity studies, for risk assessment, and as a guide to exploration. There was general agreement that we should be making more use of numerical simulator in sensitivity studies to develope better understanding of the parameters and factors which control the production of energy from geothermal reservoirs.

There was also agreement that more applications of numerical modeling to specific field cases are needed before the usefulness and validity of this approach can be satisfactorily assessed. Such applications test not only the simulators themselves but also the skill and experience of the simulator users in synthesizing various kinds of data into conceptual models which can be analyzed quantitatively. Ideally, numerical simulation of specific geothermal reservoirs should involve some form of risk assessment, so that levels of confidence in estimates of production capacity and reservoir longevity can be quantified. In my view, however, our lack of experience in simulating exploited fields and indeed the lack of data from exploited fields makes the development of valid models for risk assessment a difficult assignment.

Code Comparison Project
- Conclusions -

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ACCOMPLISHMENTS

The message that the Department of Energy heard at the Stanford Workshop is that the Code Comparison Project was successful. The geothermal industry's need to determine that different reservoir codes yield similar results was satisfied. The "test problem" approach was proper; the Final Reports and the Workshop evaluation were useful.

The models work! Surprisingly consistent results were achieved by seven groups, working independently, with five different models running on six different machines. The sets of output data agree with each other. and with analytical solutions, where available. Minor differences are explained either by use of different steam tables and thermodynamics, or by misunderstandings which resulted in data input errors.

In addition, a set of standard problems for testing other reservoir models is now available to the geothermal industry. The SHAFT '79 code developed by Lawrence Berkeley Laboratory can be obtained as Abstract 8893, from the National Energy Software Center, Argonne National Laboratory, 9700 South Cass Ave., Argonne, Illinois 60439.

However, the ability of models to contribute to investment decisions on specific geothermal reservoirs, using field data and skilled engineering team, has not been demonstrated by the present effort. It is not clear how this might be accomplished to the satisfaction of investors and their consultants; how the needed field data would be obtained; and, how the costs of comparative modeling with several simulators can be met. Whether such an effort needs the participation of the Department of Energy, is uncertain.

UNSATISFIED RECOMMENDATIONS

The original recommendation (in quotes, below) has only been partly satisfied.

"Model comparison and validation" has been "a new initiative in the (DOE) Geothermal Reservoir Engineering Program." Through competitive contracts to industry and cooperative efforts with Lawrence Berkeley Laboratory, U.S. Geological Survey and University of Auckland, N.Z., five "major codes" have been tested on a standard set of problems. "Results" have been compared "with respect to output." The 1980 Stanford Workshop included panel discussion of "the use and limitations of the various codes available."

However, the Code Comparison Project did not "run (the codes) on an actual geothermal system where adequate data exists rather than a hypothetical situation." Nor has an attempt been made to "compare results with respect to... efficiency of the code." John Pritchett observed that it may not be possible to define fair measures of efficiency for codes run on different machines; only comparisons of numerical accuracy and precision may be possible. Finally, a workshop has not considered "the use and limitations of the various codes available."

The absence of actual field data has limited this evaluation. We have not tested the skills and experience of the team of experts which defines the problem, prepares the input to the computer, analyzes the output, and interprets results in terms of reservoir performance, development, operations and investment decisions.

GEOTHERMAL INDUSTRY VIEWPOINTS

Speaking for the Field Developers, Charles Morris of Republic Geothermal stated that model validation is a major question: Is the simulator actually calculating the physical properties correctly? Morris was relatively satisfied that the simulators provide valid results; but, this exercise does not mean that the answers represent the real world.

Evan Hughes of EPRI, representing the Utilities, suggested that sensitivity studies are needed to define the most important parameters, with verification through operations at actual reservoirs. He underlined the need for geothermal models as tools for making decisions; for understanding the reservoir; for reducing complex problems to a set of variables; for assessing reservoir risk; for predicting field performance over time; and, for improving confidence by accepting new data as it becomes available. It is important that a geothermal reservoir model be understood by non-experts, and be tranferrable to other machines and users.

The Financial Community, through Norman Barrett of Carroon & Black, summarized its heavy reliance on the expertise of geothermal engineers working for potential clients, supplemented by retaining their own consultants to confirm the data. Utilities cannot bear the resource risk of the geothermal power plant's inability to achieve target capability. The private sector is now coming forward with insurance programs to expedite geothermal investment and development.

From the point of view of computer Software Developers, John Pritchett of Systems, Science and Software stated that the Code Comparison results showed that these simulators are solving Darcy's Law and the principles of mass and energy conservation. We have established that it doesn't matter which computer model engineers use. However, much more than a computer program is required to get a meaningful answer for investment decisions. This requires: 1) field data, 2) physical basis for the specific geothermal system, 3) smart engineers to use the computer tool correctly, and 4) regular (yearly) updating. The Code Comparison Project has not addressed these issues. The next step should be to test the engineering groups. Pritchett asked: What is important, in terms of differences in the conceptual models; and, which assumptions (for instance permeability distribution) are critical?

