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A Study of Geothermal Drilling and the Production of Electricity from Geothermal Energy

K. G. Pierce, B. J. Livesay

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Abstract

This report gives the results of a study of the production of electricity from geothermal energy with particular emphasis on the drilling of geothermal wells. A brief history of the industry, including the influence of the Public Utilities Regulatory Policies Act, is given. Demand and supply of electricity in the United States are touched briefly. The results of a number of recent analytical studies of the cost of producing electricity are discussed, as are comparisons of recent power purchase agreements in the state of Nevada. Both the costs of producing electricity from geothermal energy and the costs of drilling geothermal wells are analyzed. The major factors resulting in increased cost of geothermal drilling, when compared to oil and gas drilling, are discussed. A summary of a series of interviews with individuals representing many aspects of the production of electricity from geothermal energy is given in the appendices. Finally, the implications of these studies are given, conclusions are presented, and program recommendations are made.

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Summary

The decade of the 1980's was a period of growth in the use of geothermal energy to produce electricity. The gross generating capacity at the Geysers tripled. The use of flash and binary technologies to produce power from hot-brine resources appeared first in California and then in Nevada and Utah. However, by the end of the decade, the growth in the geothermal industry had slowed. By 1990, production at the Geysers was suffering from an apparent depletion of the resource. The expansion of the use of hot-brine resources has slowed significantly since the late 1980's. Data describing annual completions of high-temperature wells in California reveal relatively little activity since 1990. This lack of activity is indicative of the general state of the geothermal industry today.

There were also changes in total electrical generation during the 1980's. Data describing generating capacity and peak loads in the United States over the last twenty years indicate that the excess capacity that existed through the late 1970's and 1980's is fading; and the demand for new generating capacity can be expected to increase in the near future.

Currently, the use of gas turbines in cogeneration and combined cycle plants is the cheapest way for an electric utility to increase generating capacity. However, recent analytical studies of the cost of producing power and a study of recent power purchase contracts in the state of Nevada indicate that in the vicinity of a relatively clean resource the production of electricity from geothermal energy is competitive with the available options.

There is interest in the expansion of the use of geothermal energy for the production of electricity. Sierra Pacific Power Company in northern Nevada has contracted to purchase electricity from six new geothermal plants. The California Energy Commission predicts that geothermal energy will become the most cost effective resource for Southern California Edison (SCE) within the next decade and has recommended that SCE eventually purchase all available electricity produced from the hot-brine resources at Coso Hot Springs and in the Imperial Valley. The Bonneville Power Administration has initiated a program to define geothermal resources and to initiate the production of electricity in the Cascades of the Pacific northwest. These projects will result in the expanded use of geothermal energy for the production of electricity, if the resources can be developed. Probably no program could do more for the domestic geothermal industry than one that leads to exploration for and the definition of new geothermal resources in the western United States.

To complement the historical and cost studies in these areas, an extensive set of interviews was conducted to aid in the evaluation of the current state of the geothermal industry and to try to determine the industry's needs. These interviews included discussions with representatives of operating companies, service companies, and private contractors. A summary of these discussions is given in the appendices.

A strong interest in exploration and resource definition was expressed in the interviews. Interest in the development of high-temperature tools and instrumentation was also indicated. Historically, lost circulation has been the most costly problem encountered in drilling and

completing geothermal wells and the industry interviews left little doubt that it remains so.

A model of the methods employed to combat lost circulation estimates that a single event can easily cost a day's drilling time and upwards from \$20k. Additionally, uncorrected lost circulation zones can result in severe problems when completing the primary cement job. There are also a number of secondary costs due to modifications in casing design, drilling procedures, and completion practices that are caused by an awareness of the prevalence of lost circulation in geothermal drilling. Both the direct and secondary costs of lost circulation are discussed.

