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Geothermal Completion Technology Life-Cycle Cost Model (GEOCOM)

Volume I - Final Report
Volume II - User Instruction Manual

The BDM Corporation
1801 Randolph Road, S.E.
Albuquerque, NM 87106

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GEOTHERMAL COMPLETION TECHNOLOGY LIFE-CYCLE COST MODEL (GEOCOM)

FINAL REPORT - VOLUME I

USER INSTRUCTION MANUAL - VOLUME II

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ABSTRACT

Just as with petroleum wells, drilling and completing a geothermal well at minimum original cost may not be the most cost-effective way to exploit the resource. The impacts of the original completion activities on production and costs later in the life of the well must also be considered. In order to evaluate alternate completion and workover technologies, a simple computer model has been developed to compare total life-cycle costs for a geothermal well to total production or injection. Volume I discusses the mechanics of the model and then presents detailed results from its application to different completion and workover questions. Volume II is the user instruction manual.

VOLUME I
FINAL REPORT

Volume I
Final Report

VOLUME I
FOREWORD

This report (BDM/A-81-614-TR-R1) has been prepared by The BDM Corporation, 1801 Randolph Road, S.E., Albuquerque, New Mexico 87106, for Sandia National Laboratories under contract 46-8777. The report describes the geothermal completion technology life cycle cost project. Contributors to the document were Dr. A. J. Mansure, E. R. Anderson, and W. C. Hoessel of The BDM Corporation, and P. McKissen of the Keplinger Operating Company.

VOLUME I
TABLE OF CONTENTS

VOLUME I
TABLE OF CONTENTS (Continued)

VOLUME I
TABLE OF CONTENTS (Continued)

VOLUME I
TABLE OF CONTENTS (Continued)

VOLUME I
LIST OF ILLUSTRATIONS

VOLUME I
LIST OF TABLES

CHAPTER I
EXECUTIVE SUMMARY

GEOCOM is a model developed by BDM to evaluate the cost effectiveness of alternative technologies used in the completion, production, and maintenance of geothermal wells. The model calculates the ratio of life cycle costs to life cycle production and thus is appropriate for evaluating the cost effectiveness of a geothermal well even when the most economically profitable geothermal well does not have the lowest capital costs.

The results of the GEOCOM project are threefold: the establishment of a database for studying geothermal completions, the development of the GEOCOM model, and preliminary case/sensitivity studies. The GEOCOM code, documented in Volume II, has the database built into its structure in the form of default parameters. These parameters include geothermal resource characteristics; costs of geothermal wells, workovers, and equipment; and other data. The data for the cost of geothermal wells were taken from the generic geothermal wells developed by Dr. B. J. Livesay (reference 2). The basis for establishing workover parameters was a series of geothermal workover studies done by Paul McKissen of the Keplinger Operating Company. These studies are included as chapter VI of this report. The sensitivity studies are found in chapter V.

A. SCOPE OF PROJECT

The GEOCOM project started with data acquisition and progressed through model development to the running of test cases. The model has sufficient detail to allow comparisons between various completion and usage alternatives for both production and injection wells. To do this, the model includes capital cost of the well and other equipment; continuing costs for workovers, routine O&M, electricity, and chemicals; and an analysis of productivity. To adequately analyze productivity, the model uses different data to characterize each geothermal resource and associates the appropriate well drilling cost with each resource. Recognizing that the scheduling of workovers impacts productivity and that a purpose of the model is to compare the effectiveness of workovers, the model was constructed to allow freedom in scheduling workovers. The user can thus select which workovers he wants and when they are to be performed. The user can also select how the well is to be produced (artesian flow, submersible pump, line shaft pump, etc.). The model is, however, restricted to a single well rather than modeling an entire reservoir. The adequacy of this assumption is discussed in chapters II and V.

B. UTILITY OF THE MODEL

The GEOCOM model is an analytical tool designed to assist the engineer in evaluating the cost effectiveness of a geothermal well. Specifically it will aid in integrating engineering economics, operations, resource characteristics, etc. into a single measure of the value of a well. It will automatically account for such things as time value of money, reservoir depletion, etc., but it is not intended to replace the engineer's understanding of geothermal completions. It is possible, for example, to ask the model to determine the cost effectiveness of configurations the engineer would automatically reject, such as submersible pumps in a dry steam reservoir.

For an initial analysis, use of the model does not necessarily require less effort than doing the work without a computer; however, many workovers have already been analyzed and included in the model. Thus, even for new technologies or uses, the model provides a quick method of comparison to baseline conditions and a structure for consistent analysis. Often, a "new" technology or use is only a variation of existing methods already included in the model. The real power of the model lies in its ability to perform calculations of cost effectiveness for multiple values of the parameters. It can thus be used for sensitivity studies or optimization.

C. OVERVIEW OF REPORT

Each section of this report is intended to stand alone so that one can select which sections to read first. Chapter II, Introduction, explains in detail the background of the project, the scope of the model, the approach used to develop the model, the rationale behind this approach, and also addresses the question as to what geothermal completions are in the context of this model. Chapter III explains the intermediate parameters which form the essence of how the model integrates the various aspects of the total well and its life cycle into a cost effectiveness measure. Chapter IV details how the model accounts for engineering economics and reservoir engineering. Chapter V presents the sensitivity studies and chapter VI describes the workover studies.

CHAPTER II
INTRODUCTION

A. BACKGROUND

The regions of concentrated geothermal heat within the earth offer a potentially valuable alternative source of energy for the United States. The viability of these geothermal sources will depend to a large extent on the economics of recovering the energy by either direct use applications or electricity generation. Successful commercialization of the geothermal energy is greatly influenced by the cost of completion and operation of the well in addition to the drilling cost. An important part of the Sandia National Laboratories geothermal well technology program is developing the cost effective utilization of geothermal energy. Development and application of new drilling and completion technologies offers one means of meeting the challenge. However, the number of technologies offering a potential for reducing well costs is significant. In a sense, too many technology alternatives are currently available since budget limitations preclude the thorough investigation of each of these alternatives. Consequently, a means for studying and prioritizing the candidate technologies is warranted. A methodology for investigating the cost and performance impacts of new drilling and completion technologies would provide the basis for the prioritization effort. Technologies that are shown to result in significant reductions in well costs (or improvements in well productivity) would become candidates for further R&D programs.

This report discusses a methodology developed to assist in the geothermal well technology evaluation. This methodology consists of a computer model for estimating the cost and performance increments arising from the application of a candidate completion technology. The model quantifies the payoffs (in terms of reduced well costs or improved productivity) attributable to a given technology alternative, assuming widespread application of the concept. Alternatives that offer cost reduction for extremely limited or localized applications would not possess sufficient utility to merit expenditure of R&D funds. Consequently, the technology must be capable of multiple application in terms of geologies, temperatures, and related concerns to be a viable candidate.

To provide a balanced assessment capability, the computer model considers both performance and cost factors. A technology that results in reduced well costs, but that also drastically reduces well flow would not be appropriate. For this reason, the cost and performance increments attributable to a new technology are determined simultaneously. Incremental values are assessed relative to a given (or baseline) well in a specified reservoir. The ratio of incremental gain or loss in performance to the increment in costs forms the measure by which alternative technologies may be compared and ranked. Technologies that have the highest ratio of marginal or incremental gain in performance to incremental increase in cost become the candidates for further expenditure of research funds.

The model development program reported in this document has developed an analysis methodology capable of ranking the alternative geothermal technologies. The development of the model has resulted in several benefits in addition to the desired methodology. (1) A database has been assembled concerning the costs of workovers, repairs, and field costs of geothermal wells. The recurring cost for well maintenance appears to have received scant attention in the available literature. Over a 30-year program the maintenance costs can be considerable, and therefore merit close scrutiny. (2) Development of a comprehensive database was a second goal of this project. (3) Gaps or voids in existing data sources became apparent during the acquisition phase of the program. These gaps were noted as areas for concerted research and study. (4) The analytical model was further used to assess the severity of these data deficiencies. This assessment was accomplished through sensitivity studies in which the parameters were varied and the resulting effects upon cost or performance were determined. Parameters for which large impacts were observed become candidates for further analysis and evaluation. Parameters that result in minimal impact can be given secondary priority for investigation.

B. DEFINITION OF "COMPLETION"

The GEOCOM model was developed to evaluate alternative completion technologies. It was recognized that for many drilling and completion issues, minimum initial cost is not the proper selection criteria when determining what technology and program to use. The initial or capital cost difference of alternate completion methods may be small compared to the difference in continuing or operational costs that results from the choice of completion method. Therefore, it was concluded the model should be a life cycle model.

The various ways of completing a well can have considerable impact on productivity resulting in different returns on investment. Thus, the GEOCOM model needed to include a determination of benefit.

Recognizing that the GEOCOM is a cost effectiveness model designed to answer questions about technologies or completion alternatives where minimum cost is not the appropriate selection critieria, the question becomes "what is a completion". There is no accepted or completely appropriate definition of completions; completions have been defined differently by various authors. In "The Federal Program in Geothermal Drilling and Completion Research and Development" by S. G. Varnardo (reference 3), completion is defined as "the placement of pipe in the well and the attachment of the pipe to the formation." Others have defined completion as "everything after the bit reaches total depth." In this project we have not proposed a definition with specific language but point out two important elements of what the life cycle analyses must include:

1. Completion must include all those aspects of drilling and "finishing" a well which affect its productivity.
2. The study of completions in the GEOCOM model must be complementary to the well cost modeling done by SNLA and Dr. B. J. Livesay (reference 2) so that together they present complete picture of a well and allow the evaluation of technologies.

With this understanding of completions and the role of GEOCOM in the SNLA Geothermal Drilling and Completion Technology Development Program, it is possible to identify the important elements of this project. These include: well costs, routine operation and maintenance costs, electricity costs, chemical and supplies costs, workover costs, and productivity. These must be calculated as a function of the completion alternative assumed so that alternative technologies can be compared. As an example, cemented perforated casing and slotted liner are alternative ways to complete a well. To decide which method is best, one must consider all costs, the effect of each completion method on productivity, and the well lifetime.

C. SCOPE OF ANALYSIS EFFORT

In order for the model to be appropriately sensitive to completion technologies, it could not be based on gross averages such as workover costs equal to 7.8 percent of capital costs each year. Instead, the model had to calculate costs for each workover performed and had to determine production as a function of time. This required that the model distinguish between different technologies and reservoirs.

1. Geothermal Reservoirs

The differences in well performance and the associated appropriate technologies between The Geysers with dry steam at 365°F and East Mesa with hot water at 340°F is so great that it would have been unreasonable to try to define average parameter values. Because of this, each important reservoir was considered separately and representative parameters were determined for each. The reservoirs considered in this project are: Brawley, Heber, The Geysers, Baca Location, Roosevelt Hot Springs, and East Mesa. The basis for picking these is the work by Brown, et. al. (reference 4).

The parameters used to define the characteristics of each of these resources are: well depth, length of completion interval, well-head temperature, well life, initial well flow rate, fraction total dissolved solids, steam fraction, and reservoir performance decline rate. The last of these parameters is important in determining how long the well will flow at a useable rate. It includes such things as drawdown, interference, formation plugging, etc.; all effects outside of the well. In contrast, the well lifetime is a physical or mechanical parameter determining how long until some failure such as casing collapse destroys the well.

2. Technologies

The purpose of the GEOCOM model is to compare and evaluate completion technologies that have the potential to reduce life cycle costs. As such, many of the technologies that should be evaluated are new ones for which there are no historical data on cost or performance. These new technologies, however, must still integrate into the well system and are often comprised of, or a substitute for, existing technologies, operations, or equipment.

Jet descaling is an example of a potential technology to improve the cost effectiveness of geothermal wells. It would replace mechanical descaling (bit and reamer). Jet descaling would require many of the same support equipment items, such as a rig. The difference between mechanical descaling and jet descaling will then depend upon such things as rate of scale removal, effectiveness of scale removal, and any extra costs for additional or different equipment (frac. truck).

The GEOCOM model does not have the capability to analyze all potential completion technologies because most are still ideas for which experience data do not yet exist. GEOCOM can, however, help evaluate such ideas. To do this it must first analyze the present completion method to which the new method will be compared; second, it must be sensitive to the parameter changes which determine the cost difference between the new and old technologies; lastly, it must allow for the effectiveness of the new completion method.

The basic technologies that have been included in the GEOCOM model are:

(1) Logging
(2) Perforating
(3) Mechanical descaling
(4) Hydrojet descaling
(5) Chemical Scale Inhibition
(6) Injection Pumps
(7) Submersible Pumps
(8) Line Shaft Pumps
(9) Remedial Cementing
(10) Underreaming and Gravel Pack
(11) Slotted Liner Replacement
(12) Well Repair with a Liner

3. Single Well Analysis

A logical question to consider is "What is the system that must be modeled with GEOCOM: is it the whole well field or can it be just a single well?" If appropriate, limiting the scope of GEOCOM to a single well would simplify the model considerably.

Figure II-1a gives the whole reservoir estimate of cost effectiveness (life cycle cost divided by life cycle benefit). This cost effectiveness ratio is in essence a price, so low numbers are best. This formulation of cost effectiveness (figure II-1a) is for production wells; injection wells, nonproducing wells, and transmission lines are included in the other costs. Since there is no reason to believe that a given well is any different than any other, the sums over the numbers of wells $\left(\frac{\Sigma}{\text{number of wells}}\right)$ can be replaced by N (the total number of producing wells). With this substitution, the expression in figure II-1a becomes figure II-1b. For the purpose of comparing competition technologies, the other costs can be considered proportional to the number of wells so that the last term in the numerator is a constant, independent of the number of wells or completion technology.

Figure II-1b is also in essence the same as the single well representation. One must consider, however, that in actual practice the well will be flowed at the rate required to meet system demands rather than to optimize single well productivites. This means, for example,

$$\text{LCC/LCB} = \frac{\displaystyle\sum_{\#\text{ OF WELLS}} \left\{ \begin{array}{c}\text{CAPITAL COSTS}\\ \text{OF}\\ \text{DRILLING AND}\\ \text{COMPLETING}\end{array} + \sum_{\text{FREQUENCY OF WORKOVERS}} (\text{WORKOVER COST}) \right\} + \text{OTHER COSTS}}{\displaystyle\sum_{\#\text{ OF WELLS}} \text{PRODUCTIVITY}}$$

BDM/A-81-614-TR-R1

Figure II-1a. Reservoir System Formulation

$$\text{LCC/LCB} = \frac{\left\{ \begin{array}{c}\text{CAPITAL COSTS}\\ \text{OF}\\ \text{DRILLING AND}\\ \text{COMPLETING}\end{array} + \displaystyle\sum_{\text{FREQUENCY OF WORKOVERS}} (\text{WORKOVER COST}) \right\} + \dfrac{\text{OTHER COSTS}}{N}}{\text{PRODUCTIVITY}}$$

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Figure II-1b. Simplified Formulation

that the initial well flow rate will not be the maximum potential of a well. Because of the need for reserve capacity or spare wells each individual well will initially produce at less than its maximum capacity. Typically 10 to 20 percent additional capacity is drilled. This means that the initial well flow rate used in the GEOCOM model is obtained by reducing the average preproduction well flow during testing by 10 to 20 percent.

For modeling purposes, the initial well flow declines exponentially with time according to the reservoir performance decline factor. Actual well flows will fluctuate in time; however, the fluctuations will average out in time to give the same total production as using the exponentially decreasing flow. This point is further discussed in the sensitivity studies chapter (chapter V) where results are presented to support this assumption.

D. BDM APPROACH/ANALYSIS FLOW PLAN

For the purpose of calculating cost effectiveness, a completion of a well is defined by the parameters required to estimate the cost of drilling and completing the well; the cost of operations and maintenance, including abandonment; the performance of the well over its lifetime; and the scenario of its use. The parameters could be chosen at several different levels. They could be very high-level parameters such as the name of a technology, e.g., jet underreaming. Such high-level parameters would be inappropriate because, a priori, one cannot say what the economic relationships will be for technologies yet to be researched. At the opposite extreme, one could pick very low-level parameters, e.g., skin effect. The use of such low-level parameters would not lead to a useful model because one would have to know how skin effect interrelates to each new completion technology and such data are not available.

Instead, intermediate level parameters are needed. These parameters should be common to all completion methods, completely determine the costs and benefits of each new completion method, and be derivable from engineering data on new completion methods as these data becomes available. An example of such an intermediate variable is the frequency with which workovers are performed.

The method of identifying the intermediate parameters was to determine the basic methods of completing and using a well and determine their common characteristics in cost and benefit. To do this, a series of workover studies was performed; these studies are presented in chapter VI.

Once the key intermediate parameters were identified, the mathematical relationships that express cost effectiveness as a function of these parameters were developed. The basic structure of the mathematics was to calculate the cost (or production) at each point in time and then sum or integrate these costs (or production) over time to determine totals. The totals were expressed in present value by including exponential factors for inflation and discounting in the sums (or integrals).

Calculating costs at each point in time requires that we know what workovers will be performed and how frequently they must be performed. Thus, the construction of the model required methods for scheduling the appropriate workovers (events). Similarly, the model had to allow for choices for such alternatives (configurations) as an unpumped well, a well with a submersible pump, or a well with a line shaft pump. The GEOCOM model determines the cost of a particular configuration of the well at the chosen resource area and then simulates the events in its life determining costs and productivity associated with each event.

The GEOCOM model includes several different mathematical and algorithmic parts. It has a set of procedures for selecting the well configuration and location, procedures for determining the schedule, and equations for costing the configuration and for calculating well flow rate. It has an algorithm for integrating well flow and a tabular method for recording and summing event and continuing (O&M etc.) costs. All of these are brought together in a summary analysis that gives the total cost, the total benefit, and the cost effectiveness.

All of these aspects of the GEOCOM project were brought together to write a code, GEOCOM, that allows easy execution of the concepts of the GEOCOM project. The code was designed to be user-oriented and easily transferred from one location to another. Further information on the code can be found in "GEOCOM User Instruction Manual" (reference 1). The code was written using a structured approach employing Program Design Language so as to be essentially self documenting. It was written in 1966 ANSI (American National Standard Institute) FORTRAN.

To check the validity of the code and the adequacy of the database used by the code and to address selected key questions such as the importance of well lifetime and the trade-off between capital cost and continuing costs, sensitivity studies were done as part of the model development. These studies are reported in chapter VI.

E. RATIONALE FOR APPROACH

The methodology for assessing the cost and performance impacts of alternate drilling and completion technologies can best be described as a parametric model. As such, the model consists of a set of expected value equations that express cost and performance in terms of the influential parameters. These parameters include physical variables such as wellhead temperature and casing profile, performance factors such as pump horsepower and well flow rate, and operational considerations such as hours of pump operation and scheduling intervals for workovers (descaling). The model equations were derived from basic physical principles or causal reasoning whenever possible. Causal variables are those that actually determine or influence well cost or performance. This is in contrast to factors that are merely correlated to cost or performance. Causal variables are preferable and were selected when possible. This emphasis on causal relationships was governed by the primary purpose of the model, namely, to predict the impact of new technology applications. Prediction is almost always difficult, but it is more credible when causal relationships are employed.

The emphasis has been on developing simple, intuitive equations that relate well costs and performance to first-order factors. Simple analytical expressions were chosen to allow for extensive sensitivity analyses. This capability is an essential element of the model, since projection of future technology impacts over long lifetimes is subject to considerable uncertainty. Because uncertainty predominates, varying the underlying parameters to assess the resulting impacts in terms of well costs and well performance under a variety of conditions is a simple, effective way to establish credible estimates.

CHAPTER III
INTERMEDIATE LEVEL PARAMETER MODEL

The intermediate level parameters on which the GEOCOM model is built can be grouped according to function into the following categories: capital cost, continuing cost, productivity, schedule, and time value of money. A complete list of the parameters is given in table III-1. For certain parameters in the table, the value depends upon which geothermal reservoir is picked or upon which workover type or method of utilization is chosen. For those not dependent upon the above factors, the GEOCOM default value is given in the table. Values for the other parameters can be found in "GEOCOM Users Instruction Manual" (reference 1). In addition to the intermediate level parameters listed in table III-1, the GEOCOM model also uses selection, general, and special parameters. The selection parameters determine the geothermal resource and the method of using the well (injection or production well). General parameters include parameters such as reject temperature (important in converting from pounds of production to BTUs). Special parameters are used in costing workovers. The model automatically calculates the baseline cost for each workover type, but allows the user to change the basis for the cost calculations. For example, by use of a special parameter the user can change the number of shots per foot in cemented perforated completions. These special parameters are used in calculating intermediate parameters and are thus one level more detailed than the intermediate parameters.

A. CAPITAL COST INTERMEDIATE PARAMETERS

There are only two basic capital cost intermediate parameters: the well cost and other. Other includes capital costs of downhole pumps, satellite tubing strings for chemical injection, and etc. Others are thus capital costs associated with the selection of how the well will be used. The capital cost of the well is determined by which geothermal

TABLE III-1. INTERMEDIATE PARAMETERS

PARAMETER	VALUE	TYPE OF PARAMETER
INITIAL WELL FLOW	1	PRODUCTIVITY
RESERVOIR DECLINE RATE	1	PRODUCTIVITY
DISCOUNT FACTOR	0.00878/MO	FINANCIAL
INFLATION FACTOR	0.00695/MO	FINANCIAL
WELL LIFE	1	SCHEDULE
STUDY PERIOD	360.MO	SCHEDULE
WELL FLOW LOSS	0.125/MO	PRODUCTIVITY
INITIAL DELAY	0.0 MO	SCHEDULE
CAPITAL COSTS		CAPITAL COSTS
- WELL	1	
- OTHER	2	
WORKOVER		
- COSTS	2	CONTINUING COSTS
- FREQUENCY	2	SCHEDULE
- DURATION	2	SCHEDULE
- EFFECTIVENESS	2	PRODUCTIVITY
ROUTINE O&M		CONTINUING COSTS
- WELL	1	
- OTHER	2	
PER POUND PRODUCTION COSTS	2	CONTINUING COSTS
REPAIR		
- COST	$121,000.	CONTINUING COSTS
- TIME	999. MO	SCHEDULE
- DURATION	0.33 MO	SCHEDULE
- EFFECTIVENESS	40%	PRODUCTIVITY
ABANDONMENT COST	$18,000.	CONTINUING COST

1 RESOURCE DEPENDENT VALUE

2 CONFIGURATION AND USAGE DEPENDENT VALUE

resource is selected although, as for all other parameters in the model, the user can substitute his own value.

B. CONTINUING COSTS INTERMEDIATE PARAMETERS

There are five basic continuing cost parameters: workover cost, routine O&M cost, per pound of production cost, repair cost, and abandonment cost.

Workover costs are the cost to work over a well, such a bringing in a workover rig to mechanically drill and ream out scale. Only the costs of the specific workovers selected through model inputs are included in total cost of the well. The costs of the workovers are put into the cost stream at the times determined by the schedule.

Routine O&M costs include labor to operate the well, materials and supplies, and maintenance. Routine O&M includes a flat yearly amount ($54,000/year), plus a percentage of well capital cost (3 percent), plus a percentage of other capital costs (varying depending upon usage of the well).

Per pound production costs are operating costs that depend on the amount of production. Examples are electricity costs for downhole pumps and chemical costs for chemical inhibition.

The repair of a well is a one-time event such as the repair of a casing failure by cementing in a liner. This operation can not be repeated and changes the profile and productivity of the well.

C. PRODUCTIVITY INTERMEDIATE PARAMETERS

There are five basic productivity parameters: initial well flow, reservoir decline rate, well flow loss, workover effectiveness, and repair effeciveness. Figure III-1 shows the productivity and schedule intermediate parameters. The productivity is computed from these parameters using the following equation:

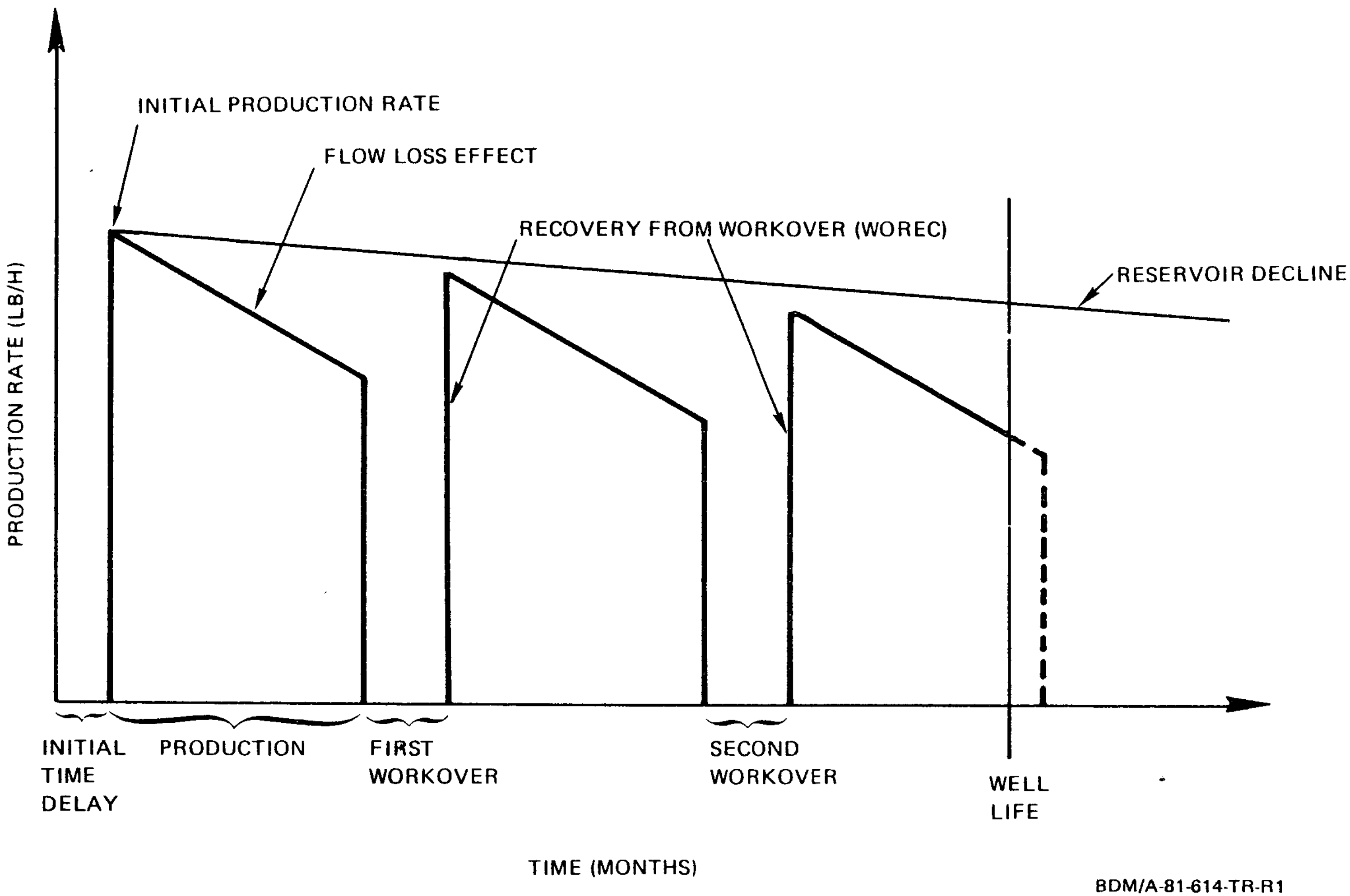

Figure III-1. Workover and Production History Illustration

$$Q(t) = Q_o R_j^{(n-1)} e^{-rt} \left\{ 1 - C_1 T_f + C_2 T_f^2 + C_3 T_f^3 \right\} \qquad \text{(Eq. III-1)}$$

where

$Q(t)$ = Time dependent well flow (lb/h)

Q_o = Initial production rate (lb/h)

R_j = Correction factor for effectivenes of workover j (fraction)

n = Workover counter

r = Reservoir decline rate (fraction/month)

t = Time since the beginning of well life (months)

T_f = Time since the last time well was descaled $t - t_f$ (months)

C_1, C_2, C_3 = Coefficients for third order polynomial of flow loss function.

After repair Q_o is replaced with a new value. Total well production is obtained by integrating equation III-1 over each period of well flow on figure III-1 and adding the integrals. However, the benefit of the well is obtained by first inflating and discounting equation III-1 before integrating.

D. SCHEDULE INTERMEDIATE PARAMETERS

There are six schedule intermediate parameters: well life, study period, workover frequency, workover duration, repair time, repair duration, and initial delay. These parameters are shown in figure III-1. The GEOCOM model allows up to three types of workovers to be scheduled. The frequencies of the workovers are assumed independent. The model calculates the combined workover scheduled and determines costs and productivity appropriately.

If the study period, e.g., power plant lifetime, is more than the well life, the model combines the appropriate number of complete well lives plus a partial one. For the partial well, it prorates initial capital cost according to the fraction of production during the partial well life divided by production of the whole well life. Continuing costs and benefit are taken as the values accumulated up to the end of the partial well life. All values for the wells needed after the inital one are discounted and inflated back to present value when the first well was drilled.

CHAPTER IV
LIFE CYCLE COST/BENEFIT MODEL PARAMETER ESTIMATION RELATIONSHIPS

A. APPROACH FOR DEVELOPING THE ENGINEERING ECONOMICS OF THE MODEL

The economic model development followed the five-step process outlined in figure IV-1. The individual steps within the process are described in the following paragraphs.

1. Develop the Cost Structure

The initial step consisted of developing a cost structure or chart of accounts. A set of cost categories was derived based on examination of the literature and familiarity with geothermal operations. Particular emphasis was placed on the operations phase of the well life cycle, with reduced attention given to the capital costs of drilling. The cost structure developed under this program is shown in figure IV-2. This structure provides a framework for accumulating costs that ensures completeness (all cost elements are considered) and eliminates the possibility of double counting. For each category identified in the structure, there is a corresponding module or estimating relationship in the computer model. Certain of these routines allow for direct throughput based on user-specified data.

2. Acquire the Data

The second step encompassed the acquisition of data as a basis for generating the model relationships. The data requirements included cost information on historical programs and current vendor products, physical/performance data on equipment such as pumps, and operational data on current geothermal wells. To guide this acquisition process, a set of scenarios was constructed for each workover cost category in the structure. Each scenario provided a representative sequence of steps to be executed in accomplishing the workover. Estimates of the task times were developed from experienced judgement and discussions with service vendors. The scenario formed the basis for requesting service company cost estimates or catalog prices. Chapter VI contains the workover studies developed for each workover that has been modeled.

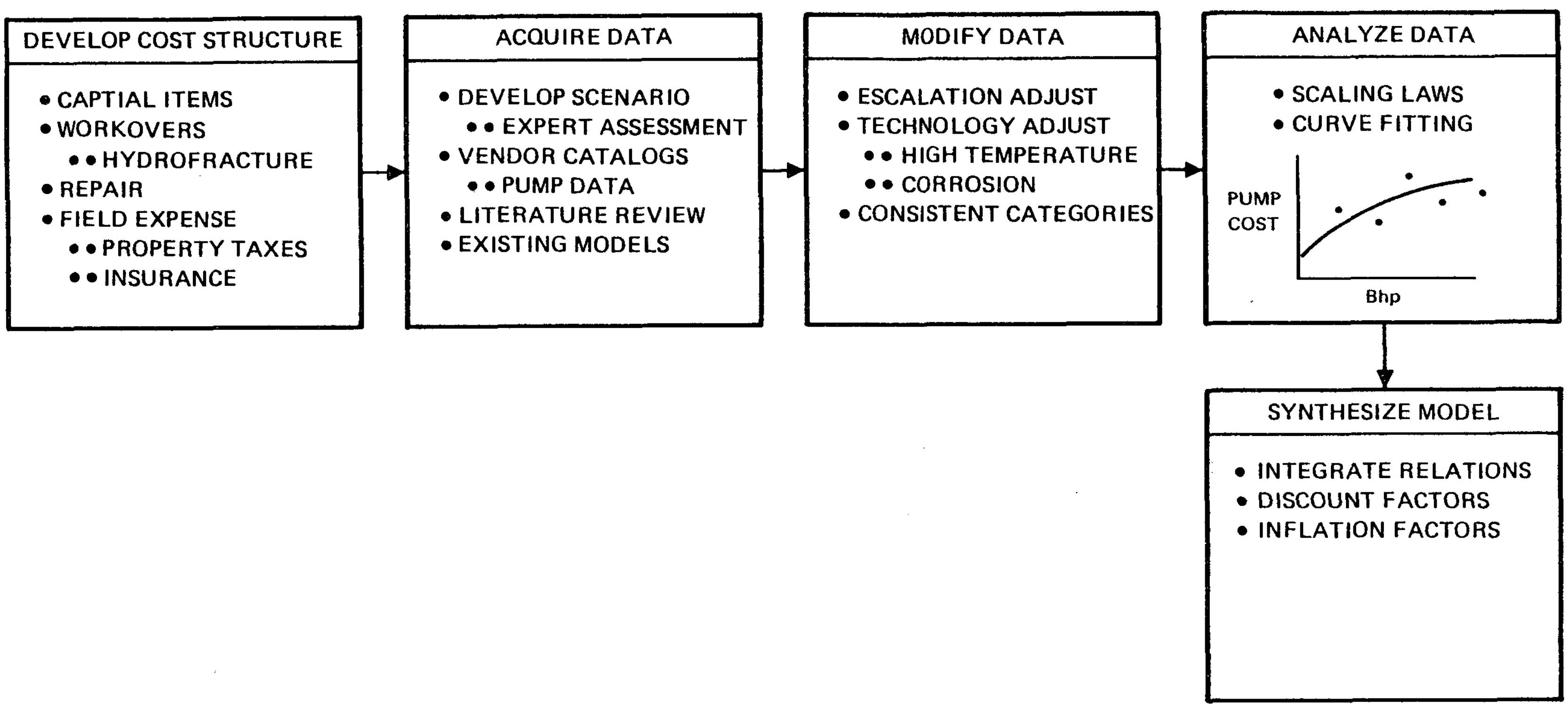

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Figure IV-1. Model Development Process

CAPTIAL ITEMS

- WELL
- PUMPS
  - INJECTION
  - LINE SHAFT
  - SUBMERSIBLE
- CHEMICAL SCALE INHIBITION SYSTEM

WORKOVERS

- LOGGING
- PERFORATING
- HYDROFRACTURE
- DESCALING
  - MECHANICAL
  - HYDROJET
  - CHEMICAL
- PUMP INSTALLATION/REMOVAL
- REMEDIAL CEMENTING
- UNDERREAMING AND GRAVEL PACK
- SLOTTED LINER REPLACEMENT

ROUTINE MAINTENANCE

OPERATING EXPENSES

- ELECTRICITY FOR PUMPS
- CHEMICALS FOR INHIBITION

REPAIR WITH TIE-BACK LINER

FIELD EXPENSES

- TAXES (PROPERTY)
- INSURANCE

ABANDONMENT

BDM/A-81-614-TR-R1

Figure IV-2. Cost Structure

Data for capital cost items such as pumps and inhibitor system equipment were obtained from vendor catalogs and published literature from the oil and chemical process industries. Maintenance data for pumps and inhibitor systems were also acquired from the literature review and vendor sources. These data are contained in the estimating notebook compiled for this study. This notebook (under separate cover) is arranged by cost structure category to facilitate easy access.

3. Modify the Data

This step provided several manipulations to the basic data to ensure reasonableness and comparability. First, the data were screened for internal consistency by a comparison among multiple sources where available, or through review by experienced analysts. The screening process considered the cost data for content i.e., installed or uninstalled costs of pumps, inclusion of sales tax and shipping, etc. The data were then adjusted for differences in terms of content so as to agree with the requirements of the model. The results were further adjusted for escalation effects (all costs were inflated to FY 1981 dollars), and technology factors. Technology adjustments were required for cases where historical data on geothermal applications were lacking, but were available for similar equipments operating in different environments. This was the case, for example, with downhole pumps. Data from chemical process and oilfield applications were obtained and then modified to account for operating temperature differences or for corrosion protection in the case of lower temperature direct use applications in high salinity reservoirs.

4. Analyze the Data

This step consisted of the development of relationships to express cost as a function of physical performance and operation parameters. The techniques for deriving relationships included use of engineering scaling laws and curve-fitting to the data. Curve-fitting was accomplished through the method of "selected points". This approach was taken due to the relatively small sample sizes available in the data and the nonlinear forms exhibited in plots of the data. The purpose of the analysis was to develop relationships that would be useful for projecting technology effects. A secondary purpose was to provide relationships that estimate current operation costs with reasonable accuracy. These considerations led to the development of simple functional forms that incorporate explanatory variables intuitively related to the costs of the workovers or capital equipment. The simple model can also treat technology impacts by altering the independent variables as appropriate. A further benefit results from the capability to perform multiple sensitivity analyses in a relatively rapid manner. These analyses project the impact on costs that result from perturbations in the underlying parameters, a capability regarded as essential for models designed to predict or assess the effect of technological change. Such assessments are always subject to considerable uncertainty, and the methodology was designed to offer a means of bounding the effects of that uncertainty.

Examples of the two major types of relationships incorporated into the model are considered next. The first example treats the use of scaling law methods as applied to the perforation workover. The second example employs curve-fitting techniques to estimate the uninstalled cost of a downhole pump.

a. Example I. Perforation

This example is based on the construction of a scenario for a perforation workover. The basic scenario data are presented in chapter VI. Based on review of the scenario, algebraic relationships were developed for the major cost factors including: mileage, depth control, guns, operations, blasting caps, cables, and equipment. Different factors or parameters influence these costs: mileage costs are naturally governed by travel distance, while the operations charge is driven by the length of the interval to be perforated. The cost of the total operation is given by the equation:

$$TC = 2.75*D + .19*d + .34*I + 63*I*Q + 8*J + 66*I + 1350 + TR,$$

where TC is the total cost (excluding sales taxes)

D is the round trip distance in miles
d is well depth in feet
I is the interval length in feet
Q is the density of shots in shots per foot
TR is the derrick travel costs

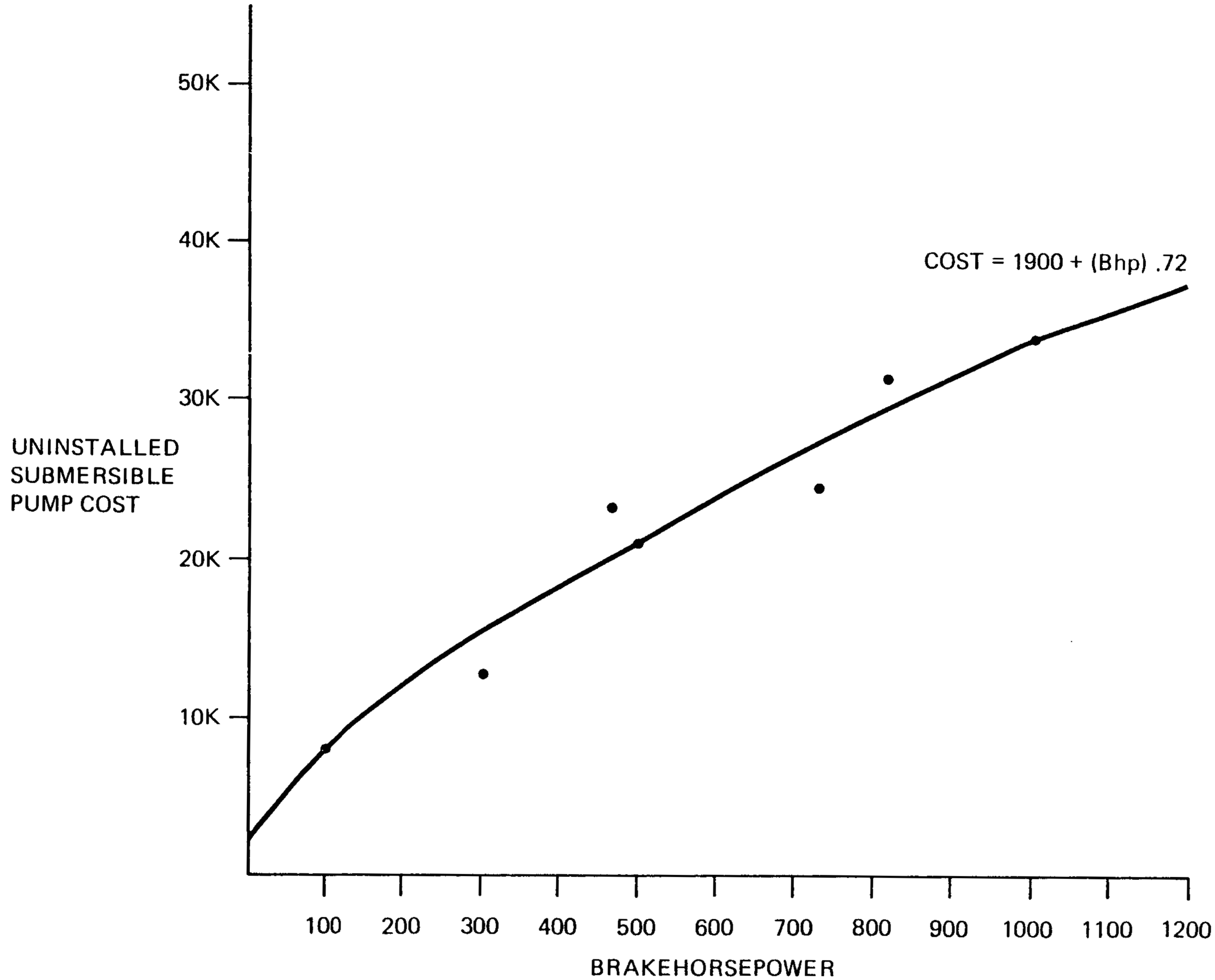
TR is a step function given by:

$$TR = \begin{cases} 0 \text{ if } D \leq 150 \\ 2.1 * (D-150) \text{ if } D > 150 \end{cases}$$

This simple additive relationship reflects current costs for well perforation services and allows for variations in the cost driving factors. Technology impacts such as the development of high temperature cables can be reflected by altering the coefficients in the equation affected by the technology. In this case, the cable charge factor of $66 per foot could be modified. The other terms would remain constant since they are unaffected by the cable development. This equation assumes 35 descents per 1000 foot interval and a bottom hole temperature of 500 degrees Fahrenheit.

b. <u>Example II. Downhole Pumps (Uninstalled)</u>

The uninstalled cost of a downhole pump was estimated by curve-fitting data for various sized pumps. Oil well pump data were the basis for the relationship. The basic relationship was then modified with selected factors for high temperature environment or low temperature corrosive environment as necessary. The resulting estimate was further factored to include the costs for installation, cabling, electric motor, and field spares. The submersible pump relationship for oil well pumps is shown in figure IV-3 together with the data. Review of existing literature indicated that brakehorsepower (Bhp) provided a reasonable correlation to pump costs. Bhp can also be readily estimated for a given well from flow rate and pressure (head) requirements. As a result, Bhp was chosen as the explanatory variable for the capital cost relationship.