As a Consultant, the focal point of the confidence issue, Herman Dykstra acknowledged that the modeling community has good mathematicians. You can trust the results of the geothermal simulators, provided that you are able to define the reservoir. That is the problem. Most geothermal reservoirs are very difficult to describe. This is compounded by the very limited data available early in the field development phase; and, the limited ability to represent the fractures and blocks that may comprise the reservoir.

RELATED PAPERS

Two other papers in the Proceedings of the 1980 Stanford Workshop bear on the fundamental issue of consultant confidence in reservoir simulators for investment decisions.

P. F. Bixley (1980) from the Wairakei Geothermal Field in New Zealand evaluated simulators from the point of view of development risks, needed information, and actual experience with modeling for investment and operating decisions. Ten years after it was done, one simulation has proven remarkably accurate in predicting steam flows from construction of an 11% increase in system efficiency. But this is only one of many simulations performed.

Kamal Golabi (1980) modeled the overall universe of risks facing an energy development project. Reservoir engineering dominates the reservoir-related uncertainties and contributes to the analysis of adverse environmental impacts and technological uncertainties. Conceptually, the reservoir simulators interact with submodels of groundwater contamination, subsidence, plant design, plant performance, and plant effluents. The reservoir model plays a major role, therefore, in simulating and deciding both reservoir operations and plant design. In turn, these are major factors in the project cost model.

FOR THE FUTURE

1) Field Data

In order to test reservoir models on actual geothermal systems, access to comprehensive field data is required. Because of the proprietary considerations of private development, such access is very limited in the United States, despite extensive drilling and testing of many geothermal reservoirs. Data is needed over an entire reservoir (not just one operator), and over a sustained period of time.

In the United States, only the Geysers field has a lengthy production history. The two joint industry-DOE demonstration projects at Baca, NM and Heber, CA are in early phases of field development, prior to the construction of power production facilities.

Several foreign reservoirs have extensive field data which has formed the basis for modeling studies. These include Lardarello, Italy; Cerro Prieto, Mexico; and Wairakei, New Zealand. The Wairakei data base has recently been compiled and reproduced on computer tape by Systems, Science and Software (Pritchett, Rice and Garg, 1978) for Lawrence Berkeley Laboratory. Joint research tasks for reservoir code comparison may be needed under Intergovernmental Agreements between the United States and Italy, Mexico and New Zealand.

2) cost

The total cost of the four contracts for the Code Comparison Project was approximately $100,000. Experts estimate that comprehensive modeling of an actual geothermal reservoir, using a single simulator, could be $250,000. A comparative study, using several codes, would approach $1 million per reservoir.

Costs of this magnitude exceed DOE's priority and anticipated availability of funds.

3) Risk/Uncertainty

There are many sources of risk and related uncertainty facing a geothermal project, such as a power plant. Many of these sources of risk, including the geothermal reservoir, are amenable to reduction of uncertainty by collection and analysis of information (measurement), and by simulation of possible outcomes and their probability of occurrence (modeling).

Except perhaps for Wairakei, geothermal reservoir simulation has yet to be placed in perspective in terms of its contribution to overall confidence in specific investment decisions. Geothermal modelers can aid this process by becoming conversant with risks and models in related disciplines. We need to be able to translate our reservoir engineering conclusions into terms which investors understand.

CONCLUSION

The Department of Energy seeks to accelerate the commercial development of geothermal energy, in accordance with the Geothermal Research, Development and Demonstration Act (Public Law 93-410).

Understanding the geothermal reservoir is a substantial part of project investment decisions. The ability to simulate reservoir behavior with a computer code can contribute to this understanding. Industry is encouraged to evaluate the performance of commercially available simulators on important geothermal reservoir decisions.

The mathematical accuracy of five participating codes has been demonstrated by comparison of results and available analytical solutions. Underlying thermodynamic equations and assumptions have provided similar answers for a standard set of test problems.

The next step is to use field data in evaluating an actual reservoir rather than hypothetical problems. In this way, the engineering teams as well as the computer can participate.

What is needed now is a definition of the next phase of this effort, the tasks that are required to accomplish that phase, and the source of field data. Perhaps an understanding of the historical development of oil and gas simulation, in reaching its current acceptance as a reliable basis for petroleum investment decisions, would clarify the steps necessary for acceptance of geothermal simulation.

We offer our best efforts in assisting industry to achieve the confidence needed for geothermal investment decisions.