This study included an examination of the expenditures in time and money necessary to complete a geothermal well. It was found that in a trouble-free well, about half of the time and a quarter of the money is spent with the bit turning on bottom. Given the relatively slow rates of penetration achieved in drilling geothermal wells, these proportions indicate that the development of a hard-rock drill bit has good potential for reducing well costs. The cost breakdown also revealed that from 35% to 45% of the costs of completing a geothermal well are capital expenditures for the casing, cement, and wellhead. These expenditures represent a practical limit on the cost reductions possible without major changes in well completion methods and technology.

The factors that influence the cost of electricity produced from geothermal energy were studied to indicate areas with the greatest potential for reducing these costs. This analysis, based on the IM-GEO model, predicts that the largest single contributor to geothermal power cost is the power plant. This is especially true with binary technology where the plant can account for more than 60% of the levelized cost of producing electricity. Expenditures for completing and operating the well field generally account for about a third of the cost of power from a geothermal plant. Exploration is predicted to account for more than 10% of the cost of producing electricity in the Cascades and in the Basin and Range. Costs for sludge handling and disposal, hydrogen sulfide abatement, scale build-up, and corrosion are significant in the Imperial Valley of California and in volcanic regions.

In summary, the most beneficial program to the domestic geothermal industry would be one directed at expanding the geothermal resource base. As a specific project, the requirements and program elements necessary to employ relatively small diameter wells in the exploration process are discussed.

The possible adverse consequences on the completion of the primary cement job magnifies the impact of lost circulation problems. The development of methods to decouple lost circulation and cementing problems could have a large impact on drilling operations. A number of programs to reduce the direct costs of lost circulation problems are suggested. Aside from drilling problems, hard-rock bit development holds as much promise as any other program for reducing the cost of drilling. As a minimum, the feasibility of extending drag bits into hard-rock drilling should be investigated. As indicated, there is significant industry interest in the development of high-temperature tools and instrumentation. The general requirements of any instrumentation program are discussed and a few specific programs are suggested.

Introduction

Because of growing environmental concerns and awareness, as well as the depletion of oil and gas reserves and the reluctance to use nuclear fission; the importance of the use of renewable resources for electric power generation will grow in the future. This report gives the results of a study of the production of electricity from geothermal energy with particular emphasis on the costs and problems associated with drilling geothermal wells.

This study was initiated with a series of interviews with individuals active in the production of electricity from geothermal resources. These interviews included operating company personnel, service company personnel, and private contractors. The main subjects during these discussions were the current state of the geothermal industry, the major problems being encountered and the direction for DOE programs to have maximum impact. Judging by the number of times each was introduced into conversation and the opinions concerning the relative magnitude of various problems, the following areas can be considered of primary concern to the geothermal industry:

1. Exploration and resource definition,
2. Lost circulation and cementing, and
3. High-temperature tools and instrumentation.

Other the following areas also received multiple mention. The authors' interpretation of the discussions and a summary of the topics addressed in the interviews are given in Appendix A.

In parallel with the industry interviews, a high-level analysis of the industry was performed. The following points became evident during this analysis:

1. Electricity produced from geothermal energy is available today,
2. Given a sufficient resource, the production of electricity from geothermal energy can be cost-competitive with the available options, and
3. The excess electrical generating capacity that existed through the late 1970's and 1980's is fading and the demand for new generating capacity will increase in the next decade.

From the above points, it would seem that the geothermal industry is on the threshold of a period of expansion. However, all major developments to date have occurred in areas characterized by obvious manifestations of geothermal energy. These obvious sources of geothermal energy have either been exploited or are protected. In order for the geothermal industry to expand and make an increased contribution to the nation's electric power requirements, less obvious areas must be explored and defined. More detailed explanations of the above points and these conclusions are discussed in the first part of this report.

There a number of factors that influence the cost of electricity produced from geothermal resources. These factors include capital costs associated with developing the resource and power plant as well as operating and maintenance costs associated with power production and maintaining the plant and well field. The relative contribution of these costs are analyzed for four geologic regions. A major element in the cost of producing power from geothermal energy is the cost of drilling and completing geothermal wells. The costs and time associated with geothermal drilling are broken down according to activity.