BDM/A-81-614-TR-R1

Figure IV-3. Submersible Pump Cost (Uninstalled)

The equation for the curve in the figure was estimated by selecting three points and solving the resulting equations for the three parameters a, b, and c in the functional form, $a+b*(Bhp)^c$.

5. Synthesize Relationships into Model

The cost relationships for the individual categories of the cost structure were integrated to form the cost model. The model considers the interrelationships between the cost equations. For example, pump repair costs are a function of the pump capital costs.

This step also incorporated the capability to escalate costs incurred during future years, and to discount future costs to present value. The discounting procedure is based on the formula for continuous time streams of cost (or benefit), e^{-rt}, where t is the elapsed time at which the expense is incurred, and r is the discount rate. The discount rate is a user input (default value = .1), and is assumed constant over the study period of concern. Similarly, the escalation of costs to future year prices was based on continuous escalation, e^{it}, where t is the time at which the cost will be incurred, and i is a constant inflation rate. For costs that are accumulated over a period of time, i.e., inhibition chemicals, this factor is integrated over the time interval of concern. It is recognized that discount rates and inflation rates are not constant over time and the use of nominal average values is meant to give a reasonable indication of the impact of geothermal technology applications in the presence of discounting and inflation. The ability to predict inflation rates 20 to 30 years in the future is at best limited, and more sophisticated models to incorporate such predictions would likely be expensive window dressing.

The use of simple discounting and escalation techniques allows for extensive sensitivity studies of the assumed values. The impact of different discount assumptions, i.e., r=0, .1, and .2, can be readily assessed by exercising the model for the three values.

B. WELL COSTS

Well costs have not been calculated as part of the GEOCOM project; instead, the generic wells developed by Dr. B. J. Livesay have been used.

The cost of these wells is summarized in table IV-1. Further information on these wells is available in "Representative Well Models for Eight Geothermal Resource Areas" (reference 2).

TABLE IV-1. GENERIC WELLS

	Brawley	Heber	Geysers	Baca	R.H.S.	East Mesa
DEPTH	6,000.	8,000.	8,000.	6,000.	7,500.	7,600.
COST ($1000)	613.	771.	1130.	1080.	1130.	724.

Since some completion alternatives require that the initial well design be changed slightly, Dr. Liversay also supplied estimated variations to the basic generic wells. These variations allow one to determine the cost effectiveness of completion alternatives such as a larger diameter well or cemented perforated casing. Thus, the trade-offs between additional cost and increased productivity of a larger diameter well can be evaluated.

These variations on the basic generic wells are:

(1) An East Mesa cemented casing (ready for perforating) instead of a slotted liner.
  - result: $17,000 reduction in cost.

(2) Larger diameter East Mesa well instead of standard casing program of 20-inch, 13 3/8-inch, 9 5/8-inch, 7-inch.
  - result for a 20-inch, 16-inch, 11 3/4-inch, 8 5/8-inch casing profile is a 15 percent increase in cost.
  - result for a 30-inch, 20-inch, 13 3/8-inch, 9 5/8-inch casing profile is a 24 percent increase in cost.

(3) 9 5/8-inch long string back to surface
  - result for East Mesa is a $15,800 increase in cost.
  - result for Salton Sea is a $9,800 in cost.

C. WELL PERFORMANCE

The performance of a geothermal well can be modeled by the equation (reference 5)

$$Q = PI(P_e - P_{wf}) \qquad \text{(Eq. IV-1)}$$

where Q is the well flow

PI is the productivity index

P_e is the average pressure of the reservoir away from the well

P_{wf} is the pressure at the well "sand face" while flowing.

Determination of P_{wf} for a geothermal well can involve complicated two-phase flow calculations that are beyond the scope of the GEOCOM project. The user of the GEOCOM model who needs to make such calculations is referred to the handbook by the Denver Research Institute and Coury and Associates (reference 6).

The completion of a well can affect well performance in the following ways:

(1) By changing the "skin effect" or near wellbore Δ pressure by formation damage or permeability enhancement by stimulation.

(2) By changing the "sand face" radius.

(3) By changing the length of the completion interval.

(4) By changing the casing profile and thereby the resistance to flow in the well.

The first three of these change the productivity index whereas the last changes the back pressure on the formation at the "sand face".

The productivity index can be expressed by the formula:

$$PI = \frac{C\ h\ k}{\ln\left(\frac{r_e}{r_w}\right) - 1/2 + S} \qquad \text{(Eq. IV-2)}$$

where h is the thickness of the completed interval,
k is the permeability,
r_w is the radius of the well,
r_e is the drainage radius,
S is the "skin effect".

Depending on the nature of the pressure loss or gain, S is given by various different formulas. For formation damage it can be expressed as

$$S = \frac{k - k_d}{k_d} \ln\left(\frac{r_d}{r_w}\right) \qquad \text{(Eq. IV-3)}$$

where k_d is the permeability of the damaged region,
r_d is the radius of the damaged region.

Tests on geothermal cores made by Terra Tek, Inc. indicate the permeability damage ratio (k_d/k) can be .5 with an invasion distance the same as one hole diameter or 8 3/4-inch (reference 7). Using these numbers and equations IV-2 and IV-3, the following examples of changes in productivity index were calculated.

(1) Elimination of the damage zone by use of a perfect drilling fluid in a 8 3/4-inch hole will result in a 17 percent improvement in productivity index.

(2) Under reaming the hole to 15-inch with the same 8 3/4-inch invasion will result in an 18 percent improvement in productivity index.

(3) Under reaming the hole to 15-inch with perfect drilling fluid will result in a 27 percent improvement in productivity index.

(4) Lengthening of completion interval (when operationally possible and reservoir properties permit) will increase in the productivity index the same percentage as the increase in completion interval.

As an example of how such data can be applied, the following comparison between lengthening the completion interval and underreaming is presented. For an East Mesa well, keeping the intermediate casing at the same depth and increasing the completion interval by 18 percent (assuming this is operationally possible and reservoir properties permit) increases the productivity index by 18 percent (number (4) and above). An examination of Dr. Livesay's generic wells shows that this will increase the well cost by $44,354 or 6.1 percent. Point number (2) above says that the underreaming and gravel pack workover reported in chapter VI will increase the productivity index by 18 percent; however, the cost is $383,736 which is a 53 percent increase in cost. Hence, the underreaming and gravel pack workover of chapter VI is not a cost-effective way to increase the productivity index when compared to basic drilling and completing, i.e., lengthening the completion interval.

An 18 percent increase in productivity index will not necessarily result in a 18 percent increase in flow. This is because the backpressure on the reservoir, P_{wf} in equation IV-1 is a function of flow rate.

$$P_{wf} = P_{wh} + \rho g h_1 + fQ^2 \qquad \text{(Eq. IV-4)}$$

where P_{wh} is the wellhead pressure,

$\rho g h_1$ is the pressure due to the weight of the fluid column.

fQ^2 is the pressure due to frictional losses of the flowing fluid.

For a well tested at Roosevelt KGRA, the Denver Research Institute used their "Geothermal Well Design Handbook" to plot figure IV-4 (reference 8). The figure shows that for a 9 5/8-inch casing, an 18 percent increase in productivity index results in a 12 percent increase in flow. This increase in flow is sufficiently greater than the 6.1 percent increase in cost to indicate that lengthening the completion interval appears cost-effective. This example illustrates several points.

(1) The benefit that results from a change in productivity index is not the same as the change in productivity index. The relationship between well flow and productivity index is beyond the

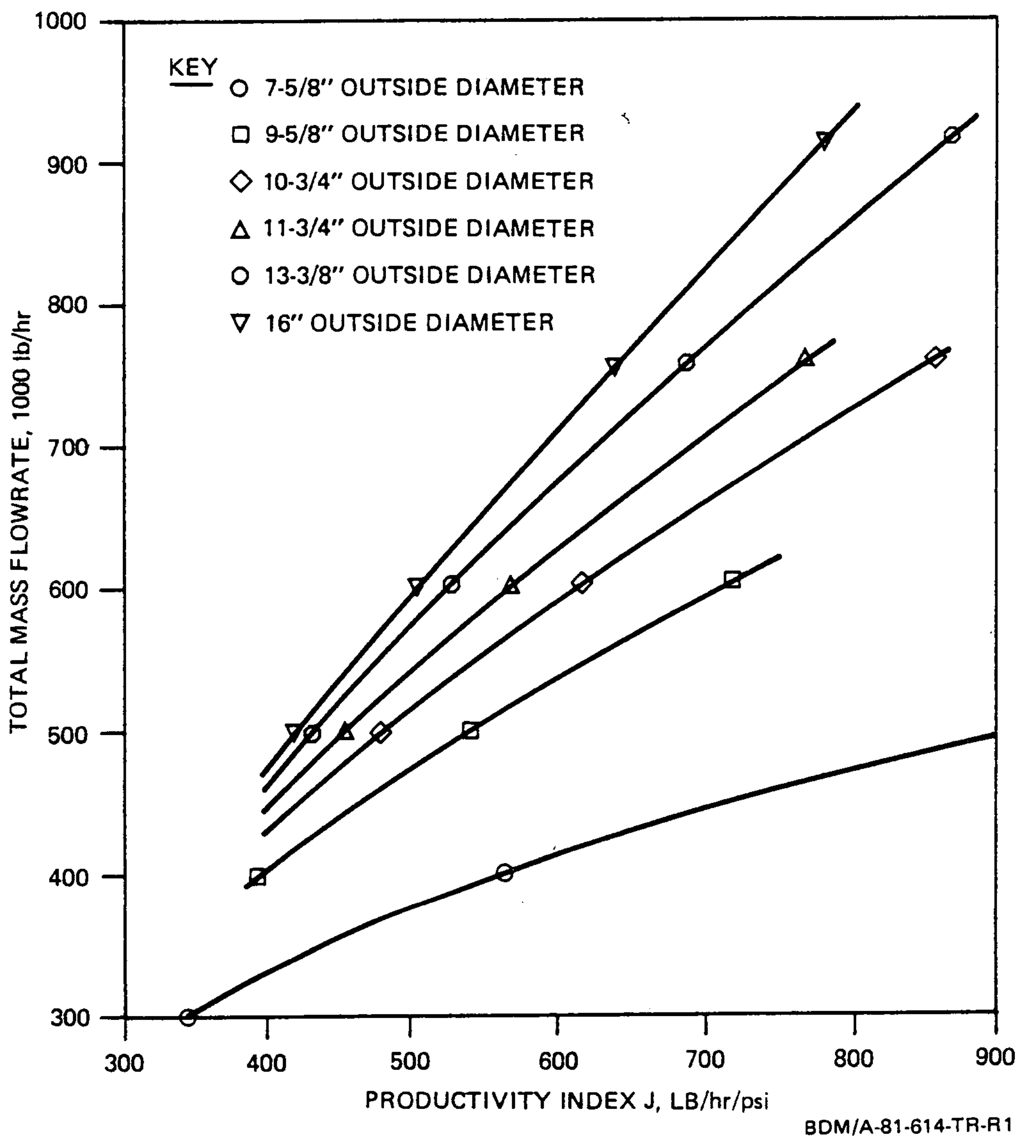


Figure IV-4. Computer Model Result of Flowrate Versus Productivity Index for h_o = 484.6 Btu/lb. (reference 8).

scope of this project but in general can be obtained from the "Geothermal Well Design Handbook" (reference 6).

(2) Actual determination of changes in benefit that result from changes in completion technologies are site-specific, i.e., they depend upon the properties of individual reservoirs. Using a Roosevelt KGRA plot (figure IV-4) to analyze an East Mesa well is not really appropriate.

(3) The actual determination of cost effectiveness must include continuing costs and is not as simple as comparing percent change in initial flow rate to percent change in captial costs. The analysis above should therefore be used as input to GEOCOM.

(4) The nature of the pressure due to friction (third term, equation IV-4) or the shape of the curves (figure IV-4) is a function of the type of flow, single-phase or two-phase. For single-phase flow, a diameter to the 5/2 power scaling law may be appropriate. For two-phase flow, the handbook should be used.

The ideas or equations of this section can be used (by applying the curves of the "Geothermal Well Design Handbook") to calculate cost effectiveness of such effects as a change in casing profile, the deposition of scale, or inclusion of a satellite tubing string. Using figure IV-4, the following flow loss examples were calculated:

(1) 1/2-inch of scale in a 7-inch tie-back string results in a 12 percent loss in flow.

(2) 1 1/2-inch satellite tubing string in a 7-inch tie-back string results in a 18.7 percent loss in flow.

(3) 1 1/2-inch satellite tubing string in a 9 5/8-inch surface casing results in a 15.6 percent loss in flow.

The latter two were calculated using the concept of hydraulic radius which is defined as the area of flow divided by the wetted circumference. The hydraulic radius must be multiplied by four to get the effective diameter. Figure IV-4 is then used to determine the flow at the effective diameter and thereby calculate the percent loss in flow.

CHAPTER V
SENSITIVITY STUDIES

Four different sensitivity studies were performed: well life, mechanical descale, baseline parameters, and injection pump. For each of the studies, parameters were varied to determine the sensitivity of the cost effectiveness ratio to the varied parameter. In addition to the sensitivity studies, this chapter includes an analysis of the cost effectiveness of chemical scale inhibition. This study was done only for expected values of the parameters.

A. RATIONALE FOR SELECTING THESE STUDIES

1. Well Life

The well life study was done for three basic reasons:

(1) To determine how important well life is and if there is a point beyond which further well life is of little value.

(2) To help identify which measure of cost effectiveness is most appropriate.

(3) To assess the validity of the "single well" assumption that was made in constructing the model.

The basic measures of cost effectiveness that the model calculates are inflated and discounted cost divided by the benefit. The benefit includes discounting with or without inflation. The time period can be either the well life or the study period (power plant life). The question raised in point (2) above is which of the methods for calculating cost effectiveness is the most appropriate: should it be with or without inflating the benefit, and should the time period be the well life or study period.

One of the assumptions of the GEOCOM model is that cost effectiveness can be calculated considering only costs and benefits of a single well. This means that the well is assumed to operate at a maximum productivity that declines with time. In actual practice, the need for reserve capacity and the need to take wells off-line for workovers means that a well will produce at a varying rate and will be throttled back part of the time. To assess this effect, levelized productivity calculations were made.

2. Mechanical Descale

The GEOCOM model is a tool for evaluating life cycle costs of completion technologies. Life cycle cost rather than initial cost is the effectiveness measure calculated by the GEOCOM model so that the impact of continuing (O&M and workover) costs can be evaluated. Mechanical descaling was analyzed in this project as representative of life cycle cost streams where workovers must be performed at regularly scheduled intervals. In this sense, it is a "generic use" of the well with workovers and contrasts to situations where the well might be pumped or where chemical inhibition is applied to present scale.

3. Baseline Parameter

To provide a basis for comparing continuing costs, the baseline parameter study was done. This study investigated the effect of non-continuing cost parameters (e.g., well cost) on the cost effectiveness ratio.

4. Injection Pump

Geothermal wells will be either producers or injectors. To evaluate the utility of the GEOCOM model for analyzing the cost effectiveness of injection wells rather than producers, an injection pump study was performed. This study also serves as an example of how parameters can interrelate and how the cost effectiveness depends nonlinearly on some parameters.

5. Chemical Inhibition Study

The intent of the GEOCOM model is to compare cost effectiveness of alternative completion technologies. The chemical inhibition study was done to contrast the mechanical descaling study. Both are intended to allow a well to be used in spite of a tendency to scale. To the degree the parameters of these studies are representative, the cost effectiveness ratio can help determine which method should be used to produce the well.

B. SCOPE OF STUDIES

1. Well Life

Each cost effectiveness ratio was calculated as a function of well life. This was done for parameters representative of a well that does not scale and for one that does scale. In this way the effect of differences in initial costs versus continuing costs can be evaluated.

The cost effectiveness ratio can be visualized as:

$$\frac{\text{Initial Costs + Continuing Costs}}{\text{Benefits}}$$

If both continuing cost and benefit are proportional to time, then for short times when inital cost is dominant, the ratio will be inversely proportional to time; whereas for long times when continuing cost is dominant, the ratio will approach a limiting value. While actual costs and benefits will not be exactly proportional to time, this simple visualization of the cost effectiveness ratio as a function of well life illustrates the significance of determining if a well has reached a point beyond which additional well life is of little value. An understanding of the value of well life is important because of the contrast between well lives at The Geysers and at other areas being developed.

Well lives projected for the Imperial Valley are about 10 years, whereas power plant lifetimes are typically 30 years. Therefore, it is important to consider if including replacement wells to complete the project life has an important effect on cost effectiveness.

With time, reservoir decline or loss in productivity of a well reduces future benefits at a rate faster than costs. This makes it possible for operating costs to accumulate at a rate faster than benefits so that cost effectiveness ratio increases with time (cost/benefit increases so system "effectiveness" decreases). Calculations have only been done for a single value of the reservoir decline parameter. This parameter is, however, representative of available data for both matrix and fractured permeability reservoirs.

Whereas the effects of inflation and discounting tend to offset each other, reservoir decline is not balanced by anything. It therefore has the potential for significant impact when the benefit stream changes. A change in the benefit stream occurs when a well is throttled up and down to meet a changing system demand. One way to assess if such variable flow actually has an important effect on cost effectiveness is to recalculate cost effectiveness using an equivalent constant well flow rate. This equivalent constant well flow rate is chosen so that the well will have the same total production over its life time. We have called these calculations "levelized" production.

2. Mechanical Descale

For the mechanical descale study, four parameters that determine the continuing cost to descale were selected and cost effectiveness was determined as a function of these parameters. The parameters are workover cost, workover frequency, workover delay (time to perform the workover), and flow loss fraction (percentage of flow lost each month due to scaling). They determine the timing and amount of continuing cost. The same parameters are important for other well completions/utilizations for which workovers are a significant factor. Baseline values used for these parameters are representative of mechanically descaling a well at the Baca location.

3. Baseline Parameters

For the baseline parameter study, five parameters were chosen that are important in determining the cost effectiveness of a well. The sensitivity of the cost effectiveness ratio to these parameters was evaluated assuming there was no scaling or workovers. These parameters are well cost, well life, initial well flow rate, initial delay between drilling and first production, and the rate at which production declines with time. Together with those of the mechanical descale study, these parameters indicate how cost effectiveness trade-offs between initial cost and continuing cost, as well as trade-offs between well productivity and scaling problems, can be evaluated.

The effect of wellhead steam quality was also investigated, but is not graphically presented in this chapter. This parameter was initially selected because it is important not in determining cash flow or in the total production, but in determining the useful BTU content of the produced fluid. It was found, however, that the sensitivity curve for steam quality coincided with the well flow rate curve and so this parameter was not included in this study.

4. Injection Well

For an injection well, important cost trade-offs occur even if there are no workovers performed on the well. One must choose at what rate to flow the well or how big an injection pump to use. The basis for the choice is balancing pump operating costs against initial well costs to obtain the most cost effective system. If the injectivity of the well decreases with time, the choice becomes particularly important.

To determine how key parameters affect the cost effectiveness of injection and how the optimization of an injection system depends upon these parameters, sensitivity runs were made. The parameters which were varied were well cost, initial well flow rate, well life, maximum pump pressure, injectivity decline rate, and the "effective depth" to the water table. Pump pressure, well flow, and pump horsepower were determined as a function of time to help understand how these parameters interrelate to determine the cost effectiveness.

5. Chemical Inhibition Study

Since the primary reason for doing the chemical inhibition study was for comparison to mechanical descaling, a single point calculation was made rather than a sensitivity study. Results used for comparison were cost effectiveness and total production over the well life. No workovers were considered in the chemical inhibition study; however, the presence of a tubing string in the well to inject the chemicals at the bottom of the well was considered to reduce well flow. For the chemical inhibition system, this reduction was taken to be 18 percent, corresponding to 1½ inch tubing string in a 7 inch casing. The basis for determining this reduction in flow is given in the well performance section of this report.

C. RESULTS

1. Well Life

If both continuing costs and benefits are added in constant amounts each month, the cost effectiveness ratio can be visualized as:

$$\frac{\text{(Initial Cost)} + \text{MCC*(Time Value of Cost)*M}}{\text{MB*(Time Value of Benefit)*M}}$$

where MCC = Monthly Continuing Cost
MB = Monthly Benefit
M = Number of Months

As the number of months grows, the initial cost will become unimportant and this reduces to:

$$\frac{\text{MCC*(Time Value of Cost)}}{\text{MB*(Time Value of Benefit)}}$$

It may be argued that the "value" of this ratio could change in time, but if the cost effectiveness ratio assumes a limiting value based on monthly continuing costs and benefits, the most reasonable estimate of this ratio is its initial value when costs and benefits are accurately known rather than forecasted. This implies that the (Time Value of Costs) and (Time Value of Benefits) should be the same function.

Figure V-1 shows the effect of treating continuing costs differently rather than with the same time value. The top two cost effectiveness curves are for inflated, discounted, continuing costs but only discounted benefits; the top curve being for cost effectiveness measured over the study period (360 months) and the bottom one over the well life. The continuing cost stream is uniform and initial capital costs of extra wells are prorated according to the fraction of the well life used. When the well life approaches the study period (right-hand side of the curves), the two measures of cost effectiveness coincide as they must; but for small well lives there is a big difference in the two measures.

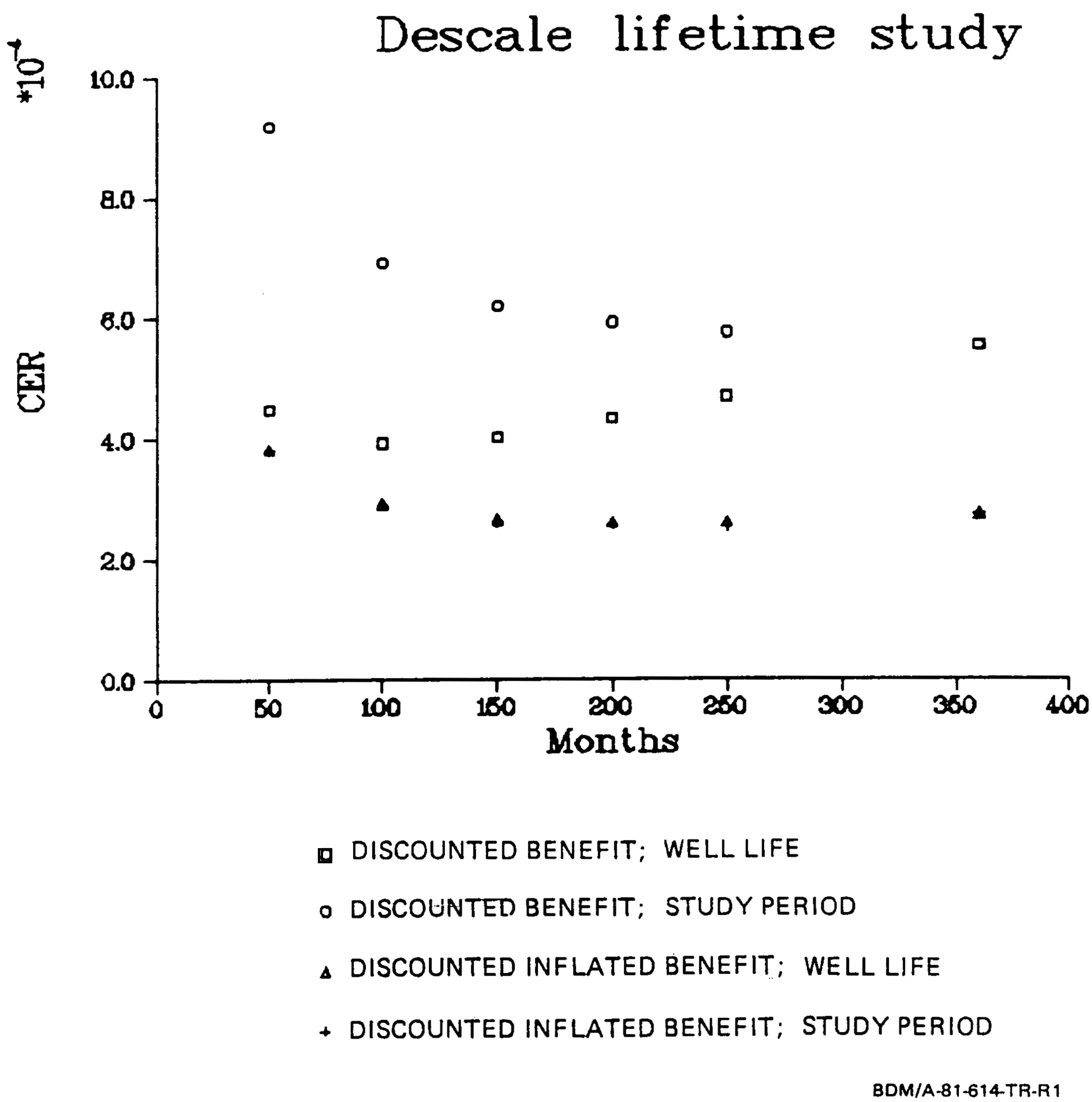


Figure V-1. Cost Effectiveness Ratio for Different Time Periods and Time Values of Money

There is no logical reason why this should be true and discrepancy is merely a result of inflating continuing costs but not benefits. When continuing costs and benefits are both inflated and discounted, the two curves (bottom figure V-1) coincide as they should. If the continuing cost or benefit stream is not uniform, then they would not necessarily coincide but would be expected to be close compared to the big difference between the top two curves of figure V-1.

In conclusion, the best measure of cost effectiveness is the one that includes inflation and discounting for both continuing costs and benefits and which uses the study period for comparison between wells of different lifetimes.

Figure V-2 shows the cost effectiveness for various lifetimes for both a well that does not have to be descaled and one that does. The effect of the extra continuing cost of descaling raises the curve and increases the curvature ever so slightly. An examination of the figure shows that for lifetimes up to about 100 months, increased lifetime results in significant decrease in the cost effectiveness ratio (lower numbers for cost/benefit imply improved system performance). From 100 to 200 months there is some improvement in cost effectiveness with lifetime. After 200 months the cost effectiveness ratio becomes worse (higher number).

Our previous arguments showed that it is not surprising that the cost effectiveness ratio does not continue to improve with increased lifetime; however, the rise in cost effectiveness ratio for long lifetimes requires some explanation. Even though the effect of time value on continuing cost and benefit tend to cancel, the benefit actually decreases with time. This is because the reservoir performance decline factor causes the well flow to decrease with time. After 12 years, the well flow is only 50 percent of the initial flow rate as a result of this decrease in performance. This decrease not only causes the curve to turn back up for high lifetimes, but also affects the minimum cost effectiveness ratio attained on figure V-2. The actual minimum is about 2½ times larger than the limiting value if there were no performance decline. The decline parameter, based on the best data available, is about the same

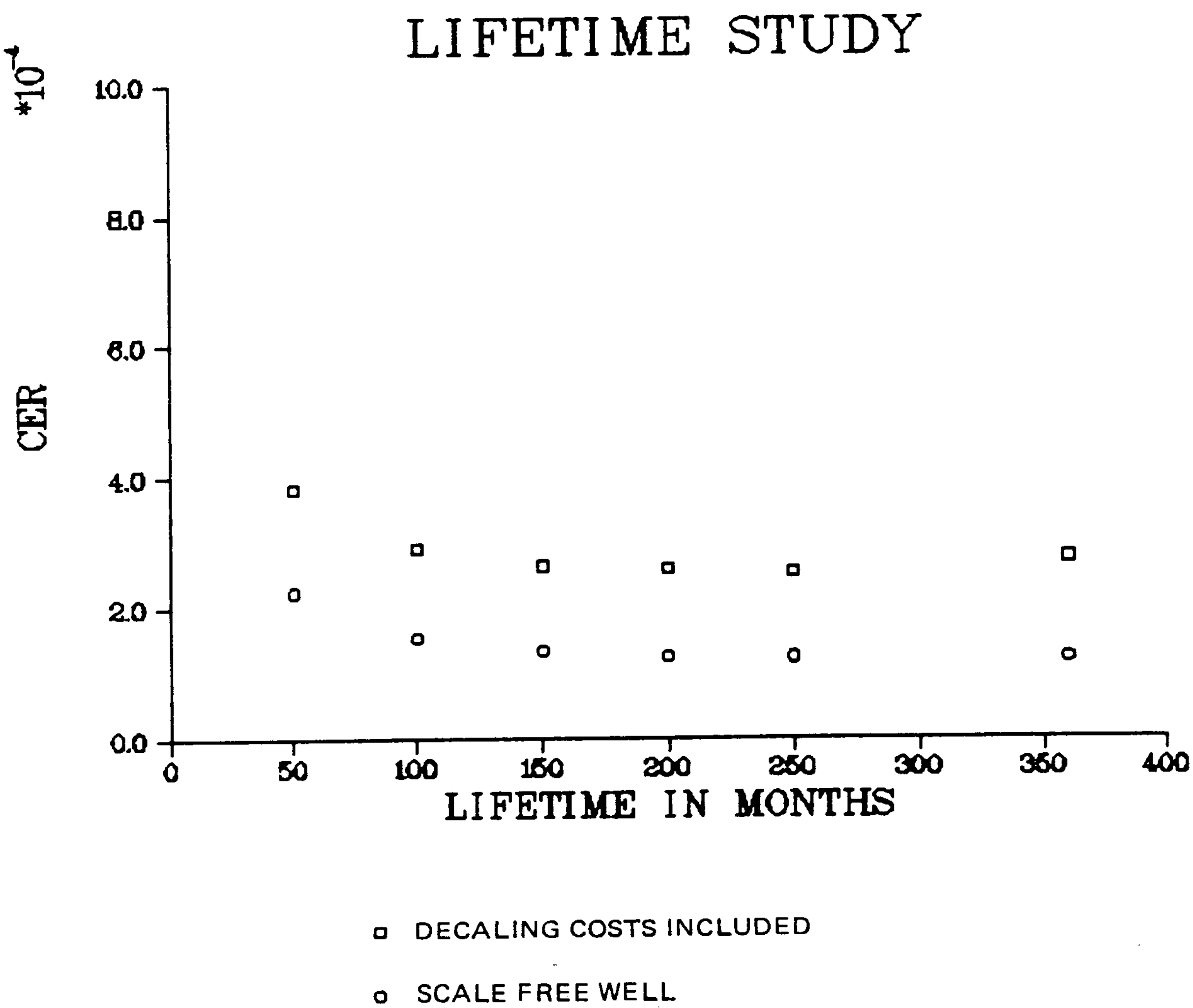


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Figure V-2. Comparison of Cost Effectiveness as a Function of Well Lifetime with and without Scaling for the different reservoirs studied, even though the cause of decline is likely to be different for different reservoirs.

The conclusion drawn from figure V-2 is that after about 10 years, the lifetime becomes unimportant. This conclusion does not appear to be dependent upon whether there are workovers or not, but will depend upon the value used for the reservoir decline rate. For zero reservoir decline rate, the cost effectiveness has not yet reached its limiting value after 30 years.

Figure V-3 shows the cost effectiveness ratios calculated levelizing the flow, i.e., maintaining the flow at a constant rate. The rates used were changed for each lifetime on the figure so that the total production was the same as for the cases shown in figure V-1. Thus, for levelized production, reservoir decline was set to zero but well flow was adjusted to give the same total production.

The cost effectiveness curves on the levelized production graph (figure V-3) coincide with those of figure V-1 for inflated benefit, but do not coincide when the benefit is not inflated. This further supports the statement that the continuing costs and benefit must both have the same time value. The fact that they coincide for the appropriate measure of cost effectiveness suggests that the restriction of the GEOCOM model to a single well does not bias the cost effectiveness calculated by the model.

The primary effect of including the whole well field rather than looking at a single well should be that the well will be flowed at a rate to meet system requirements rather than at the maximum rate possible. Levelizing does not flow the well at the rate which would meet system requirements but does flow it at a different rate and at a rate that has the right total production to cause the same net reservoir depletion or formation plugging. Thus, the fact that the levelized calculations give the same results as the basic GEOCOM calculations supports the argument that restricting GEOCOM to a single well is a valid assumption.

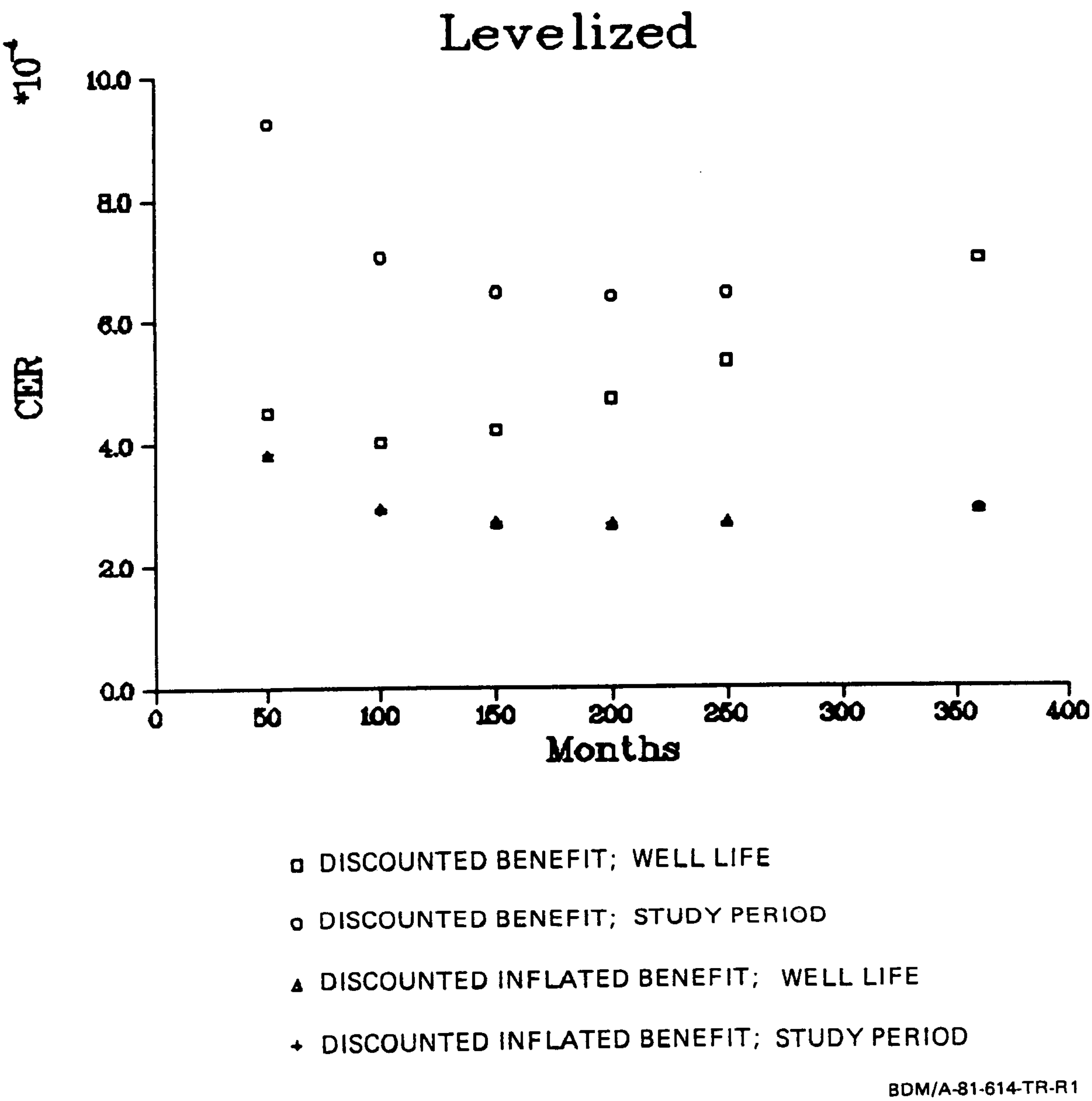

Figure V-3. Cost Effectiveness Ratio for Levelized Production

2. Mechanical Descale

The parameters used to establish the baseline conditions for mechanical descaling were taken to be representative of the Baca Location Well #11. Data on this well were taken from DOE open file information on the Baca project. Baca #11 is an anomalous well and is not representative of other wells in the Valles Caldera. The data for this well, however, are quite similar to the New Zealand well #KA8, a well representative of scaling problems in the Kawerau field. The baseline data for this case are given in table V-1. The descaling scenario on which the choice of these parameters was based is the workover study given in chapter VI.

TABLE V-1. MECHANICAL DESCALING BASELINE DATA

Parameter	Value
Workover Cost	$28,000
Workover Frequency	4 Months
Workover Delay Time	.333 Month
Flow Loss	.125/Month

It assumes that the descaling is trouble-free and that it only requires reaming, i.e., the liner does not have to be pulled. If the descaling job is more complicated, the cost could be much higher (more than a factor of two).

The flow loss of 1/8 per month and the workover frequency of 4 months hopefully are extreme cases. If the scaling rate is worse than this, the adequacy of the model must be questioned. Even if a workover every week were to be calcuated as cost effective on paper, it is hardly practical. A workover every 4 months would require one or more workover rigs dedicated to each project. If the well scaling rate is worse than this, some other method such as chemical inhibition or keeping the fluid pressurized should be considered. The effect of this scaling rate is to raise (worsen) the cost effectiveness ratio by 80 percent from a similar well with no scaling (figure V-2).

Figure V-4 shows the sensitivity of cost effectivness to these parameters. Examination of the figure shows that the cost effectiveness is linear with workover cost and workover delay while it varies non-linearly with flow loss and workover frequency.

The figure shows that the time it takes to do the workover is not critical. Increasing this time by a factor of six from 1/3 of a month to 2 months would cause a 30 percent increase in the cost effectiveness ratio. By contrast, an increase of only a factor of 2 in the workover cost raises cost effectiveness by the same 30 percent. Thus, the cost of a workover is much more important than how long it takes.

The flow loss parameter has no effect on costs but affects the benefit or production that can be derived from the well. As the flow loss increases, the benefit goes down and the cost effectiveness is worse (larger number or more dollars per pound must be charged to make a profit). The dependence of cost effectiveness is not a simple inverse function because the flow loss combines with reservoir performance decline, inflation, and discounting to determine benefit.

The dependence of cost effectiveness on workover frequency is complicated. If the workover is performed too frequently, there will be a significant increase in cost but little additional benefit because the well does not have enough time to loose much flow. If the workover is too infrequent, a point will be reached when there is no more flow or benefit but continuing costs accumulate. So for either extreme, the cost effectivness gets worse (higher number). Thus there will be minimum cost effectiveness ratio or optimum time to do the workover. Figure V-4 shows this time to be slightly more than 4 months (at 4 months the flow is 61 percent or exp (-.125 x 4) of the initial flow). The actual optimum time will be a function of the other parameters: that is, as the flow loss and workover cost parameters change, the optimum time for workover will change.

3. Baseline Parameters

As a comparison for the continuing costs curves of figure V-4, a sensitivity study was done for baseline parameters of a scale-free well. Baseline data used are given in table V-2. The well cost is that developed for the Baca Location by Dr. B.J. Livesay (reference 2).