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Pritchett, J.W., Rice, L.F., and Garg, S.K., "Reservoir Engineering Data: Wairakei Geothermal Field, New Zealand", Systems, Science and Softwar Final Report SS-R-72-3597-1, Vols. I and II, Mar. 1978, "Summary of (IBID.)", Lawrence Berkeley Laboratory, LBL-8669, GREMP-2, UC-66a, Jan. 1979.

Appendix I

THE D.O.E. CODE COMPARISON STUDY: ANALYSIS OF INTERCOMP SIMULATIONS

Robert Aydelotte, INTERCOMP

As a participant in the Department of Energy Geothermal Code Comparison Study, INTERCOMP set up and simulated a series of six problems of interest to the geothermal community. At the presentation of the results of these problems by various investigators, the INTERCOMP results were found to be different from other investigators' results. Upon re-working the problems, several errors were detected in the data input to the model. These errors were as follows:

(a) Problem 3: infinite communication between the wellbore and the adjacent node;

(b) Problem 4: improperly specified permeabilities at the developing steam-water interface; and

(c) Problem 6: improper statement of the lower boundary conditon.

These errors were corrected, and INTERCOMP's results closely match the results of other investigators. A partial presentation of the revised results are given in Figures 1 through 4.

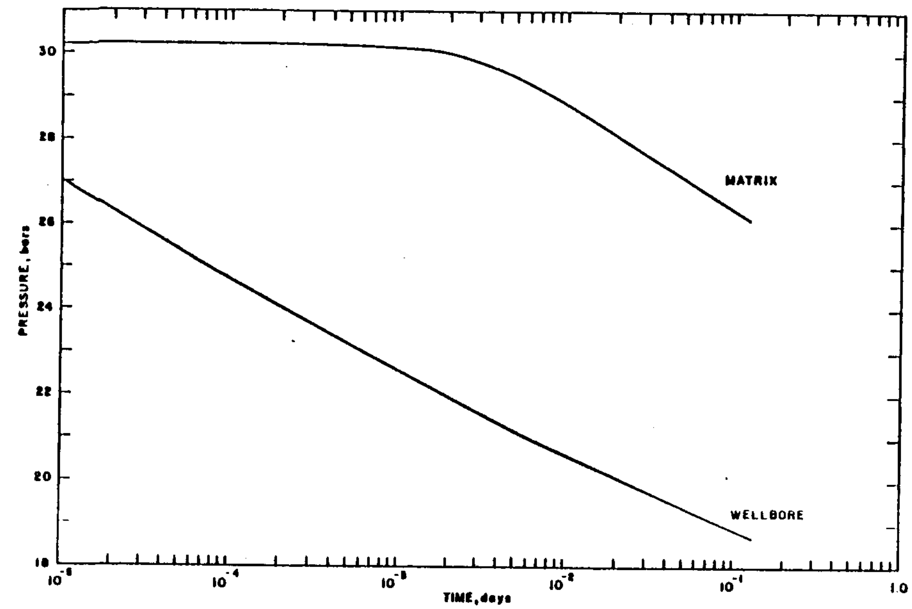

Figure 1 Results of Problem 3B

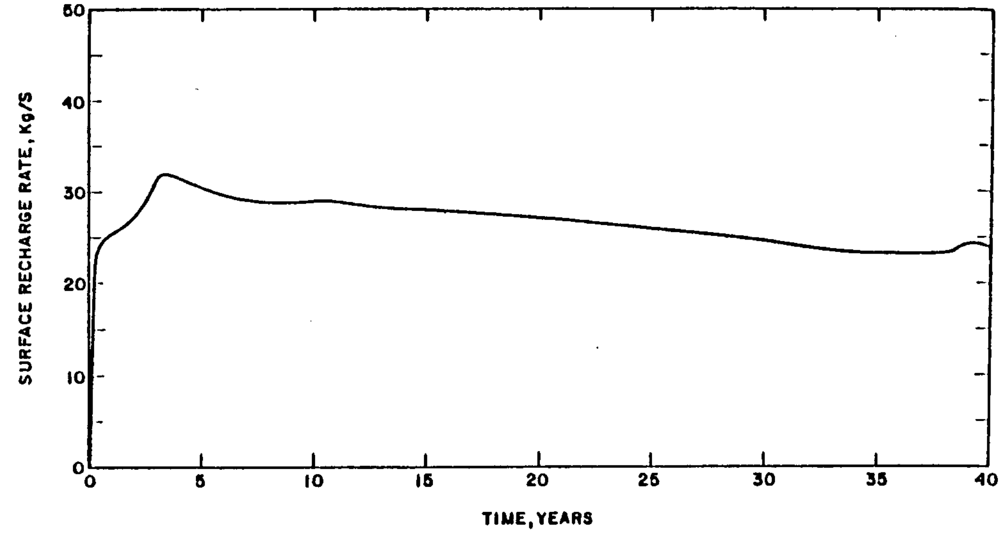

Figure 2 Recharge rate calculated in Problem 4

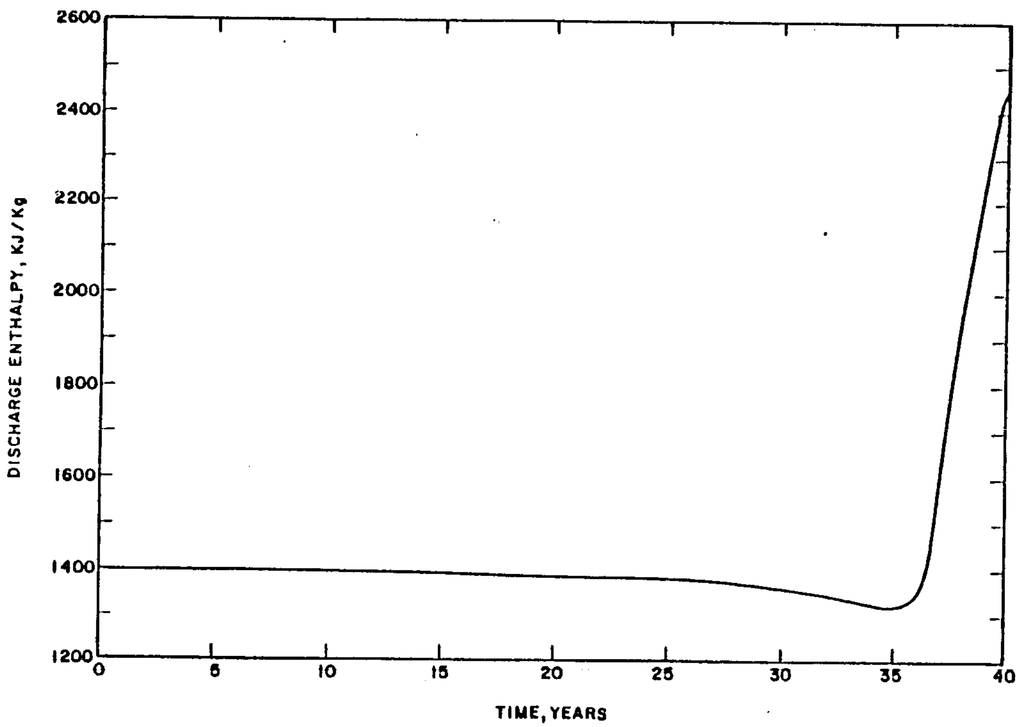

Figure 3 Discharge Enthalpy calculated in Problem 4

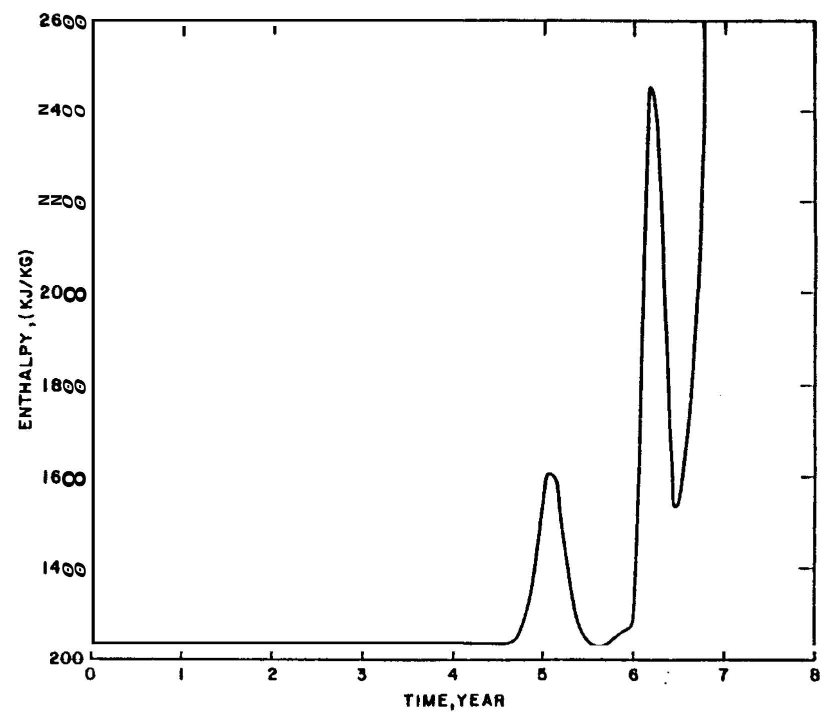

Figure 4 Discharge Enthalpy calculated in Problem 6