The geothermal industry employs oil and gas technology for exploration, drilling, and completion. However, a typical geothermal well costs significantly more than a typical oil and gas well. Some of this difference is due simply to the difference in the size of the wells. However, there is more than just size to the difference in well costs. Due to fractured formations drilled in geothermal applications, lost circulation is a significantly larger problem than in the sedimentary regions typical of oil and gas drilling. Furthermore, the high temperatures, hard rock, and corrosive fluids encountered in geothermal drilling often result in extra problems or premium costs when compared to oil and gas drilling.

Lost circulation, high temperature, hard rock, and corrosive fluids on geothermal operations are endemic to geothermal drilling, completion, and production. These problems cannot be solved; these problems cannot be made to go away. Dealing with these problems involves a continuous search for the most efficient method of combatting their effects. The immediate and secondary effects of lost circulation, high temperature, hard rock, and corrosive fluids on geothermal operations are discussed.

History of Geothermal Development

Currently about thirty companies are actively involved in the development of geothermal energy in the United States. Of the major oil companies that were pursuing domestic geothermal development in the early 1980's, none remain. Unocal was the last major oil company to be active in the U.S. Based on interest in geothermal resources, as late as 1992 Unocal controlled half of the operating and planned capacity (ref. 1). However, with the exception of their holdings at the Geysers, Unocal has sold all domestic geothermal interests and is actively pursuing the development of geothermal resources only at overseas locations. The dominant companies in the domestic industry today are CalPine Corporation in Santa Rosa, California Energy Company in Ridgecrest, and Magma Energy Company in the Imperial Valley.

The commercial development of geothermal energy for the production of electricity in the United States began in the mid-1950's (ref. 2). The first power plant to produce electricity from geothermal energy was commissioned in 1960 by Pacific Gas and Electric (PG&E) at the Geysers. The first hydrothermal flash and binary plants came on line in the Imperial Valley of California in 1980. The use of geothermal energy to generate electricity was initiated in Utah and Nevada in 1984, and the first commercial generation of electricity from geothermal energy in Hawaii was initially scheduled to come on line in the Fall of 1991. The history of the growth of gross electrical generating capacity from geothermal energy in the United States for the period from 1970 through 1991 is given in Figure 1.

Figure 1: Geothermal Power On-Line
Source: Geothermal Resources Council

Though development of the Geysers began in the late 1950's, the gross generating capacity of steam plants in 1970 was less than a tenth of the capacity available today. There was significant development in the Geysers in the early 1970's, but the major development of this resource occurred in the 1980's when nearly 1400 MW of new capacity was added. As shown in Figure 1, toward the end of the 1980's the growth in generating capacity at the Geysers ceased. This is believed to be due to depletion of the resource. However, the lack of demand for new generating capacity in California in the late 1980's would have significantly reduced growth at the Geysers with or without depletion of the resource.

Though the first plants came on line in 1980, there was little development of flash or binary plant capacity through 1984. Through 1987, the expansion of the use of these two technologies for generation of electricity was nearly parallel. A dramatic increase in the generating capacity of flash plants occurred in 1988 and 1989 due primarily to the development of the Coso Hot Springs and Salton Sea fields.

The gross electrical generating capacity from geothermal steam reached a maximum of about 2100 MW in 1989. The gross generating capacity of flash plants is a little over 700 MW and the existing capacity of binary plants is approximately 270 MW, including the 45-MW Heber facility. There is about 200 MW of additional flash and binary generating capacity planned to enter operation before the end of 1994; there are no plans for new steam plants. The great majority, 85%, of the currently planned expansion is in Nevada and Hawaii. Nearly 60% of the planned capacity expansion is binary plants. This expansion in binary capacity will be due to the development of a number of generally small plants, less than 15 MW. Such relatively small units make up 75% of the binary plants currently in operation.