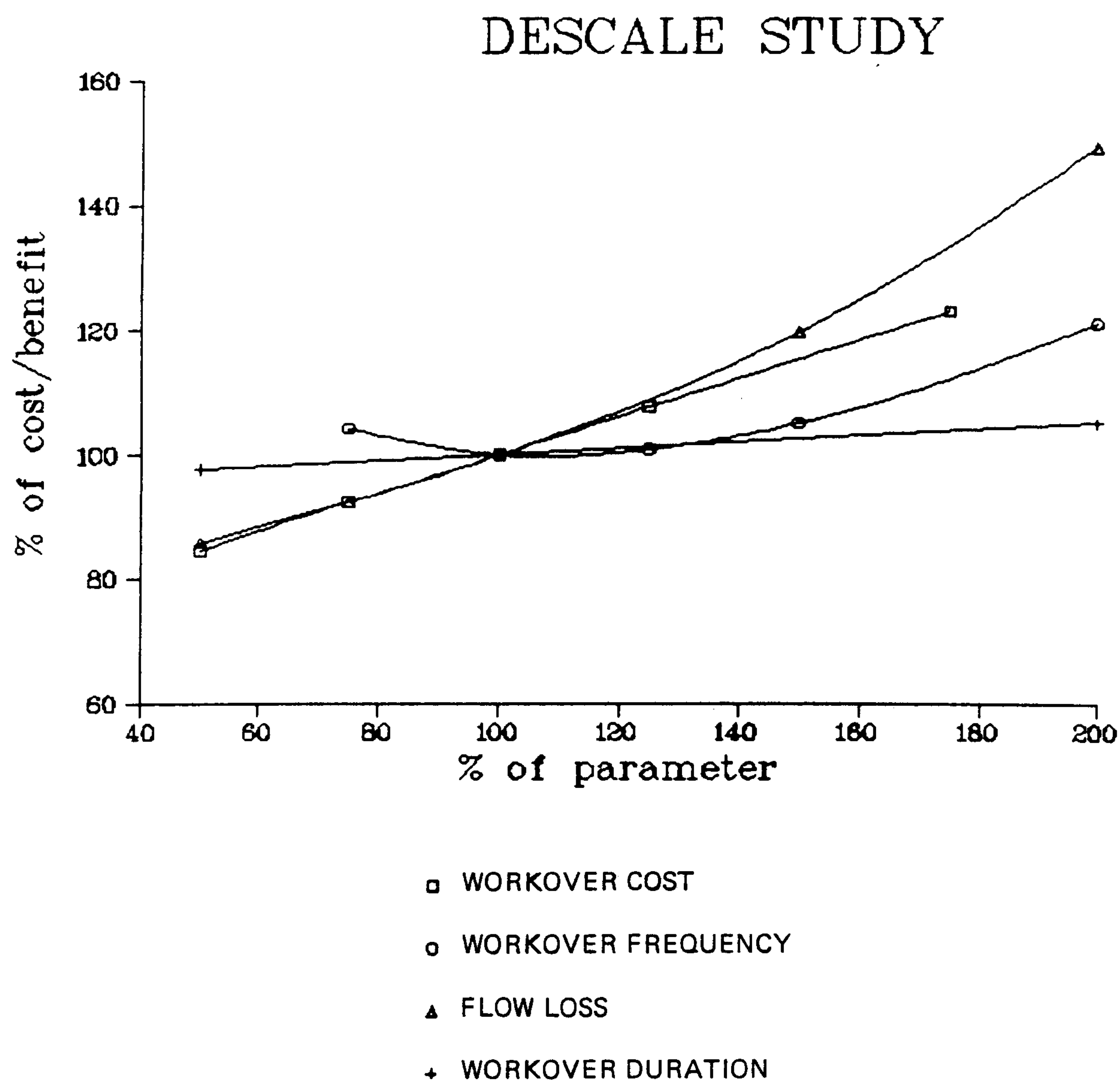

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Figure V-4. Mechanical Descaling Parameter Study

TABLE V-2. BASELINE PARAMETERS OF A SCALE-FREE WELL

Parameter	Value
Well Cost	$1,075,290
Initial Delay	36 Months
Well Life	180 Months
Initial Well Flow Rate	200,000 lbs/hr
Reservoir Performance Decline Rate	.00308/Month

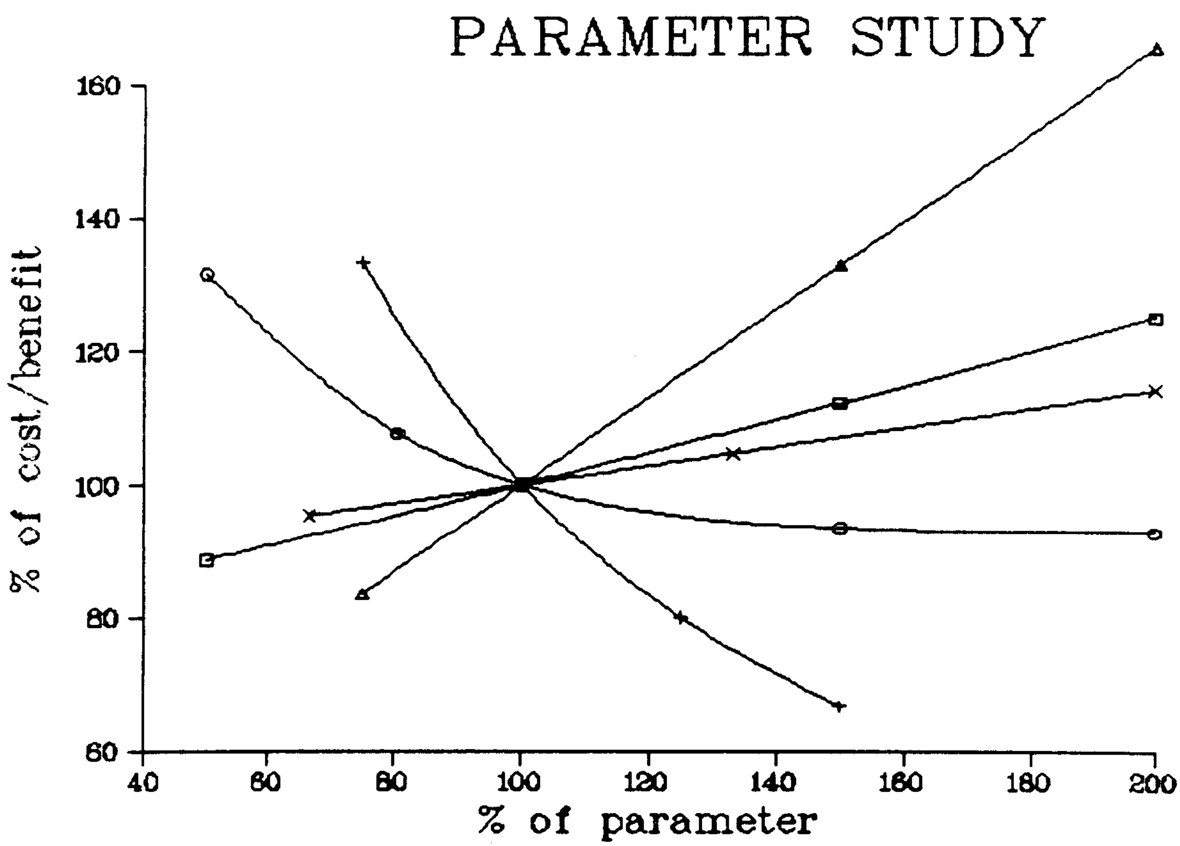
The well life, initial well flow, and reservoir performance decline rate are all based on data from "Geothermal Demonstration Power Plant Volume II", by Union Oil Company and Public Service Company of New Mexico (reference 9).

Figure V-5 shows that the cost effectiveness is linear with well cost and initial delay and is almost linear with the reservoir performance decline rate. The dependence on initial flow rate and well life is nonlinear. The axes of figure V-5 are the same as figure V-4 to allow convenient comparison of these parameters.

The shape of the well life curve is similar to the upper curve of figure V-2, but it does not level off until about 140 percent, or 250 months, whereas in figure V-2 the curve had essentially leveled off by 150 months. The reason for the difference is the initial delay. For figure V-2, there was no initial delay whereas now the initial delay is 36 months causing postponement of benefits and relative increase in the importance of initial costs. As a result, it takes longer for the monthly cost and benefit to become the dominant effect.

The benefit is proportional to the initial well flow rate, but the benefit is in the denominator of cost effectiveness so that cost effectiveness does not depend linearly on initial well flow rate, but rather inversely. In other words, if we plot one over initial well flow rate $\left(\frac{1}{Q_o}\right)$ against cost effectiveness we will get a straight line.

Comparing figures V-4 and V-5, we see that the most critical variables are well cost and initial well flow, followed by well life and



□ RESERVOIR DECLINE RATE

o WELL LIFETIME

▲ WELL COST

+ INITIAL WELL FLOW

× INITIAL DELAY

BDM/A-81-614-TR-R1

Figure V-5. Baseline Parameter Study

flow loss, workover cost, reservoir performance decline, workover frequency, and initial delay. Thus, initial capital cost and the output of the well are the most critical parameters, but the parameters determining continuing cost are almost as important.

4. Injection Pump

To the degree possible, all baseline values of parameters for the injection pump study were representative of the Baca Location Redondo Creek reservoir. Data for this resevoir were obtained from "Geothermal Demonstration Power Plant, Volume II", January 1978 by Union Oil Company and Public Service Company of New Mexico (reference 9). The well cost is that of the "generic well" developed for the Baca Location by Dr. B. J. Livesay (reference 2). In using this generic well as the basis for cost, it has been assumed that the injection well was drilled as a potential producer but turned out to be dry.

Since this field is not yet operational, there are no data on injectivity decline. There have been, however, long-term (6 months) field tests including injection with no reported decline in injectivity. Thus it was assumed that the half-life for the injection well should be at least 8 years. Eight years would correspond to a 5-percent loss in 6 months which should have been observable. Of course, field tests do not necessarily reinject fluid of the same quality as operating conditions and so may not be representative. Experience with fractured reservoirs indicates that 8 years is a reasonable minimum lifetime; however, for porous reservoirs with primary permeability, the expected lifetime is likely to be quite different. To quote the final report for the Geothermal Loop Experimental Facility (reference 10): "Half-life calculations based on data obtained from membrane filters and core samples suggested significant injection well impairment could occur within several months" in porous reservoirs.

The "effective depth" to the water table was determined by extrapolating injectivity tests back to zero pump pressure, then dividing the flow by the injectivity index. The extremely high value of the "effective depth" may not be representative of other reservoirs. The expected useful mechanical well life was picked to be 90 months, just less than the half-life for injection. The basis for this choice is that for mechanical well lives much longer than the half-life of injection, the well will not be able to inject its share of the effluent and so loses its value to the system even if it still can be operated.

Table V-3 gives the baseline values of the parameters. For the sensitivity study, these parameters were varied to new values convenient for plotting. No attempt was made to determine reasonable ranges of variations for the parameters. Thus all the curves except initial well flow, as will be explained later, can be extended and were only terminated for convenience of plotting. An important parameter not varied as part of the study is injectivity index. The value used for this parameter is 431 pounds per hour per foot of head.

TABLE V-3. INJECTION STUDY BASELINE PARAMETERS

Well Cost	\$1,075,290
Initial Well Flow	780,000 (#/hr)
Injectivity Decline Rate	.00722/mo
Well Lifetime	90 mo
Maximum Injection Pump Pressure	1155 ft of head
"Effective Depth" to Water Table	1640 ft

Figure V-6 shows the relationship of the cost effectiveness to the changes in parameter values. Only one parameter is changed at a time while all others are kept fixed at the baseline value. Both cost effectiveness and the parameters are plotted as a percent of the value corresponding to the baseline conditions of table V-3. For the baseline values of the parameters, the actual cost effectiveness number calculated was 7.57×10^{-5} dollars/pound. The percentages plotted in figure V-6 are thus interpreted as follows: if well costs increases to twice the value in table V-3 (200 percent), then the cost effectiveness increases to 137 percent or 1.37 times the expected value reported above (7.57×10^{-5} dollars/pound).

Figure V-6 shows that the relationship between cost effectiveness and well cost is linear and that over the range of "effective depth"

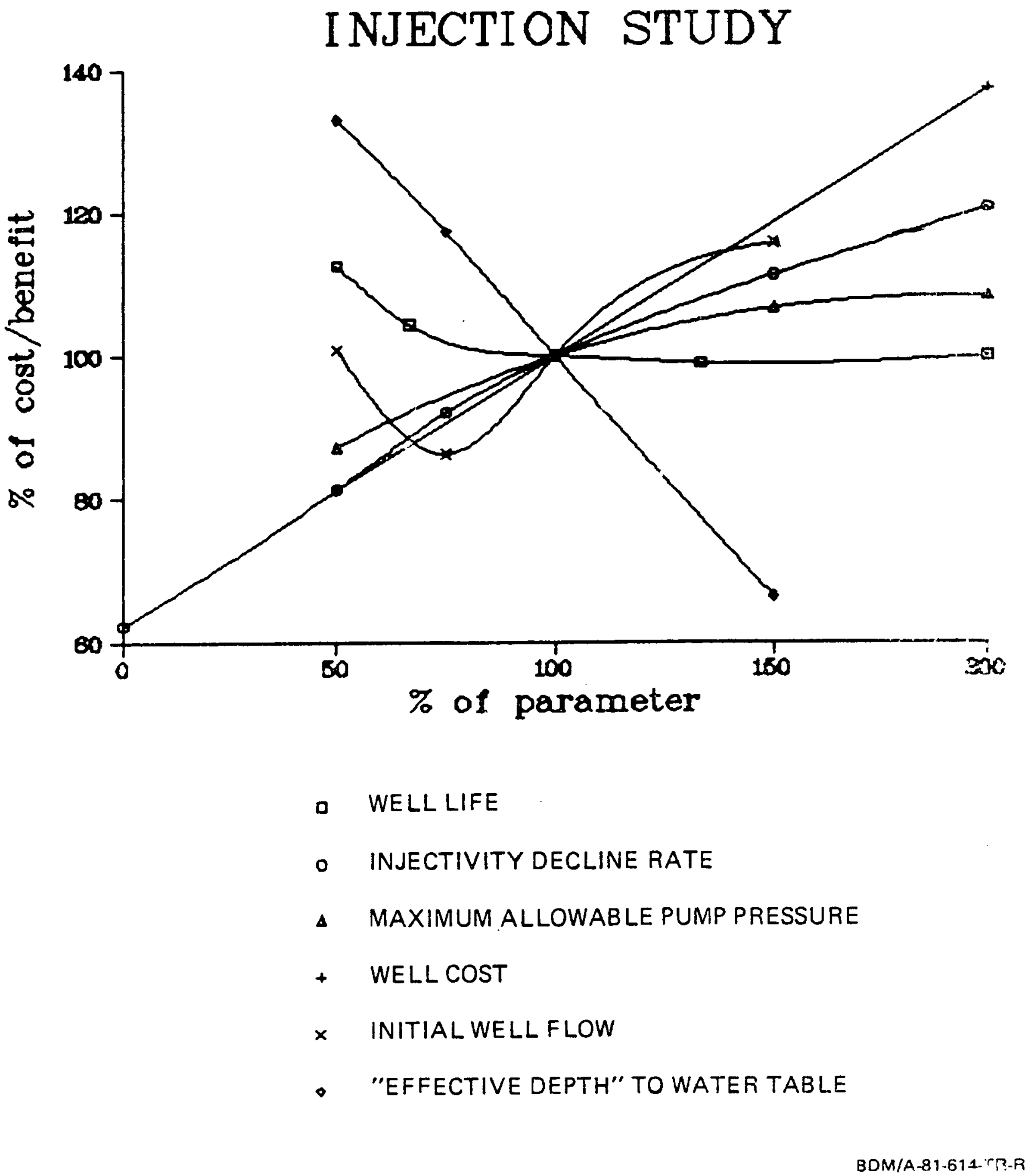


Figure V-6. Injection Pump Parameter Study plotted, the relationship between cost effectiveness and "effective depth" is also almost linear. The steepness of the line for "effective depth" and slight curvature for small values, suggests that extrapolating from the baseline condition to zero "effective depth" is inappropriate.

The curve for maximum allowable pump pressure bends so that higher maximum allowable pump pressures result in little additional benefit. This is because eventually the maximum allowable pump pressure becomes so large that the actual pump pressure never reaches this value and the flow is never limited by the maximum allowable pump pressure.

In figure V-6, the well life curve reaches a minimum at about 11 years and then gradually rises. This is because by that time the well flow is very low and so little additional benefit is accrued, yet pumping continues to increase costs. Eleven years is greater than the injectivity half-life of 8 years but not significantly greater. If workovers were considered in this study, it would be reasonable to schedule a workover that improves injectivity (hydrofractures, back flushing, acidization, etc.) before the 11-year point. The best point in time to do the workover would be a function of the cost and effectiveness of the workover.

The curve in figure V-6 for the initial well flow exhibits interesting nonlinear effects. For low initial flow rates, the cost effectiveness rapidly gets worse (high percent). This is because as the flow decreases so does the benefit, but the initial high capital costs are still there. For large initial flow rates, the cost effectiveness reaches a limiting value because eventually the desired initial flow is more than the pump can deliver. Flow is therefore limited by the maximum allowed pressure of the pump and cannot reach the desired value. For the baseline value of maximum allowable pump pressure, initial well flow reaches its maximum value at 154 percent and thus the curve for initial well flow rate on figure V-6 ends at this point. To achieve a higher initial well flow, it would be necessary to use a larger pump.

The relationship between initial well flow and maximum wellhead pressure can be understood by examining figure V-7. This shows actual

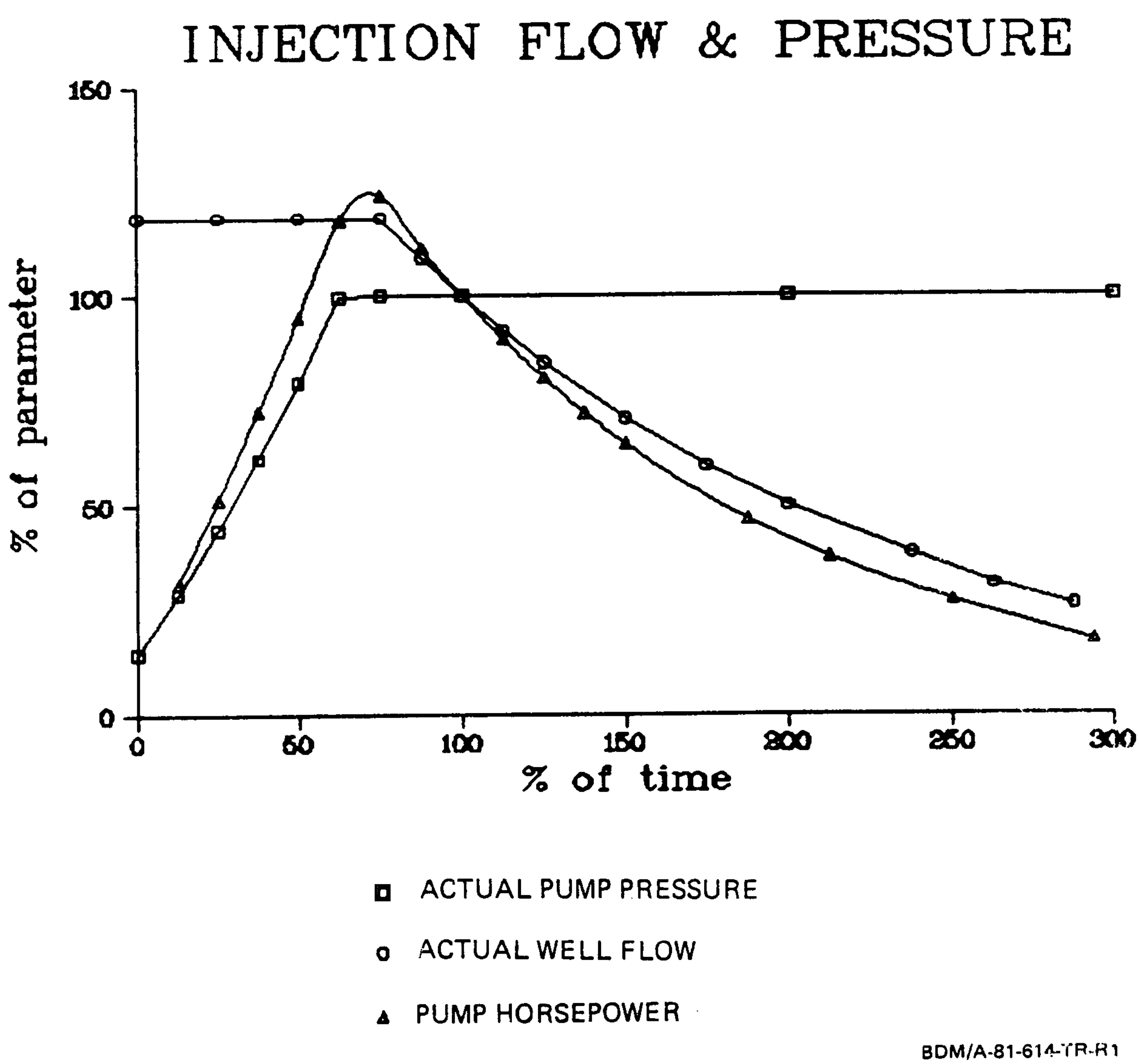


Figure V-7. Injection Flow and Pressure

wellhead pressure and actual well flow rate as a function of time for the baseline values of the parameters. Initially (0 percent on time scale), the well flow is at the desired level and pump pressure is low. As the well is used (50 percent on time scale), the injectivity declines and the pump pressure increases to maintain the desired flow rate. Eventually, a point is reached (67 percent on time scale) where the pump is at maximum pressure and can no longer maintain flow at the desired value. From this point on, the pump remains at maximum pressure but the well flow declines because of the reduced injectivity. This figure also shows the pump horsepower as a function of time.

The high degree of nonlinearity for cost effectiveness as a function of initial well flow in figure V-6 suggests that the actual shape of the curve is a function of the other parameters. In other words, the position of the minimum cost effectiveness ratio as a function of initial well flow is dependent on the values assumed for the other parameters. To investigate this, two additional plots were made: cost effectiveness as a function of well life for various flows and cost effectiveness as a function of initial well flow rate for various "effective depths" to the water table. The first of these graphs is figure V-8 which shows that the cost effectiveness reaches a minimum as a function of flow at about 175 months for high flow rates, decreases to 90 months for 585,000 pounds/hour, and then begins to increase again as the flow rate decreases further.

Figure V-8 shows that for different times (vertical lines), the best initial flow rate changes. For example, if the well is expected to last 90 months, the best initial flow rate is 585,000 pounds/hour but if it lasts longer (150 months), a slightly lower rate (390,000 pounds/hour) may be better. However, the figure also shows that there is an element of risk if the lower rate is used because if the well lasts only 90 months instead of 150 months, the lower flow rate costs more. Similarly, figure V-8 shows that while a 780,000 pounds/hour initial flow rate is less cost effective for well lifetimes greater than 50 months, it is more cost effective for well lifetimes of less than 50 months. This suggests

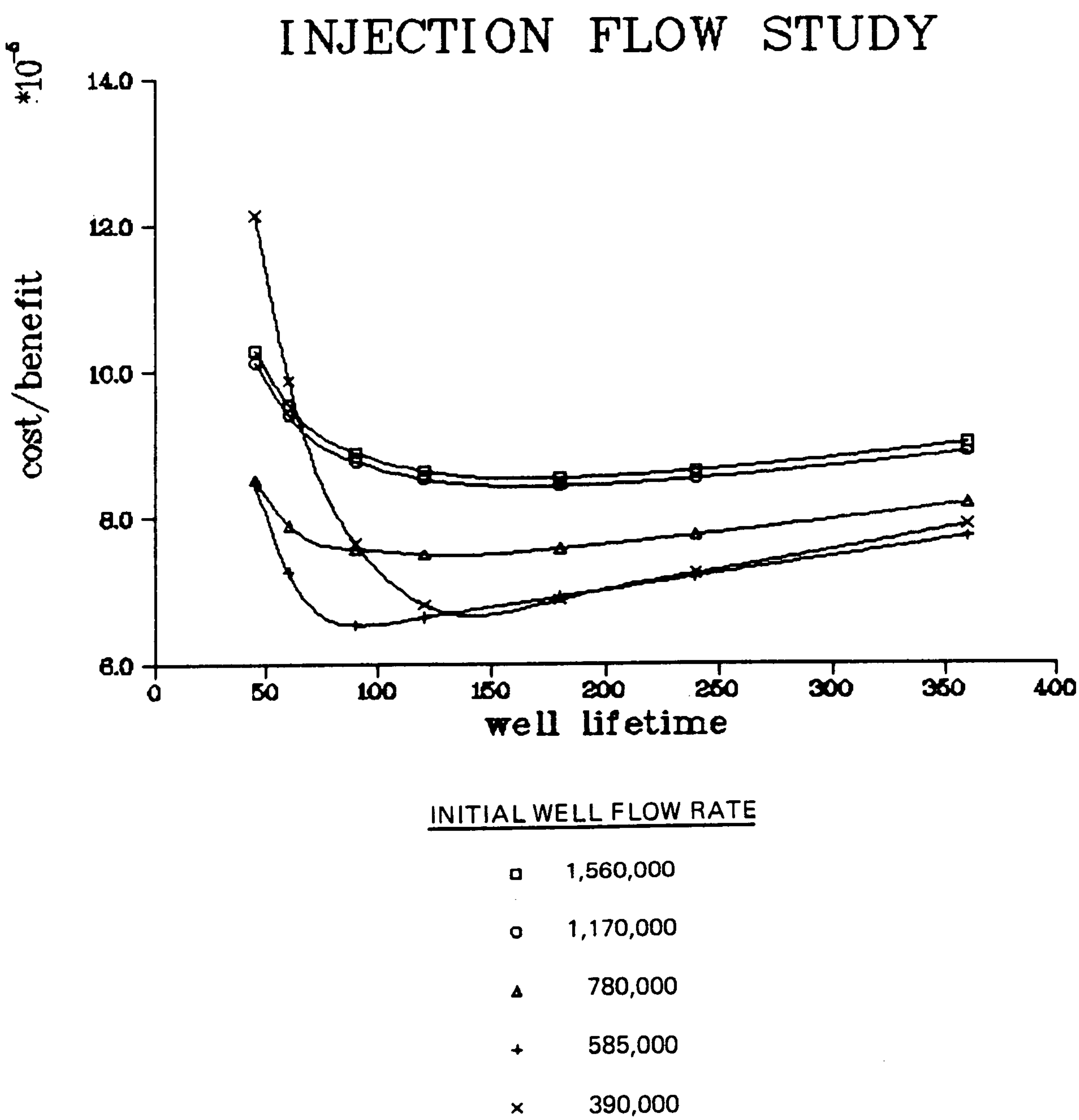


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Figure V-8. Injection Flow Study

such strategies as deliberately starting the well flow high and then allowing it to decline with time. This means adding wells to the injection field at later times.

The final plot of this study (figure V-9) shows cost effectiveness as a function of the initial flow rate for various values of the "effective depth" to the water table. The figure shows that if the "effective depth" is low or high, the choice of flow rate is not as critical. However, for intermediate values of "effective depth" the choice of desired flow rate becomes more important. When the "effective depth" is low, the pump is at its maximum pressure all the time so the desired initial well flow rate cannot be reached. When the "effective depth" is high, the pump does not have to do much work. For intermediate "effective depths" the trade-off between pumping cost and benefit (pounds of fluid injected) becomes critical, as shown by the sharp dip at 600,000 pounds/hour.

The injection pump study illustrates how parameters interrelate to determine cost effectiveness:

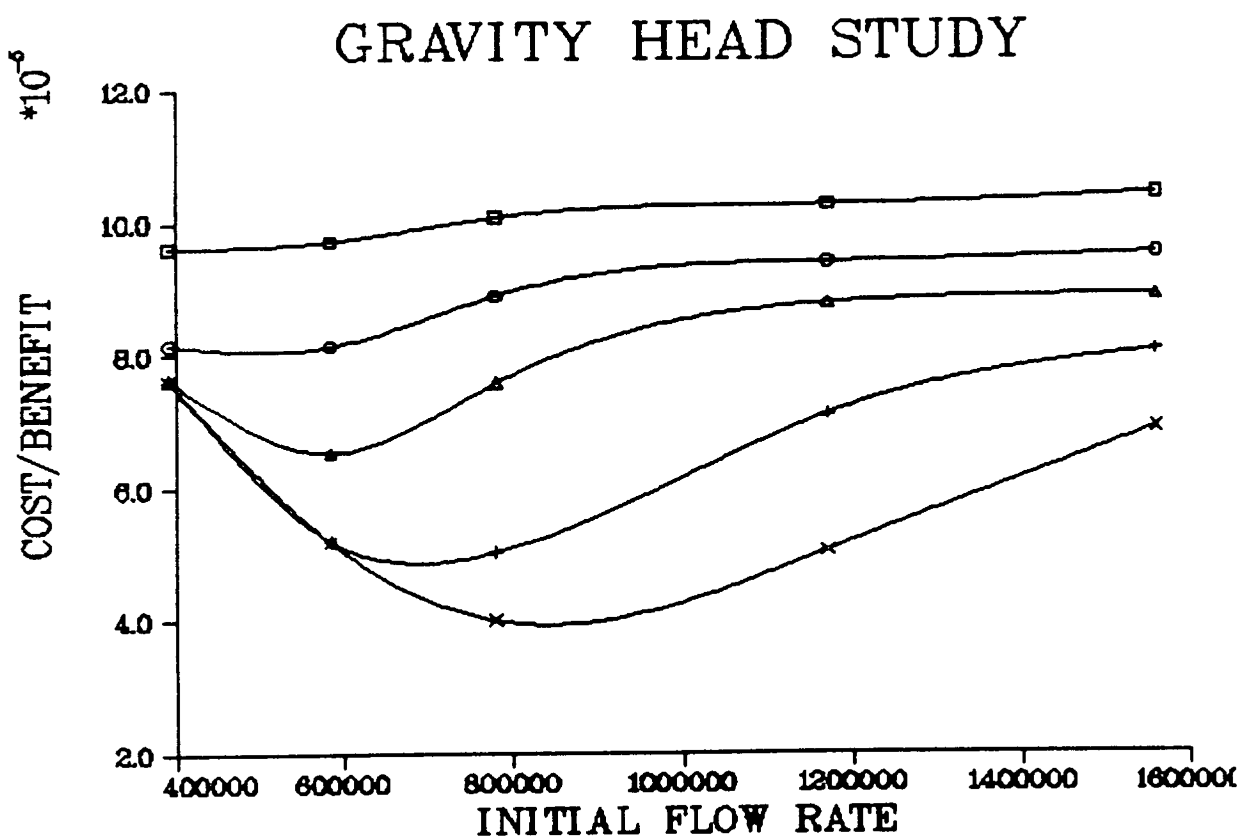
(1) The shapes of the sensitivity curves and interrelationships of the parameters can depend upon the baseline values of the parameters used.

(2) Understanding the dependence of cost effectiveness on the parameters can require a variety of plots to present results.

These points indicate the value of the GEOCOM model. Whereas a single point estimate of cost effectiveness can as easily be made by hand calculations as it can be set up as a GEOCOM model case, GEOCOM can perform repeated calculations and provide the data for plots that help illustrate how cost effectiveness depends on parameters. These plots show important effects that would otherwise not be apparent and which are beyond the scope of hand calculations.

5. Chemical Inhibition Study

The chemical inhibition case is based on the workover study given in chapter VI. Key data are summarized at the top of table V-4. The initial well flow rate has been reduced by 18 percent from the



"EFFECTIVE DEPTH" TO WATER TABLE

□ 820

○ 1,230

△ 1,640

+ 2,460

× 3,280

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Figure V-9. Gravity Head Study

no-scale flow of 200,000 pounds per hour to account for the presence of the satellite tubing in the well. See the section on well performance for the basis of picking 18 percent as the flow loss. The well life has been chosen to be 360 months. The no-scale and mechanical descaling results on table V-4 are for this same well life.

TABLE V-4. CHEMICAL INHIBITION

CASE DATA:

Initial Well Flow Rate	=	164,000*
Cost Per Pound of Chemical	=	$0.97
Chemical Concentration	=	30 ppm
Well Life	=	360 Months

COSTS: CHEMICAL INHIBITION OF SCALE

	CAPITAL COSTS	ROUTINE O&M	COST/POUND
WELL COSTS	$1075290.	7188.$/MO	
INHIBITION SYSTEM	58067.	175.$/MO	.036 MILLS/LB
(DISC + INFLA) TOTAL	$1133357.	1941510.$/WL	729799.$/WL
% OF GRAND TOTAL	29.72%	50.91%	19.13%

COMPARISON TO MECHANICAL DESCALING AND NO SCALE

	NO SCALE	INHIBITION	MECHANICAL DESCALING
Production (Billion Pounds)	31.8	26.0	22.0
LCC/LCB (Mills/lb)	0.121	0.189	0.274

*Reduced 18% from no-scale flow to account for effect of tubing.

The summary of costs on table V-4 shows that the chemical costs are only about 20 percent compared to more than 30 percent workover costs for mechanical descaling. While this suggests that the chemical price or concentration could be higher, inhibition is still a viable way to prevent scale. For the inhibition case, the total production was 82 percent of the no-scale case, whereas for mechanical descaling it is only 69 percent.

In conclusion, the results on table V-4 show that chemical inhibition raises (worsens) the cost effectiveness over no-scale (56 percent), but may be cost-competitive with mechanical descaling. This, of course, will depend upon the parameters that describe the actual well. It should be further noted that it has been assumed that the chemical inhibition will work and that the chemicals will not damage the well. This has yet to be demonstrated.

CHAPTER VI
WORKOVER STUDIES

This chapter contains general or generic workover studies that were analyzed and costed so that a realistic operational history of life cycle costs of a geothermal well can be determined. These studies incorporate more detail than is required to estimate bottom line costs. This detail is necessary to assess how changing technologies will affect workover costs. These studies were used to establish a number of cost estimating relationships or algorithms that have been incorporated into the GEOCOM model.

The studies were:

(1) Mechanical Descaling
(2) Jet Descaling
(3) Cement Squeeze
(4) Well Repair with Tie-Back Liner
(5) Slotted Liner Replacement
(6) Under Ream and Gravel Pack
(7) Chemical Injection
(8) Tubing washover
(9) Hydrofacture
(10) Perforating
(11) N_2 Start-Up
(12) Abandonment

Quotations were obtained from service companies for logging, perforating, and hydrofracture jobs; the latter two are included in this chapter. All quotations from service companies are in 1981 prices current at the time of quotation and are subject to change without notice. The prices are also subject to the service company standard terms and conditions.

For the initial study, mechanical descaling, estimates were made for five different resource areas and three different workover companies.

These variations on mechanical descaling were done to determine the importance of remoteness, service company selected, and reservoir characteristics, etc., as compared to the nature of the scaling problem (i.e., how hard is the scale, where is it located, or will more than one bit run be required because of a change in well diameter). Comparison of these descaling studies revealed that the nature of the scaling problem was far more important than the location of the resource or which service company was selected. Thus for all subsequent studies only one location and service company was considered. Summary data is included for all mechanical descaling studies, but only the Roosevelt Hot Springs study is presented in detail.

These workover studies are trouble-free operations or optimized sequences and are designed for one specific and simple function. Actual workovers may be much more complicated, combining the workovers studied or including trouble. For example, an actual mechanical descaling operation may include not only drilling and reaming out the scale within the casing and liner, but also removing the liner to clean the sandface; or a fishing operation because of some problem during cleanout.

Where service company service rates did not include fuel costs, fuel costs were calculated seperately. This was done using the rule of thumb that fuel consumption is one gallon per hour per cylinder regardless of whether the motor was at maximum output or idling. Cost of fuel was assumed to be one dollar per gallon.

A. MECHANICAL DESCALING

1. General Results

Table VI-1 sets forth a summary of the mechanical descaling studies for the Baca Location, Heber, Northern Nevada Group, and Brawley. Variations in the effect of remoteness is up to 7 percent. Variation in cost per foot due to differences in casing profile, are up to 7 percent when remotness is excluded (i.e., if move-in move-out costs are not included in calculating cost per foot). Variation in the extent of scaling, whether the whole well or only the completion interval need to be descaled, cause as much as 41 percent variations in cost. These results led us to conclude there was little to be gained in trying to perform workover studies separately for each resource area. Therefore, we have presented in this chapter only one location for each workover study.

2. Detailed Results Mechanical Descaling Roosevelt Hot Springs

The following generic well has been on-line with a gradual decline in production. It has 4,000', 9 5/8" casing cemented to surface with a 7" liner hung from 3,750' to T.D. of 5,000', a well-head pressure of 1,000 psi and a bottom hole temperature of 550°F.

After using onsite wireline equipment consisting of sinker bars and a 5 7/8" gauge ring, it was found that the gauge ring could get no deeper than 3,750'. This information infers that scale or some other obstruction has constricted flow at or near the top of the liner.

A well service company in Grand Junction, Colorado, the closest town with service equipment, was contacted to use a workover rig, pump and circulating tank, rental 2 3/8" drill pipe, a power swivel, a 6", 3,000# double hydraulic blowout preventer, a hydraulic stripper head, a bit and casing scraper to do a conventional mechanical descaling operation.

The well was not killed to do the clean-out operation so that the well flow would help keep the scale debris from falling to the bottom of the well.

TABLE VI-1. MECHANICAL DESCALING COMPARISON

BACA MECHANICAL DESCALE

MOVE IN - MOVE OUT	$2,362
RIG UP - RIG DOWN	2,302
DESCALING RIG COST	
UPPER 3750 FEET	4,500
1275 FEET STARTING AT 3750 FEET	3,867
SUPPLEMENTAL EQUIPMENT	11,405
SUB-TOTAL	$24,936
WATER TRUCKING (IF REQUIRED)	900
TOTAL:	$25,836

REMOTENESS FACTOR: 9% (-1% FROM AVERAGE)
COST PER FOOT OF SCALE: $5.14 (-4% FROM AVERAGE OR -2% EXCLUDING REMOTENESS)
INCREASE FOR UPPER SECTION: 21%

HEBER MECHANICAL DESCALING

MOVE IN - MOVE OUT	$2,680
RIG UP - RIG DOWN	2,649
DESCALING RIG COST	
UPPER 7000 FEET	11,312
1050 FEET OF HOLE AT 7000 FEET	6,495
SUPPLEMENTAL EQUIPMENT	14,658
SUB-TOTAL	$37,794
WATER TRUCKING (IF REQUIRED)	180
TOTAL:	$38,974

REMOTENESS FACTOR: 7% (-3% FROM AVERAGE)
COST PER FOOT OF SCALE: $4.84 (-9% FROM AVERAGE OR -5% EXCLUDING REMOTENESS)
INCREASE FOR UPPER SECTION: 41%

NORTHERN NEVADA GROUP MECHANICAL DESCALING

MOVE IN - MOVE OUT	$5,488
RIG UP - RIG DOWN	2,694
DESCALING RIG COST	
UPPER 2750 FEET	4,928
2550 FEET OF HOLE AT 2750 FEET	6,290
SUPPLEMENTAL EQUIPMENT	12,150
SUB-TOTAL	$31,550
WATER TRUCKING (IF REQUIRED)	900
TOTAL:	$32,450

REMOTENESS FACTOR: 17% (+7% FROM AVERAGE)
COST PER FOOT OF SCALE: $6.12 (+15% FROM AVERAGE OR 7% EXCLUDING REMOTENESS)
INCREASE FOR UPPER SECTION: 18%

BRAWLEY MECHANICAL DESCALE

MOVE IN - MOVE OUT	$2,604
RIG UP - RIG DOWN	2,604
DESCALING RIG COST	
UPPER 5000 FEET	3,388
1000 FEET OF HOLE AT 5000 FEET	5,022
SUPPLEMENTAL EQUIPMENT	12,630
SUB-TOTAL	$31,248
WATER TRUCKING (IF REQUIRED)	180
TOTAL:	$31,428

REMOTENESS FACTOR: 8% (-2% FROM AVERAGE)
COST PER FOOT OF SCALE: $5.24 (-2% FROM AVERAGE OR 1% EXCLUDING REMOTENESS)
INCREASE FOR UPPER SECTION: 37%

After the descaling operation, casing and cement evaluation logs were run to verify the integrity of the casing and the cement in the well.

The following sequence of operations is optimized and represents a trouble-free descaling operation. The actual times could vary due to unknown conditions.

In the plans and specifications, rental 2 3/8" drill pipe was used because of availability and good upkeep by the rental company. Drill pipe will withstand transportation shock much better than tubing. Rental tubing is not as available and its mechanical soundness is not as reliable.

As an alternative, a string of 2 7/8" J-55, 6.5#/ft. could be purchased and prorated for one well workover per year for five years. No taxes or depreciation were considered. Thus, tubing would be stored and maintained in the field area and moved to a given well for remedial work as needed.

Rig anchors (dead men) must be installed prior to a workover rig being used, and are included as a one-time purchased item to be used as needed for the life of each well.

a. Mobilization-Demobilization Sequence Mechanical Descaling

The distance from Grand Junction, Colorado, to Roosevelt Hot Springs, Utah, is 325 miles. Due to the weight and size of the equipment, it will take approximately ten hours to make the trip. The rig is overwidth, 10'±, overweight and overheight. This factor calls for special permits and travel is restricted to daylight hours and weekdays on the highway. The overall average speed for the rig is 30-35 miles-per-hour, average speed 32.5 mph.

All equipment - rig, winch truck with float, loaded with power swivel, the circulating tank and pump and other equipment and the crew pickup - will travel in convoy because all pieces must arrive at the well at the same time to be effective.

The scenario for the rig-up operation would be:
Leave yard - Grand Junction - at 0700 hours; travel to location; arrive location approximately 1700 hours (10 hours); start rig-up (2 hours) 1900

hours; shut down for night and drive to town, Beaver (1/2 hour). Next day leave Beaver 0630 hours; drive to rig and arrive 0700 hours (1/2 hour); finish rig-up 1100 hours (4 hours); total rig-up driving time one hour, total rig-up time six hours.

b. Workover Sequence Mechanical Descaling

(1) Move in tubular goods and place on racks in proper position for workover unit. NOTE: Rig anchors already installed.

(2) Set unit, raise mast, anchor rig with guylines.

(3) Set and fill circulating tank.

(4) Close master valve.

(5) Remove production well head to master valve.

(6) Install BOP and stripper assembly.

(7) Measure and tally tubular goods, check for drift with rabbit, visually inspect for shipping damage and internal obstructions.

(8) Pick up first joint tubular goods, make up scraper and bit.

(9) Pick up tubulars, strip in and tag scale.

(10) Pick up and rig-up power swivel.

(11) Ream through obstructed area to total depth.

(12) Circulate to clean up hole.

(13) Strip out of hole, laying down tubulars.

(14) Close master valve.

(15) Rig down BOP and stripper

(16) Install and nipple-up production wellhead.

(17) Open master valve.

(18) Drain all surface equipment.

(19) Load pump, power swivel, BOP, stripping assembly and circulating tank.

(20) Rig down, guylines, lower mast.

(21) Move out all equipment.

(22) See cost time breakdown on the following pages.

c. Cost Analysis Mechanical Descaling Service Company A

	UNIT	RATE	COST	TOTAL COST
MOBILIZATION-DEMOBILIZATION				
Workover Rig	20 hrs	$105.00	$2,100.00	
Fuel Cost Adjustment	20 hrs	3.50	70.00	
Ten-Ton Winch Truck, Float & Driver	20 hrs	55.00	1,100.00	
Pickup, Crew Transport	20 hrs	75.00	1,500.00	
Subsistence/Man/Day (4 men)	2 days	45.00	360.00	
				$ 5,130.00
RIG UP AND RIG DOWN				
Workover Rig	12 hrs	$105.00	$1,260.00	
Fuel Adjustment	12 hrs	3.50	42.00	
Ten-Ton Winch Truck, Float & Driver	12 hrs	55.00	660.00	
Pickup, Crew Transport	1 day	75.00	75.00	
				$ 2,037.00
DESCALING				
Pick-up First Joint, Makeup BHA	.25 hrs	$105.00	$26.25	
Strip in Hole @500'/hr	7.50 hrs	105.00	788.00	
Wash & Ream Scale @150'/hr.	8.00 hrs	105.00	840.00	
P.O.O.H. Laying Down @500'	10.00 hrs	105.00	1,050.00	
Lay down BHA	.25 hrs	105.00	26.25	
Fuel Cost Adjustment	26.00 hrs	3.50	90.50	
				$ 2,821.00
SUPPLEMENTAL EQUIPMENT				
Drill Collars 4-4 3/4" OD	5.0 Days Min.		$ 100.00	
Power Swivel S-2.5	3.0 Days	$475.00	1,425.00	
Duplex Pump	3.0 Day Min.	375.00	1,125.00	
BOP 6", 3,000# DBL Hydraulic	5.0 Day Min.	40.00	200.00	
Hydraulic Stripper Head 3,000#	5.0 Day Min.	37.00	185.00	
100 bbl Circ. Tank	5.0 Day Min.	40.00	200.00	
Thread Dope per trip		22.00	22.00	
Bit (purchased)		520.00	520.00	
Casing Scraper (rental)	Per Run	300.00	300.00	
*Casing Scraper Drayage	650 Miles	.80	520.00	
5,000', 2 3/8", 6.65#, "E" Drill (Pipe Per Foot/Day)	4 Days	0.0725	1,450.00	
Round Trip Drayage - Drill Pipe & Collars	73,000#	5.25/cwt.	3,833.00	
Pipe Racks (2 sets)	4 Days	16.00	128.00	
Wet Pay (4 Men)	4 Days	12.00	192.00	
Subsistence (4 Men)	4 Days	45.00	720.00	
Permits, Replacement Elastomers	(Contingencies)		900.00	
				$11,820.00

*NOTE: If Brought With Rig Delete

d. Cost Analysis Mechanical Descaling Service Company B

	UNIT	RATE	COST	TOTAL COST
MOBILIZATION-DEMOBILIZATION				
Workover Rig	20 hrs.	$ 108.00	$ 2,160.00	
Ten-Ton Winch Truck, Float & Driver	20 hrs.	55.00	1,100.00	
Pickup, Crew Transport	20 hrs.	75.00	1,150.00	
Subsistence/Man/Day (2 days)		40.00	320.00	
				$ 5,080.00
RIG UP AND RIG DOWN				
Workover Rig	12 hrs.	$ 108.00	$ 1,296.00	
Ten-Ton Winch Truck, Float & Driver	12 hrs.	55.00	660.00	
Pickup, Crew Transport	1 hrs.	75.00	75.00	
				$ 2,031.00
DESCALING				
Pick-up First Joint, Makeup BHA	.25 hrs.	$ 108.00	$ 27.00	
Strip In Hole @ 500'/hr.	7.50 hrs.	108.00	810.00	
Wash & Ream Scale @ 500'/hr.	8.00 hrs.	108.00	864.00	
P.O.O.H. Laying Down @ 500'/hr.	10.00 hrs.	108.00	1,080.00	
Laydown BHA	.25 hrs	108.00	27.00	
				$ 2,808.00
SUPPLEMENTAL EQUIPMENT				
Drill Collars 4-4 3/4" OD	5 Days Min.		$ 100.00	
Power Swivel S-25	3 Days	$450.00	1,350.00	
Duplex Pump	3 Days	225.00	675.00	
BOP 6", 3,000#, Hydraulic	3 Days	55.00	165.00	
Stripper included w/Pump				
Thread Dope included w/Rig				
Bit (purchased)			520.00	
Casing Scraper (rental)	Per Run	300.00	300.00	
Casing Scraper Drayage	650 Miles	.80	520.00	
5,000', 2 3/8", 6.65#, "E" Drill (Pipe Per Foot/Day)	4 Days	0.0725	1,450.00	
Round Trip Drayage - Drill Pipe & Collars	73,000#	5.25/cwt.	3,833.00	
Pipe Racks (2 Sets)	4 Days	15.00	120.00	
Wet Pay Per (4 Men)	4 Days	15.00/day	240.00	
Subsistence (4 Men)	4 Days	40.00/day	640.00	
Permits, Replacement Elastomers	(Contingencies)		900.00	
				$10,813.00

NOTE: If brought with rig, delete

FUEL COSTS		NO. CYLINDERS	NO. HOURS	COST	TOTAL
Move In - Out Rig		8	20	$160.00	
Rig Up - Rig Down		8	12	96.00	
Trips, Etc.	Rig	8	36	288.00	
	Pump	6	36	216.00	
					$760.00

e. One Time Cost Items Mechanical Descaling

	UNIT	RATE	COST	TOTAL COST
DEAD MAN ANCHORS WITH MARKERS				
Rig Anchors Installed (4)		$ 375.00	$ 375.00	
Anchor Markers Installed	4	4.00	16.00	
Mileage Round Trip	960 Miles	.40	384.00	
Subsistence 2 Men	2 Days	40.00	160.00	
				$ 935.00
ALTERNATE TO DRILL PIPE RENTAL				
BUY 2 7/8" TUBING AND LEAVE IN THE FIELD TO BE USED FOR FUTURE REMEDIAL WORK, EXPECTED LIFE - 5 YEARS				
Trucking (in field)	2 Hours	$ 55.00	$ 110.00	
5,000', 2 7/8" J-55, 6.5#/ft.	Per 100'	379.59	18,979.50	
Tubing Drayage (32,500#)	Per cwt.	5.25	1,706.25	
Pipe Racks - 2 sets	Per Set	700.00	1,400.00	
				$22,085.75

PRORATED COST OF ALTERNATE TO DRILL PIPE RENTAL

	TOTAL COST	YEARLY COST
Purchase 2 7/8" Tubing Leave in Field for Maintenance Use	$22,085.75	
Cost/Year for 5 Years		$ 4,417.15
In-Field Trucking ea. Use		110.00
TOTAL		$ 4,527.15

WATER

	UNIT	RATE	COST	TOTAL COST
IF WATER REQUIRED HAULED TO FILL CIRCULATING TANK				
One Water Truck	8 Hours	$ 45.00	$ 360.00	
				$ 360.00

f. Summary of Mechanical Descaling Costs Roosevelt Hot Springs

MECHNICAL DESCALING WITH RENTED TUBULARS

	SERVICE COMPANY A	SERVICE COMPANY B
Move In - Out	$ 5,130.00	$ 5,080.00
Rig Up - Rig Down	2,037.00	2,031.00
Descaling, Rig Cost	2,821.00	2,808.00
Supplemental Equipment	11,820.00	10,813.00
Fuel Costs	0.00	760.00
SUB-TOTAL	$21,808.00	$21,492.00
Water Trucking (if required)	360.00	360.00
TOTAL	$22,168.00	$21,852.00

MECHANICAL DESCALING WITH PURCHASED TUBULARS

Total Cost WO w/Rental Pipe	$22,168.00	$21,852.00
Less Rental Pipe	1,450.00	1,450.00
Less Drayage	3,491.00	3,419.00
Less Pipe Rack Rental	128.00	120.00
SUB-TOTAL	$17,099.00	$16,863.00
Own Tubing Used (plus)	4,527.00	4,527.00
TOTAL	$21,626.00	$21,390.00
Difference Rental vs Own (Tubulars)	542.00	462.00

B. JET DESCALING

For jet descaling the same Roosevelt Hot Springs well characteristics were assumed. This well has 4000 feet of 9 5/8 casing with a 7" liner. Scale is assumed to be confined to the inside of the liner and does not extend into the casing. The jet descaling would require the same workover rig, rental drill pipe, power swivel (maximum circulating pressure 5000 psi) as the mechanical descaling. Additionally, it would require a jet head and a high pressure Triplex pump (fract pump).

1. Hydraulic Program

(1)	Mud Weight (lb./gal.)	8.3
(2)	Plastic Viscosity (CPS)	3.0
(3)	Yield Point (lb./100 ft^2)	0
(4)	Stand pipe pressure	4000
(5)	Optimum Flow Rate (bbls/min)	4.8
(6)	Desired Flow Rate (bbls/min)	6.0
(7)	Nozzles (1/32")	10,10,9
(8)	Head Diameter	6.125"
(9)	Drill String O.D.	2.375"
(10)	Annular Velocity FPM	194
(11)	Pressure Loss at Head (psi)	1048
(12)	Percent Pressure Loss at Head	26
(13)	Jet Velocity (FPS)	375
(14)	Head Hydraulic Impact Force (lb)	405
(15)	Head Hydraulic Horsepower (HP)	154
(16)	Head Hydraulic Horsepower (HP/in)	5.2
(17)	Pump Hydraulic Horsepower (HP)	588

2. Cost Analysis Jet Descaling

PUMP TRUCK

Mobilization	334 miles	$ 2.00	$668.00	
Subsistence 2 men	1 day	75.00	150.00	
				$ 818.00

TIME-COST JET DESCALING WORKOVER RIG & PUMPER

P.U. first joint, make up BHA	.25 hours	$108.00	$ 27.00	
Strip in hole @500'/hr.	7.50 hours	108.00	810.00	
Jet Descale @50'/hr.	25.00 hours	108.00	2,700.00	
P.O.O.H. Laying Down @500'/hr.	10.00 hours	108.00	1,080.00	
Lay down BHA	.25 hours	108.00	27.00	
Pump truck 1st 4 hours			521.00	
Pump truck after 4 hours	21 hours	102.00	2,142.00	
Rig, wet pay (4 men)	4 days	15.00	240.00	
Rig, subsistence (4 men)	4 days	40.00	640.00	
Pumper, subsistence (2 men)	4 days	75.00	600.00	
				$ 8,787.00

SUPPLEMENTAL EQUIPMENT

Power Swivel S-25	4 Days	$450.00	$1,800.00	
BOP 6", 3,000#, w/stripper	4 Days	55.00	220.00	
Circulating tank	4 Days	225.00	900.00	
5,000', 2 3/8", 6.65#, "E" drill pipe (per ft./day)	4 Days	0.0725	1,450.00	
Round trip drayage - drill pipe	66,500#	5.25cwt	3,491.00	
Pipe racks (2 sets)	4 Days	15.00	120.00	
Jet Descale head-first, 8 hrs.			713.00	
Jet Descale head	17 Hours	34.00	578.00	
Water	100 bbls.	.50 bbl	50.00	
Travel time rig crew	4 Hours	75.00	300.00	
Travel pump crew per mile	200 Miles	.80	160.00	
Replacement elastomers, permits (contingencies)			978.00	
				$10,760.00

FUEL COSTS	NO. CYLINDERS	NO. HOURS	COST	TOTAL
Move In - Out Rig	8	20	$160.00	
Rig Up - Down Rig	8	12	96.00	
Trips, Etc. Rig	8	43	344.00	
				$600.00

3. Summary of Jet Descaling Costs

JET DESCALING

Workover rig mob.-demob. (See Mechanical Descaling for details)	$ 5,080.00
Rig up, rig down (See Mechanical Descaling for details)	2,031.00
Pump truck mobilization	818.00
Descaling time-cost, rig & pumper	8,787.00
Supplemental Equipment	10,760.00
Fuel Costs	600.00
TOTAL	$28,076.00

Remoteness Factor $\frac{5,080}{28,076} = 18\%$

C. REMEDIAL CEMENT SQUEEZE JOB

The following generic well at Roosevelt Hot Springs has 4,000', 9 5/8", J-55 buttress casing cemented to surface. A 7" flush joint liner has been hung and cemented from 3,750' to 5,000' (T.D.). The shut-in well-head pressure is 1,000 psi.

There has been a drop in production and a loss of temperature. A laboratory analysis of the production water shows change in the chemical makeup of the water.

A wireline survey of the hole with sinker bars and a gauge ring went to bottom at 5,000' with no problems; therefore, scale buildup doesn't appear to be the problem. A Kuster temperature survey was run from the surface to total depth and a cooler than normal temperature was recorded at 3,500'. Then a detail run was made to 3,900' to 3,500'. A review of drilling records showed a cold water influx in this interval.

A wireline logging company was called to run a casing survey of the well. This log confirmed a crack in the casing. A cement bond log was also run and it showed cement deterioration from 3,500' to 3,600'.

A cement squeeze was planned to repair the faulty cement and to shut off the cold water flow.

A cementing company in Cortez, Colorado, the nearest service facility (334 miles distant) was contacted and plans for the work were initiated.

1. Cement Squeeze Mobilization-Demobilization

A pump truck, a bulk truck, a special tools operator, and a cementer (foreman) were dispatched. The special tools are a retrievable bridge plug with setting tool, and an RTTS packer.

A total amount of 25 sacks of cement was calculated to be used with an excess of 50 percent. The bridge plug was to be set at 3,740' (10 feet above the top of the liner hanger), five sacks (11.7') of sand was to be spotted on top of the retrievable bridge plug to keep cement away from the plug and facilitate removal when the job was completed.

The travel time from Cortez to the well is 11 hours. Therefore, the crew must be paid subsistence for approximately 2 days - one day to drive to location and one day to do the job. The tools operator must stay one more day to retrieve the packer and plug after the tools are removed from the well.

The cement to be used with this squeeze job has a thickening time of 3 hours and 55 minutes at 550°. The specifications are:

Class "G" Cement, 1 cubic foot Perlite (1:1), 40% SSA-1 (Silica Flour), 3% Gel, 0.5% CFR-2, 0.4% HR-12.

Water Ratio: 1.30 cubic feet water/sack.

Slurry Volume: 2.12 cubic feet/sack.

Weight: 13.5 lb./gal.

This particular type cement slurry has been used successfully in the Geysers KGRA, and will work as well in this area. The rather long thickening time was used to diminish the possibility of "flash" setting before the squeeze was completed. If premature setting occurred, the well could be lost or a very expensive fishing job could result.

The bridge plug and the packer are set away from the squeeze area to avoid cementing the pipe in the hole or plugging the tubing (see figure VI-1).

The cementing crew would stay one night in Beaver, Utah, after the successful completion of the squeeze job.

2. Cement and Water Required for Remedial Cementing

Capacity Tubing: 0.00579 bbls/lin. ft.
Capacity 9 5/8" casing: 0.0758 bbl/lin. ft.

3,450' tubing holds 3,450 x 0.00579 = 19.98 bbls (20).
50', 9 5/8" casing holds 50 x .0758 = 3.79 bbls (4).
Total Water To Displace Cement = 24 bbls.

100', 9 5/8" casing holds 100 x .0758 = 7.58 bbls (8).
50% excess = 50 x .0758 = 3.79 bbls (4).
Total Cement = 12 bbls.

12 bbls x 2.45 yield = 25 sacks.

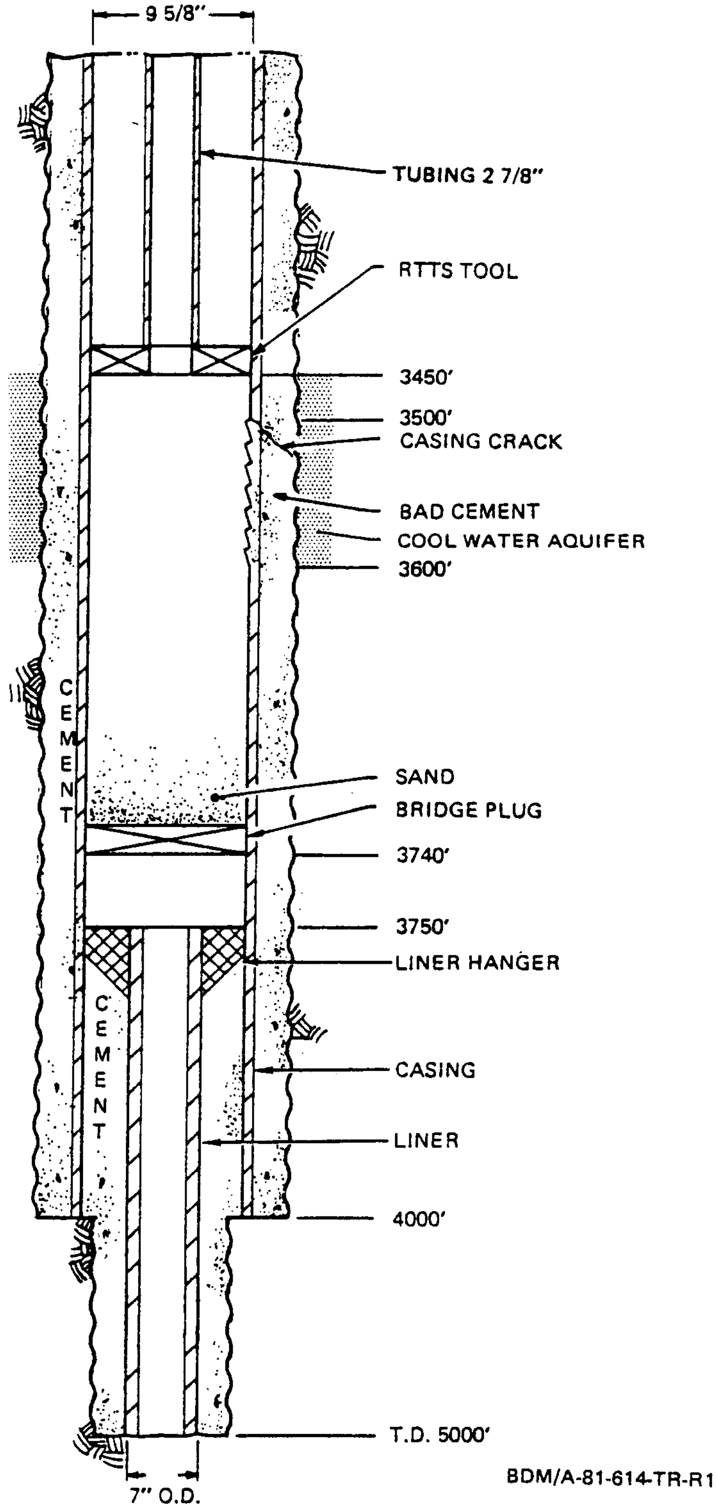


Figure VI-1. Cement Squeeze at Roosevelt Hot Springs, Utah

3. Operations Initial Squeeze for Remedial Cementing

(1) Schedule all equipment.
(2) Move in tubing from storage area and place on racks for use by workover rig. From storage area (4 hours).
(3) Move in workover rig, pump, circulating tank, and power swivel (6 hours).
(4) Move in cementing equipment (cement mobilization).
(5) Go in hole with retrievable bridge plug, setting tool and tubing. Set bridge plug at 3,740' at 400'/hour (9 hours).
(6) Set bridge plug, pick up to 3,725', pump down 5 sacks sand (11.7'". Pump at least 285 bbls cold water to cool hole (1 1/2 hours).
(7) P.O.O.H. Lay-down setting tool (1 1/2 hours).
(8) G.I.H. to 3,450', set RTTS packer at 60 ft/min (1 hour).
(9) Close pipe rams, pressure test casing and RTTS to 1,000 psi (1/4 hour).
(10) Mix and pump cement at 3 bbls/min. followed by 24 bbls water (1/4 hour).
(11) Squeeze:
Pump 2 bbls water, wait 1/4 hour.
Pump 2 bbls water, wait 1/4 hour.
Pump 2 bbls water, wait 1/4 hour.
Pump 2 bbls water, wait 1/4 hour.

If pressure builds up to 2,500 psi and holds at this point, stop. If pressure bleeds off, pump 2 bbls water (or any portion), stop at 2,500 psi, wait 1/4 hour. If pressure bleeds off, repeat, pumping until total 12 bbls cement is displaced (1/4 hour).
TOTAL (maximum) 1 1/2 hours.
(12) Slowly release pressure on tubing. If it goes to zero and stays, the squeeze was a success (1/4 hour).
(13) Release casing annulus pressure, reverse circulate 22 bbls water to flush tubing and RTTS of possible cement (1/4 hour).
(14) Reset RTTS, pressure casing annulus and tubing to 1,000 psi, wait on cement (12 hours).
(15) Release pressures (1/4 hour).
(16) Release RTTS, P.O.O.H. stand-back tubing. Lay down RTTS (2 1/2 hours).
(17) Pick up bit, G.I.H. to 3,450' (2 1/2 hours).
(18) Wash and ream to 3,740' (2 hours).
(19) Circulate bottoms-up to clean out sand and cement fragments (1 1/2 hours).
(20) P.O.O.H., stand-back tubing lay-down bit (2 1/2 hours).
(21) Pick up setting tool, G.I.H. to 3,740' (2 1/2 hours).
(22) Latch onto retrievable bridge plug, P.O.O.H. laying-down tubing (4 hours).
(23) Load out RTTS, setting tool and bridge plug. Rig down workover equipment (6 hours).
(24) Clean up location, move tubing back to storage (5 hours).

TOTAL = 71.24 hours
12 Hour Days 5.94 days - 6 Days

4. Repeating the Cement Squeeze

It is not unexpected that the squeeze job will not be successful the first time - 100' is a long interval to fully squeeze in one step, due to the apparent high permeability and low formation pressure. The hydrostatic pressure of water @ 3,600' is 8.3 x .052 x 3,600 = 1,553.8 psi or 1.432 psi/ft. The cement used for the squeeze job weighs 13.5 lb./gal. and has a hydrostatic pressure of 3,600' x .052 x 13.5 = 2.527.2 psi or 0.702 psi/ft. The over-pressure is 2,527.2-1,553.8 = 973.4 psi or 0.279 psi/ft. This over-pressure is enough to make the cement invade only the bottom portion of the open casing without applying any pressure at the surface. If this occurs, more cement must be emplaced after a 10-12 hour waiting period, to set the first batch of cement.

The cement will go to the point of least resistance first and progressively follow until equilibrium is achieved. Subsequent batches of cement could be larger by 50 percent than original 25 sacks to complete the squeeze.

The success ratio of squeezing the 100' interval, as diagramed, could be one chance in five. At that interval it is very difficult to control placement and pressure, due to the very low pressure gradients in hydrothermal wells.

5. Cost Analysis Initial Cement Squeeze

	UNIT	RATE	COST	TOTAL COST
CEMENT EQUIPMENT MOBILIZATION				
Mileage, one way				
One Pump Truck	334	2.00	668.00	
One Bulk Truck	334	2.00	668.00	
Subsistence, 3 Men/Day/Man	2 Days	75.00	450.00	
				$1,786.00
CEMENT COSTS				
Class "G" Sacks	7.0125	6.02	44.22	
Perlite 1:1 cu. ft.	7.0125	2.25	15.28	
40% SSA (Silica Flour)				
Sack 70#	700 lb.	.105/lb.	73.50	
3% Gel Sack	.75 sx	7.35	5.51	
0.05% CFR-2 Sack 43#	.125 sx	3.40/lb.	18.28	
0.4% HR-12 Sack 23.2#	.1 sx	2.10/lb.	4.87	
Water bbl (42 gal.)	7.47 bbl	.50	3.74	
				$ 163.90
CEMENTING EQUIPMENT				
Depth Charge: 3,000 to 5,000' per unit, $1,219.00 plus per 100' or fraction below 3,000'-$10.55/unit for first 8 hours.				
One Pump Truck	8 hours	1,219.00	1,219.00	
Footage below 3,000' (450')	8 hours	10.55	47.48	
One Bulk Truck	8 hours	1,219.00	1,219.00	
Footage below 3,000' (450')	8 hours	10.55	47.48	
Each additional 8 hrs. or fraction thereof per unit $1,160.00	9 hours	1,160.00	2,610.00	
Retrievable Bridge Plug	8 hours	1,161.00	1,161.00	
After 8 hrs. $34/hr.	33 hours	34.00	1,122.00	
RTTS Tool, first 8 hr.	8 hours	1,230.00	1,230.00	
After 8 hrs. ea $34/hr.	33 hours	34.00	1,122.00	
Sand 11.7	5 sacks	6.00/sx	30.00	
Mileage Tool Operator	334 miles	.80	267.20	
Subsistence, 3 men	1 Day	75.00	225.00	
Subsistence, 1 Man (tool operator)	3 Day	75.00	225.00	
				$10,524.00
WORKOVER RIG MOBILIZATION-DEMOBILIZATION				
Workover Rig	20 hrs	108.00	2,160.00	
10-ton winch truck,	20 hrs	55.00	1,110.00	
Pick up, crew transport	20 hrs	75.00	1,500.00	
Subsistence/man/day	2 Days	40.00	320.00	
				$5,080.00

5. Cost Analysis Initial Cement Squeeze (Continued)

	UNIT	RATE	COST	TOTAL COST
RIG UP - RIG DOWN				
Workover Rig	12 hrs	108.00	1,296.00	
10-ton winch truck	12 hrs	55.00	660.00	
Pick up, crew transport	1 day	75.00	75.00	
				$2,031.00
WORKOVER RIG TIME COST-SQUEEZING				
Go in hole w/tubing & Bridge plug @400'/hr	9 hrs	108.00	972.00	
Set plug, circulate	1½ hrs	108.00	162.00	
POOH lay-down setting tool	1½ hrs	108.00	162.00	
GIH set RITS	1 hr	108.00	108.00	
Mix cement squeeze	1½ hrs	108.00	162.00	
Reverse circulate	½ hr	108.00	54.00	
W.O.C.	12 hrs	108.00	1,296.00	
Release pressures	¼ hr	108.00	27.00	
POOH lay-down RTTS	2½ hrs	108.00	270.00	
PU setting tool, GIH	2½ hrs	108.00	270.00	
Wash & ream	2 hrs	108.00	216.00	
Circulate	1½ hrs	108.00	162.00	
POOH stand-back tubing	2½ hrs	108.00	270.00	
PU setting tool, G.I.H.	2½ hrs	108.00	270.00	
Release bridge plug POOH	4 hrs	108.00	432.00	
Laying down tubing	-	-	-	
Subsistence/man/day 4 men	5 days	40.00	800.00	
Pick up, crew transport	4 hrs	75.00	300.00	
Contingencies			593.00	
				$6,526.00
SUPPLEMENTAL EQUIPMENT				
Power swivel - 52.5	7 days	450.00	3,150.00	
Duplex pump	7 days	225.00	1,575.00	
BOP 10" double hydraulic	10 day min.	107.00	1,070.00	
Stripper	10 day min.	530.00	530.00	
Bit (purchased)		710.00	710.00	
2 7/8" tubing (owned)			4,417.00	
Infield trucking	8 hrs	55.00	440.00	
Contingencies (10%)			1,189.00	
				$13,081.00

FUEL COSTS	NO. CYCLINDERS	NO. HOURS	COST	TOTAL
Move In - Out Rig	8	20	$160.00	
Rig Up - Down Rig	8	12	96.00	
Trips, Etc. Rig	8	20.5	164.00	
				$420.00

WATER TRUCKING (IF NECESSARY)	UNIT	RATE	COST	TOTAL
Water truck	12 hrs	45.00	540.00	
				$540.00

6. Summary of Costs for Initial Cement Squeeze

	COST	SUB-TOTAL	TOTAL
CEMENT AND CEMENT EQUIPMENT COSTS			
Mobilization	1,786.00		
Cement	164.00		
Equipment & Operation	10,524.00		
		12,474.00	
WORKOVER RIG			
Mobilization-Demobilization	5,080.00		
Rig Up - Rig Down	2,031.00		
Rig (squeezing)	6,526.00		
Supplement Equipment	13,081.00		
Fuel Costs	420.00		
		27,138.00	
WATER TRUCK (If Required)	540.00		
		540.00	
			$40,152.00

REMOTENESS FACTOR

$$\frac{\text{Mobilization}}{\text{Total Cost}} \quad \frac{6,866}{40,152} = 17\%$$

7. Cost Analysis of Repeating Cement Squeeze

	UNIT	RATE	COST	TOTAL COST
CEMENT				
50% over original mixture	1.5	163	$ 225.00	$ 225.00
CEMENTING EQUIPMENT				
Each additional 8 hrs. or fraction thereof per unit $1,160.00	14 x 2/8	1160	4060.00	
Retrievable Bridge Plug After 8 hrs. $34 ea. hr.	14	34	476.00	
RTTS Tool, first 8 hrs. After 8 hr. ea. $35/hr.	14	34	476.00	
Subsistence 3 men	1 day	75.00	225.00	
Subsistence 1 man (tool operator)	1 day	75.00	75.00	
				$5,312.50
WORKOVER RIG TIME COST-SQUEEZING				
Mix cement squeeze	1½	108.00	162.00	
Reverse circulate	½	108.00	54.00	
W.O.C.	12	108.00	1,296.00	
Release pressures	½	108.00	27.00	
				$1,539.00
GRAND TOTAL				$7,076.00

D. <u>WELL REPAIR WITH TIE-BACK LINER</u>

For this workover the same well and problem as for the cement squeeze job has been assumed, and it has been assumed that the squeeze was unsuccessful. Therefore, a decision was made to run a tie-back liner and cement it in over the crack in the casing. The configuration for that well was 4000' of 9 5/8, J-55 buttress casing cemented to the surface with a 7" flush joint liner hung and cemented from 3750' to 5000' (TD). The crack in the casing is from 3500' to 3600'

When the squeeze job was unsuccessful, the rig was removed from the hole, but the bridge plug left in the hole, while the decision to run the liner was being made, and while the tubular goods were being obtained. If the tubulars were on hand and the decision was made immediately, the mobilization-demobilization and rig-up rig-down costs can be eliminated.

1. <u>Operations Required for Well Repair with Tie-Back Liner</u>

(1) Go in hole to bridge plug wash and ream as necessary, trip-out (6 hours).
(2) Go in hole with bridge plug unlatching tool, retrieve bridge plug, if it will not unseat, P.O.O.H. (5 hours).
(3) Go in hole with bit, drill out bridge plug, wash and ream, to liner hanger, trip out of hole (10 hours).
(4) Go in hole with 6" retrievable, drillable bridge plug, reset 50± feet below liner hanger. Spot 3 sacks (3 cu. ft. x 4.794 ft./cu. ft. = 14.4') sand on top of bridge plus, P.O.O.H. (6 hours).
(5) Go in hole with tie-back bowl scraper. Ream and clean any scale and debris from tie-back bowl. P.O.O.H. (6 hours).
(6) Inspect, tally, and prepare 7", 26#, K-55 buttress casing to run to 3,750' (1 hour).
(7) Make up tie-back extension on bottom of bottom joint of casing with centralizer at mid-point of first joint @ first collar and each collar next 8 joints. (total 9 centralizers up to 3,390' ±), two-stage cementing tool @ 3,600'±.
(8) Go in hole with 7" tag liner hanger, set string into liner hanger while pumping water. Watch pressure when it starts to pressure up (+250-500 psi). Pick up 2-3 feet, pump pressure rise indicates tie-back mandrel is engaged in liner hanger (6 hours).
(9) Pump cement, displace with water, do not over-displace (1/2 hour).
(10) Set casing down into tie-back bowl (1/4 hour).
(11) Drop stage collar opening plug, circulate through stage tool until first stage cement takes initial set (6 hours).

(12) Run second stage cement, drop stage collar closing plug, displace with water, close stage tool with 2,5000-3,000 psi pump pressure, wait 15 minutes, check backflow, if 1 bbl or less, stage tool has closed (1 hour).
(13) If good cement returns, and have no fall-back, 7" is cemented in place, and casing leak is repaired.
(14) Put 7" in tension, set in slips, W.O.C. (12 hours).
(15) Cut off 7" nipple up B.O.P. and hydraulic stripper head (4 hours).
(16) Go in hole, with 6" bit, cleanout, cement, plugs, stage collar, plugs, cement to bridge plug, P.O.O.H. (8 hours).
(17) Pick up bridge plug retrieving tool, G.I.H. retrieve bridge plug P.O.O.H. (6 hours).
(18) Nipple down B.O.P. stack, nipple up production head (6 hours).
(19) Flow well if possible (5 hours).
(20) Rig down and release rig (6 hours).
(21) If well will not flow, use N_2 start-up.

2. Cost Analysis Well Repair with Tie-Back Liner

	UNIT	RATE	COST	TOTAL COST
RIG TIME COST				
G.I.H. Wash Ream P.O.O.H.	6.00 hrs.	$108.00	$ 648.00	
Retrieve Bridge Plug	5.00 hrs.	108.00	540.00	
Drill Out Bridge Plug	10.00 hrs.	108.00	1,080.00	
Set 6" Retrievable Plug	6.00 hrs.	108.00	648.00	
Clean Liner Hanger	6.00 hrs.	108.00	648.00	
Inspect Pipe 2 Men	1.00 hr.	15.00	30.00	
G.I.H. w/7"	6.00 hrs.	108.00	648.00	
Pump Cement	.5 hr.	108.00	54.00	
Set Casing	.25 hrs.	108.00	27.00	
Circulate Hole	6.00 hrs.	108.00	648.00	
Run Second Stage Cement	1.00 hr.	108.00	108.00	
W.O.C.	12.00 hrs.	108.00	1,296.00	
Cut Off 7" Nipple Up	4.00 hrs.	108.00	432.00	
G.I.H. Cleanout	8.00 hrs.	108.00	864.00	
Retrieve Bridge Plug	6.00 hrs.	108.00	648.00	
N.D. BOP N.U. Production Equipment	6.00 hrs.	108.00	648.00	
Flow Well	5.00 hrs.	108.00	540.00	
Rig Down	6.00 hrs.	108.00	648.00	
Subsistence 3 Men	8 Days	40.00	960.00	
Crew Transport	8.00 hrs.	75.00	600.00	
Contingencies 10%			1,172.00	
				$12,887.00
SUPPLEMENTAL EQUIPMENT (RIG)				
Power Swivel S 2.5	8 Days	$ 450.00	$ 3,600.00	
Duplex Pump	8 Days	225.00	1,800.00	
BOP 10" Double Hydraulic	8 Days	107.00	856.00	
Stripper	10 Day Minimum		530.00	
				$ 6,786.00
CEMENT				
Cement "G" Sacks	197	6.02	1,186.00	
Perlite 1:1 Cu. Ft.	196	2.25/cu.ft.	441.00	
SSA Sack 70# (28 cu.ft.)	19,670 lb.	.105/lb.	2,065.00	
Gel	21	7.35	154.00	
CFR-2 Sack 43#	172 lb.	3.40/lb.	585.00	
HR-12 Sack 23.2#	70 lb.	2.10/lb.	147.00	
Water bbls	53	.5	27.00	
				$ 4,605.00
CASING				
7" 26#/ft. N-55 Butt.	3,750.00	1,200.07/c	45,003.00	
Trucking	97,500.00	5.75/cwt.	5,606.00	
				$50,609.00
SAND PAD				
3 Cu. Ft.	3 sx	8.50	26.00	
				$ 26.00

2. Cost Analysis Well Repair With Tie-Back Liner (Continued)

	UNIT	RATE	COST	TOTAL
CEMENTING EQUIPMENT				
Depth Charge: 3,000'		1,174.00	1,174.00	
100' or Fraction	750	10.05	75.00	
Bulk Handling/cu. ft.	702	.85	597.00	
Mileage on Bulk Truck(s) ton-mil	33 tons 334 mi.	.70	7,715.00	
Pumper Mileage (one-way)	334	2.00	668.00	
Second Stage Charge		982.00	982.00	
Centralizers	9	59.00	531.00	
Limit Clamp	1	8.40	8.00	
Tie-Back Mandrel	1	5,130.00	5,130.00	
Auto Fill Landing Collar w/Plug	1	865.00	865.00	
Stage Collar w/plugs	1	3,774.00	3,774.00	
Thread Sealant (Teflon)	1-Five Gal.	168.00	168.00	
Tool Service Time Per Hour	8	29.00	232.00	
Torque Turn Make-Up/Joint	94 Jts.	33.00/Jt.	3,102.00	
Mileage Round-Trip	668	.90/mi.	601.00	
Subsistence 4 men/day/man	1 Day	75.00	300.00	
6" Retrievable Bridge Plug	8 Hours	1,161.00	1,161.00	
After 8 Hours $34/8 hours	12	34.00	408.00	
Contingencies 10%			2,749.00	
				$30,240.00
CASING CREW				
Casing Cost 3,000' min. (includes tongs)			$3,000.00	
Per Foot over 3,000'	370 ft.	$ 1.00/ft.	370.00	
Elevators Per Job			280.00	
Slips Per Job			195.00	
Thread Protectors/Job			300.00	
Mileage Round Trip	650 miles	1.25/mi.	813.00	
Subsistance/man/day	3 men 1 day	40.00	120.00	
				$5,078.00

	NO. CYLINDERS	NO. HOURS	COST	
FUEL COSTS				
Move In - Out Rig	8	20	$160.00	
Rig Up - Rig Down	8	12	96.99	
Tie Back Liner Rig	8	59.5	476.00	
				$732.00

3. Cost Summary Well Repair With Tie-Back Liner

Cement Equipment Mobilization (See cement squeeze job for details)	$ 1,786.00
Workover Rig Mobilization-Demobilization (See cement squeeze job for details)	5,080.00
Rig Up - Rig Down (See cement squeeze job for details)	2,031.00
Fuel Costs	732.00
Rig Time Cost	12,887.00
Supplemental Equipment	6,786.00
Cement	4,605.00
Cementing Equipment	30,240.00
Casing	50,609.00
Sand Pad	26.00
Casing Crew	5,078.00
GRAND TOTAL	$119,860.00

E. SLOTTED LINER REPLACEMENT

The generic well at Roosevelt Hot Springs, with a 7" slotted liner hung from 3,750'-5,000', has been in production for five years. Production has fallen off and it has been determined that the slots are scaled shut and the remedial action is to pull the liner, redrill the hole, and replace the liner.

The operation can be very straightforward and rather routine if the liner can be unseated and the liner hanger and liner pulled, unscrewed and laid down. If the liner hanger cannot be unseated, the hanger must be milled away, the liner speared and pulled out of the well. To ensure that the liner can be pulled, jars and a bumper sub will be used on any tool runs made while attempting to pull the liner. A larger rig capable of a pull equal to the tensile strength of the drill pipe should be used to be able to exert as much force as possible on the liner. In other words, if a smaller rig was used, maximum would be 200,000 ± 10,000 lbs., which might or might not move the liner. A bigger rig with a mximum pull of 350.00 ± 10,000 lbs. will ensure that, if the liner can be pulled, the rig will be big enough to the job.

If, after either unseating the liner hanger or milling it away, the liner cannot be moved, the only way to resolve the problem would be to mill away the entire liner or plug back, side-track and drill a new hole.

The clearances with 9 5/8" casing, 8 3/4" hole and 7" liner are such that wash pipe would not go in the hole and over the liner collars. Drift diameter of 9 5/8", 36#/ft. casing is 8.765"; collar O.D. of 7", 26#/ft. casing is 7.656". The O.D. of 26#/ft. hydril flush joint wash pipe is 8.625", the I.D. is 7.835". Recommended minimum hole size is 9", recommended maximum fish diameter to wash over is 7.5". Recommended minimum clearances are: open hole and O.D. of wash pipe 0.25", I.D. wash pipe O.D. of fish 0.125". These specifications are from a fishing tool company data sheet. These minimums are needed to circulate while washing over. Closer tolerances would stick the wash pipe and complicate the liner removal beyond all hope of completion of the job.

The rig for pulling the liner from subject Roosevelt Hot Springs well would have to come from Rangely, Colorado, a distance of 410 miles from Roosevelt Hot Springs. This operation would necessitate a 24-hour work schedule due to the problems that could be encountered. Primarily, the fact that with open hole or associated open hole fluid entry, the drill pipe should be kept moving at all times to avoid sticking pipe and tools. Therefore, 3 crews of 4 men each are needed, plus a generator to supply lights and power for auxiliary equipment.

1. Operational Sequence for Slotted Liner Replacement

(1) Tally and caliper all pipe, drill collars and tools. (2 hours)
(2) Go in hole with liner hanger retrieving tool jars, drill collars, bumper sub and 4 1/2" drill pipe, tag liner hanger. (4 hours)
(3) Unseat liner hanger, attempt to pull and jar loose. (2 hours)
(4) If successful, pull out-of-hole (P.O.O.H.) to bumper sub. (3 hours)
**SEE NOTE
(5) Lay down bumper sub. (.25 hour)
(6) P.O.O.H. to jars and lay down same. (.25 hour)
(7) Unlatch liner hanger, retrieving tool, lay down. (.25 hour)
(8) Lay down 7" liner, cut joints above collar with welder. (6 hours)
(9) Pick up 8 3/4" bit, drill collars, go in hole to 3,750' (liner hanger seat) (2 hours)
(10) Wash and ream to bottom (3,750-5,000') (12 hours)
(11) Circulate bottoms up to clean hole. (3 hours)
(12) P.O.O.H. (3 hours)
(13) Pick up new 7" slotted liner, G.I.H. with same. (5 hours)
(14) Pick up liner hanger, pick up liner hanger setting assembly. (.5 hour)
(15) Go in hole with liner, liner hanger and drill pipe. (4 hours)
(16) Tag bottom, pick up off bottom, set liner hanger 10 feet above previous liner hanger seat unlatch drill pipe from liner. (.5 hour)
(17) P.O.O.H. laying down drill pipe and liner hanger setting tool. (4 hours)
(18) Go in hole with drill collars and drill pipe in excess of liner length. (1 hour)
(19) P.O.O.H. with above, laying down drill pipe and drill collars. (2 hours).
(20) Nipple down BOP and stripping equipment (2 hours).
(21) Nipple up production equipment (2 hours).
(22) Flow test well (4 hours).
(23) Release rig, tear down, move out equipment (10 hours).
(24) If well does not flow, initiate N_2 start-up.
**NOTE: IF LINER HANGER WILL NOT UNSEAT ADD: (Milling & jarring operations are maximums)

(1) P.O.O.H. lay down bumper sub and jars (2 hours).
(2) Pick up mill, G.I.H. (2 hours).
(3) Tag liner hanger, mill on liner hanger until mill wears out (10 hours).
(4) P.O.O.H. put on new mill (2 hours).
(5) G.I.H. tag liner hanger (2 hours).
(6) Mill on liner hanger or until mill wears out (10 hours).
(7) P.O.O.H. put on new mill (2 hours).
(8) G.I.H. with new mill, tag hanger (2 hours).
(9) Mill on liner hanger until hanger milled up or mill wears out (10 hours).
(10) P.O.O.H. (2 hours).
(11) Pick up spear, jars, bumper sub, G.I.H. (2.5 hours).
(12) Latch on fish, pull, and jar (4 hours).

NOTE: If liner comes loose, procedure would be from Step #7-23.
If liner cannot be moved, set cement plug, cut window, side track and drill new hole.