Figure 2 shows the history of the development of geothermal wells in the state of California. These data indicate a fair number of hot-water wells drilled before the first flash and binary plants came on line in 1980. These wells were exploratory in nature.

Figure 2: California Development Wells

Source: California Division of Oil and Gas

Comparison of Figure 1 with Figure 2 reveals a number of similarities. The growth in steam production wells parallels the growth in steam generating capacity. The hot-water and injection well curves demonstrate the same general shapes as the growth in flash and binary plant capacity with the wells preceding the plant capacity by about a year. The development of the Coso Hot Springs and Salton Sea fields appear in 1988 and 1989 in Figure 1 with similar increases in production wells from 1987 through 1989 in Figure 2.

One predominant characteristic in both figures is the reduced slopes of all curves since 1989. This is indicative of a general lack of growth in the industry. Due to the apparent field depletion, the plants at the Geysers are generating at about two-thirds capacity, with the operators working hard to maintain that level. PG&E retired units 1 through 4, with approximately 80 MW of capacity at the Geysers, in 1992 (ref. 3). There was a significant drilling program being conducted at Coso through 1992; however, this was to maintain capacity, not for expansion. It is generally believed that the reservoir at the Salton Sea will support further expansion, but there is little need for more capacity in southern California at this time. Development in Hawaii was slowed by the blowout of KS-8 at the Puna Geothermal Venture (PGV) site in June, 1991, in conjunction with the opposition to the use of geothermal energy on the island. The only signs of expansion appear in the development of small binary plants in Nevada.

The Effects of PURPA on the Geothermal Industry

Though its full effects did not begin to show prior to 1984, the passage of the Public Utilities Regulatory Policies Act (PURPA) in 1978 resulted in major changes in the structure of the geothermal industry (ref. 4). With the passage of PURPA, local electric utilities were required to interconnect and purchase electricity from power producers, even though the producers may not be other utilities. Of equal importance, utilities were also required to accept bids for new generating capacity. However, other than requiring "just and reasonable rates", PURPA did not specify the details of the power purchase contracts.

Prior to the implementation of PURPA, the geothermal industry consisted almost entirely of oil and gas companies selling steam to utilities at the Geysers. However, the utilities were under no obligation to buy. Consequently, the steam had to be offered at a price below that paid for fossil fuels to entice the utilities to build power plants. Under these conditions, the utilities generally received excellent bargains: electricity produced below the cost of generation with fossil fuels and related capital costs below those of conventional steam plants.

The composition of the geothermal industry has changed dramatically since 1984. A number of the major companies active at that time have either left the industry or greatly reduced their activities. The only major oil company still actively working in geothermal energy is Unocal and Unocal's operations are entirely overseas. Those leaving the industry have been replaced by a number of independent operators, resource companies, and unregulated utility affiliates. It is this mixture of companies that, under PURPA, has led the expansion of the geothermal industry out of the Geysers and into the use of high-temperature brine for the production of electricity. In 1984, 99% of the installed generation capacity was at the Geysers. Today, the power plants at the Geysers represent about two-thirds of the installed geothermal capacity in the United States. In the future, the proportion of the total generating capacity that is located at the Geysers will only decrease.

Expansion Under the SO4 Contracts

As mentioned previously, PURPA did not specify how the required provisions would be implemented; this part of the law was left to the individual states. To comply with PURPA, California adopted a set standard offer contracts to encourage the development of renewable resources for the generation of electricity. Much of the development of binary and flash technology in the 1980's was a direct result of these standard offer contracts in California, specifically Standard Offer 4 (SO4). For qualifying facilities (QF's), as defined by PURPA, SO4 contracts offered fixed capacity payments for up to thirty years and forecasted energy payments, with built-in escalators, for ten years. These contracts provided the income security necessary to obtain long-term financing (ref. 5). With a guaranteed-price contract, the operator was only required to demonstrate an adequate resource to obtain the financing necessary for development.