2. Equipment List for Slotted Liner Replacement

RIG:	$149.00/hr.
900 H.P. 117', 365,000# Derrick, includes Driller and 2 men	
ROTARY EQUIPMENT:	$ 17.00/hr.
17 1/2" Rotary Table on 12', 300,000# substructure, pipe racks and catwalk, 40' x 3 1/2" Hex Kelley, swivel and high pressure rotary hose	
CIRCULATING EQUIPMENT:	$ 35.00/hr.
Will be charged rig hours.	
5 x 8 Triplex pump 300 H.P.	
High Pressure steel lines, unions and Chicksans, 4 valve manifold	
CIRCULATING TANKS:	$ 5.00/hr.
120-180 bbl tank with mud guns, partitions and hopper (must use circulating pump to mix mud)	
LIGHT PLANT:	$ 10.00/hr.
EXTRA LABOR:	$ 16.00/hr.
Each additional man (7 extra @$16.00/hr.)	
Crew Chief (driller) (2 extra)	
Pusher	$ 19.00/hr.
TOTAL PER COST OF RIG PER HOUR	$251.00
SUBSISTANCE CREWS $40.00/day/man (12 men)	$480.00/day
SUBSISTANCE PUSHER $50.00/day (1 man)	$ 50.00/day
TRUCKS:	
19,000-24,000# w/float & driver	$ 60.00/hr.
Truck Supervisor (pusher) on rig move	$ 19.00/hr.
Subsistance/man/day	$ 40.00
DRILL PIPE:	
4 1/2", 16.60#ft. "E" 4 1/2" FH 6 1/4" O.D. tool joint	
Minimum 5 days	$ .07/ft/day
Transportation	$ 5.75/cwt
DRILL COLLARS:	
6" O.D. 5 day minimum	$110.00/day
Each Additional Day	$ 15.00/day
85#/ft.	
Transportation	$ 5.75/cwt.
JARS:	
6 1/2" O.D. 3 day Minimum	$861.00
Each Additional Day	$464.00
BUMPER SUB:	
3 day minimum	$243.00
Each additional day	$120.00
SPEAR:	
To catch 7" O.D. - First Day	$520.00
Each additional day	$260.00
MILL:	
With Pilot largest O.D./inch/job	
8.679" x 277.00	$2,404.00 each

3. Cost Analysis for Slotted Liner Replacement

	UNIT	RATE	COST	TOTAL COST
RIG MOBILIZATION				
Move Rig, Rangely-R.H.S.	14 hrs.	$149.00/hr	$2,086.00	
3 Pickups, 4 men each	14 hrs.	64.00/hr	2,688.00	
Pusher	14 hrs.	19.00	266.00	
Pusher subsistence, 1 day	1 man	50.00	50.00	
Crew subsistence, 1 day	12 men	40.00	480.00	
4 Trucks w/float & driver	14 hrs.	60.00	3,360.00	
Truck Supervisor	14 hrs.	19.00	266.00	
Subsistence/man/day	5 men	40.00	200.00	
				$ 9,396.00
RENTAL AUXILIARY EQUIPMENT				
Drill pipe rental 4,850'	6 days	.07/ft/day	$2,037.00	
Drill pipe trucking 4,850'/16.6 ft.	2 trips/81,000#	5.75/cwt	9,259.00	
Six drill collars 6", 85#/ft., 180',	5 day min.	110.00 ea.	660.00	
Additional Day	1 day	15.00 ea	90.00	
Trucking	2 trips/15,300#	5.75/cwt	1,760.00	
BOP 3,000#, 11"	10 day min.		726.00	
Trucking BOP	2 trips/9,900#	5.75/cwt	1,140.00	
Hydril Series 10-900	10 day min.		800.00	
Trucking Hydril	2 trips/18,200#	5.75/cwt	2,094.00	
Jars First Day		861.00	861.00	
Bumper Sub (3 day min.)		243.00	243.00	
Trucking Jars & Bumper Sub	2 trips/5,807#	5.75/cwt.	668.00	
Mill w/pilot	3	2404.00	7,212.00	
Trucking Mills	2 trips/300#	5.75/cwt	35.00	
Spear to Catch 7" Pipe First Day	520.00	520.00	520.00	
Spear Trucking	2 trips/500#	5.75/cwt.	58.00	
				$28,163.00
RIG UP				
Workover Rig	15.5	149	2,310.00	
Truck Pusher	13	19.00	247.00	
Tool Pusher	13	19.00	247.00	
Subsistence Drivers, Crews/ man/day	13	40.00	520.00	
Tool Pusher Subsistence	1	50.00	50.00	
Fill Tanks w/water	300 bbl	.50	150.00	
Contingencies 10%			352.00	
LINER HANGER COST				
7" x 9 5/8" Hanger w/Lead Seal Packoff			5,865.00	
Tie Back			2,280.00	
Rental Tools, Setting Tool & Subs			500.00	
Tool Man Service Charge/day	2 days	250.00	500.00	
Mileage Round Trip (Vernal, UT.)	900 miles	.90/mi	810.00	
				$ 9,955.00
CASING CREW				
Service Charge 3,000' min.			3,000.00	
Elevators Per Job			280.00	
Slips Per Job			195.00	
Thread Protectors Per Job			300.00	
Mileage	650 miles	1.25/mi	813.00	
Subsistence (3 men)	1 day	40.00	120.00	
				$ 4,708.00

3. Cost Analysis for Slotted Liner Replacement (Continued)

	UNIT	RATE	COST	TOTAL COST
RIG COSTS (TROUBLE FREE LINER REMOVAL)				
Tally & Caliper Pipe, Collars & Tools	2 hrs.	251.00	502.00	
G.I.H. (Go In Hole) w/Tools	4 hrs.	251.00	1,004.00	
Unseat Liner Hanger, Jar	2 hrs.	251.00	502.00	
P.O.O.H. To Bumper Sub	3 hrs.	251.00	753.00	
Laydown Bumper Sub	.25 hrs.	251.00	63.00	
P.O.O.H. To Jars Lay Down	.25 hrs.	251.00	63.00	
Unlatch Liner Hanger Tool	.25 hrs.	251.00	63.00	
Lay Down 7" Liner	6 hrs.	251.00	1,506.00	
Pick up 8 3/4" Bit Collars G.I.H.	2 hrs.	251.00	502.00	
Wash & Ream to Bottom (3,750 - 5,000)	12 hrs.	251.00	3,012.00	
Circulate Bottoms Up	3 hrs.	251.00	753.00	
P.O.O.H.	3 hrs.	251.00	753.00	
Pick Up New Liner, G.I.H.	5 hrs.	251.00	1,255.00	
Pick Up New Liner Hanger	.5 hrs.	251.00	126.00	
G.I.H. w/Liner & Liner Hanger	4 hrs.	251.00	1,004.00	
Tag Bottom, Set Liner Hanger	.5 hrs.	251.00	126.00	
P.O.O.H. Lay Down D.P. & Hanger	4 hrs.	251.00	1,004.00	
Liner Hanger Tool	--	--	--	
G.I.H. w/ D.C. & Excess D.P.	1 hrs.	251.00	502.00	
Contingencies 10%			1,349.00	
Tool Pusher Subsistence	2 Days	50.00	100.00	
Crew Subsistence/Men/Day 12 Men	2 Days	40.00	960.00	
Crew Travel Time	6 Hrs.	64.00/Hr.	384.00	
Fuel	2,000 Gal.	1.00/Gal	2,000.00	
Welder	6 Hrs.	30.50	183.00	
Welder Travel Time	1 Hr.	31.00	30.50	
				$18,500.00
RIG COSTS (IF LINER HANGER MUST BE MILLED)				
P.O.O.H.	2 hrs.	251.00	502.00	
Sub & Jars	--	--	--	
Pick Up Mill, G.I.H.	2 hrs.	251.00	502.00	
Tag Liner Hanger, Mill On Same	10 hrs.	251.00	2,510.00	
P.O.O.H. Put On New Mill	2 hrs.	251.00	502.00	
G.I.H. w/New Mill Tage Hanger	2 hrs.	251.00	502.00	
Mill on Liner Hanger	10 hrs.	251.00	2,510.00	
P.O.O.H.	2 hrs.	251.00	502.00	
Pick Up Spear, Jars, Bumper Sub	2.5 hrs.	251.00	628.00	
G.I.H., Latch on Fish, Pull & Jar	4 Hrs.	251.00	1,004.00	
Contingencies 10%			916.00	
Tool Pusher Subsistence	2 Days	50.00/Day	100.00	
Crew Subsistence (12 men)	2 Days	40.00/Day	960.00	
Fuel	2,000 Gal.	1.00/Gal.	2,000.00	
Crew Travel Time	6 Hrs.	64.00/Hr.	384.00	
				$13,522.00
CASING				
7", 26#, K-55, LTC	1,300'	$1,121.56/c	$14,580.00	
Trucking	33,800#	5.75/cwt	1,944.00	
Slotting F.O.B., Torrance, Calif.	300'	4.77/ft	1,431.00	
Trucking 300' of casing A.A.	15,600#	5.75/cwt	897.00	
				$18,852.00

4. Cost Summary for Slotted Liner Replacement

	COST	TOTAL
TROUBLE FREE		
Rig Mobilization (move in)	$ 9,396.00	
Rig Demobilization (move out)	9,396.00	
Rental Auxiliary Equipment	28,163.00	
Rig Up Costs	3,876.00	
Rig Down Costs	3,876.00	
Trouble Free Liner Removal	18,500.00	
Replacement Liner	18,852.00	
Replacement Liner Hanger	9,955.00	
Casing Crew	4,708.00	
		$106,722.00
If Liner Ranger Milled	$13,522.00	
		$120,244.00

5. Cost Analysis Slotted Liner Removal Only With No Replacement

COSTS NOT REQUIRED	
Rig (13 hours @ $251)	$ 3,263.00
Liner	18,852.00
Liner Hanger	9,955.00
Casing Crew	4,708.00
	$ 36,778.00

TROUBLE FREE COST FOR REMOVAL WITHOUT REPLACEMENT.

$106,722.00
\- 36,778.00
$ 69,944.00

REMOVAL ONLY COST WITHOUT REPLACEMENT INCLUDING MILLING.

$120,244.00
\- 36,778.00
$ 83,466.00

F. UNDER REAM AND GRAVEL PACK

The subject well had sand control problems and scale problems; the 7" slotted liner was pulled, and the decision was made to under ream from 8 3/4" to 15", run a new 7" slotted liner and gravel pack the liner. Length to be reamed is 750 feet at the end of 7,250 feet of 9 5/8 36#/ft casing.

The liner emplaced in this manner becomes a permanent installation and further remedial action (liner withdrawal) is not operational or financially feasible.

The under reaming operation will call for a large rig capable of handling 4½" drill pipe, and 6" ± drill collars. The operation has some inherent hazards that must be recognized and preparations for remedial action should be part of the operational plan.

The problems are:

(1) Extreme high drill pipe torque can be expected and extreme care must be taken while reaming.

(2) There can be no stabilization of the under reamer and a crooked doglegged hole could be detrimental to getting a concentric casing - hole annulus configuration that would allow for an adquate and controlled gravel pack.

(3) The mud invasion problem was present when drilling and when under reamingis done, mud must be used again to clean the hole, and stabilize the new annulus. This being the case, mud invasion could be a problem again.

(4) Hole wall stability is going to be questionable due to water saturation of the shale sections during production. This problem could cause sloughing shale to be severe enough to stick the drill pipe causing expensive fishing jobs.

(5) Drilling with water would be out of the question because of acceleration of sloughing shale.

(6) The penetration rate of underreaming would be approximately 50 percent of normal drilling due to light drilling weights to avoid excessive drill string torque and to maintain a straight

hole. The recommended drilling parameters are weight on bit 1000#/inch of under reamer body, 60-80 R.P.M., and adequate pump volume to clean the hole (9.9 BPM maximum output of pump). The hydraulics of the operation would be as follows:

Pump Pressure:	2,000 psi
Equivalent Nozzle Size:	2-12/32", 1 11/32"
Annular Velocity FPM:	Casing/DP-181
	Open Hole/D.P.-50
	Open Hole/D.C.-54
Bit Pressure Loss:	1,460 psi (73%)
Pump Hydraulic Horsepower:	485
Equivalent Circulating Density:	9.08#/Gal.
SWAB:	8.98#/Gal.
Surge:	9.02#/Gal.
	(Trip @ 1,000'/Hr.)

The following operational sequences are based on a "rough neck factor" (human error) of +25 percent. This factor is applied to the rig up, tripping and materials handling portion of the operation.

A study of Imperial Valley drilling histories show some lost circulation zones. With careful control of drilling fluid flow properties and weight, and slower than normal trip rates to avoid surging or swabbing the hole on any trip, circulation losses can be kept to a minimum.

The costs noted are optimum with no sloughing shale (sticking) or time lost to restore circulation. Blind drilling, or drilling with no returns, would be catastrophic, due to the large volumes of material that will be cut while under reaming (+58 percent). If this amount of material is not removed as it is drilled, a very difficult and expensive fishing job would be the result.

The rig used for this operation would be moved from Long Beach, California to Heber a distance of 234 miles at an average speed of 47 M.P.H. Six trucks with floats will be required to move the drilling support equipment, including substructure and matting boards, a mud pump, mud circulating tanks with solids control equipment, a blow out preventer stack, a hydril, the catwalk and pipe racks, and a light plant.

When rigging up this type of rig, a truck supervisor is needed to coordinate material placement and movement with the rig-up operations of the drilling crew and tool pusher. The rig-up trucks would be released until such time as needed to rig down the drilling equipment and move back to the base of operations.

The light plant and extra crews are needed because, in the under reaming operation with open hole, continuous operations are an absolute necessity to assure an effective use of time and material.

1. Material List and Basic Prices Under Reaming

Rig:	
900 HP 117', 365,000# Derrick and 2 men.	$149.00/hr.
Rotary Equipment	$ 17.00/hr.
Includes: 17½" rotary table on 12' 300,000# substructure, pipe racks and catwalk, 40' x 3½" Hex Kelley, swivel and high pressure rotary hose, will be charged rig hours.	
Circulating Equipment:	
Charged @ rig hours,	$ 58.00/hr.
6 x 7 Py7 Triplex Pump 700 HP. 9.9 Bbls./Min. Hi pressure steel lines, unions and chicsans, 4 valve manifold.	
Circulating Tanks:	$ 17.00/hr.
Includes: 2-190 Bbls. steel pits with mud guns, partitions, hopper, shale shaker, and desanders, 5" x 6" centrifugal pump for mixing through low pressure mixing systems and to pump through desander, centrifugal pump driven by 4-71 GMC Diesel.	
Extra Circulating Tank:	$ 5.00/hr.
Includes: 1-180 Bbl. tank with mud guns, and partitions.	
Light Plant:	$ 10.00/hr.
Extra Labor:	
Each additional man (7 extra)	$ 16.00/hr.
Crew Chief (driller) (2 extra)	
Pusher	$ 19.00/hr.
Total Rig Cost	$291.00
Under Reamer: (telephone quote)	
Body Rental $1,000.00 per month	$1,000.00/mo.
Cutters, set of three	$2,150.00/set
Body O.D. 8¼" open to 15"	
Drill Pipe:	
4½" API Grade "E" 5-day minimum	
Additional per foot/day	$ .065
D.P. Protector Rubbers	
Each 20.00 15-day minimum additional days	$
1.35/each	

Drill Collars:	
6" OD. Each 1-day minimum $54.00 each.	
Additional days	$ 17.00/each
Equipment:	
BOP 3,000# 11" (11" vert. bore.) 10-day minimum	$ 726.00
Additional day	$ 72.00/each
Trucking 9,999#	$ 5.75/cwt.
Hydrill 11" 3,000# W.P. 10-day minimum	$ 800.00
Additional day	$ 80.00
Trucking 18,200#	$ 5.75/cwt.
Gravel Pack Equipment:	
Water Requirements:	$ .50/BBL.
Gravel Pack 600 BBLS.	
Versa Gel Fluid 350 BBLS.	$ 10.92/BBL.
16-30 sand	$ 6.66/cwt.
Sand Handling Charge	$ 0.85/cu.ft.
Sand Delivery Charge Per Ton Mile	$ 0.65
Pump truck each 4 hours or fraction	$1,150.00
Fluid pumping charge minimum	$1,150.00
Pump truck mileage one way, each unit per mile	$ 2.00
Blender mileage one way, each unit per mile	$ 2.00
Proppant pumping charges per hundred pounds	$ .75
Casing Crew:	
Mileage	$ 1.25/mile
Standby/Man/Hour	$ 22.00
Elevators/Job	$ 280.00
Slips/Job	$ 195.00
Thread Protectors/Job	$ 300.00
7" casing: 3,000' minimum:	
Includes tongs	$3,000.00
Casing:	
7" 26#/ft K-55 LTC	$1,121.56/c
Trucking	$ 5.75/cwt.
Slotting, F.O.B. Torrance, CA	$ 4.77/ft.

2. <u>Operational Sequence Under Reaming (Liner Removal Already Completed)</u>

<u>TIME (HRS.)</u>

32	1.	Move in and rig up and test BOP and Hydril
1	2.	Pump mud through kill line, kill well
.25	3.	Pick up under reamer
2	4.	Pick up drill collars
10.5	5.	Pick up drill pipe; G.I.H. @ 686'/hour strap in

TIME (HRS.)		
3.5	6.	Start pump, open under reamer, open hole to 15"
20.0	7.	Start under-reaming with maximum weight on bit 8,000# RPM 70-80, pump pressure 2,000 psi, continue until excessive torque, or penetration of less than 4'/hr. shows cutters worn. Approximately 83 feet of reaming.
4.5	8.	P.O.O.H.
.5	9.	Change out under-reamer cutters
4.5	10.	G.I.H. with under-reamer new cutters
235.0	-	Repeat steps 6, 7, 8, & 9 seven times (trip time increases with depth; average trip time 6.5 hours)
20	11.	Under ream to T.D. (8,000')
8	12.	Circulate hole clean
8.5	13.	P.O.O.H.
2	14.	Lay down 820' drill pipe
3	15.	Lay down 6" drill collars

3. Operational Sequence Casing Running and Gravel Pack

2.5	1.	Rig Up casing equipment
4.0	2.	Pick up and run casing with slots placed at correct intervals
1.0	3.	Pick up liner hanger, and subsurface gravel pack tools
10	4.	G.I.H. with liner and tools tag bottom
1.0	5.	Pick up to 6,990' set liner hanger
1.0	6.	Rig up gravel pack surface equipment
1.5	7.	Pump 400 BBLS. water to cool well and displace mud
5.0	8.	Pump 16-30 sand @ 3 BPM
1.0	9.	Rig down pumping equipment
8.0	10.	P.O.O.H. Laying down drill pipe
4.0	11.	Close master valve nipple down hydril & BOP
2.0	12.	Nipple up production head
12.0	13.	Release rig; see rig down cost sheet
	14.	Flow test well, if no flow initiate N_2 start up procedure

4. Cost Analysis Under Reaming and Gravel Pack

	UNITS	RATE	COST	TOTAL
SUPPLEMENTAL RIG EQUIPMENT RENTAL				
Under-Reamer	1 Month	$1,000.00	$1,000.00	
Cutters - Set of 3/Set	8 Sets	2,150.00	17,200.00	
Drill Pipe Per Ft./Day	7,843'/22 Days	.065	11,215.00	
Drill Pipe Rubbers - 15 Day Min.	80	20.00	1,600.00	
Drill Pipe Rubbers - Additional Days	80	1.35	108.00	
Drill Collars - 1 Day Min.	6	54.00	324.00	
Drill Collars - Additional Days	6 Ea. 21 Days	17.00	2,142.00	
Trucking Rd. Trip Drill Pipe 16.6#/ft.	260,388#	5.75/ cwt	14,972.00	
Trucking Rd. Trip - D.C. 85#/ft.	30,600#	5.75/ cwt	1,760.00	
Liner Hanger, Port, & E&C			10,625.00	
Liner Hanger Trucking	8 Hrs.	50.00/ Hr.	400.00	
BOPE	10-Day Min.		726.00	
BOPE - Additional Days	12 Days	72.00	864.00	
Trucking BOPE Rd. Trip	18,000#	5.75/cwt	1,035.00	
Hydril	10-Day Min.		800.00	
Hydril - Additional Days	12 Days	80.00	960.00	
Trucking Hydril Rd. Trip	22,600#	5.75/cwt	1,300.00	
Replacement & Contingencies			10,055.00	
				$77,086.00

NOTE: Rig support equipment rentals included in rig costs

GRAVEL PACK EQUIPMENT AND MATERIALS				
Water	600 bbls	0.50	$ 300.00	
Vera-Gel Fluid	350 "	10.92	3,322.00	
16-30 Sand	1,200 cu. ft.	6.60	7,992.00	
Sand Handling Charge	1,200 " "	0.85	1,992.00	
Sand Delivery Charge/Ton	265.60	0.65	10,335.00	
Pump Truck Mileage 2	265 Mi.	2.00	1,060.00	
Blender Mileage 2	265 Mi.	2.00	1,060.00	
Pump Truck Each 4 Hrs. or Fraction - 2 Trucks	6.5 Hrs.	1,150.00	3,744.00	
Blender Each 4 Hrs. or Fraction - 2 Trucks	6.5 "	1,150.00	3,744.00	
Proppant Pumping Charge	1,100 cwt	0.75	900.00	
				$33,977.00

4. Cost Analysis Under Reaming and Gravel Pack (Continued)

	UNITS	RATE	COST	TOTAL
MOBILIZATION - RIG				
Rig Travel Time	5 Hrs.	$149.00	$ 745.00	
Pickups w/Crews (3)	5 "	64.00	960.00	
Pusher	5 "	19.00	95.00	
Trucks - Float & Drive (6)	5 "	60.00	1,800.00	
Truck Pusher	5 "	19.00	95.00	
Permits, Contingencies (10%)			370.00	
				$ 4,065.00
DEMOBILIZATION - RIG				
Rig Travel Time	5 Hrs.	149.00	745.00	
Pickups w/Crews (3)	5 "	64.00	960.00	
Pusher	5 "	19.00	95.00	
Trucks - Float & Driver (6)	5 "	60.00	1,800.00	
Truck Pusher	5 "	19.00	95.00	
Permits, Contingencies			370.00	
				$ 4,065.00
RIG UP				
Truck Usage - 6 Trucks	11.75	60.00	4,230.00	
Truck Pusher	11.75	19.00	223.00	
Move in, unload nipple up, and drill mouse-hole	32	291.00	9.312.00	
				$13,765.00
RIG DOWN				
Nipple up tree, load up rig down, and move out	22	291.00	6,402.00	
Truck Usage (6 Trucks)	12	60.00	4,320.00	
Truck Pusher	12	19.00	228.00	
				$10,950.00
RIG COSTS UNDER REAMING				
Pump Mud; Kill Well	1	291.00	291.00	
Pick Up Under Reamer	.25	291.00	73.00	
Pick Up Drill Collars	2	291.00	582.00	
Pick Up Drill Collars, Strap In	10.5	291.00	3,056.00	
Open Reamer and Hole to 15"	3.5	291.00	1,019.00	
Under-Ream	20	291.00	5,820.00	
P.O.O.H.	4.5	291.00	1,310.00	
Change Reamer Cutters	.5	291.00	146.00	
G.I.H. w/New Cutters	4.5	291.00	1,310.00	
Repeat reaming for approximately 580 feet	234.0	291.00	68,094.00	
Under-Ream to ID (8000 ft)	20	291.00	5,820.00	
Circulate Hole Clean	8	291.00	2,328.00	
P.O.O.H.	8.5	291.00	2,474.00	
Lay Down 820' Drill Pile	2	291.00	582.00	
Lay Down Drill Collars	3	291.00	873.00	
Contingencies 10%			9,160.00	
Fuel	11,340 Gal.	1.00/Gal	11,340.00	
Crew Subsistence - 12 Men	21 Days	40.00/Day	10,080.00	
Crew Travel Time	63 Hours	64.00/Hour	4,032.00	
Tool Pusher - Subsistence	21 Days	50.00	1,050.00	
				$129,440.00

4. Cost Analysis Under Reaming and Gravel Pack (Continued)

	UNITS	RATE	COST	TOTAL
RIG COSTS GRAVEL PACK				
Rig Up Casing Equipment	.25 hrs	291.00	73.00	
Pick Up - Run Casing	4 hrs	291.00	1,164.00	
Pick Up Liner Hanger	1 hrs	291.00	291.00	
G.I.H. w/Liner & D.P. Tag Bottom	10 hrs	291.00	2,910.00	
Pick Up to 6,990; Set Hanger	1 hrs	291.00	291.00	
Rig Up Gravel Pack Equipment	1 hrs	291.00	291.00	
Pump Cooling Water	1.5 hrs	291.00	437.00	
Pump Sand	5 hrs	291.00	1,455.00	
Rig Down Pump Equipment	1 hrs	291.00	291.00	
P.O.O.H., Lay Down, Drill Pipe	8 hrs	291.00	2,328.00	
Close Master Valve R.D. BOP	4 hrs	291.00	1,164.00	
Nipple Up Production Equip.	2 hrs	291.00	582.00	
Fuel	1,370 Gal.	1.00	1,370.00	
Contingencies 10%			1,265.00	
Crew Subsistence - 12 Men	2 Days	40.00	960.00	
Crew Travel Time - 2 Days	6 Hours	64.00	384.00	
Tool Pusher Subsistence	2 Days	50.00	100.00	
				$15,356.00
LINER COSTS				
7" 26# K-55 LTC	1,000 ft.	1,121.56/C	11,216.00	
Trucking 200' Casing	5,200#	5.75/cwt	299.00	
Slotting	800 ft	4.77/ft.	3,816.00	
Trucking Slotted Liner	20,800#	5.75/cwt	1,196.00	
				$16,527.00
ROUND TRIP, EMPTY TRUCKS (6)	8 Hrs.	60.00	2,880.00	
				$ 2,880.00

5. Cost Summary for Under Ream Gravel Pack Recapitulation

	COST	TOTAL
Rig Mobilization	4,065.00	
Rig Demobilization	4,065.00	
Round Trip - Empty Trucks	2,880.00	
Rig Up	13,765.00	
Rig Down	10,950.00	
Under-Ream Rig Cost	129,440.00	
Rental Equipment	77,086.00	
Gravel Pack, Rig Costs	15,356.00	
Liner Costs; Pipe & Slotting	16,527.00	
Liner Hanger & Port Collar	10,625.00	
Gravel Pack Equipment	33,977.00	
Mud Costs, Trouble Free*	65,000.00	
		$383,736

*SEE IMCO PROPOSAL

$$\text{Remoteness Factor: } \frac{8130}{383,736} = 2\%$$

6. Service Company Supporting Data For Under Reaming and Gravel Pack

The following nine pages contain data supplied by Halliburton and IMCO supporting the cost analysis in the previous section. Quotations are in 1981 prices current at the time of quotations and are subject to change without notice. The prices are also subject to the service company standard terms and conditions.

HALLIBURTON SERVICES

SUITE 440, 410 17TH STREET, DENVER, COLORADO 80202
(303) 893-9565

SERVICE SALES DEPARTMENT

June 22, 1981

Mr. Paul McKesson
Keplinger and Associates
2200 Security Life Building
Denver, Colorado 80202

RE: Proposal for Gravel Pak
Heber Area
Imperial Valley

Dear Paul:

Enclosed for your consideration is a cement analysis and cost estimate on the above referenced well.

Halliburton Services is pleased to have the opportunity to present this analysis for your consideration and earnestly solicits the service work on this well. Please let us know if further information is required.

Respectfully submitted,

J. F. Callahan

J. F. Callahan
Service Sales Engineer

JFC/klv
Enclosure
cc: Los Angeles Division Office
Santa Fe Springs District Office
File

A Halliburton Company

Mr. Paul McKesson
Keplinger and Associates
June 22, 1981
Page Two

WELL DATA:

Total Depth	-	8,000 ft.
Hole Size	-	15"
Last Casing	-	7,200 ft.
Casing Size	-	9 5/8"
Liner Size	-	7"
Slot Size	-	0.02" by 2" long
Drill Pipe	-	4 1/2"
Pressure Grad.	-	.429 psi/ft.
BHST	-	500° F

Sand carrying fluid - VERSAGEL 2500 - Fresh water w/50 lbs. WG-12, 0.5 gal CL-11 and required breaker.

Treating Procedure -

1. Turn well bore over to clear fluid.
2. Run liner.
3. Pump 400 bbls. of water as a cooling stage.
4. Pump 16-30 sand at 10#/gal.at 3 BPM using 100,000# of sand.
5. Flush to top of liner.
6. Repeat with 20,000 lbs. sand stages if necessary.

Required Volumes -

350 bbls. of VERSAGEL fluid
600 bbls. of water
1,200 sks. of 16-30 sand

COST ESTIMATE: $30,500.00

Prejob planning when this work would actually be done will be very important.

Mr. Paul McKesson
June 22, 1981
Page Three

The unit prices stated in this proposal are based upon our current published prices. The projected equipment, personnel and material needs are estimates only based upon information about the work presently available to use. At the time the work is actually performed, conditions then existing may require an increase or decrease in the equipment, personnel and/or material needs. Charges will be based upon unit prices in effect and/or material actually utilized in the work. Taxes, if any, are not included.

We are pleased to have the opportunity to present this proposal for your consideration. If you accept our proposal, all materials and equipment furnished and services performed will be under our General Terms and Conditions and pursuant to our applicable Work Order Contract (whether or not executed by you.) Copies of the General Terms and Conditions and applicable Work Order Contract will be furnished upon request.

SERVICE POINT: Santa Fe Springs, California
(213) 863-8701

HALLIBURTON

WELLBORE TEMPERATURE CALCULATION

KEPLINGER & ASSOC.
STEAM WELL, HEBER AREA, IMPERIAL VALLEY, CA

PUMP RATE(BBL/MIN)= 4.0
TUBING: ID 4.000 OD 4.500 INCHES
CASING: ID900.000 OD 9.625 INCHES
PRANDTL NUMBER FOR FLUID= 1.50
THERMAL CONDUCTIVITY OF FLUID(BTU/HR-SQ.FT-F)= 0.3630
THERMAL CONDUCTIVITY OF TUBING AND CASING(BTU/HR-SQ.FT-F)= 26.0
THERMAL CONDUCTIVITY OF MEDIUM(BTU/HR-SQ.FT-F)= 0.3930
THERMAL DIFFUSIVITY OF EARTH(SQ.FT/D)= 0.040
SPECIFIC GRAVITY OF FLUID= 1.0000
SPECIFIC GRAVITY OF MEDIUM= 1.0000
THERMAL CONDUCTIVITY OF EARTH(BTU/HR-FT-F)= 1.4000
GEOTHERMAL GRADIENT (F/FT)= 0.0525
SURFACE TEMPERATURE(F)= 80.0
SURFACE TEMPERATURE OF FLUID(F)= 80.00
SPECIFIC HEAT OF TUBING AND CASING(BTU/LB-F)= 0.1080
SPECIFIC HEAT OF MEDIUM(BTU/LB-F)= 1.0000
SPECIFIC HEAT OF EARTH(BTU/LB-F)= 0.2650
SPECIFIC HEAT OF FLUID(BTU/LB-F)= 1.0000

DEPTH(FT)= 8000.0

FORMATION TEMPERATURE(F)=500.0

TIME(MIN)	FLUID VOLUME(GAL)	FLUID TEMPERATURE(F)
1.00	168.0	474.0
11.00	1848.0	293.5
21.00	3528.0	246.1
31.00	5208.0	221.3
41.00	6888.0	204.7
51.00	8568.0	194.2
61.00	10248.0	185.6
71.00	11928.0	179.2
81.00	13608.0	173.9
91.00	15288.0	169.2
100.00	16800.0	166.1

IMCO

July 30, 1981

K & A Inc. Minerals Management
1616 Glenarm Place, Suite 2200
Denver, Colorado 80202

ATTN: Mr. Paul McKissan

Dear Mr. McKissan:

Earl Springer, Division Engineer for IMCO Services in Denver, informed me that your company is planning to rework an 8,000 foot geothermal well in the Heber area, Imperial Valley, California. He stated that you required a drilling fluid that is temperature stable at 500°F with a 12 to 15 ml fluid loss.

Recently, our Research and Development Laboratory in Houston, Texas formulated a geothermal drilling fluid that showed excellent temperature stability at 500°F, as tested on a Fann Consistometer. This fluid is composed of the following materials:

fresh water	
IMCO Durogel	15 ppb
IMCO Gel	5 ppb
IMX 129*	2 ppb
IMCO SP-101	3 ppb
caustic soda	0.5 ppb
IMCO Sulf-X II	6 ppb

* an experimental high temperature polymer

The laboratory work done on this drilling fluid formulation consisted of static-aging the mud for 60 hours at 460°F, solids contamination tests, carbon dioxide and hydrogen sulfide contamination tests, and Fann Consistometer temperature stability tests. The following test results show that this formulation is temperature stable, has excellent rheological and fluid loss control, and will tolerate various contaminants.

IMCO Services
2134 Main Streeet • Suite 230 • Huntington Beach, California 92648 • (714) 960-6563

K & A Inc. Minerals Management
Page 2

Test Results - IMCO Services Laboratory Report # F3-059-80FW

Table I - Temperature stability

Sample #	1	2
Test	Hot-rolled 16 hrs @150°F	Static-aged 60 hrs @460°F
PV,cps	20	17
YP,#/100ft^2	10	6
10 sec. Gel	3	2
10 min. Gel	5	4
pH	9.9	8.5
API filtrate, mls.	5.4	10.0

Table #2 - Solids contamination test (static-aged 24 hours @460°F)

Sample#	3	4	5	6
Solids, ppb*	Base	3.5	10.5	21
PV, cps	17	19	16	20
YP,#/100ft^2	13	10	6	15
10 sec. Gel	2	2	2	2
10 min. Gel	5	8	7	18
pH	8.6	8.6	8.6	8.4
API filtrate, mls.	9.0	9.0	10.4	10.4

* - solids added in this test consisted of - 200 mesh shale

Table #3 - CO_2 and H_2S contamination test (hot-rolled 24 hours @460°F)

Sample #	7	8	9
Contaminate	Base	CC_2	H_2S
PV, cps	16	15	16
YP,#/100ft^2	8	5	9
10 sec. Gel	2	2	2
10 min. Gel	4	4	4
pH	8.6	8.5	9.2
API filtrate, mls.	7.2	7.4	6.8

K & A Inc. Minerals Management
Page 3

Table #4 - Fann Consistometer Test *(to 500°F with 5,000 psi constant pressure)

Temperature, °F	Consistometer Units
100	110
200	112
300	116
400	96
500	100
400	100
300	102
200	106
100	114

* this test measures the relative viscosity of the mud while it is being heated or cooled. A dramatic increase in the consistometer units or a large difference between the initial and final relative viscosity at the same temperature shows that the mud has been adversely affected. This test shows none of these conditions, meaning that the mud is temperature stable to at least 500°F.

This formulation was field tested in a well in South Louisiana recently, and although the expected bottom hole temperature of 460+°F was never reached, the fluid showed excellent rheological and fluid loss control. The 6 ppb Sulf-X II added to the mud was to remove expected hydrogen sulfide gas.

A second field test of this formulation was recently made in a geothermal area near Fallon, Nevada. The mud program recommended was to drill the well with a low solids, non-dispersed (LSND) mud consisting of IMCO Gel, IMCO Gelex, and IMCO SP-101 until the flow-line temperature indicated a change in the temperature gradient. At this time, the mud was watered back to reduce the IMCO Gel content to 5 ppb, and 15 ppb Durogel, 2-2.5 ppb IMX-129, and 2 ppb IMCO SP-101 added to the system. After conversion, the drilling fluid had the following properties:

Weight, ppg	9.3
Plastic viscosity, cps	14
Yield point, #/100ft^2	21
10 sec. Gel	7
10 min. Gel	31
pH	9.3
API filtrate, mls.	10.6

On your proposed well in the Heber area, we recommend the following mud formulation:

fresh water	
IMCO Durogel	15-20 ppb
IMCO Gel	5 ppb
IMCO SP-101	3 ppb
IMX 129	2-2.5 ppb
IMCO Lig	4-5 ppb
caustic soda	.25-.5 ppb

In addition, it will be necessary to add soda ash or bicarbonate to keep soluble calcium levels below 80 ppm. This will maximize the effectiveness of the polymers fluid loss control capabilities.

The following is a brief description of the products mentioned above.

IMCO Gel - Wyoming bentonite. It's use in the drilling fluid is for particle size distribution and its excellent wall-building characteristics.

IMCO Durogel - sepiolite clay. This material is similar in nature to IMCO Brinegel (attapulgite clay) in that it requires shearing to produce viscosity. However, it is an extremely temperature stable clay, with laboratory tests showing excellent stability in excess of 700°F.

IMCO SP-101 - sodium polyacrylate (Cypan) - this polymer is used in many geothermal fluids because of its excellent temperature stability and imparted fluid loss control.

IMX 129 - an experimental polymer that has the benefits of SP-101, but also imparts additional temperature stability to the fluid.

Estimated Cost: $60,000 to $65,000 based on minimal mud weights and 8 to 10 days underreaming, with no unusual or severe hole problems.

In using this type of fluid, a few precautions should be made. First, good solids control should be maintained to help in keeping daily costs down and to avoid having drill solids affect the fluid loss and rheology of the mud. Second, to avoid dehydration of the mud system, a stream of water should be added whenever the mud is circulated. This will also help to dilute drill solids buildup. Third, cooling towers for the mud should be employed to help lower the temperature of the mud as much as possible.

Our stockpoint for your operations will be in El Centro, California. In addition to providing a Sales and Service Representative to run the mud, our Houston Research and Development Laboratory will provide a Field Service Representative to monitor the drilling fluid on a 24 hour basis.

We appreciate this opportunity to be of assistance to you in answering your questions about our geothermal fluids, and do not hesitate to call if we can be of further help.

Sincerely yours,

IMCO Services

John A. Toups
Division Technical Advisor
Los Angeles Division

(714) 960-6563

JAT:lp

DRILMOD Calculations

Drilling Fluid

Weight, ppg	9.0
Plastic Viscosity, cpa	14
Yield Point, #/100ft^2	21
10 sec. Gel	7
10 min. Gel	31

Pumps
7.5 bpm
1770 psi standpipe pressure

Well Geometry

9-5/8" casing	7,250 ft.
15" open hole	750 ft.
4-1/2" drill pipe	7,700 ft.
6-1/2" collars	300 ft.
casing I.D.	8.835 inches
drill pipe I.D.	3.826 inches
collar I.D.	2.25 inches

I Optimum Hydraulics

A. Flow rate calculated	7.6 bpm
B. Flow rate desired	7.5 bpm
C. Nozzle sizes (1/32")	11, 11, 10

II Hydraulics

A. Annular Velocity	38 feet/minute
B. Pressure loss at bit	1,199 psi
	68 %
C. Jet Velocity	385 feet/sec.
D. Bit hydraulic impact force	564 lbs.
E. Bit hydraulic horsepower	220 hp
F. Bit hydraulic horsepower	1.2 hp/in.^{2}
G. Pump hydraulic horsepower	325 hp.

III Hole Cleaning

Hole Section	Annular Velocity fpm	Slip Velocity fpm	Critical Velocities fpm
9-5/8" casing, 4½" d.p.	134	27	399
15" open hole, 4½" d.p.	38	19	323
15" open hole, 6½" d.C.	42	20	388

IV Equivalent Circulation Density

A. at 7,250 ft. (casing seat)	9.27 ppg
B. at 8,000 ft. (total depth)	9.25 ppg

G. SCALE INHIBITION BY CHEMICAL INJECTION

A 5000 foot well with 7" casing and 550°F BHT and 1,000 PSI WHP has had a history of scaling throughout its productive life, with periodic mechanical descaling at the liner hanger lap. Loss of production was significant (approximately 50 percent) over a 90 to 120 day period of production.

It was decided to run a tubing string into the hole so that inhibition chemicals could be injected at the bottom of the well. The presence of this tubing string in the hole will reduce the well productivity by decreasing the cross-sectional area and increasing the friction to flow. This potential loss in productivity is discussed elsewhere in this report.

It will be necessary to purchase a tubing hanger flange to hang the tubing and an extra spool for product to be piped out of the well below the tubing hanger.

To prevent the inhibition fluid from flashing in the tubing it will be necessary to put a nozzle at the bottom of the tubing and keep the fluid in the tubing pressurized. This means that when the tubing is being run into the hole it will have to be filled from the top to prevent it from collapsing. Also to reduce the potential corrosive nature of the concentrated inhibition chemical, it will have to be diluted ten to one before injection.

1. Chemical Injection Operation Sequence

Hours		
4 Hrs.	1.	Close master valve, install tubing spool and flanged "T" nipple up BPO's and diverter equipment.
12½ Hrs.	2.	Put on 5/32 orifice on tubing and strip in hole to TD stopping every ±100' to fill the tubing with fresh water to prevent tubing collapse and provide extra weight.
2 Hrs.	3.	Fill the well with fresh water from the surface so that blowout preventers and diverter equipment may be torn down.

4 Hrs. 4. When well is dead, tear down diverter blowout preventers and hang tubing.

6 Hrs. 5. Nipple up production equipment and injection equipment.

6. Flow test well, initiate N_2 start up if needed.

2. Pricing Data: Chemical Inhibition

Workover Rig	$ 111.50/Hr.
Truck	55.00/Hr.
Pick Up, Crew Transport	74.00/Hr.
Subsistence Per Man Per Day	40.00
B.O.P. 6" 3,000# Hydraulic 5 Day Minimum	465.00
Hydraulic Stripper Head/3 Day Minimum	170.00
Injection Pump	1,102.00
Piping	6.50/Ft.
Storage Tanks for Chemicals 400 BBl. 5 Day Minimum	20.00/Day
Storage Tank Trucking $49.00/Hr.	49.00/Hr.
Liquid Chemical 55 Gallon Lots 10 Drums F.O.B. Locations	.97/Gal
Liquid Chemical Bulk 42,000 Gal. Lots F.O.B. Location	.855
10" x 3,000# Valve	1,741.00
Tubing Hanger Adapter Flange	2,400.00
Flanged 10" x 3,000# "T"	8,400.00
Trucking Per Hour	55.00

3. Cost Analysis Chemical Injection

	UNIT	RATE	COST	TOTAL
OPERATIONAL: RIG COSTS				
INSTALL "T" FLANGE & TUBING SPOOL, B.O.P.	4 Hrs.	111.50	$ 446.00	
Trip in Hole	12.5 Hrs.	111.50	1,394.00	
Kill Well	2 Hrs.	111.50	223.00	
Nipple Down B.O.P. Hang Tubing	4 Hrs.	111.50	446.00	
Nipple Up Production Equipment and Injection Equipment	6 Hrs.	111.50	669.00	
Contingencies (15%)			476.00	
Subsistence (3 men)	1 Day	40.00	120.00	
Pick Up, Crew Transport	2 Hrs.	72.00	144.00	
TOTAL				$3,918.00
PURCHASE ITEMS				
Injection Pump			$1,102.00	
Stainless Steel Pipe	50 ft.	6.50/ft.	325.00	
In Line Check Valve			17.00	
Tubing Hanger Adapter Flange			2,400.00	
10" Valve			1,741.00	
Flanged 10" x 3,000# "T"			8,400.00	
Trucking	8 Hrs.	55 Hr.	440.00	
Contingencies 10%			1,443.00	
TOTAL				$15,868.00
CHEMICAL COSTS				
30 Day Costs For Chemical And Water				
Chemical @ 30 Gal/Day	900 Gal.	10.85/Gal	9760.00	
Injection Water	214.2 Bbls.	.50 Bbl.	107.00	
Fract Tank Rental	30 Days	20.00 Day	600.00	
Fract Tank Trucking	16 Hrs.	49.00	784.00	
Contingencies 10%			1125.00	
TOTAL				$12,376.00
RENTAL ITEMS				
B.O.P. "6" 3000# Hydraulic	5 Day Min.		465.00	
Hydraulic Stripper	3 Day Min.		170.00	
TOTAL				$635.00

		NO. CYLINDER	NO. HOURS	COST	TOTAL
FUEL COSTS					
Move In - Out	Rig	8	12	$ 96.00	
Rig Up - Down	Rig	8	12	96.00	
Run Tubing	Rig	8	18.5	148.00	
Kill Well		6	2	12.00	
					$352.00

4. Cost Summary Chemical Injection for 30 Day Test

Mobilization-Demobilization (see Mechanical Descale for details)		$ 2,362.00
Tubing Costs	"	22,086.00
Rig Up - Rig Down	"	2,302.00
Rig Operation Costs		3,918.00
Purchased Items		15.868.00
Chemical & Water		12,376.00
Fuel Costs		352.00
Rental Items		635.00
TOTAL		$59,899.00

Remoteness Factor: 4.7%

5. Chemical Data

The following four pages contain data supplied by NL Treating Chemicals on their recommended treatment chemical and its cost.

NL Treating Chemicals

July 17, 1981

Mr. Paul McKissen
Keplinger and Associates, Inc.
2200 Security Life Building
Denver, Colorado 80202

RE: Scale Inhibition
Geothermal Fluids
Baca Project

Dear Mr. McKissen:

Formula selection for the Baca Generic Well has been made.

A. TREATING STRING:

I. Chemical:
NL TREATING CHEMICALS Scale Inhibitor BAROCHEM - S35 is recommended.

II. Initial Treatment:
Inject into the total volume of re-circulating water, 30 - gallons, (335.7 pounds) BAROCHEM - S35/day.

III Continuous Treatment:
Following initial treatment, a continuous injection into treating string to maintain 30 PPM - BAROCHEM - S35 is recommended. Treatment rate to be adjusted by monitoring of Scale Coupons, and residual BAROCHEM - S35 in produced water.

B. MONITORING:

NL TREATING CHEMICALS personnel will monitor chemical performance monthly by scale coupons, iron counts and product residual.

NL Treating Chemicals/NL Industries, Inc.
410 Building - Suite #200, 410 Seventeenth Street, Denver, Colorado 80202 Tel. (303) 623-7361

July 17, 1981
NL TREATING CHEMICALS
Page 2

C. PRODUCT COST:

		LIQUID PRODUCTS PRICED PER POUND F.O.B. LOCATION	
	NET WEIGHT	55 - GALLON DRUMS	BULK GALLONS
PRODUCT	PER DRUM	10	42,000
SURFLO-S35	615	$0.97	$0.865

Prices quoted above are in effect through July 31, 1981. Chemical stocks are maintained in Channel View, Texas.

Sales engineers resides in Farmington, New Mexico.

On behalf of NL TREATING CHEMICALS, I wish to thank you for this opportunity to be of service.

Yours truly,

W.W. Taylor

W.W. Taylor
Account Representative
NL TREATING CHEMICALS

Enclosure:

WWT/gls

General Information:

BAROCHEM-S35 is a water soluble, liquid scale inhibitor used for the prevention of alkaline earth metal deposits. The product exhibits the "threshold effect" in aqueous solutions to prevent the formation of scale deposits. BAROCHEM-S35 at normal use concentrations will gradually remove calcium carbonate and calcium sulfate deposits by softening and disintegrating the scale that has already formed. The product also functions as a dispersing agent to prevent the formation of scale deposits.

Physical Properties:

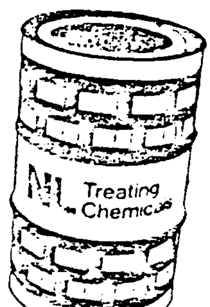
Specific Gravity at 68 F	1.343
Density, lb/gal	11.19
Viscosity, SUS at 70 F	135
Flash Point, F (Tag Closed Cup)	None
Pour Point, F	-10
pH (1% solution)	10.4

Chemical Description:

BAROCHEM-S35 is a slightly alkaline, anionic, organic phosphonate scale inhibitor. The product will not revert to ineffective compounds on exposure to high temperature as do the inorganic polyphosphates. BAROCHEM-S35 exhibits the "threshold effect"; i.e. small concentrations of chemical prevent scale deposition by holding a much larger quantity of multivalent cations in solution. BAROCHEM-S35 is stable and effective in aqueous solutions at temperatures up to 500 F.

Limitations:

BAROCHEM-S35 tends to be corrosive to mild steel, copper, brass, or aluminum chemical injection pump parts. Injection pump parts and lines should be stainless steel or plastic.



BAROCHEM-S35 may be subject to evaporation of the water phase and crystallization of active chemical ingredients under certain extreme conditions such as high temperature and/or low relative humidity. If evaporation and crystallization should occur, dilution and mild mixing with fresh water will readily dissolve the crystals.

Recommended Uses:

BAROCHEM-S35 is recommended for inhibition of alkaline earth metal scale deposits such as calcium carbonate and calcium sulfate in:

1. process water systems
2. cooling water systems
3. steam generators.

Treatment Requirements:

Recommendations should be based on complete water and scale analyses prior to treatment with BAROCHEM-S35. Equipment inspection and supplemental tests (membrane filter, scale coupons) can be made to provide additional information.

These analyses should establish (a) the presence of a scale-forming condition, (b) the type of scale being formed, (c) the severity of the scale problem, (d) the temperatures at which the scale will most likely form, and (e) the most effective place in the system to inject the chemical.

The severity of the scale problem and the economics of treating the system will, in most cases, dictate the treatment concentration. Optimum inhibition of alkaline earth metal scale deposition is obtained by continuous treatment with BAROCHEM-S35. The average treating rate is 3 to 5 ppm although rates will vary. For example, when BAROCHEM-S35 is used to control scaling problems in mill process waters, 1 to 3 ppm added to the reclaim water (thickener overflow) before the water returns to process is adequate.

H. TUBING WASHOVER SEQUENCE

On a well in the Baca Ranch area of New Mexico, 2 7/8", 6.4#/ft. H-40 tubing was run so chemical inhibition material could be injected at 5,000' T.D. to aid in the prevention of scale buildup. However, a steady decrease in production indicates that a scale buildup has occurred despite the injection of scale inhibitor.

A workover rig was mobilized to pull the tubing out of the hole and ream out the scale buildup. However, when an attempt was made to pull the tubing, 31,000# over the weight of the string was pulled, and the conclusion was that the tubing was stuck. By using freepoint calculations, it was determined that the tubing was free down to ±3,775'. At the temperatures encountered in this well (550°F), it is impossible to get an exact freepoint due to temperature limitations of freepoint tools. Collar locators will work at these temperatures, however, so it was decided to contact a wireline company in Vernal, Utah to run a string shot and back the string off the freepoint. A fishing tool company in Vernal was contacted to supply the necessary equipment and supervision to fish the remainder of the tubing from the hole.

Approximate calculations using 4,530 - 2 7/8" tubing freepoint constant (Baker Tech Facts)

$$\text{Approximate freepoint} = \frac{S}{F} \times 4{,}530$$

$$3{,}775 = \frac{25 \text{ in.}}{31 \text{ M}} \times 4{,}530$$

F = Pull force in thousands of pounds.

S = Stretch in inches.

1. Operational Sequence for Tubing Workover

6 Hrs.	1.	Rig up workover rig.
2½ Hrs.	2.	Pump fresh water down tubing and kill well, rig down surface production equipment.
2 Hrs.	3.	Pull on tubing and try to work it free.

20 Hrs.	4.	Contact wireline company and fishing tool company and wait on same.
1 Hr.	5.	Rig up wireline company with collar locator and string shot.
½ Hr.	6.	Go down inside tubing with wireline to 3,8000'.
1 Hr.	7.	Log collars from 3,800 to 3,600.
½ Hr.	8.	Select collar at 3,762 to back off, put 3 3/4 rotations of left hand torque in tubing, fire shot and back off.
1 Hr.	9.	Pull wireline from hole and rig down wireline truck.
4 Hrs.	10.	Pull free tubing from hole and lay down 3 joints above back off point.
2½ Hrs.	11.	Pick up 6" cut lip rotary shoe, 2 joints 4½ washover pipe, 1 rotary drive bushing, 1 set oil jars, 1 set bumper jars and 1 crossover sub (total length of fishing tools 89').
2 Hrs.	12.	Run fishing tools in the hole on tubint to ±3,730, pick up power swivel and begin washing to top of the fish.
1 Hr.	13.	Tag the top of fish and work tools until rotary shoe gets over the top of the fish.
½ Hr.	14.	Begin washing and rotating down over the fish, tag scale at 3,785.
4 Hrs.	15.	Washover from 3,785 - 3,801 and fishing string ceases to take any weight, indicating that the stuck tubing has fallen free.
6 Hrs.	16.	Pull washover pipe from the hole, standing the tubing back but laying down drive bushing and washover pipe.
½ Hr.	17.	Pick up overshot and extension with a cut lip guide and make them up on bottom of the jars and bumper sub.
2 Hrs.	18.	Go in the hole to 3,770 and tag the fish (note the difference in the 3,762' back off point and the present top of the fish due to slack in the pipe when it fell free).
1 Hr.	19.	Work tools and catch the fish.
3 Hrs.	20.	Slowly pull fish from the hole.
2½ Hrs.	21.	Break down and load out fishing tools.
1½ Hrs.	22.	Lay down top joint of fish, stand remainder of tubing in the derrick.
3 Hrs.	23.	Pick up 6" bit, 6" casing scraper, bumper jars, oil jars 1 - 4½" drill collar and 1 crossover sub and go in the hole to the liner hanger (3,750).
6 Hrs.	24.	Ream scale buildup from 3, 750 to 5,000' T.D.
3 Hrs.	25.	Pull out of hole, lay down bit casing scraper, drill collar, jars and bumper sub.
2 Hrs.	26.	Go in hole open-ended to ±4,940 (note 2 joints of tubing were not in string due to string shot being fired in back off operations).
4 Hrs.	27.	P.O.O.H. laying down tubing.
4 Hrs.	28.	Close master valve, rig down B.O.P. and diverter equipment and tubing hanger spool.
3 Hrs.	29.	Nipple up production equipment.
4 Hrs.	30.	Open master valve and attempt to flow well.
	31.	Release rig, and tear down.
	32.	If well does not flow, initiate N_2 start up.

2. Price

Workover Rig	$ 108.00/Hr.
Ten Ton Winch Truck and Driver	55.00/Hr.
Pick Up, Crew Transport	75.00/Hr.
Power Swivel	450.00/Day
Duplex Pump	255.00/Day
B.O.P., 6" 3,000# Hydraulic	55.00/Day
Casing Scraper	300.00/Run
Pipe Racks	15.00/Day/Set
Subsistence Per Man Per Day	40.00
Washover Pipe 4½" Per Foot 1st Day, $3.30 Each Additional Day	1.35/Ft.
Washover Pipe Shoe Per Job	360.00
4 3/4" Jars $606.00 First Day, $402.00 Each Additional Day	
Bumper Jar $471.00 1st Day, $315.00 Each Additional Day	
Subs	40.00/Day
Overshot $266.00 First Day, $169.00 Each Additional Day	
Extension	97.00/Day
Fishing Tool Supervisor Mileage	.70/Mile
Fishing Tool Supervisor Subsistence	350.00/Day
Wire Line Back Off Equipment - Service Charge	645.00
Wire Line String Shot Charge	975.00
High Temperature Charge 100% Base Price	1,950.00
Mileage	2.05/Mile
4" Drill Collars $41.00 Each First Day $12.00 Each Additional Day	

3. Cost Analysis Tubing Washover Sequence

	UNITS	RATE	COST	TOTAL
RIG MOBILIZATION-DEMOB (see Mechanical Descaling for details)				$ 2,862.00
RIG UP - RIG DOWN (see Mechanical Descaling for details)				2,302.00
TUBING WASHOVER RIG COSTS				
Pump Water, Kill Well	2.5 Hrs.	111.50	278.75	
Pull On Tubing, To Work Free	2 Hrs.	111.50	223.00	
Wait On Wireline & Fishing Tools	20 Hrs.	111.50	2,230.00	
R.U. Wireline Company	1 Hr.	111.50	111.50	
G.I.H. to 3,800' w/Collar Locator	.5 Hrs.	111.50	55.75	
Log Collars From 3,800-3,600	1 Hr.	111.50	111.50	
Put In Left Hand Torque	.5 Hrs.	111.50	55.75	
P.O.O.H. w/Wire Line R.D.	1 Hr.	111.50	111.50	
Pull Free Tubing From Hole	4 Hrs.	111.50	446.00	
Pick Up Wash Over Tools	2.5 Hrs.	111.50	278.75	
G.I.H. w/Tools & Wash Over Pipe	2 Hrs.	111.50	223.00	
Tag Fish & Scale	.5 Hrs.	111.50	55.75	
Wash Over 3,785 - 3,801	4 Hrs.	111.50	446.00	
P.O.O.H. w/Wash Pipe, Lay Down	6 Hrs.	111.50	669.00	
Pick Up Over Shot	.5 Hrs.	111.50	55.75	
G.I.H. To Top Of Fish	2 Hrs.	111.50	223.00	
Work Tools Catch Fish	1 Hr.	111.50	111.50	
P.O.O.H. w/Fish	3 Hrs.	111.50	334.00	
Break Down, Load Fishing Tools	2.5 Hrs.	111.50	278.75	
Lay Down Top Jt. Fish Stand Back	1.5 Hrs.	111.50	167.25	
G.I.H. w/6" Bit - Casing Scraper	3 Hrs.	111.50	334.50	
Ream Scale to T.D.	6 Hrs.	111.50	669.00	
P.O.O.H. Lay Down Bit & BHA	3 Hrs.	111.50	334.50	
G.I.H. Open-Ended	2 Hrs.	111.50	223.00	
P.O.O.H. Lay Down Tubing	4 Hrs.	111.50	446.00	
Close Master Valve R.D. B.O.P.	4 Hrs.	111.50	446.00	
R.U. Production Equipment	3 Hrs.	111.50	334.50	
Open Master Valve Flow Test	4 Hrs.	111.50	446.00	
Contingencies 10%			970.00	
Subsistence 3 Men	8 Days	40.00	960.00	
Crew Travel Time	16 Hrs.	72.00	1,152.00	
				$12,782.00
RENTAL EQUIPMENT COSTS				
Wire Line Mileage, Round Trip	900 Mi.	2.05	$1,845.00	
Wire Line Service Charge		645.00	645.00	
Wire Line Service Charge		975.00	975.00	
High Temperature Charge			3,240.00	
Wash Over Pipe 1st Day	60 Ft.	3.30	198.00	
Wash Over Pipe Shoe/Job			360.00	
Jars	1 Day	606.00	606.00	
Bumper Jar	1 Day	471.00	471.00	
Change Over Subs	1 Day	40.00	40.00	
Over Shot	1 Day	266.00	266.00	
Over Shot Extension	1 Day	97.00	97.00	
Fishing Supervisor Mileage	1,000 Mi.	.70	700.00	
Fishing Supervisor Maintenance	2 Days	350.00	700.00	
Power Swivel	7 Days	450.00	3,150.00	
Duplex Pump	7 Days	225.00	1,575.00	
B.O.P.	7 Days	55.00	385.00	
Casing Scraper 1 Run		300.00	300.00	
Pipe Racks (2 sets)	7 Days	15.00/Set	210.00	
Water	550 Bbls.	.50/Bbl.	275.00	
Drill Collars 1st Day	6	41.00/Ea.	246.00	
Drill Collars Additional Days (6 Drill Collars)	2 Days	12.00/Ea.	144.00	
Trucking, Fishing Tools, Round Trip	22 Hrs.	55.00	1,210.00	
Contingencies 15%			2,646.00	
				$20,284.00

		NO. CYLINDER	NO. HOURS	COST	TOTAL
FUEL COSTS					
Move In - Out	Rig	8	12	$96.00	
Rig Up - Down	Rig	8	12	96.00	
Run Tubing	Rig	8	18.5	148.00	
Kill Well	Pump	8	2	16.00	
					$356.00

4. Cost Summary Tubing Washover and Fishing Job

	COST	TOTAL
RIG MOBILIZATION-DEMOB.	$ 2,862.00	
RIG UP - RIG DOWN	2,302.00	
RIG COSTS	12,782.00	
RENTAL EQUIPMENT COSTS	20,284.00	
FUEL COSTS	356.00	
		$38,586.00

REMOTENESS FACTOR: 7%

I. HYDROFRACTURE

Hydrofracture jobs vary considerably in size, objectives, cost, and success. For this study we requested a quotation for a hydrofracture job from Western Petroleum Services. The request made was for a moderate fracture job, requiring a minimum of proppants, to be done without a rig onsite and with reservoir and well conditions corresponding to the Baca Location. Such a job would most likely correspond to an objective of correcting for skin damage done by mud invasion. This objective does not correspond well to stimulation needs at the Baca Locations and is more in keeping with needs in sedimentary locations like East Mesa. Hydrofracture has been done at the Baca Location to create a large fracture that will connect with sufficient remote fracture permeability to overcome a lack of near well bore permeability. The cost of these fracture jobs has been in the order of $1¼ million compared to the $¼ million for the study presented here.

Clearly, with a factor of five potential cost variations in the price of a hydrofracture job, the relationships between frac costs, increase in productivity, and well costs are very important. At the January '81 International Conference on Geothermal Drilling and Completion Technology, D. A. Campbell reported on hydrofracture stimulation at Raft River and East Mesa. Results varied from little increase in flow to a five-fold increase in flow, but still subeconomic, at Raft River and were reported as very successful at East Mesa.

This study makes no attempt to evaluate the cost effectiveness of hydrofracture stimulation or present adequate data for such an evaluation. For the information required for such an evaluation the reader is referred to the DOE Stimulation Program. The GEOCOM Model, however, is a potentially valuable tool in evaluating such cost effectiveness when adequate data is used. The Western proposal attached is only one reference point in the cost of geothermal stimulation and is included so that the reader may see some of the costs involved.

Quotations are in 1981 prices current at the time of quotation and are subject to change without notice. The prices are also subject to the Service Company standard terms and conditions.

Western Petroleum Services

GENERALIZED

FRACTURE STIMULATION RECOMMENDATION

FOR A GEOTHERMAL PRODUCING WELL

PREPARED FOR

KEPLINGER AND ASSOCIATES, INC.

Prepared By:
Rick Grisinger
The Western Company
Denver, Colorado

May 29, 1981

410 17th Street • Suite 1920 • Denver, Colorado 80202 • Phone 303/623-6037

DISCUSSION:

A generalized fracturing design has been prepared for a geothermal producing well at Keplinger and Associates request.

The design was based on the interval from 4660-4960 feet with a 300 foot fracture height. It is recommended that the zone to be treated be open hole or a perforated section, since it is next to impossible to frac through slots in a liner.

It is recommended that the job be pumped at a high rate of 60-80 BPM with a miximum treating pressure of 3,000 psi.

The suggested volumes are 150,000 gallons of water as a cool-down pre-pad followed by 160,000 gallons of Mercury gel containing 50,000# of 100 mesh sand and 170,000# of 20/40 mesh bauxite.

Computer runs of the temperature survey, volume vs. length, and the proppant profile have been attached for inspection.

WELL DATA:

Formation:	Bandelier Tuff
Average Depth To Zone:	4,810 ft.
Zone Height:	300 ft.
Casing Size:	9 5/8", 40# surface to 4,000 ft.
Perforated Interval:	4660-4960 ft. (slotted liner)
Bottom Hole Temperature:	550^{o} F
Fracture Gradient:	.68 psi/ft
Bottom Hole Fracture Pressure:	3,270 psi
Bottom Hole Pressure:	1,230 psi
Overburden:	2,040 psi
Hydrostatic Head:	2,100 psi with gelled water
ISDP (gelled water):	1,170 psi
Porosity:	10%
Permeability:	1 md (but naturally fractured)
Well Spacing:	160 acres
Perferred Rate:	60-80 bPM
Maximum Surface Treating Pressure:	3,000 psi

TREATMENT PROCEDURE:

Frac via casing at a maximum rate up to 80 BPM with a maximum surface treating pressure of 3,000 psi. Treatment is to consist of a 150,000 gallons of water as a cool-down pad followed with 160,000 gallons of Mercury gel containing 50,000# of 100 mesh sand and 170,000# of 20/40 mesh bauxite. Stage as follows:

1. Pump 150,000 gallons of water as a cool-down prepad.
2. Pump 20,000 gallons of Mercury Gel as a pad to initiate the fracture and establish sufficient fracture width to accept sand.
3. Pump 20,000 gallons of Mercury Gel with 1.0 ppg 100 mesh sand.
4. Pump 20,000 gallons of Mercury Gel with 1.5 ppg 100 mesh sand.
5. Pump 40,000 gallons of Mercury Gel with 1 ppg 20/40 mesh bauxite.
6. Pump 40,000 gallons of Mercury Gel with 2 ppg 20/40 mesh bauxite.
7. Pump 20,000 gallons of Mercury Gel with 2.5 ppg 20/40 mesh bauxite.
8. Flush to top of zone with water.

TREATMENT REQUIREMENTS:

Treating Conductor:	9 5/8" casing
Injection Rate:	60-80 BPM
Expected Surface Treating Pressure:	3,000 psi
Total Pumpable Volume of Water: (used as a prepad and flush)	165,000 gallons
Total Pumpable Volume of Mercury Gel:	160,000 gallons
Total 20/40 Mesh Bauxite Required:	170,000#
Total 100 Mesh Sand Required:	5,000#

Auxiliary Materials:

1,600# gel master

COST ESTIMATE:

160,000 gallons of Mercury Gel	$ 65,600.00
1,600# Gel Master	1,760.00
Chemical Delivery Charge	1,400.00
50,000# 100 Mesh Sand	2,850.00
170,000# Bauxite	126,500.00
Sand Pumping Charge	125.00
Bauxite Pumping Charge	1,360.00
Proppant Delivery Charge	15,444.00
80 BPM Master Mixer	1,350.00
5,883 HHP @ 3.55/HHP	20,884.62
Blending Charge @ 375/hr	3,000.00
Mileage Charge	4,050.00
Suction Manifold	1,621.00
	$247,069.62

Temperature Profile with Prepad

DIST. FROM WELLBORE (FEET)	TEMP. (F)	FLUID PUMPED (GALLON)	TIME (MINUTE)	FRACTURE LENGTH (FEET)
0	80	150,000	44.6	464
46	139			
92	184			
139	219			
185	248			
232	272			
278	293			
324	313			
371	334			
417	358			
464	550			

Fracture Geometry

N PRIME	= .75	K PRIME	= .0050000
SPURT	= .0 CC	FLUID LOSS	= .0018 Ft/SOR (Min)
WEIGHT	= 300 Ft	YOUNGS MOD.	= 6.00E+06 PSI
INJECTION RATE	= 80.0 BPM		

VOLUME (GALLONS)	LENGTH (FEET)	WIDTH (INCHES)
11,826	100	.202
32,616	200	.246
59,889	300	.276
92,837	400	.300
131,013	500	.320
(Volume of proposed frac job 160,000 gallons)		
174,121	600	.337
221,951	700	.352
274,341	800	.366
331,166	900	.378
392,322	1000	.390

THE WESTERN COMPANY

PROPPANT PROFILE STUDY

PERFECT SUPPORT FLUIDS

Fluid Studied - Mercury Gel
Total Volume - 167,709 Gallons
Fluid Penetration - 641 Feet

Perm. to Simulation Fluid - 1.000 MD
Perm. to Reservoir Fluid - 1.000 MD
Leak-off Fluid Viscosity - 1.00 CP
Reservoir Fluid Viscosity - .02 CP
Reservoir Fluid Comp. - 1.00E-or 1/PSI
Stim. Fluid C-III - 0.00300 Ft/SQ (Min)
Combined C - 0.00150 Ft/SQ (Min)

Frac. Pressure - 3270 PSI
Resevoir Pressure - 1230 PSI
N Prime - .750
K prime - 0.005000 lb-Sec/Ft
Youngs Modulus - 6.00E+06 PSI
Width - .340 Inches
Injection Rate - 80.0 BPM

FLUID VOLUME (GALLONS)	SURFACE PROPPANT CONC (LB/GALLON)	LOCATION IN FRACTURE (FEET)	FRACTURE PROPPANT CONC (LB/FEET^2)	CUMULATIVE PROPPANT (POUNDS)
20,000	.00	601 to 641	.000	0
20,000	.00	556 to 601	.000	0
20,000	.00	504 to 556	.000	0
40,000	1.00	366 to 504	.482	40,000
40,000	2.00	153 to 366	.627	120,000
20,000	2.50	0 to 153	.543	170,000

Total Frac Fluid Volume - 160,000 Gallons

J. PERFORATING

To determine the costs of a geothermal perforating job we requested quotations from several service companies. The attached reply from Schlumberger is representative of the cost quotations we received. The quote is for 4 shots per foot and a 1000 foot interval. This density and interval were selected to produce a completion as similar as possible to a typical open hole completion. Quotations are in 1981 prices current at the time of quotation and are subject to change without notice. The prices are also subject to the service company standard terms and conditions.

THE BDM CORPORATION

Schlumberger

SCHLUMBERGER WELL SERVICES
5000 GULF FREEWAY P O BOX 2175
HOUSTON, TEXAS 77001. (713) 928-4000

PLEASE REPLY TO
1450 METROBANK BUILDING
475 SEVENTEENTH STREET
DENVER, COLORADO 80202
(303) 825-5207

March 11, 1981

Paul McKissen
K & A Helton
Suite 2200
1616 Glenarm Place
Denver, CO 80202

Dear Sir:

The following is a cost estimate for current charges on a well in Millard County, Utah. The well has an estimated BHT of 500° F. and you wish to perforate it from 4000 to 5000 feet with a shot density of 4 per foot.

Service charge (450 miles Round Trip)		$1240.00
Perforating Depth Control		
Depth control - Depth chg. (.19/ft.)(5000 ft.)	950.00	
Operation (.17/ft.)(2000 ft.)	340.00	1290.00
		$2530.00
4" Guns - High Temperature		
Depth - 10 shots	1060.00	
Operation - (3991 shots)($63/shot)	251,433.00	
Blasting caps - High temperture (100)($80)	8000.00	
		260,493.00
Cable Charges - High Temperature ($1900/descent)(35 descents)		66,500.00
Standard Pressure Equipment		300.00
Portable Derrick ($350/day)(3 days)	1050.00	
(300 miles)(2.10/mile in excess 150)	630.00	
		1680.00
Estimated total cost less tax		$331,503.00

These costs are at the current price schedule and would vary according to any pricing changes.

All prices and services would be sugject to Schlumberger's General Terms and Conditions.

If I may be of further help, please call.

Very truly yours,
SCHLUMBERGER WELL SERVICES

Craig Rang
Senior Sales Engineer

A DIVISION OF SCHLUMBERGER TECHNOLOGY CORPORATION

K. N_2 START UP

To start up a well by N_2 injection the tubing string is set low enough to lighten the back pressure at the sand face and allow the well to flow and begin flashing. Under flowing conditions the flash point is a function of formation temperature and drawdown, gravity head up to flash point, and frictional losses below the flash point. Initially these parameters are not known until the well has been tested. Typical depths reported for flashing in flowing wells have been up to 2000 feet. Under shut-in conditions the flash point will be the boiling point at pressure. The objective of the N_2 and foam is to reduce the pressure at the depth the tubing is set to essentially atmospheric. Therefore, the point where the shut-in temperature is 212°F is the minimum tubing depth. For fields like East Mesa this point is 1500 feet; normally without the N_2 lift the flash temperature at this depth would be over 450°F. For this study 2000 feet was chosen as a representative depth to set the tubing string.

1. Operation Sequence N_2 START UP

(1) Move continuous coil tubing unit, nitrogen pumper, fluid pumper, NEX 800 (foamer), 5,000 psi stuffing box and blowout preventers with blind rams, cut-off rams, hydraulically operated slips, and tubing rams on location.

(2) Rig up all equipment and test (3 hours).

(3) Go in hole with coiled tubing at 60'-per-minute to top of water.

(4) Start nitrogen, wait for flow to start, slowly lower tubing with nitrogen flowing to calculated flash point. If well starts erratic flow, inject foamer to mingle with water to displace as smoothly as possible to unload cool and/or cold water. If it flows unassisted, pressure builds, and flashing occurs, pull out of hole with tubing at 150'/minute.

(5) Check well flow, if satisfactory, rig down continuous tubing, B.O.P. stack and accessary equipment.

(6) If not satisfactory, G.I.H. and repeat water lift procedure.

(7) When well is flowing properly, release equipment. The above sequence does not include a detailed time breakdown due to the unknown depth of the top of the water, the temperature of the water, and the flash point depth. With this many unknowns, an off-site operation prediction is not reliable enough to make a firm estimate of operational times and material costs.

2. <u>Capacities and Prices</u>

Nitrogen

1st 25,000 SCF	(included with pumper)
2nd 25,000 SCF	@ \$1.75/c
3rd 25,000 SCF	@ \$1.65/c
Additional N_2	@ \$1.55/c

Pumper

Set up	\$625.00
Hourly change	60.00/hr.

Transfer Pump

Set up (inc. 4 hours)	495.00
Additional hours	100.00/hour

NEX 800 Foamer (concentration ½%) — 24.00/gallon

N_2 Required for 2000 feet

2000 feet of 9/58 40# casing @ .4257 cu ft/linear foot
= 851 cu ft

Correcting from pressure @ 2000 feet to standard pressure

$$= 851 \times \frac{(2000 \times .433 + 15)}{15}$$

= 49,982 cubic feet

Injection Rate — 800 SCF/minute

Foam Required

851 cu ft x .005 x 7.48 gal/cu ft = 31.8 gal

3. Cost Analysis N_2 Start Up

	UNITS	RATE	RATE	TOTAL
TUBING UNIT				
Set up charge (8 hours on location)			$1,850.00	
Footage Charge	2,000 ft	.10/ft	200.00	
Mileage Charge	350 miles	2.00/mile	700.00	
Stripper Rubber			105.00	
				$2,855.00
NITROGEN				
N_2 Pumper	25,000	-	$625.00	
2nd Unit	25,000	$1.75/c	437.00	
3rd Unit	25,000	1.65/c	412.00	
Mileage	350	2.00	700.00	
8 Hours Pumping Time	8	60	240.00	
				$2414.00
TRANSFER PUMP				
1st 4 Hours			$495.00	
Mileage	350	2.00	700.00	
				$1195.00
FOAM				
	31.8 gal	24	$764.00	
				$ 764.00
GRAND TOTAL				$7,258.00

L. ABANDONMENT

A well at Roosevelt Hot Springs, Utah with 9 5/8-inch casing cemented to surface, a 7-inch cemented perforated liner hung from 3,750 feet to a T.D. of 5,000 feet, with a well-head pressure of zero, has been steadily declining over its productive life to a time when it will no longer flow.

Temperature and spinner surveys confirm that there is no longer enough heat to cause flow. The well must be plugged and abandoned to governing agency specifications, "The Oil & Gas Conservation Act Regulations and Rules of Practice and Procedure," State of Utah, July 1, 1955.

The area has developed enough wells and power plants to warrant service companies to make local facilities available.

The prices quoted are 1980-81 because long-range forecasts are beyond the scope of this work. Instead of mobilization from distant areas, the mobilization/demobilization costs will be very insignificant.

1. Abandonment Operational Sequence

(1) Move facility's own tubing to well and place for use by work-over rig (4 hours).

(2) Move in rig from Beaver, Utah (1 hour).

(3) Set rig, pump and circulating tank. Nipple-down production wellhead, nipple-up B.O.P. stack (6 hours).

(4) Move cementing equipment, that is, pumper and bulk truck or trucks on location, spot and rig up (2 hours).

(5) Fill circulating tank with water and have sufficient water available via water-line to satisfactorily do the plugging operation (1 hour).

(6) Water needs: 350 bbls
Mud needs: 340 bbls
Cement: 3 bbls + 7 washup = 10 bbls.

(7) P.U. bridge plug and setting tool G.I.H. (3 hours).

(8) Set bridge plug, P.U. 6'-10' displace water with mud (mix 100 bbl, pills) (3½ hours).

(9) Rig up cementers to tubing mix and pump 21 sacks. Cement plug (½ hour).

(10) Pump cement followed by 25 bbls mud at 5 bbl/min. (¼ hour).

(11) Pull 4 strands tubing, rig down cementers (¼ hour).

(12) P.O.O.H. laying-down tubing, lay-down setting tool (3 hours).

(13) H.I.H. with 4 stands in derrick, lay-down (¼ hour).

(14) Drain pump, lines and circulating tank (¼ hour).

(15) Rig down B.O.P. and rig (6 hours).

(16) Move rig to yard (1 hour).

NOTE: The final cement plug and marker will be emplaced by field personnel at a later date. The sequence would be:

(1) One yard Ready-Mix cement moved to well (1 hour).

(2) One piece 4" x 10' line pipe or equivalent placed in cement in well with 4' exposed (½ hour).

(3) Use electric welder to inscribe well data on pipe (plus travel time) (½ hour).

(4) Use cutting torch and electric welder to "orange peel" top of marker (¼ hour).

(5) Clean up and regrade location (6 hours).

2. Cost Analysis Abandonment

LOGGING COSTS PRIOR TO ABANDONMENT	DEPTH	OPERATION	COST	TOTAL
Service Charge			$ 595.00	
Wireline Charge			740.00	
Equipment Charge			1,160.00	
Differential Temperature Log			2,330.00	
Spinner Flow Log			2,330.00	
Casing Collar Locator			NO CHARGE	
Instrument Protection Charge			130.00	
Mast Truck (1 day)			340.00	
Lubricator			600.00	
				$8,225.00

MOBILIZATION	UNITS	RATE	COST	TOTAL
Move Tubing to Well	4	55.00	$220.00	
Move Rig to Well	1	108.00	108.00	
Crew Pick Up	1	75.00	75.00	
10-Ton Truck Float & Driver	1	55.00	55.00	
Rig Up Rig and Equipment	6	108.00	648.00	
10-Ton Truck Rig Up	6	55.00	330.00	
Mud Drayage (3.65 tons)	25 mi.	.70	64.00	
Water (piped) Barrels	350	.50/bbl	175.00	
Move Cementing Equipment	2 units 25 mi.	2.00/mi.	100.00	
				$1,775.00

CEMENT AND CEMENTING EQUIPMENT				
Depth Charge/unit (3,000')	2	1,219.00	2,438.00	
Plus/100' or Fraction (1,500')	2	10.55	317.00	
Bridge Plug	1	981.00	981.00	
"G" Cement	13 Sacks	6.02	78.00	
SSA-1/Pound	560#	.105	59.00	
$CaCl_2$/Sack	.4 Sacks	25.00	10.00	
				$3,883.00

MUD TO FILL CASING	UNITS	RATE	COST	TOTAL
Gel/Sack	136 sx	7.50	1,020.00	
Lime/Sack	6 sx	7.00	42.00	
Caustic/Sack	4 sx	22.00	88.00	
				$1,150.00

RIG TIME-COST FOR PLUGGING				
P.U. Bridge Plug and Setting Tool	.25	108.00	27.00	
Go In Hole	2.75	108.00	297.00	
Set Bridge Plug, Mix Mud to Dis-Place Water	3.5	108.00	378.00	
R.U. Cementers to Tubing	.25	108.00	27.00	
Mix Cement, Pump, Displace	.5	108.00	54.00	
Pull 4 Stands, R. D. Cementers	.25	108.00	27.00	
Pull Out of Hole, Laying Down	3.00	108.00	324.00	
G.I.H. 4 Strands P.O.O.H. Lay-Down Tubing	.25	108.00	27.00	
				$1,161.00

2. Cost Analysis Abandonment (concluded)

EQUIPMENT & LABOR TRAVEL TIME (ROUND TRIP)	UNITS	RATE	COST	TOTAL
DEMOBILIZATION				
Rig Down Rig and Equipment	6	108.00	648.00	
10-Ton Truck, Float and Driver	6	55.00	330.00	
Move Tubing to Storage	4	55.00	220.00	
Move Rig to Contractor's Yard	1	108.00	108.00	
Crew Transport	1	75.00	75.00	
10-Ton Truck, Float and Driver	1	55.00	55.00	
				$1,436.00
MATERIAL				
One Cubic Yard, Ready-Mix		51.00/yd.	51.00	
One Piece 4" x 10' Line Pipe		3.80/ft.	38.00	
				$89.00
EQUIPMENT & LABOR TRAVEL TIME (ROUND TRIP)				
2-Ton Truck with Tools/Less Driver	2	17.50	35.00	
Driver	2	15.50	31.00	
Helper	2	14.00	28.00	
Welder and Rig	2	30.50	61.00	
Motor Grader with Operator	3	40.00	120.00	
				$275.00
MARKER EMPLACEMENT TIME-COST				
2-Ton Truck	.5	17.50	8.75	
Driver	.5	15.50	7.75	
Helper	.5	14.00	7.00	
Welder and Rig	1	30.50	30.50	
				$54.00
LOCATION CLEANUP AND REGRADE				
Motor Grader with Operator	6	40.00	240.00	
2-Ton Truck	3	17.50	52.50	
Driver	3	15.50	46.50	
Helper	3	14.00	42.00	
				$381.00

3. <u>Cost Summary Abandonment</u>

Mobilization/Demobilization	$3,211.00	
Cement and Cementing Equipment	3,883.00	
Mud to Fill Casing	1,150.00	
Rig Cost for Plugging	1,161.00	
Marker Emplacement Material	89.00	
Equipment and Labor Travel Time (round-trip)	275.00	
Marker Emplacement Time-Cost	54.00	
Location, Cleanup and Regrade	381.00	
Confirming Electric Logs	8,225.00	
		$18,429.00

Volume II
GEOCOM User Instruction Manual

VOLUME II
GEOCOM USER INSTRUCTION MANUAL

VOLUME II

FOREWORD

This manual has been prepared by The BDM Corporation, 1801 Randolph Road, S.E., Albuquerque, New Mexico 87106 for Sandia National Laboratories under contract 46-8777. This manual describes the computer program GEOCOM which can be used for analyzing life cycle cost of a geothermal well. The manual also describes how to use GEOCOM. Contributors to this document were E. R. Anderson, W. C. Hoessel, and Dr. A. J. Mansure.

VOLUME II
TABLE OF CONTENTS

VOLUME II
LIST OF ILLUSTRATIONS

LIST OF TABLES

CHAPTER I
INTRODUCTION

The development of geothermal wells as an economically viable source of energy for the world's future energy needs is an important area for careful economic analysis. This document discusses a computer program (GEOCOM) which can be used by an analyst or engineer to assess the cost effectiveness of various life cycle scenarios of geothermal wells. This document also instructs the reader how to use the program.

The key output generated by GEOCOM is the cost effectiveness ratio, life cycle cost divided by life cycle benefit, which is in dollars per mBtu of energy produced. Life cycle cost takes into account capital costs, operation and maintenance costs, workover costs, and other costs. GEOCOM inflates and discounts the money as expended over the life of the well. The life cycle benefit is the inflated, discounted total production of the well over its life. GEOCOM models production as a function of time and accounts for interruptions for workovers and possibly a repair. More detailed discussion is provided in chapter II on how to define the functional relationship of production in addition to the costing parameters and well definition. Additional information on the model is also available in the GEOCOM final report.

Program GEOCOM has been written in ANSI (American National Standard Institute) FORTRAN[1] 1966 version. This allows the user freedom to install GEOCOM on any computer installation which has an ANSI FORTRAN compiler. There are two versions of this FORTRAN predominantly in use today, the 1966 version and the 1977 version. Although GEOCOM is written for the 1966 version, it can also be compiled and executed with the 1977 version.

A structural approach to developing GEOCOM was used. This approach is a technique called PDL (Program Design Language). PDL is simply the construction of comment cards into a logical sequence of processing steps before writing any FORTRAN statements. After the logic of the PDL has been debugged, the FORTRAN code is inserted to process the steps described in the comments. This approach to developing GEOCOM emphasizes developing the problem-solving aspects of the code. It also provides documentation in the code for easy modification or addition of software.