Figure 3 shows the development of flash and binary generating capacity from 1980 through 1991 according to contract type, SO4 and other (non-SO4). As shown, the majority of the expansion in generating capacity has been in conjunction with SO4 contracts. Excluding the Heber facility,

more than 40% of the current binary capacity is selling power under SO4 contracts. Nearly 90% of the current flash capacity is operating under SO4 contracts. Not indicated in Figure 3 are steam plants at Bear Canyon and West Ford Flat at the Geysers which are also operating under SO4 contracts.

Figure 3: Flash and Binary Development

It is difficult to completely isolate the effect SO4 contracts have had on the geothermal industry. The development of the steam resource at the Geysers was well under way by the time the standard offer contracts were made available. Also, as shown in Figure 3, there is currently over 200 MW of flash and binary capacity operating under other types of contracts. Additionally, though the Oxbow facility at Dixie Valley, Nevada, is selling power to Southern California Edison under an SO4 contract (ref. 1), the development of geothermal resources in Nevada and Utah has generally been accomplished without the security of SO4 contracts. These points indicate that with the passage of PURPA (giving independent developers access to utility contracts), the use of high-temperature brines to generate electricity would have occurred even without the California standard offer contracts.

On the other hand, nearly three-fourths of the current generating capacity from hot-brine resources are operating under SO4 contracts. The entire industry has benefitted by the availability of guaranteed income under these contracts. The majority of the non-SO4 development has been in Nevada and Utah, but a large part of the exploration and resource definition in these states was conducted under the DOE-Industrial Coupled Program initiated in 1977 (ref. 6). So when DOE sponsored programs are considered in addition to the California SO4 contracts, the influence of government support on the development of geothermal resources appears quite large. Without

these programs, it is doubtful that the generating capacity from hot-brine resources would exceed a third of the currently operating production.

The conclusion that the SO4 contracts have been critical to the expansion of the geothermal industry is supported by the findings of the California Energy Commission (CEC):

"The Commission finds a small role for the renewable set-aside to play in technology development... Current history suggests that California's standard offer contracts have been crucial to the development of the national renewables industry." (ref. 7)

Electricity Demand and Generation Capacity

As discussed in the previous section, much of the development of flash and binary generating capacity in the 1980's was due to PURPA and the standard offer contracts in California, specifically SO4. California suspended the issuance of new SO4 contracts in 1985 due to concerns about excess generating capacity.

California was not the only state with concerns about excess electrical generating capacity in the mid to late 1980's. There was a excess of generating capacity across the United States, and especially in the western part of the country, during this period (ref. 8). The Energy Information Administration's (EIA) 1989 report on electric power states:

"Most utilities are not fully utilizing their existing plants, so in most areas of the country there is little need for additional capacity at this time." (ref. 9)

Also in the 1989 report, the EIA predicted that through the early 1990's the growth in demand for electricity would be met primarily through increased utilization of existing plants. The EIA did not expect that significant additional capacity would be needed until the latter half of the 1990's. In its 1990 report (ref. 10), the EIA attributed the surplus capacity of the 1980's to plant construction based on estimates of growth in electricity usage that did not materialize.

One quantitative measure of surplus capacity is the reserve margin, sometimes referred to as the capacity margin. This margin is defined as the percentage of reliable electricity supply above peak load. Based on data published by Edison Electric Institute (ref. 11), Figure 4 shows the estimated electric capacity margin for the United States since 1970.

The desired reserve margin varies among utilities due to a number of factors including sensitivity to forced outages, the amount of interconnection support available from other utilities, and the likelihood of extreme temperatures. The reserve margins adopted by the major California utilities vary from 15% to 29% (ref. 7). Overall, a reserve margin in the neighborhood of 20% is generally considered necessary to ensure reliable service.

As shown in Figure 4, the reserve margin for the U.S. rose above 20% in 1974, climbed to 25% in 1975, and did not drop below 23% until 1988 when the margin was estimated at 20%. The surplus capacity of the late 1970's and early 1980's is evident in Figure 4. It is also evident that the surplus capacity of the last decade has faded in recent years. Based on these data,

Figure 4: U.S. Electric Capacity Margin

Source: 1991 EEI Statistical Yearbook

construction of new generating capacity could be expected in the near future.