CHAPTER II
FEATURES OF GEOCOM

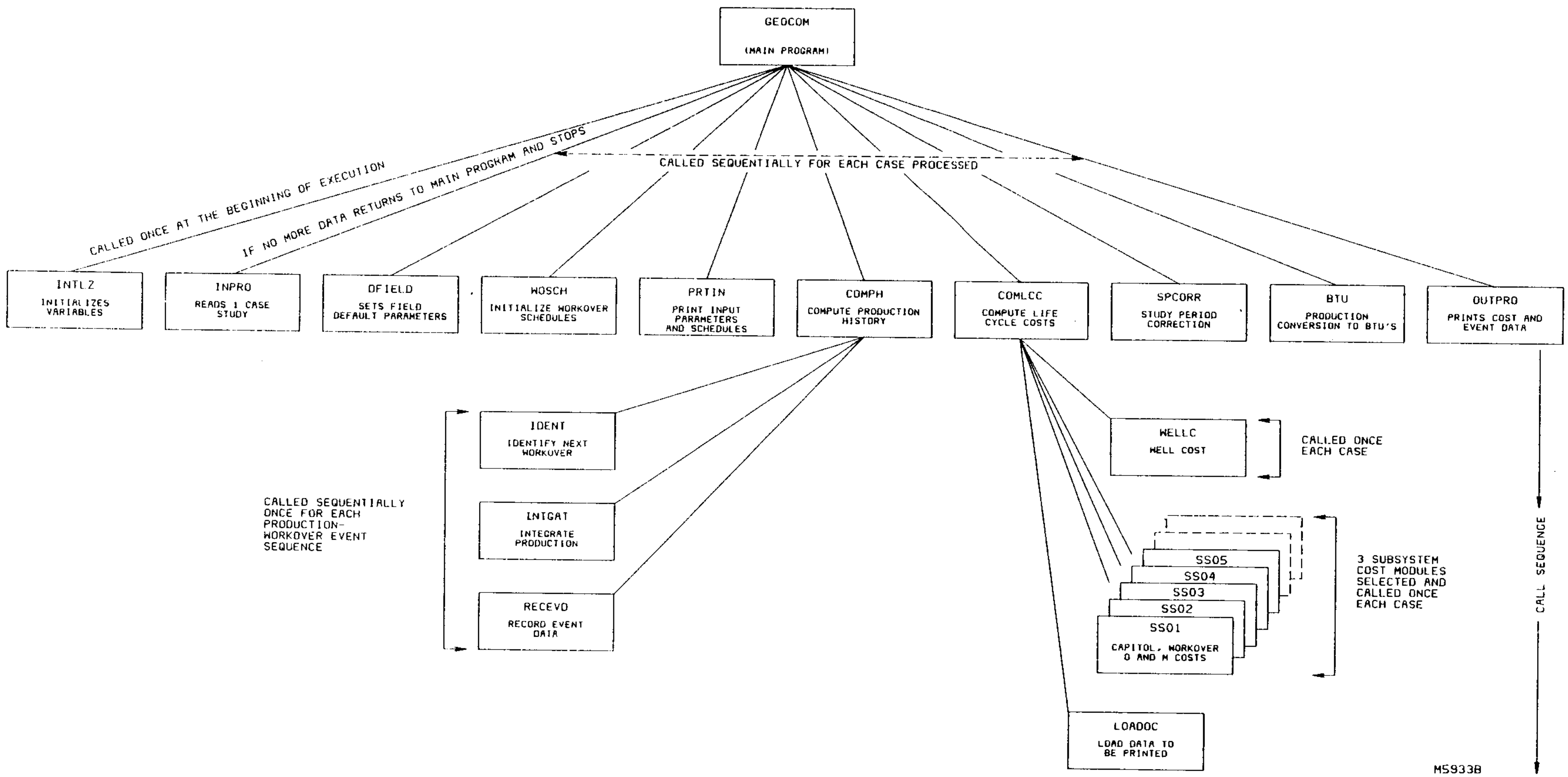
A. FUNCTIONAL OVERVIEW

The structure and general program flow of GEOCOM is illustrated in figure II-1. The main program GEOCOM calls all the first level subroutines from left to right and two of the first level subroutines, COMPH and COMLCC, call additional subroutines in order from top to bottom. The first level subroutines INPRO to OUTPRO are repeated for multiple cases on the input file. After completing all cases GEOCOM terminates execution. All data or parameters are passed between subroutines through a common block of memory. An important feature of GEOCOM is the subsystem costing subroutines (SS01-SS22). They include workovers, pumps, chemical inhibition, logging and a user-specified subsystem. The user has three options: 1) select a subsystem and let it compute the cost, 2) select a subsystem and override the cost calculation, or 3) create a new subsystem through the user-specified subsystem. This feature gives the user flexibility in defining subsystems.

GEOCOM is designed for batch processing. This was done for ease of use. The user only need create an object program from the source program using a FORTRAN compiler. Then save the object program on a permanent disc file or some device for permanent storage. To execute GEOCOM the user then loads the object program with Job Control Language (JCL) cards followed by the input data cards which are discussed in detail in the following section. Then the results will appear on the output file or listing.

B. INPUT

The input card deck is a set of cards defining one or more case studies to be executed in one batch process run. These input cards follow the JCL's as illustrated in figure II-2. The input deck is



BDM/A-81-614-TR-R1

Figure II-1. GEOCOM Structure and Program Flow

```
          COLUMN NUMBER                                       INPUT
          1111111111222222222233333333334444444444445          CARD
1234567890123456789012345678901234567890123456789 0           NO.
-------------------------------------------------------     ----
"User supplied JCLs"


"End of JCLs"
SAMPLE DEFAULT CASE                                            1
01 USER DEFINED SUBSYSTEM                                      2
                                                               3
                                                               4
                                                               5
END                                                            6
BRAWLEY WELL WITH TWO YEAR DELAY FOR INITIAL OPERATION         7
11 MECHANICAL DESCALE EVERY YEAR                               8
22 SLOTTED LINER REPLACMENT EVERY 3 YEARS                      9
                                                              10
REPAIR WELL WITH TIE-BACK LINER AT 9 YEARS                    11
FIELD          1.                                             12
TID           24.                                             13
WOFQ1         20.       11.8                                  14
WOFQ2         20.       35.8                                  15
WODLY          .2         .2                                  16
FLFC1         .042                                            17
FLFC2         .042                                            18
R1FQ          109.                                            19
WL            143.                                            20
END                                                           21
END GEOCOM                                                    22
-------------------------------------------------------
          1111111111222222222233333333334444444444445
12345678901234567890123456789012345678901234567890
```

Figure II-2. Batch Processing Input Structure divided into one or more cases. Each case consists of five title cards, zero or more parameter cards, followed by an end card.

A fixed input structure was implemented to simplify program transportability between different types of computers which use FORTRAN. Figure II-3 describes the format of the input cards and their order. The input structure is basically one or more cases followed by an "END GEOCOM" card. The first card in each case is the title or description of the case being run. This title is printed on the output file for the user to identify the run. The next three cards numbered 2, 3, and 4 are used by GEOCOM to identify what subsystems the user has selected for a run. There may be one, two, or, three subsystems selected. Columns one and two are the numeric field which identify the appropriate subsystem type(s). Figure II-4 lists all the subsystem types and their parameters. If the numeric field is left blank no subsystem will be selected. Columns 3 through 80 is a descripter that GEOCOM saves for output printing identification of subsystems used. The fifth card is a card used to describe a repair if one is specified. Cards 3 through 5 may be blank if the user doesn't need them, but these cards cannot be left out.

Cards 6 through N-1 are the parameter specification cards. These cards are used to specify values (C1-C4) different from the default. If the user wishes to use a default value for a parameter, the card is just left out. If a parameter is an array and requires multiple values on the same card, and the user wishes to change only one of the values from default, then the user must put "-999." in each of the other fields or array elements. This is required since a blank field is interpreted as zero and GEOCOM will load a zero in these parameter value fields C1, C2, C3 and C4. Also all values must be specified in floating point format. This means the user must use decimal points on all numbers; integers are not allowed. These fields will accept exponential notation (-1.0E-7); however, the user must be sure to right justify this value in the field because trailing blanks after the exponent are interpreted as zeros. Figure II-5 lists all the input parameters, the fields they use (C1-C4), and their definitions. These parameters may be specified in any order

CARD NUMBER	FIELD COLUMN	DEFINITION
1*	1-80	Case Description (any user description, for output identification only)
2*	1-2 3-80	First Subsystem type (numeric identifier) First Subsystem Description (any user description, will be displayed on output)
3*	1-2 3-80	Second Subsystem type (numeric identifier) Second Subsystem Description (May be left blank if second subsystem not needed)
4*	1-2 3-80	Third Subsystem type (numeric identifier) Third Subsystem Description (May be left blank if third subsystem not needed)
5*	1-80	Description of Repair (troubled completion, also may be left blank if one is not required)
6	1-6 7-16 17-26 27-36 37-46	Parameter Name First Value (C1) Second Value (C2) Defined in figure II-5 Third Value (C3) Fourth Value (C4)
7 through N-1		Same as card 6
N*	1-6	"END" End card for terminating parameter definitions (N may be 6 for all defaults)
N+1		Begin repeating cards 1 through N for next case (there is no limit on the number of cases which may be added)
LAST CARD*		"END GEOCOM" after last "END" card

*Required cards that must be in this order

Figure II-3. Format and Order of Input Cards

ID NO.	SUBSYSTEM
	GENERAL
01	User Input
03	Logging
	STIMULATION
05	Perforating with out logging
	DESCALING
11	Mechanical
12	Hydojet
13	Chemical Scale Inhibition
	PUMPS
16	Injection
17	Submersible
18	Line Shaft
20	Remedial Cement
21	Underreaming and Gravel Pack
22	Slotted Liner Replacement

SUBSYSTEM PARAMETERS	22	21	20	18	17	16	13	12	11	05	03	01
CHEMC	+	+	+	+	+	+	O	+	+	+	+	+
CMPPM	+	+	+	+	+	+	O	+	+	+	+	+
COMINT	O	O	+	+	+	+	+	O	O	O	O	+
DEPTH	+	+	+	+	+	+	O	O	O	O	O	+
DIST	O	O	+	+	O	+	O	O	O	O	O	+
EFF	+	+	+	+	O	O	+	+	+	+	+	+
ELECT	+	+	+	+	O	O	+	+	+	+	+	+
FPC	+	+	+	+	O	+	+	+	+	+	+	+
H0	+	+	+	+	+	O	+	+	+	+	+	+
IDSCLC	+	+	+	+	+	+	+	+	O	+	+	+
IDSCLI	+	+	+	+	+	+	+	+	O	+	+	+
LOGG	+	+	+	+	+	+	+	+	+	+	O	+
NRCS	+	+	O	+	+	+	+	+	+	+	+	+
PI	+	+	+	+	+	O	+	+	+	+	+	+
PIDR	+	+	+	+	+	O	+	+	+	+	+	+
PPSSC	+	+	+	+	O	*	O	+	+	+	+	O
PSD	+	+	+	+	O	+	+	+	+	+	+	+
Q0	+	+	+	+	O	O	+	+	+	+	+	+
SL	O	O	+	+	+	+	+	+	+	+	+	+
SPF	+	+	+	+	+	+	+	+	+	O	+	+
SSCC	+	+	+	+	O	O	O	+	+	+	+	O
SSYC	+	+	+	+	O	O	O	+	+	+	+	O
WHPMH	+	+	+	+	+	O	+	+	+	+	+	+
WOC	O	O	O	O	O	O	O	O	O	O	O	O
WODLY	O	O	O	O	O	O	O	O	O	O	O	O
WOFQC	O	O	O	O	O	O	O	O	O	O	O	O
WOFQ1, 2, or 3	O	O	O	O	O	O	O	O	O	O	O	O
WOREC	+	+	+	+	+	+	O	O	O	O	O	O
XT	+	+	+	+	+	+	O	O	O	O	+	O

\+ Parameter not used
O Parameter used for above subsystems
* Cost per Bhp-hr consumed

Figure II-4. Subsystem Types and Their Parameters

PARAMETER	FIELD LOC	DEFINITION	DEFAULT
ABAND	C1	Abandonment cost($)	18000.
CCCI	C1	Completion cost coefficient of completion interval($/ft)	90.23*
CHEMC	C1	Chemical cost($/lb)	0.97
CMPPM	C1	Chemical concentration	30.0E-6
COMINT	C1	Completion interval(ft)	3000.0*
CTIC	C1	Cost coefficient to intermediate casing($/ft)	195.9*
DCCI	C1	Drilling cost coefficient of completion interval($/ft)	72.3*
DEPTH	C1	Well depth(ft)	6000.0*
DF	C1	Discount factor(fraction/month)	0.00878
DIST	C1	Round trip distance(miles)	150.0
EFF	C1	Efficiency of the pump(fraction)	0.7
ELECT	C1	Cost of electricity($/kWh)	0.06
END	NONE	Ends input parameters for present case	
FIELD	C1	Field type: 1 = Brawley	4.0
		2 = Heber	
		3 = Geysers	
		4 = Baca	
		5 = RHS	
		6 = East Mesa	
FLFC1	C1,	Workover flow loss before repair(fraction/month)	0.125
	C2,	Flow Loss Fraction = 1 - (C1*t + C2*t**2 + C3*t**3)	0.0
	C3	t = Time since last flow loss time reset by XT	0.0
FLFC2	C1,	Workover flow loss after repair(fraction/month)	0.125
	C2,	Same form as FLFC1	0.0
	C3		0.0
FPC		Down hole pump cost correction factors:	
	C1,	First	1.0
	C2,	Second	1.0
	C3	Third	2.0
FTDS	C1	Fraction of total dissolved solids	6100.0*
H0	C1	Depth to water table(ft of head)	1640.0
IDSCLI	C1	Descale intermediate casing; 0=no, 1=yes	1.0
IDSCLC	C1	Descale completion liner; 0=no, 1=yes	1.0
INFLAT	C1	Inflation rate(fraction/month)	0.00695
LOGG	C1	This parameter is a six digit number representing six types of logging. These types are defined as follows: 100000. = Caliper	11000.0
		10000. = Temperature	
		1000. = Flow meter	
		100. = Perforating depth control	
		10. = Cement bond	
		1. = Casing inspection	
		Any combination of the above types may be added together to define a set of logging types to be performed.	
NRCS	C1	Number of repeat cement squeezes	0.0
PI	C1	Productivity Index(lb*h/ft of head)	431.3
PIDR	C1	Productivity index decline rate(fraction/yr)	0.0
PPSSC		Per pound subsystem cost for:	
	C1,	user specified subsystem one($)	-999.0
	C2,	user specified subsystem two($)	-999.0
	C3	user specified subsystem three($)	-999.0

*Field parameter default for BACA

Figure II-5. GEOCOM Input Parameter Definitions and Defaults

PARAMETER	FIELD LOC	DEFINITION	DEFAULT
PSD	C1	Pump set depth(ft)	1200.0
Q0	C1,	Initial flow rate at begining of well life(lb/h)	200000.0*
	C2	Initial flow rate after repair(lb/h)	88000.0*
RDR	C1	Reservoir decline rate (fraction/month)	0.003083*
R1CST	C1	Repair cost($)	121000.0
R1DLY	C1	Repair delay time(months)	0.33
R1FQ	C1	Time repair begins(months)	999.0
SL	C1	Slotted interval(ft)	1000.0
SP	C1	Study period(months)	360.0
SPF	C1	Shots per foot	4.0
SSCC		Subsystem capital cost for:	
	C1,	user specified subsystem one($)	-999.0
	C2,	user specified subsystem two($)	-999.0
	C3	user specified subsystem three($)	-999.0
SSYC		Percent of subsystem capital cost per year for operation and maintenance of:	
	C1,	user specified subsystem one($)	-999.0
	C2,	user specified subsystem two($)	-999.0
	C3	user specified subsystem three($)	-999.0
TEMP	C1	Well head temperature(F)	358.0*
TF	C1	Flashing temperature(F)	344.0
TID	C1	Initial delay between drilling well and beginning of production.(months)	0.0
TR	C1	Rejection temperature(F)	125.0
USAGE	C1	Type of energy consumption: 1 = Electrical 2 = Direct Heat 3 = Total Energy 4 = Injection	1.0
WCC		Well capital cost: GEOCOM computes the default for BACA.	
	C1,	Cost to bottom of intermediate casing($)	479700.0
	C2,	Drilling cost of completion interval($)	216900.0
	C3,	Completion cost of completion interval($)	270700.0
	C4	Sum the above three costs($)	967300.0
WHPMH	C1	Well head pump maximum head for injection pump(ft)	1155.0
WL	C1	Well life(months)	360.0*
WOC		Subsystem workover costs:	
	C1,	user specified subsystem one($)	-999.0
	C2,	user specified subsystem two($)	-999.0
	C3	user specified subsystem three($)	-999.0
WODLY		Workover delay:	
	C1,	user specified subsystem one(months)	**
	C2,	user specified subsystem two(months)	**
	C3	user specified subsystem three(months)	**
WOFQC		This factor is used to change frequency of scheduling workovers as a function of time. The following expression is used: f = f0*c**n f = Time between workovers f0 = Initial workover frequency c = Workover frequency correction factor n = Workover number	
	C1,	user specified subsystem one(fraction)	1.0
	C2,	user specified subsystem two(fraction)	1.0
	C3	user specified subsystem three(fraction)	1.0

*Field parameter default for BACA
**Default depends on user specified subsystem

Figure II-5. GEOCOM Input Parameter Definitions and Defaults (Continued)

PARAMETER	FIELD LOC	DEFINITION	DEFAULT
WOFQ1		This parameter is used to define the schedule for sub-system one:	
	C1,	Number of workovers to be performed by the first user specified subsystem	**
	C2	Time between each workover(months)	**
		This card may be repeated with different values of C1 and C2. The number of workovers specified on all WOFQ1 cards are added to the schedule table. The sum of all C1s for the WOFQ1 cards must not exceed 100 for each case.	
WOFQ2	C1,C2	Same format as WOFQ1 except it defines a schedule for the second user specified subsystem.	
WOFQ3	C1,C2	Same format as WOFQ1 except it defines a schedule for the third user specified subsystem.	
WOREC	C1,	Workover recovery factor for the first subsystem	**
	C2,	Workover recovery factor for the second subsystem	**
	C3	Workover recovery factor for the third subsystem	**
WRC		Well routine operation and maintenance cost:	
	C1,	$/year	54000.0
	C2,	% Capital Cost / year	3.0
	C3	$/lb	0.0
X	C1	Well head steam quality(fraction)	0.3*
XT		Reset flow loss reference time for:	
	C1,	user specified subsystem one	1.0
	C2,	user specified subsystem two	0.0
	C3	user specified subsystem three	0.0
		1.0 = Reset reference time at each workover	
		0.0 = Don't reset reference time	

*Field parameter default for BACA
**Default depends on user specified subsystem

Figure II-5. GEOCOM Input Parameter Definitions and Defaults (Concluded) with one exception. Multiple specifications of the WOFQ's parameters must be specified in the proper order for constructing a workover schedule.

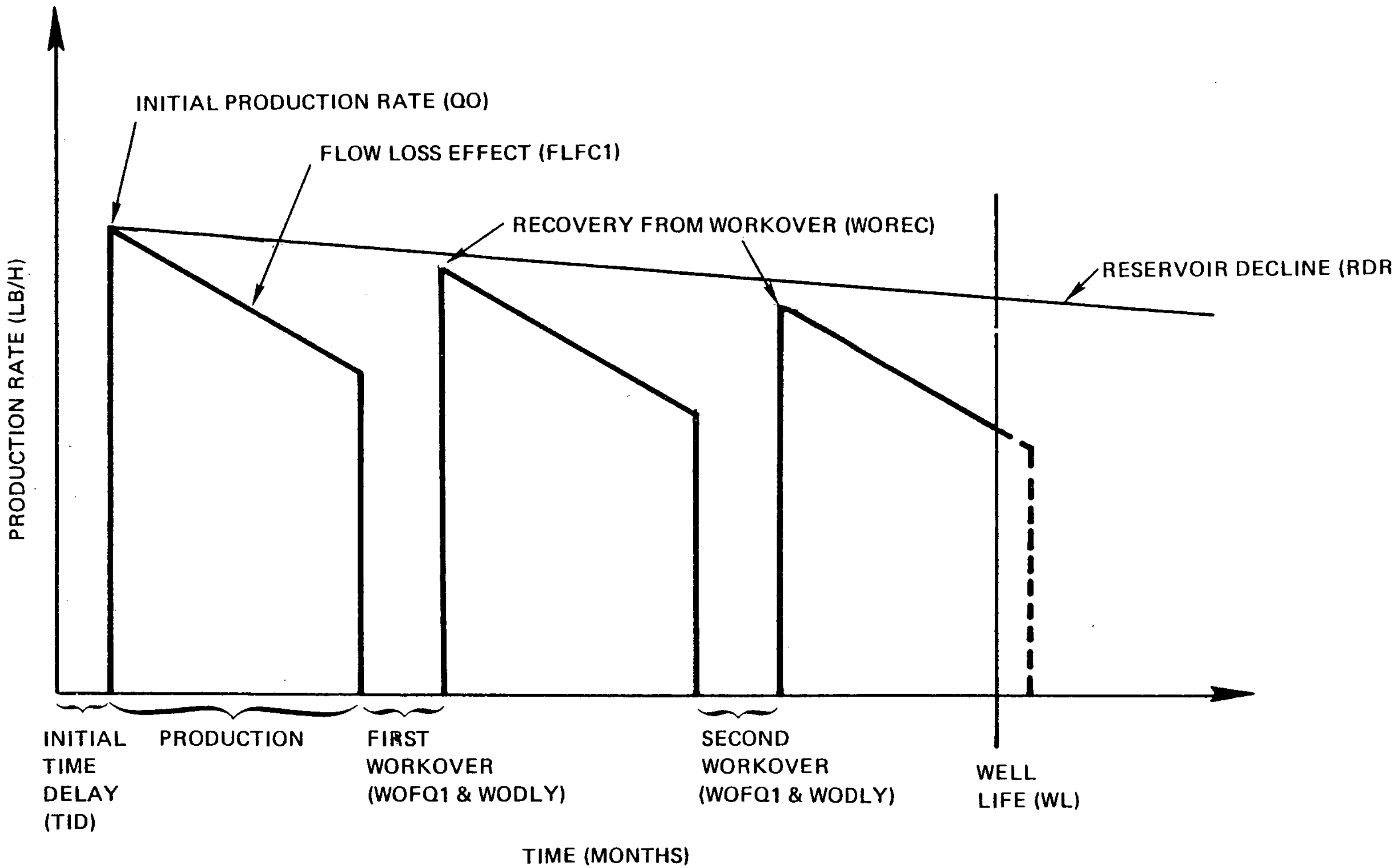
In order to set up a deck of cards for running GEOCOM, the user must select the appropriate parameters to describe the geothermal well to be modeled. The first step is to describe or title each case to be run. The description can include such items as purpose of run, location, data, etc. Whatever the user needs to uniquely describe the first case should be entered on the first card of each case. Two such case descriptions are depicted in figure II-6. This figure illustrates a two case run. Both cases have a unique descriptor.

```
SAMPLE DEFAULT CASE
01 USER DEFINED SUBSYSTEM


END
BRAWLEY WELL WITH TWO YEAR DELAY FOR INITIAL OPERATION
11 MECHANICAL DESCALE EVERY YEAR
22 SLOTTED LINER REPLACMENT EVERY 3 YEARS

REPAIR WELL WITH TIE-BACK LINER AT 9 YEARS
FIELD          1.
TID           24.
WOFQ1         20.       11.8
WOFQ2         20.       35.8
WODLY           .2        .2
FLFC1         .042
FLFC2         .042
R1FQ         109.
WL           143.
END
END GEOCOM
```

Figure II-6. Sample Input Deck (Created on the SNLA NOS interactive time share)

The next step is to select the subsystem types to be run in each case. From one to three subsystems can be scheduled for each well study case. These subsystems are listed in figure II-4. Workovers are a subset of the subsystem table. On the input card deck cards 2, 3, and 4 are reserved for specifying the numeric identifier of the subsystem type, and provide space for a comment used for the user's identification of the subsystem. Once the user has selected the subsystems to be modeled, a schedule can be defined using default values for each subsystem . Figure II-7 is a graphic illustration of a workover schedule. A "look-up" table of default values for the schedule parameters is included in appendix A. A copy of this table is in appendix A. Additional parameters which can be specified for each subsystem are listed in figure II-4. Two types of parameters are required for scheduling subsystems. These are "WOFQ" and "WODLY" parameters. The WOFQ1, WOFQ2, and WOFQ3 parameters are used to specify number and frequency of scheduling subsystem events. If frequency changes are desired over the life of the well, the user must put in additional "WOFQ1, 2, or 3" cards for each subsystem specified as illustrated in figure II-8. This input deck illustrates how to vary the workover schedule for the first specified subsystem. The sum of events must not exceed 100 for each subsystem. If the user wishes to generate a geo- metric change in frequency, then the WOFQC parameter may be specified to increase or decrease frequency of subsystem events. Another parameter is used to specify the production delay, "WODLY", of the well during a subsystem event. This is associated with a workover of the well. If this workover will improve the productivity of the well, a recovery factor parameter "WOREC" may be specified.

During the life of the well a repair may be required. If a repair is required, the user should identify it with a description of the repair on card number 5. A repair can be specified using parameters prefixed with "R1". A repair may be performed only once in the life of a well because it usually represents a major problem and results in a reduced diameter casing at some depth in the well which in turn restricts flow. Additional parameters associated with repair are QØ and FLFC. QØ resets



BDM/A-81-614-TR-R1

Figure II-7. Workover and Production History Illustration flow after repair and FLFC redefines the production decline model. Also, the XT parameter recovers flow for the same workovers as specified before repair.

```
BRAWLEY WELL WITH TWO YEAR DELAY FOR INITIAL OPERATION
11 MECHANICAL DESCALE EVERY YEAR
22 SLOTTED LINER REPLACMENT EVERY 3 YEARS

USAGE         2.
WOFQ1         6.      11.8
WOFQ1         8.       8.8
WOFQ2         4.      35.8
WODLY          .2       .2
FLFC1         .042
WL           143.
END
END GEOCOM
```

Figure II-8. Well Usage and Schedule Construction

The next step in generating an input deck for GEOCOM is to select a field in which the well will be or has been drilled. These parameters are found in the input parameter list in figure II-5. A "look-up" table has been built into GEOCOM so when a field is selected the default values for eleven parameters are retrieved and loaded for use. A copy of this default field table is found in appendix A. If the user wishes to change any of the parameters found in this table, then the desired parameter need only be specified with the new value. This is illustrated in the second case of figure II-6. A field parameter "WL" was specified with a new value. Well life is changed until reset or until FIELD is reentered.

The next step is to determine the energy usage of the well. There are four options to choose from: (1) electrical, (2) direct heat, (3) total energy, and (4) injection pump. This parameter is specified as illustrated in figure II-8.

The productivity of the well is the next item of discussion. Three parameters QØ, FLFC, and XT" are used to describe the well production model. QØ sets the initial flow rate. FLFC defines the coefficients for a cubic fit of the decline in production as a function of time since the last workover which reset calibration time. XT defines the workover (subset of subsystems) which reset calibration time. This means the first, second, or third subsystem specified or any combination of the three can reset calibration time.

Now that all the physical characteristics of the well and subsystems have been defined, the next step in setting up the input deck is the economic parameters. These parameters must be selected and specified if different from default.

The final step in setting up the input deck involves two parameters. These parameters are "SP" and "TID". SP is the study period in months (must be greater than the well life) over which the model is to compute the ratio of life cycle cost to life cycle benefit. Study period models replacing the first well with a second well after the first well's end of productive life. This replacing of wells is continued until the study period is complete. Parameter "TID" is used to model an initial delay in beginning operation of the well after it is drilled. If the user wants to model the well being dormant for a period of time before it goes into operation, TID avails this option.

Once the input deck is constructed with all the desired options, it may be submitted with the JCLs. There is one word of caution in preparing the card deck. Be careful to properly define values for parameters as right justified floating point numbers in the parameter fields.

C. PROCESSING CHARACTERISTICS

After the user has generated an input deck for use by GEOCOM, a run may be submitted for execution and printing of results. The following discussion will give the user a close look at what processes are performed inside GEOCOM.

When GEOCOM commences execution the first subroutine called is INTLZ. This routine is called only once for each run and initializes 76 common variables. Twenty-one of these variables are a subset of the input parameters and are initialized to -999. The use of -999. is required for GEOCOM to identify the need to retrieve a default from a look-up table or override the default by specifying a value in the input deck. The parameters which use -999. are found in figure II-5.

After INTLZ subroutine INPRO is called. This routine reads the first case study for execution. All the information as described in figure II-3 down to the first "END" card are read in for processing. The user must be careful how the input deck is set up because of the rigid format. All the parameters which need to be changed from default are specified with this case. Any misspelled names will be an error. For the next case in the same run, if the user wishes to use the default field, or subsystem values for parameters specified in the first case, then the value -999. must be entered for each field or subsystem scheduling parameter. Figure II-9 illustrates the user requirement to specify -999. in order for GEOCOM to pick up defaults for the table look-up parameters. Also in figure II-9 an unusual line with 40 numbers is inserted. This line is ignored by GEOCOM but can be used by the user as a guide to locate fields on the card if a computer terminal is being used to generate the input cards. When INPRO reads the "END GEOCOM" card an end of the file flag is set for GEOCOM to terminate execution.

The next subroutine GEOCOM calls is DFIELD. This routine retrieves default values from the field parameter table. This table is found in appendix A. If the user specifies a value for any one or more of these parameters the default value is ignored for each specified parameter. Also as discussed for INTPRO if in multiple cases the user wishes to switch back to default, -999. must be specified for each parameter which has been specified in previous cases.

Subroutine WOSCH constructs the workover schedule for specified subsystems. Figure II-7 illustrates the scheduling of one subsystem which is a workover to recover production. This workover was scheduled twice. Up to three subsystems can be scheduled parallel in time with each other, each having a unique schedule. Any overlapping of workovers is accounted for in the production history routine COMPH by summing the workover delays. If a repair occurs the same set of schedules used from

```
TEST CASE 1
01 USER DEFINED SUBSYSTEM


1234567890123456789012345678901234567890
FIELD          3.
DEPTH       7000.
COMINT      3000.
END
TEST CASE 2
01 USER DEFINED SUBSYSTEM


DEPTH       -999.
END
TEST CASE 3
01 USER DEFINED SUBSYSTEM


FIELD          2.
COMINT      -999.
END
END GEOCOM
```

Figure II-9. Sample Input Deck Illustrating How to Reset Default Field Parameters the beginning of the well life will be repeated after the repair is completed.

After the schedule has been generated subroutine PRNTIN is called. Routine PRNTIN prints all the input parameters which display all field, well, and subsystem parameters. PRNTIN also prints the economic parameters selected by the user. Several economic parameters may have -999. as a value. This means they have not been assigned values yet. The default values for these parameters are retrieved in subroutine COMLCC. PRNTIN also prints the workover schedule generated by WOSCH.

The next routine called is COMPH. COMPH computes the production history based on selected parameters and workover schedule. Within COMPH is a loop which steps through time from the beginning of well production to the end of the well's life. The illustration in figure II-7 requires three passes through this loop. Three subroutines are called in each pass through this loop. The first subroutine IDENT identifies the next scheduled workover or workovers to be performed. This establishes the time interval for computing well production by subroutine INTGAT. Then the information is recorded in an event table by subroutine RECEVD. When the well life is reached the production and event history table is complete. Also two economic parameters, discounting and inflating, are folded into the production history table for later computation of energy present value.

Subroutine COMLCC is called next to compute all the costs associated with the well and subsystems over the well's life. COMLCC in turn calls subroutine WELLC which computes the capital cost of the well. Then a set of routines (SS01-SS22) have been written to compute the cost of the subsystems selected for each case. These subsystem cost routines have a common set of four cost parameters. These cost parameters are 1) capital cost (SSCL), 2) workover costs, (WOC), 3) yearly routine operation and maintenance cost (SSYC) and 4) cost per pound of hot water (PPSSC). These parameters can be either user-specified or computed by each subsystem. Not all the subsystems require all four parameters, but a common set of parameters was defined in order to simplify the process of adding new subsystems to GEOCOM. After the costing information has been accumulated, subroutine LOADOC is called to load the event table with discounted and inflated expenses occurring throughout the life of the well. All these costs are summed to compute the total cost of the well.

The next subroutine called is SPCORR. It computes the life cycle cost of consecutive wells over a period of time greater than the well's life. If the user wishes to analyze time periods greater than well life, then SPCORR computes a new life cycle cost to life cycle benefit ratio. This ratio is computed by inflating and discounting each new whole well life. Then SPCORR inflates and discounts the partial well life and sums the partial with the whole well life costs and production to compute the new ratio.

After SPCORR subroutine BTU is called. This routine converts the energy production into BTUs. There are four types of energy production: (1) electrical, (2) direct heat, (3) total energy, and (4) injection.

The final subroutine called for each case is OUTPRO. In this routine the costs, the ratio of life cycle cost to life cycle benefit, and the production and event history table are printed out. After OUTPRO subroutine INPRO is called again in order to read in another case or read the "END GEOCOM" card to terminate execution.

D. OUTPUT

The output listing is divided into four parts as illustrated in figure II-10. The first part lists the input parameters and their values in addition to the workover schedule table. The user should compare these printed values with the values specified on the input deck. If any parameters were misspelled they will show up at this point as an error message telling the user an undefined parameter has been specified. Five parameters appear with -999. for their values unless the user specified otherwise on the input deck. These parameters will compute default values for each when the costing subroutine is called.

```
            GEOCOM INPUT FOR CASE NUMBER:   1
    SAMPLE DEFAULT CASE
     1 USER DEFINED SYSTEM
     0
     0

                                   ARRAY ELEMENT NUMBER (N)
     PARAMETER          ONE            TWO            THREE          FOUR
     ISSTYP(N)=          1              0              0
     FIELD    =          4
     USAGE    =          1
     DEPTH    =      6000.
     COMINT   =      3000.
     TEMP     =       358.00
     WL       =       360.00
     Q0(N)    =    200000.       88000.
     X        =          .300
     RDR      =   .30830E-02
     CTIC     =       195.90
     DCCI     =        72.30
     CCCI     =        90.23
     FTDS     =      6100.
     SP       =       360.00
     TR       =       125.00
     TF       =       344.00
     DF       =   .87800E-02
     INFLAT   =   .69500E-02
     ELECT    =          .060
     WODLY(N) =         0.00           0.00           0.00
     WOFQC(N) =         1.00           1.00           1.00
     WOREC(N) =         1.00           1.00           1.00
     XT(N)    =         1              0              0
     FLFC(1,N)=          .1250         0.0000         0.0000
     FLFC(2,N)=          .1250         0.0000         0.0000
     R1FQ     =       999.00
     R1DLY    =          .33
     R1CST    =    121000.
     ABAND    =     18000.
     WRC(N)   =     54000.00          3.00           0.00
     SSCC(N)  =      -999.          -999.          -999.
     WOC(N)   =      -999.          -999.          -999.
     SSYC(N)  =      -999.          -999.          -999.
     PPSSC(N) =  -999.00        -999.00        -999.00
     WCC(N)   =      -999.          -999.          -999.          -999.
     TID      =         0.00
     WHPMH    =      1155.
     EFF      =          .700
     H0       =      1640.
     PI       =       431.30
     PIDR     =0.
     DIST     =       150.
     SPF      =         4.00
     IDSCLC   =         1
     IDSCLI   =         1
     PSD      =      1200.
     FPC      =         1.00           1.00           2.00
     SL       =      1000.
     LOGG     =     11000
     CHEMC    =          .970
     CMPPM    =  .3000E-04
     NRCS     =         0
```

Figure II-10. Sample Output

WORK OVER SCHEDULE FOR CASE NUMBER 1

	WORKOVER ONE		WORKOVER TWO		WORKOVER THREE	
M	WOFQ1	TWOP	WOFQ2	TWOP	WOFQ3	TWOP
1	8.00	8.00				
2	8.00	16.00				
3	8.00	24.00				
4	8.00	32.00				
5	8.00	40.00				
6	8.00	48.00				
7	8.00	56.00				
8	8.00	64.00				
9	8.00	72.00				
10	8.00	80.00				
11	8.00	88.00				
12	8.00	96.00				
13	8.00	104.00				
14	8.00	112.00				
15	8.00	120.00				
16	8.00	128.00				
17	8.00	136.00				
18	8.00	144.00				
19	8.00	152.00				
20	8.00	160.00				
21	8.00	168.00				
22	8.00	176.00				
23	8.00	184.00				
24	8.00	192.00				
25	8.00	200.00				
26	8.00	208.00				
27	8.00	216.00				
28	8.00	224.00				
29	8.00	232.00				
30	8.00	240.00				
31	8.00	248.00				
32	8.00	256.00				
33	8.00	264.00				
34	8.00	272.00				
35	8.00	280.00				
36	8.00	288.00				
37	8.00	296.00				
38	8.00	304.00				
39	8.00	312.00				
40	8.00	320.00				
41	8.00	328.00				
42	8.00	336.00				
43	8.00	344.00				
44	8.00	352.00				
45	8.00	360.00				

Figure II-10. Sample Output (Continued)

```
        GEOCOM RESULTS FOR CASE  1: SAMPLE DEFAULT CASE

                      CAPITAL COSTS  WORKOVER COSTS   ROUTINE O+M    COST/POUND
WELL COSTS
  INTERMEDIATE            587700.
  COMP. DRILL.            216900.
  COMPLETION              270690.
                        ----------
  WELL TOTAL             1075290.                    7188.$/MO   0.000 MILS/LB

SUBSYSTEM:  USER DEFINED SYSTEM
  ONE WORKOVER                                0.
  TOTAL DISC + INF             0.             0.           0.$/MO   0.000 MILS/LB
                        **********     **********   ************   *************
TOTALS ($)               1075290.             0.     1895366.$/WL         0.$/WL


GRAND TOTAL =  2979971.$/WL
% OF GRAND TOTAL        36.08%         0.00%         63.60%          0.00%

REPAIR:
  TIME =999.00, COST =    121000., DELAY =    .33

ABANDONMENT =      9314.$/WELL

INITIAL DELAY=  0.00MONTHS

STUDY PERIOD =360.00, WELL LIFE =360.00, EVENT AT STUDY PERIOD =  0

USAGE = 1, CONVERSION =  84.76

                        DISCOUNTED BENEFIT      INFLATED DISCOUNTED BENEFIT
                       --------------------     ---------------------------
                       WELL LIFE  STUDY PERIOD   WELL LIFE  STUDY PERIOD
  LCC/LCB ($/LB)      .4834E-03   .4834E-03     .2402E-03   .2402E-03
  LCC/BTU ($/BTU)     .5704E-05   .5704E-05     .2834E-05   .2834E-05
```

Figure II-10. Sample Output (Continued)

EVENT TIME MONTHS	WORKOVER 1	2	3	WO DELAY MO	INC PROD M.LB.	WORKOVER COSTS ($) WO1	WO2	WO3	FLOW RATE LB	AC DIS PROD B.LB.	AC DIS INF PD B.LB.
8.00	1	0	0	0.00	579.	0.	0.	0.	200000.	.57	.58
16.00	2	0	0	0.00	565.	0.	0.	0.	195128.	1.08	1.13
24.00	3	0	0	0.00	551.	0.	0.	0.	190374.	1.55	1.66
32.00	4	0	0	0.00	538.	0.	0.	0.	185736.	1.97	2.18
40.00	5	0	0	0.00	525.	0.	0.	0.	181211.	2.36	2.67
48.00	6	0	0	0.00	512.	0.	0.	0.	176796.	2.71	3.14
56.00	7	0	0	0.00	500.	0.	0.	0.	172489.	3.03	3.60
64.00	8	0	0	0.00	487.	0.	0.	0.	168287.	3.33	4.04
72.00	9	0	0	0.00	476.	0.	0.	0.	164187.	3.59	4.46
80.00	10	0	0	0.00	464.	0.	0.	0.	160187.	3.83	4.86
88.00	11	0	0	0.00	453.	0.	0.	0.	156284.	4.05	5.25
96.00	12	0	0	0.00	442.	0.	0.	0.	152477.	4.25	5.62
104.00	13	0	0	0.00	431.	0.	0.	0.	148762.	4.43	5.98
112.00	14	0	0	0.00	420.	0.	0.	0.	145138.	4.60	6.33
120.00	15	0	0	0.00	410.	0.	0.	0.	141602.	4.75	6.66
128.00	16	0	0	0.00	400.	0.	0.	0.	138152.	4.88	6.98
136.00	17	0	0	0.00	390.	0.	0.	0.	134787.	5.01	7.29
144.00	18	0	0	0.00	381.	0.	0.	0.	131503.	5.12	7.58
152.00	19	0	0	0.00	372.	0.	0.	0.	128299.	5.22	7.87
160.00	20	0	0	0.00	363.	0.	0.	0.	125174.	5.31	8.14
168.00	21	0	0	0.00	354.	0.	0.	0.	122124.	5.40	8.40
176.00	22	0	0	0.00	345.	0.	0.	0.	119149.	5.48	8.66
184.00	23	0	0	0.00	337.	0.	0.	0.	116246.	5.55	8.90
192.00	24	0	0	0.00	328.	0.	0.	0.	113414.	5.61	9.13
200.00	25	0	0	0.00	320.	0.	0.	0.	110651.	5.67	9.36
208.00	26	0	0	0.00	313.	0.	0.	0.	107955.	5.72	9.57
216.00	27	0	0	0.00	305.	0.	0.	0.	105325.	5.77	9.78
224.00	28	0	0	0.00	298.	0.	0.	0.	102759.	5.81	9.98
232.00	29	0	0	0.00	290.	0.	0.	0.	100256.	5.85	10.17
240.00	30	0	0	0.00	283.	0.	0.	0.	97813.	5.89	10.36
248.00	31	0	0	0.00	276.	0.	0.	0.	95430.	5.92	10.53
256.00	32	0	0	0.00	270.	0.	0.	0.	93106.	5.95	10.70
264.00	33	0	0	0.00	263.	0.	0.	0.	90837.	5.98	10.87
272.00	34	0	0	0.00	257.	0.	0.	0.	88624.	6.00	11.03
280.00	35	0	0	0.00	250.	0.	0.	0.	86465.	6.03	11.18
288.00	36	0	0	0.00	244.	0.	0.	0.	84359.	6.05	11.32
296.00	37	0	0	0.00	238.	0.	0.	0.	82303.	6.06	11.46
304.00	38	0	0	0.00	233.	0.	0.	0.	80298.	6.08	11.60
312.00	39	0	0	0.00	227.	0.	0.	0.	78342.	6.10	11.73
320.00	40	0	0	0.00	221.	0.	0.	0.	76434.	6.11	11.85
328.00	41	0	0	0.00	216.	0.	0.	0.	74571.	6.12	11.97
336.00	42	0	0	0.00	211.	0.	0.	0.	72755.	6.14	12.09
344.00	43	0	0	0.00	206.	0.	0.	0.	70982.	6.15	12.20
352.00	44	0	0	0.00	201.	0.	0.	0.	69253.	6.16	12.30
360.00	0	0	0	0.00	196.	0.	0.	0.	67566.	6.16	12.41

TOTAL 0.00 15.940(BILLION POUNDS)

****

Figure II-10. Sample Output (Continued)

GEOCOM INPUT FOR CASE NUMBER: 2
BRAWLEY WELL WITH TWO YEAR DELAY FOR INITIAL OPERATION
11 MECHANICAL DESCALE EVERY YEAR
22 SLOTTED LINER REPLACMENT EVERY 3 YEARS
0
REPAIR WELL WITH TIE-BACK LINER AT 9 YEARS

		ARRAY ELEMENT NUMBER (N)			
PARAMETER		ONE	TWO	THREE	FOUR
ISSTYP(N)	=	11	22	0	
FIELD	=	1			
USAGE	=	1			
DEPTH	=	6000.			
COMINT	=	2000.			
TEMP	=	344.00			
WL	=	143.00			
Q0(N)	=	500000.	220000.		
X	=	.058			
RDR	=	.40000E-02			
CTIC	=	68.16			
DCCI	=	43.97			
CCCI	=	57.83			
FTDS	=	80000.			
SP	=	360.00			
TR	=	125.00			
TF	=	344.00			
DF	=	.87800E-02			
INFLAT	=	.69500E-02			
ELECT	=	.060			
WODLY(N)	=	.20	.20	0.00	
WOFQC(N)	=	1.00	1.00	1.00	
WOREC(N)	=	1.00	1.00	1.00	
XT(N)	=	1	0	0	
FLFC(1,N)	=	.0420	0.0000	0.0000	
FLFC(2,N)	=	.0420	0.0000	0.0000	
R1FQ	=	109.00			
R1DLY	=	.33			
R1CST	=	121000.			
ABAND	=	18000.			
WRC(N)	=	54000.00	3.00	0.00	
SSCC(N)	=	-999.	-999.	-999.	
WOC(N)	=	-999.	-999.	-999.	
SSYC(N)	=	-999.	-999.	-999.	
PPSSC(N)	=	-999.00	-999.00	-999.00	
WCC(N)	=	-999.	-999.	-999.	-999.
TID	=	24.00			
WHPMH	=	1155.			
EFF	=	.700			
H0	=	1640.			
PI	=	431.30			
PIDR	=	0.			
DIST	=	150.			
SPF	=	4.00			
IDSCLC	=	1			
IDSCLI	=	1			
PSD	=	1200.			
FPC	=	1.00	1.00	2.00	
SL	=	1000.			
LOGG	=	11000			
CHEMC	=	.970			
CMPPM	=	.3000E-04			
NRCS	=	0			

Figure II-10. Sample Output (Continued)

WORK OVER SCHEDULE FOR CASE NUMBER 2

	WORKOVER ONE		WORKOVER TWO		WORKOVER THREE	
M	WOFQ1	TWOP	WOFQ2	TWOP	WOFQ3	TWOP
1	11.80	11.80	35.80	35.80		
2	11.80	23.80	35.80	71.80		
3	11.80	35.80	35.80	107.80		
4	11.80	47.80	35.80	143.80		
5	11.80	59.80	35.80	179.80		
6	11.80	71.80	35.80	215.80		
7	11.80	83.80	35.80	251.80		
8	11.80	95.80	35.80	287.80		
9	11.80	107.80	35.80	323.80		
10	11.80	119.80	35.80	359.80		
11	11.80	131.80	35.80	395.80		

1

```
          GEOCOM RESULTS FOR CASE  2: BRAWLEY WELL WITH TWO YEAR DELAY FOR INITI
AL OPERATION

                       CAPITAL COSTS   WORKOVER COSTS   ROUTINE O+M   COST/POUND
 WELL COSTS
   INTERMEDIATE          272640.
   COMP. DRILL.           87940.
   COMPLETION            115660.
                       ----------
   WELL TOTAL            476240.                        5691.$/MO   0.000 MILS/LB

 SUBSYSTEM:  MECHANICAL DESCALE EVERY YEAR
   ONE WORKOVER                          24806.
   TOTAL DISC + INF           0.        229444.            0.$/MO   0.000 MILS/LB

 SUBSYSTEM:  SLOTTED LINER REPLACMENT EVERY 3 YEARS
   ONE WORKOVER                          95227.
   TOTAL DISC + INF           0.        240090.            0.$/MO   0.000 MILS/LB
                       ----------                   ------------  -------------
 TOTAL OF SUBSYSTEMS          0.                           0.$/MO   0.000 MILS/LB
                       ==========     ==========    ============  =============
 TOTALS ($)              476240.        469533.      818844.$/WL         0.$/WL


 GRAND TOTAL =   1872737.$/WL
 % OF GRAND TOTAL        25.43%         25.07%          43.72%          0.00%

 REPAIR: REPAIR WELL WITH TIE-BACK LINER AT 9 YEARS
   TIME =109.00, COST =    121000., DELAY =    .33

 ABANDONMENT =     13260.$/WELL

 INITIAL DELAY= 24.00MONTHS

 STUDY PERIOD =360.00, WELL LIFE =143.00, EVENT AT STUDY PERIOD =  6

 USAGE = 1, CONVERSION =  12.14

                       DISCOUNTED BENEFIT         INFLATED DISCOUNTED BENEFIT
                    ------------------------     ---------------------------
                    WELL LIFE   STUDY PERIOD      WELL LIFE   STUDY PERIOD
   LCC/LCB ($/LB)  .1375E-03    .2176E-03        .8224E-04    .8069E-04
   LCC/BTU ($/BTU) .1132E-04    .1792E-04        .6772E-05    .6645E-05
```

Figure II-10. Sample Output (Continued)

EVENT TIME MONTHS	WORKOVER 1	2	3	WO DELAY MO	INC PROD M.LB.	WORKOVER COSTS ($) WO1	WO2	WO3	FLOW RATE LB	AC DIS PROD B.LB.	AC DIS INF PD B.LB.
11.80	1	0	0	.20	3173.	23232.	0.	0.	500000.	2.46	3.01
23.80	2	0	0	.20	3024.	22728.	0.	0.	476567.	4.56	5.81
35.80	3	1	0	.40	2882.	22234.	85356.	0.	454232.	6.37	8.43
47.80	4	0	0	.20	2714.	21751.	0.	0.	432598.	7.90	10.84
59.80	5	0	0	.20	2618.	21279.	0.	0.	412653.	9.23	13.11
71.80	6	2	0	.40	2496.	20817.	79914.	0.	393314.	10.37	15.23
83.80	7	0	0	.20	2350.	20364.	0.	0.	374581.	11.34	17.18
95.80	8	0	0	.20	2267.	19922.	0.	0.	357312.	12.18	19.02
107.80	9	3	0	.40	2161.	19489.	74819.	0.	340566.	12.90	20.74
109.00*	0	0	0	.33	186.	0.	0.	0.	324345.	12.96	20.89
121.13	10	0	0	.20	901.	19020.	0.	0.	142068.	13.22	21.59
133.13	11	0	0	.20	859.	18607.	0.	0.	135410.	13.45	22.24
143.00	0	0	0	0.00	713.	0.	0.	0.	129064.	13.62	22.77
	TOTAL			3.13	26.346(BILLION POUNDS)						

*NOTE: TIME AT WHICH REPAIR WAS INITIATED

****

Figure II-10. Sample Output (Concluded)

The next part of the output listing only appears when the user specifies an injection pump for one of the subsystems. This part prints the time when the pump is turned on, reaches max output, or is turned off as illustrated in figure II-11. Also the summed discounted inflated number of horsepower-hours for each integration period between workovers is printed out.

The third part of the output is the cost information. This consists of capital costs, workover costs, routine operation and maintenance costs, cost per pound of hot water, abandonment cost, repair cost, electrical cost, ratio of life cycle cost to life cycle benefit, percentages of various costs, and a few other miscellaneous values. This area of the output provides the bottom line in cost of a well and illustrates the driving factors in the cost.

The final part of the output is the production and event history table. This table illustrates the scheduling of workovers and their costs. It also lists the flow rate, total production, summed discounted production, and summed discounted inflated production. The production was discounted and inflated to avoid a second loop to discount and inflate the dollar value of energy over the well's life.

After the production and event history table is printed a line of asterisks is printed to indicate the end of a case run.

This completes the output for one case. Interspersed in the output there may be error messages which the user should observe and correct. A complete list of all the error messages and what to do about them is listed in figure II-12.

E. PERFORMANCE CHARACTERISTICS

The performance of GEOCOM is divided into three areas: execution time, memory required, and quantity of input and output. The execution time for the example run provided in the previous section was 1.092 seconds. This run was made on the SNLA NOS time share system. The memory required was 16,000 (decimal) words (10 byte words, 6 bit bytes) of central memory. Both the execution time and memory required will vary significantly depending on the type of computer used. The quantity of output can vary significantly also depending on the number of cases run. For each case there is about four pages of output. Each case consists of from six cards (for all defaults) to as many as required to change parameters from default, and they may be stacked as illustrated in the figure II-6.

```
   WORK OVER SCHEDULE FOR CASE NUMBER  1

    WORKOVER ONE     WORKOVER TWO   WORKOVER THREE
  M  WOFQ1   TWOP    WOFQ2   TWOP    WOFQ3   TWOP
  1  24.00  24.00
  2  24.00  48.07
  3  24.00  72.13
  4  24.00  96.20
TIME=  0.00, PUMP ON, HEAD= 446.715    FEET
DISCOUNTED INFLATED HPH= .177326E+07, HEAD= 1.46783
TIME= 24.07, PUMP ON, HEAD= .374976    FEET
TIME= 25.27, PUMP TURNED OFF
DISCOUNTED INFLATED HPH= 65.5708     , HEAD=0.
TIME= 48.13, PUMP TURNED OFF
DISCOUNTED INFLATED HPH=0.           , HEAD=0.
TIME= 72.20, PUMP TURNED OFF
DISCOUNTED INFLATED HPH=0.           , HEAD=0.
TIME= 96.27, PUMP TURNED OFF
DISCOUNTED INFLATED HPH=0.           , HEAD=0.
```

Figure II-11. Injection Pump Printout

Error Messages and Possible Correction

ERROR, PARAMETER ______ NOT IN GEOCOM

Correct spelling of parameter

WARNING FIELD NO. ___ HAS NOT BEEN DEFINED,
NO. 4 (BACA) WILL BE USED
Specify correct field number

FATAL ERROR* INTEGRATION TIME NEGATIVE,
TIME = ____, STOP = ____
Examine schedule table for negative times

WARNING DELAY TIME IS MORE THAN 1/3
OF PERIOD
The user is scheduling an eccessive amount of well down time with activities to recover production. The user needs to reexamine the schedule.

WARNING PRODUCTION BEGAN AT ___ MONTHS
WENT TO ZERO AT ____ MONTHS UNTILL _____ MONTHS
This message means well production went to zero
Production stays at zero until a workover is encountered which recovers production. The user needs to check the flow loss coefficients or the reservoir decline parameter. The user must remember that these are monthly rates.

****FATAL ERROR**** TO MANY EVENTS HAVE OCCURED
The number of events in the schedule table for one subsystem has exceeded 100 entries. Reduce the number of entries and resubmitt job.

****FATAL ERROR**** TO MANY WORKOVERS PERFORMED
The number of events in the event table has exceeded 100.
The user needs to reduce the number of total workovers and resubmit the job.

WARNING USER SPECIFIED TOTAL WELL COST OF: ______
COMPUTER FOUND WCC(1) + WCC(2) + WCC(3) = ______.
GEOCOM will use the value specified by the user.

WARNING STUDY PERIOD OF ______ MONTHS IS LESS THAN WELL LIFE
OF ______.
The user can not use a study period less than the well life.
Therefore, the user needs to redefine the study period desired.

Figure II-12. Error messages in GEOCOM

WARNING FRACTIONAL LIFETIME FOR STUDY PERIOD IS _____%
If the study period ends during the life of the last well the user needs to be informed when less than 20% of a well is being used.

WARNING THE FLASHING FRACTION IS ______
This message is printed when the flashing fraction exceeds 1.0 for computing the Btu conversion.

WARNING SUBSYSTEM CAPITAL COST IS ZERO, O&M COST WILL BE SET TO ZERO
This means the user needs to change the user specified value of Subsystem Capital Cost from zero to a reasonable value.

Figure II-12. Error Messages in GEOCOM (Concluded)

CHAPTER III
THEORY OF APPLICATIONS

A. THE PROGRAM MODEL

Two major types of modeling are incorporated in GEOCOM's design. The first type includes the physical characteristics of the wells total production. The second modeling type involves the economic aspects for computing the life cycle cost of the well.

Modeling the physical characteristics of well production involves five areas. These areas are workover scheduling, flow loss due to scaling, reservoir performance decline, well repair, and energy production. The workover scheduling is done by setting up a table of times when the well will have workovers performed. An example of this is mechanically descaling the well every year. Several other types of workovers are available for the user. The end result of a workover may be an improvement in production. However, there are some workovers or subsystems which do not improve production.

The second area in modeling a well's performance is the reservoir performance decline. This is an exponential relationship of a fractional decline per month starting with an initial production rate. This decrease in production exponentially approaches zero. This decline is for reservoir pressure depletion or other factors that happen independently of the completion and workover of an individual well. This factor acts as a "discounting effect" that limits the value of a "perfect well."

The third area in modeling a well's performance is the flow loss due to well or completion effects. The primary use of the flow loss function is to model the reduced output of a well due to scaling effects. A third order polynomial is used to model the flow loss effect as a function of time where time is measured from the last descaling workover as specified by the user. This polynomial can be reduced to a linear relationship by zeroing out the second and third order coefficients. A linear flow loss of 12.5 percent per month is the present default. If for example a descaling job was not perfect because scale was formed back through slots onto the sand face and the descaling workover was only reaming inside the liner, then the recovery factor can be used to determine how much of the well's potential output can be obtained.

Modeling the well performance in area number four is well repair. This is a trouble condition in the well requiring repair which will change the casing profile, can be done only once, and will probably restrict flow. An example of repair is to insert a smaller liner inside the well to replace damaged tubing. The effect this has on the well is that it will change the resumed production rate to a smaller value. The repair may also require the user to put in a new set of flow loss coefficients.

The last modeling area of well performance is energy production. There are four options for computing the usable energy generated by the well. They are electrical, total energy, direct heat and injection. Algorithms have been derived to convert the electrical, total energy, and direct heat into btu's for comparison purpose of energy output. These algorithms are discussed in the algorithm analysis section. The injection option assumes the value of energy is based on pounds of fluid injected. Therefore there is no conversion for injection.

The second major type of modeling in GEOCOM is the economic model. Two categories of costs are taken into account. Costs at the beginning of well life is the first category (i.e., capital cost of drilling well). Discounted and inflated costs accounted for through the life of the well is the second category (i.e., workover cost). All costs are totaled to compute the life cycle cost of a geothermal well. This life cycle cost is divided by the life cycle benefit to compute a ratio.

GEOCOM is an effective tool for doing geothermal well production analysis. Studies can be done such as trade-off studies in workover schedules, determination of which workovers are most cost effective, what economic parameters have the most effect on life cycle benefit. The user can get the bottom line cost of a geothermal well over its life. The output is broken into fractions of various cost of the system. The code allows a wide range of analysis capability and identifies acceptable ranges of parameters.

B. ALGORITHM ANALYSIS

This section describes the more complex algorithms used in GEOCOM for modeling the production and costing of geothermal wells. The production is modeled by integrating production rate over time between workover events. The following integral is computed by GEOCOM between workovers.

$$P = \int_{\text{Time}}^{\text{Stop}} Q_o R_j^{(n-1)} e^{-rt} \left\{ 1 - C_1 T_f + C_2 T_f^{\,2} + C_3 T_f^{\,3} \right\} dt \qquad \text{(Eq. III-1)}$$

$$= \int_{\text{Time}}^{\text{Stop}} Q(t)\, dt = \text{integrated production between events (lb)}$$

P = Productivity (lbs of fluid produced)

Q_o = Initial production rate (lb/h)

R_j = Correction factor of work over j (fraction)

n = Work over counter

r = Reservoir decline rate (fraction/month)

t = Time since the beginning of well life (months)

T_f = Time since the last time well was descaled $t - t_f$ (months)

C_1, C_2, C_3 = Coefficients for third order polynomial of flow loss function.

Time = Time production begins after workover or beginning of well life.

Stop = Time production stops before workover or end of well life.

In order to compute the discounted and inflated value of energy over time, the integral equation III-2 is also computed at the same time using equation III-1.

$$P_{id} = \int_{Time}^{Stop} Q(t)e^{(i-d)t} \; dt \qquad \text{(Eq. III-2)}$$

= integrated inflated discounted production between events (lb)

i = inflation rate (fraction/month)

d = discount rate (fraction/month)

If an injection pump is specified, then the utility costs are estimated by determining the time integrated Bhp used by the pump and multiplying by the electricity cost of a hp-hr. The equation for electricity consumption is

$$\text{Elect. cost} = \int \frac{(\$/\text{Bhp-hr}) \; \text{Bhp} \; (t) \; dt}{0.8 \; \text{EFF}} \qquad \text{(Eq. III-3)}$$

where the 0.8 factor is the assumed efficiency of the motor and EFF is the efficiency of the pump. Substituting in for the Bhp as a function of time:

$$\text{Elect. cost} = \int_{Time}^{Stop} \left\{ \frac{0.746 \; (\text{ELECT})}{0.8 \; \text{EFF}} \right\} \frac{Q(t) \; H(t) \; dt}{1.772 \times 10^6 \; (\#/\text{hr})(\text{ft/hp})} \left(\frac{\text{kw-hr}}{\text{hp-hr}} \right)$$

(Eq. III-4)

where EFF is the efficiency of the pump,
Q(t) is the flow rate in pounds per hour,
H(t) is pump head in feet,
ELECT is the cost of electricity in $/kw-hr
0.746 converts from to hp-hr to kw-hr

This equation can be broken into two parts:

$$\text{Elect. Cost} = 0.9325 \frac{\text{ELECT}}{\text{EFF}} \{\text{Integrated hp - hour output}\}$$

$$\text{hp-hour output} = \int Q(t)\ H(t)\ dt/1.772\text{x}10^6 \qquad \text{(Eq. III-6)}$$

The coefficient for equation III-5 is calculated in the subroutine for subsystem 16 (SS16). The integral of equation III-6 is calculated in subroutine INTGAT using the following relationships:

$$\begin{aligned} Q(t) &= Q\emptyset e^{-RDRt} \\ H(t) &= Q(t)/PI(t) - Ho \\ PI(t) &= PI\emptyset e^{-PIDRt} \end{aligned} \qquad \text{(Eq. III-7)}$$

Where PI is the time dependent productivity index, and Ho is the gravity head (essentially depth of water table below surface). Substituting into the equation for hp-hour output this gives

$$\text{hp-hour output} = \int Q(t) \left\{Q(t)/PI(t) - Ho\right\} dt/1.772\text{x}10^6$$

$$= 5.643 \times 10^{-7} \int Q\emptyset e^{-RDRt} \left\{Q\emptyset e^{-(RDR - PIDR)t}/PI\emptyset - Ho\right\} dt \qquad \text{(Eq. III-8)}$$

Note that all costs are inflated and discounted so that in subroutine INTGAT factors for inflation and discounting are inserted in the above equation. A detailed discussion is provided next concerning the various possible uses of the total pounds of fluid produced.

As the method of completing a well or the usage of a well changes the value of a pound of fluid may change. To allow comparisons of completion technologies that may affect temperature and steam quality the GEOCOM code contains a subroutine, BTU, that calculates the useful Btu's contained in a pound of produced fluid. This allows the cost effectiveness ratio to be changed from dollars per pound to dollars per million Btu of usable energy. The basic methods for determining the useful Btu content of a pound of fluid have been taken from reference 2.

Four different usages of the well have been programmed into the code.

(1) Electrical: This usage is based on the useful energy content of the produced fluid assuming it is flashed and the steam is used to run a turbine and generate electricity.

(2) Direct Heat: This usage is the total Btu content of the fluid referenced to the Btu content at the reject temperature.

(3) Total Energy: This usage assumes the use of a binary cycle, total flow, or some other method that maximizes the useful heat content for the generation of electricity.

(4) Injection: This usage makes no Btu calculations, since it is assumed the true value of the process is the number of pounds of fluid injected.

In principal the methods of calculation for usages (2) and (4) are accurate; however, (1) and (3), both producing electricity, do not include all the losses in inefficiencies of real systems (i.e., non-idealized carnot cycle thermodynamics).

The relationship for liquid enthalpy (H_L) is assumed to be a function of temperature. Pressure cannot be used since there is no distinct temperature versus depth or pressure relationship that applies to all geothermal reservoirs. Total dissolved solids have been ignored except it was assumed that only the energy in the water part of the pound of fluid could be used. Dissolved gasses were totally ignored. The liquid enthalpy relationship used is based on data presented by Barr et. al., GRC, Trans., Vol. 3, September 1979. This relationship is

$$H_L = 1 + 6.635 \times 10^{-13} T^4 \quad 1 - FTDS \times T/700^oF \quad T - 32^oF \qquad \text{(Eq. III-9)}$$

Where H_L is in Btu/lb, referenced to 32°F

T is in °F

FTDS is the fraction of "dissolved" solids

TABLE III-1. CHECK OF LIQUID ENTHALPY RELATIONSHIP FOR NO DISSOLVED SOLIDS

T(°F)	H (steam tables)	H_L	Error (%)
100	67.97	68.00	0.0
200	167.99	168.12	0.1
300	269.59	269.44	-0.0
400	374.97	374.25	-0.2
500	487.82	487.40	-0.0
600	617.00	616.84	-0.0
700	774.41	823.30	-5.9

This relationship was derived as a best fit between 100°F and 600°F. It ignores compressed liquid effects which can produce errors up to 3 percent over a range of geothermal conditions. Table III-1 shows that when there are no dissolved solids and compressed liquid effects are ignored, the liquid enthalpy relationship is accurate within one percent up to 600°F. Note if the $6.635 \times 10^{-13}T^4$ term were left out of the equation the error at 600°F would be 7.9 percent. Table III-2 shows that up to 250,000 TDS (fraction .25) the error in the liquid enthalpy relationship is only 3.4 percent.

TABLE III-2. CHECK OF LIQUID ENTHALPY RELATIONSHIP INCLUDING DISSOLVED SOLIDS

FTDS	% Decrease	FTDS T/700°F	Error (%)
	T = 575°F		
.10	6.6	0.082	+1.6
.25	20.8	0.205	-0.3
	T = 400°F		
.10	2.3	0.057	+3.4
.25	16.2	0.142	-2.0

The relationship for enthalpy of the steam fraction (H_s) is based on the assumption of pressure, temperature conditions along the saturation line. The relationship used is a function of temperature:

$$H_s = 856.6\ T^{0.05631} \qquad \text{(Eq. III-10)}$$

where T is in °F. This formula was selected for the interval between 300°F and 500°F, a range suitable for wellhead conditions. Table III-3 shows the accuracy of this steam enthalpy relationship.

TABLE III-3. STEAM ENTHALPY RELATIONSHIP

T	H_s	H (Steam Tables)	ERROR %
300	1181.0	1179.7	+0.1
400	1200.3	1201.0	-0.1
500	1215.5	1201.7	+1.1
600	1228.0	1165.5	+5.4

The formulas used to calculate the usable Btu's per pound are:

(1) Mixture enthalpy

$$H_m = X\, H_s + (1 - X) H_L \qquad \text{(Eq. III-11)}$$

Where X is steam quality at initial condition

(2) Fraction of steam after flashing

$$XF = \frac{H_M - H_{LF}}{H_{SF} - H_{LF}} \qquad \text{(Eq. III-12)}$$

Where H_m is the mixture enthalpy (Btu/lb of fluid)

H_{LF} is the liquid enthalpy at flashing pressure (Btu/lb of fluid)

H_{SF} is the steam enthalpy (liquid + latent heat) at flashing pressure (Btu/lb of steam)

XF is the steam quality at flashing pressure (fraction)

(3) Direct heat usable Btu's per pound

$$= H_m - 1 + 6.635 \times 10^{-13}(TR)^4 \quad TR - 32^oF$$

(Eq. III-13)

where TR is the reject temperature.

(4) Total energy usage useful Btu's per pound for electrical power generation

$$= (H - 1 + 6.635 \times 10^{-13}T^4 \quad TR - 32\ ) \times (1 - TR'/T')$$

$$+ (1 + 6.635 \times 10^{-13}T^4)\ (T - TR - TR'\ln(T'/TR'))$$

(Eq. III-14)

(5) Electrical usage (flashing) useful Btu's per pound

$$= XF\ (HSF - HLF)\ (1 - TR'/TF') + XF(1 + 6.635 \times 10^{-13}T^4)$$

$$\times\ (TF - TR - TR'\ln(TR'/TR'))$$

(Eq. III-15)

NOTE: Temperatures with "prime" (') must be absolute, i.e., $^oF + 459.6$

The cost of a geothermal well is computed by summing all the initial costs such as capital costs and adding them to inflated and discounted expenses throughout the well life. The algorithm equation used to inflate and discount future expenses is:

$$C_{id} = Ce^{(i-d)T}$$ (Eq. III-16)

= inflated and discounted cost

C = future cost ($)

T = time since beginning of well (months)

i = inflation factor

d = discount factor

The summation of these costs yields the life cycle cost of the geothermal well.

C. EXTENSIONS AND LIMITATIONS

GEOCOM has several extensions and limitations the user should keep in mind. There are two main extensions to the use of GEOCOM. These are adding subsystems and changing default parameters. A subsystem can be added to GEOCOM by using subsystem 01. This subsystem is designed to let the user input values for a subsystem not defined by GEOCOM. The other type of extension is freedom given to the user to change default values which represent new well locations or new subsystems.

Six limitations in GEOCOM's capability are compiled in the following discussion. The first limitation is that automatic optimization has not been included in the model. It was assumed that optimization needs to take place at the analyst level through careful evaluation of the GEOCOM output listings. The second limitation is bounding the injection pump flow rate by maximum head and zero. Third, if well production rate goes negative, the production rate is reset to zero. The fourth limitation concerns workovers. There cannot be more than three workover types scheduled in one case, but there must be at least one workover or subsystem specified. Also the fifth limitation concerns the number of times one workover can be scheduled which is 100. The final limitation is the fixed format input fields. The user must be careful of number placement and order of lines. The number of limitations of GEOCOM has not been exausted, but the key areas have been presented.

In summary, GEOCOM is a viable tool to assist engineers and analysts in assessing the potential use of geothermal energy to meet the worlds energy needs.

APPENDIX A
DEFAULT TABLES

Two tables are included in this appendix. They are the field default table and the subsystem default scheduling table. These tables provide values for field parameters and subsystem scheduling parameters.

FIELD PARAMETER DEFAULTS

FIELD

Parameter	Units	1 Brawley	2 Heber	3 Geysers	4 Baca	5 R.H.S.	6 East Mesa
DEPTH	(feet)	6,000.	8,000.	8,000.	6,000.	7,500.	7,600.
COMINT	(feet)	2,000.	2,500.	2,500.	3,000.	4,100.	2,100.
TEMP	(^{o}F)	344.	360.	365.	358.	344.	340.
WL	(Months)	120.	120.	330.	360.	200.	120.
QØ C1	(#/hr)	500,000.	500,000.	200,000.	200,000.	580,000.	500,000.
QØ C2	(#/hr)	220,000.	220,000.	88,000.	88,000.	255,000.	220,000.
FTDS	PPM by mass	80,000.	14,000.	0.	6,100.	6,500.	2,200.
X	(fraction)	.058	0.	1.	.30	.20	0.
RDR	(fraction/month)	.004	.005	.00495	.00308	.004	.005
CTIC	($/ft)	102.24	88.32	151.55	195.90	187.90	86.77
DCCI	($/ft)	43.97	57.49	66.59	72.30	74.51	49.48
CCCI	($/ft)	57.83	56.70	52.65	90.23	45.10	67.86

Equivalent Cost of Wells

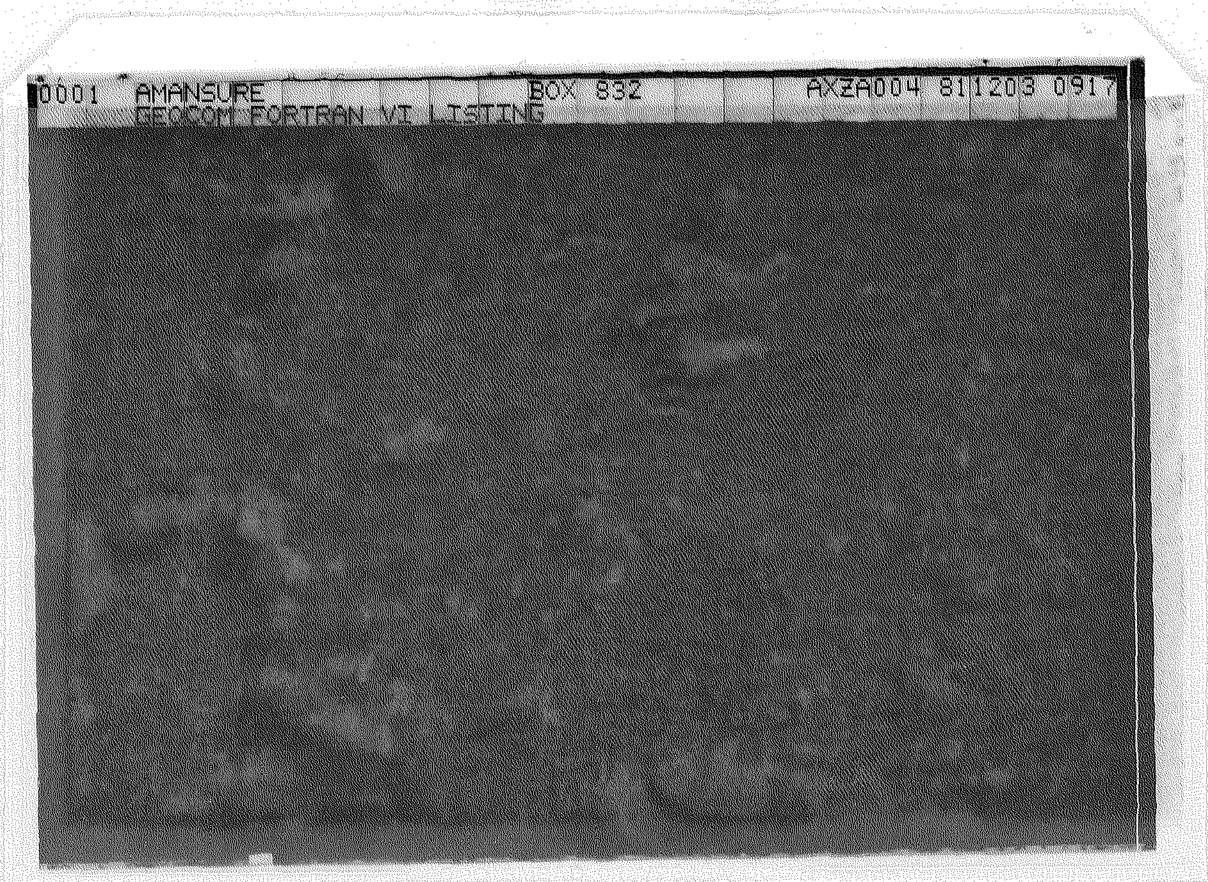
WCC, C1	($1,000)	409.0	485.8	833.5	587.7	638.9	477.2
C2	($1,000)	87.9	143.7	166.5	216.9	305.5	103.9
C3	($1,000)	115.7	141.8	131.6	270.7	184.9	142.5
C4	($1,000)	612.6	771.3	1131.6	1075.3	1129.3	723.6

SUBSYSTEM DEFAULT SCHEDULING

Subsystem Type	Identification	WORK OVER Delay WODLY	Frequency WOFQ	Recovery WOREC
	GENERAL			
01	User Input	0.00	8.0	1.0
03	Logging	0.03	360.0	1.0
	STIMULATION			
05	Perforating WO Logging	0.10	360.0	1.0
	DESCALING			
11	Mechanical	0.25	4.0	1.0
12	Hydraulic Jet	0.25	4.0	1.0
13	Chemical Scale Inhibition	0.10	48.0	1.0
	PUMPS			
16	Injection	.07	6.0	1.0
17	Submersible	.20	6.0	1.0
18	Line Shaft	.33	6.0	1.0
20	Remedial Cement	0.20	360.0	1.0
21	Underreaming and Gravel Pack	1.00	360.0	1.0
22	Slotted Liner Replacement	0.30	360.0	1.0

APPENDIX B
FORTRAN LISTING OF GEOCOM

A fortran listing of GEOCOM has been included on microfiche.



APPENDIX C
PROCEDURES FOR USING GEOCOM ON SNLA NOS COMPUTER

A. INITIATION AND PROTOCALS

Before a user can run GEOCOM a NOS user number and password must be obtained through Password Control. If the user needs to acquire a user number, then the preferred subsystem on the NOS application form is batch. The user should also acquire a copy of the NOS News Notes.

Once the user has established an account on NOS the user will need to retrieve a copy of the GEOCOM program and two procedure files, FTNGEOA and RUNGEOA. These procedure files are listed in figure C-1. If these files are not available in another users area they may be retrieved from a TFILE tape using the following command:

TFILE,R,11309,GEOCOMA,FTNGEOA,RUNGEOA

After this command is executed the files will appear in the users file space about an hour later, depending on the work load of the computer operators. The user need not stay on line while waiting for these files to appear.

Before GEOCOM can be prepared for execution an input file will need to be created. File creation is discussed in the NOS News Notes, but for the user's convenience a brief discussion is included in section B of this appendix. After the input file has been created the procedure FTNGEOA should be executed as illustrated in figure C-2 to create a relocatable GEOCOM program. The commands which are underlined are commands entered by the user. The format of the FTNGEOA command is:

CALL,FTNGEOA(TAPE5= <u>lfn1</u>, TAPE6= <u>lfn2</u>)

lfn1 = input, lfn2 = output

The FTNGEOA procedure file can also be used to make permanent software changes to the user's copy of GEOCOM, which is its primary function.

```
RT,FTNGEOA.
XEDIT,GEOCOMA,P.;P
RP,GEOCOMA.
RA.
FTN(I=GEOCOMA,L=FTNLST,EL=A,PMD,R=3,OPT=0,BL,P,B=GEOBINA,A)
RP,GEOBINA.
XEDIT,TAPE5,P.;P*
RP,TAPE5.
GEOBINA,TAPE5,TAPE6,OP=T.
RT,GEOBINA,TAPE5,GEOCOMA.
EXIT.
SDAYBOT.
XEDIT,FTNLST.;P
EXIT. FTN ERRORS OR FATAL ERROR IN EXECUTION
```

```
RT,RUNGEOA.
XEDIT,TAPE5,P.;P*
RP,TAPE5.
G,GEOBINA.
GEOBINA,TAPE5,TAPE6,OP=T.
RT,GEOBINA,TAPE5.
EXIT.
SDAYBOT.
EXIT. FATAL ERROR ENCOUNTERED WHILE EXECUTING GEOCOM
```

Figure C-1. Listing of Procedure Files FTNGEOA and RUNGEOA

```
/CALL,FTNGEOA(TAPE5=TEST1)
 XEDIT VER.SLA.8.1D REVISED 81/06/02. 15.56.39.
GEOCOMA IS EDIT FILE
       PROGRAM GEOCOM(INPUT,OUTPUT,TAPE5=INPUT,TAPE6=OUTPUT)
>? E
GEOCOMA IS A LOCAL FILE
 XEDIT VER.SLA.8.1D REVISED 81/06/02. 15.56.39.
TEST1   IS EDIT FILE
SAMPLE INPUT FOR CASE 1
01 USER SUPPLIED INPUT FOR SUBSYSTEM 1



END
END GEOCOM
END OF FILE
>? E
TEST1   IS A PRIMARY FILE
EXIT.
/
```

Figure C-2. Prepare GEOCOM For Use

B. INPUT PREPARATION

Figure C-3 illustrates how to create an input file. The first step for the user is to decide what to name the new file. Then the user must create the file with the TEXT command. After the file is complete the user must enter a control-c. This will terminate the text mode and return control to the NOS monitor.

```
/NEW,TEST1
/TEXT
ENTER TEXT MODE.

SAMPLE INPUT FOR CASE 1
01 USER SUPPLIED INPUT FOR SUBSYSTEM 1
-
-
-
END
END GEOCOM
 PACK COMPLETE.

 EXIT TEXT MODE.
/SAVE
```

Figure C-3. Input File Creation

Then the user should save the input file with the SAVE command.

C. RUN PROCEDURE

A procedure file (RUNGEOA) has been written which will execute program GEOCOM. The form of the command used is:

CALL,RUNGEOA(TAPE5 = lfn1, TAPE6 = lfn2)

lfnl = input file

lfn2 = output file

This procedure brings lfnl into the editor for the user to correct or change. Then it replaces the old lfnl with the new, and executes GEOCOM. If the user wishes to have all output generated by GEOCOM printed at the terminal then replace lfn2 with the name OUTPUT. The user can leave the TAPE6 parameter out of the command and all output will be written to TAPE6.

D. OUTPUT HANDLING

The output from GEOCOM can be all printed at the terminal, sent to the central site for printing or it can be edited to pick out the desired information. To print all the output at the terminal enter "TAPE6=OUTPUT" in the RUNGEOA command. To send output to the central site enter the command "PRINT, lfn2" after execution is complete. The print file may be TAPE6 if TAPE6 was not equated to lfn2 in the RUNGEOA command. The last option is to edit the output file. Figure C-4 illustrates editing the output file and using two macros to do it, which lists only part of the output for the user. Two macros are illustrated in the figure C-4. The user will need to generate these macros using the macro command found in the NOS News Notes.

E. ERROR HANDLING AND RECOVERY PROCEDURES

Two types of errors can be encountered by the user, nonfatal and fatal. A nonfatal error means the program terminated in the normal

```
/XEDIT,TAPE6
 XEDIT VER.SLA.8.1D REVISED 81/06/02. 15.56.39.
TAPE6   IS EDIT FILE
>? FIND
XL/GEOCOM RESULTS/;XN-6;P48;XL/BILL/;XN-2;P9
  43    8.00 344.00
  44    8.00 352.00
  45    8.00 360.00

1

          GEOCOM RESULTS FOR CASE  1: SAMPLE INPUT FOR CASE 1

                     CAPITAL COSTS  WORKOVER COSTS   ROUTINE O+M    COST/POUND
 WELL COSTS
   INTERMEDIATE          587700.
   COMP. DRILL.          216900.
   COMPLETION            270690.
                      ----------
   WELL TOTAL           1075290.                       7188.$/MO   0.000 MILS/LB

 SUBSYSTEM:  USER SUPPLIED INPUT FOR SUBSYSTEM 1
   ONE WORKOVER                              0.
   TOTAL DISC + INF           0.             0.           0.$/MO   0.000 MILS/LB
                      ==========    ==========   ============   ============
 TOTALS ($)             1075290.             0.   1895366.$/WL          0.$/WL


 GRAND TOTAL =  2979971.$/WL
 % OF GRAND TOTAL       36.08%        0.00%         63.60%          0.00%

 REPAIR:
   TIME =999.00, COST =    121000., DELAY =    .33

 ABANDONMENT =       9314.$/WELL

 INITIAL DELAY=  0.00MONTHS

 STUDY PERIOD =360.00, WELL LIFE =360.00, EVENT AT STUDY PERIOD =  0

 USAGE = 1, CONVERSION =  84.76
                          DISCOUNTED BENEFIT     INFLATED DISCOUNTED BENEFIT
                       ----------------------   ------------------------
                       WELL LIFE  STUDY PERIOD   WELL LIFE  STUDY PERIOD
   LCC/LCB ($/LB)     .4834E-03   .4834E-03      .2402E-03   .2402E-03
   LCC/BTU ($/BTU)    .5704E-05   .5704E-05      .2834E-05   .2834E-05

1

  EVENT                 WO   INC                                   FLOW   AC DIS  AC DIS
  TIME    WORKOVER   DELAY  PROD       WORKOVER COSTS ($)          RATE    PROD   INF PD
 MONTHS    1  2  3    MO    M.LB.       WO1        WO2        WO3   LB     B.LB.   B.LB.
 360.00    0  0  0  0.00    196.        0.         0.         0.  67566.   6.16   12.41
                    ----  ------
           TOTAL    0.00  15.940(BILLION POUNDS)


*************************************************************************************
```

Figure C-4. Output File Macros Use

```
/XEDIT,TAPE6
 XEDIT VER.SLA.8.1D REVISED 81/06/02. 15.56.39.
TAPE6    IS EDIT FILE
>? FINDLCC
XL/ED BE/;P6;XL.C/L.;P3;XL.C/L.;P3;XL.C/L.;P3;XL.C/L.;P3;XL.C/L.;P3;XL.C/L.;P3
                          DISCOUNTED BENEFIT      INFLATED DISCOUNTED BENEFIT
                        ------------------------  -----------------------
                        WELL LIFE  STUDY PERIOD    WELL LIFE  STUDY PERIOD
   LCC/LCB ($/LB)      .4834E-03   .4834E-03     .2402E-03   .2402E-03
   LCC/BTU ($/BTU)     .5704E-05   .5704E-05     .2834E-05   .2834E-05

END OF FILE
>? E
TAPE6    IS A LOCAL FILE
/
```

Figure C-4. Output File Macros Use (Concluded) manner. The error will appear on the output file such as, a misspelled input parameter, a bad value used for one of the parameters, missplacement of a number in a field or the user made a mistake by selecting a wrong parameter. There are many ways a non-fatal error can be generated. Correction of these errors will require the user to rerun the job; then corrections can be made to the input file.

The second type of error is the fatal error. This type error causes GEOCOM or NOS to abruptly terminate execution of GEOCOM. If GEOCOM terminates execution a message will be printed on the output file indicating why execution was terminated. Then the user can examine the output file and determine what needs to be corrected on the input file in order to rerun the job. If the NOS causes the program to terminate abnormally the user may need to examine both the output file and a day file. A day file can be generated by entering the following command:

SDAYBOT(N=50)

The N parameter tells the system how many lines before the last command to start printing. If the user cannot find the cause of the error an extensive dump of all the internal variable values can be sent to the printer. This may not be a very pleasing exercise but should yield the cause of the error. This dump is generated by calling the FTNGEOA procedure and after the error terminates the program enter the following command.

PRINT,PMDUMP

When the error is located the user should make the correction in the input file and rerun the job. If the error is in the software a correction can be made by calling FTNGEOA and correcting the error with the editor. To do this the user must become familiar with the program. A listing of GEOCOM is included in appendix B.

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1. American National Standards Institute, Inc., FORTRAN, ANSI X3.9-1966, August 1966.

2. Milora, S. L. and J. W. Tester, GEOTHERMAL ENERGY AS A SOURCE OF ELECTRIC POWER, MIT Press, 1976.

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