The need for new capacity in the 1990's is not entirely a surprise. The EIA predicted that between 84 GW and 110 GW of capacity additions would be needed before the turn of the century (ref. 10). In a 1987 report (ref. 12), the DOE predicted that all areas of the country would need new capacity in the 1990's and, in particular, the western states would need additional electricity supply, beyond then current construction, between 1994 and 1998.

In Nevada, both Sierra Pacific Power and Nevada Power have recently contracted for new capacity. In addition, Nevada Power is expanding their transmission network and considering construction of new combustion turbines (ref. 13). The CEC predicted that 10.8 GW of new resources will be needed in California before 2001 (ref. 7). Of this, the commission recommends that 3460 MW be supplied through new generation. Additionally, by 2001, Southern California Edison alone will have nearly 4000 MW of oil- and gas-fired units that are forty years old or older. This number climbs to 7355 MW by 2009. While some of these plants will be refurbished and continue operating, others will be retired and replaced.

The Bonneville Power Administration (BPA) still forecasts a surplus of capacity in the Northwest. However, more than 80% of the electricity generation in both Oregon and Washington is hydroelectric. For planning purposes, BPA must consider only firm energy: that electricity generated in a worst water year, i.e. that with the lowest runoff. With the expected-load forecasts, the region is predicted to experience firm energy deficits in 1993 (ref. 14). With

the medium-low forecast, considered a one in four probability, firm energy deficits are predicted in 1999. Only in the minimum-load forecast, a one in twenty probability, is the region predicted to experience firm energy surpluses for the next twenty years.

The capacity surpluses of the 1970's and 1980's appear to be fading. New electricity generation capacity will be needed throughout the West in the 1990's. The geothermal industry should gain from this expansion.

Opportunities for Expansion of the Geothermal Industry

As discussed in the previous section, there are a number of indications that the surplus generating capacity of the 1970's and 1980's has disappeared or is greatly reduced. This reduction in surplus capacity, coupled with the aging of the existing power generation system, leads to an expectation of a need for new generating capacity in the next decade. The important question for the industry concerns how much of this new generation will be from geothermal resources.

Gas turbines are generally considered the major competition to geothermal plants for new capacity. The use of gas turbines to generate electricity underwent major expansion during the 1970's when this technology was employed primarily to provide peaking capacity. More recently, gas cogeneration and combined cycle plants have been built to increase baseload capacity.

The primary reason cited for the expansion of the use of gas turbines to generate electricity is cost. Natural gas is abundant and relatively cheap. Domestic production of natural gas is not expected to peak for at least another decade (ref. 15). Also, compared to oil- and coal-fired plants, gas turbines are relatively clean burning. The capital cost associated with installing a small, aero-derivative, gas plant is on the order of one-fourth to one-sixth the capital cost associated with a new geothermal plant (ref. 16). Even if the field development and drilling were free, a new flash plant would still cost twice as much as a similar sized gas plant, with a binary plant running two and a half to three times as much. The reasons for the difference in cost are many. The technology associated with gas turbines is highly developed. Gas plants are significantly smaller than geothermal plants allowing relatively simple installation and lighter foundations. There is also no large heat exchanger required in a gas plant. Gas turbines do require high pressures for operation, but again, this is a highly developed technology. Until the price of natural gas increases, it is not likely that any technology will challenge gas turbines in terms of cost.

In addition to gas cogeneration and combined-cycle plants, the geothermal industry will also face major competition from conservation programs. The electric utilities are looking to demand-side management programs to offset requirements for new generation. Nevada Power Company has a number of demand-side programs in the areas of air conditioning management and retrofit, commercial lighting, providing energy-use consultants, and insulation, to name a few (ref. 13). Southern California Edison and Pacific Gas and Electric have both experienced essentially zero growth by their industrial customers since 1980 (ref. 4). This is attributed to conservation programs, and the utility industry believes that similar results can be achieved with commercial and residential customers if aggressive demand-side programs are instituted. The CEC believes

that more than two-thirds of the capacity increases needed in California in the next decade can be avoided through demand-side management (ref. 7). If conservation programs are as successful as expected, the result will be significantly reduced requirements for new generation facilities.

Another major fuel source for electricity generation is coal. More than 55% of the electricity generated in the United States in 1990 employed coal as the energy source (ref. 11). However, in the Pacific coast states coal accounted for only 3.3% of the energy used to generate electricity. The California Energy Commission found that:

"... almost all coal technologies have significant research and development needs for cost reduction, improved performance, lower operations and maintenance costs, and environmental impact mitigation [and], as a group, coal technologies face many significant deployment issues." (ref. 17)

The CEC also found coal to be less cost effective than geothermal and, furthermore, found no evidence that any utility in the state was considering the purchase of a coal-fired plant (ref. 7). In spite of this, there is a project under consideration where coal might compete with geothermal for generating capacity. The Thousands Springs Project, located near Wells, Nevada, is a plan for a 2000-MW coal-fired plant (ref. 18). It is to be an independent power project, built in 250-MW increments as the need arises. The developers intend to sell power to all areas surrounding the plant. If initiated, this project will compete with geothermal for power purchase contracts.

There are a few projects already initiated and others under consideration in which geothermal is the planned energy source. Sierra Pacific Power Company in Nevada has new contracts to purchase electricity from six binary plants, totalling about 80 MW, with initial delivery dates between 1992 and 1995. In the northwest, BPA has initiated a program to explore and develop the geothermal potential (ref. 19). BPA hopes that this program will demonstrate a minimum of 300 MW of geothermal potential with initial development of at least 30 MW. In California, the CEC predicts that geothermal will become the most cost effective resource for Southern California Edison (SCE) at about the turn of the century (ref. 7). Consequently, the CEC recommends that SCE add 600 MW of geothermal power before 2004 and all additional capacity available from the Imperial Valley and Coso Hot Springs fields in subsequent years.

Of the above programs, only the Nevada contracts represent definite expansion of the geothermal industry. However, the BPA program indicates interest in developing a geothermal resource that some believe to be one off the largest in the country. The recommendations of the California Energy Commission portend a major expansion in southern California in future years.

Analytical Studies of the Cost of Producing Electricity

Though not the only factor, cost will be a major factor in determining how much of the market for electrical generation capacity is controlled by the geothermal industry. Exploration, licensing, drilling, plant construction and operation, maintenance, power transmission, and debt service are a few of the factors that enter into the cost of producing electricity from geothermal energy. Determining the magnitude and degree to which each of these affects the busbar cost of

electricity is a difficult task. However, there have been a number of studies and publications in recent years that compare the cost of producing electricity for various options available to the utility companies.

The Electric Power Research Institute (EPRI) published a comparison of the economics and performance of advanced generating options in 1987 (ref. 20). This study concentrated primarily on the expected characteristics of advanced coal, gas, and nuclear plants, but generation from renewable resources was also treated. EPRI estimates the capital and operating costs for a fifty megawatt hydrothermal plant, operating at a 65% capacity factor, to be lower than most advanced coal and gas plants. Only after fuel costs are included does the EPRI study predict that the life-cycle costs of a geothermal plant will be more higher than those of the next generation of coal plants. Evidently the author of the EPRI study concluded that the delivery of hot water or steam to a geothermal plant will be significantly more expensive than the delivery of fuel to the next generation of coal plants.

More recently, a report by Science Applications International Corporation (SAIC) gives the cost of generating electricity from coal-fired plants at about six cents per kilowatt-hour (ref. 21). This same report estimates the cost of electricity generated from hydrothermal sources at less than eight cents per kilowatt-hour. A 1990 DOE interlaboratory study estimated the cost of producing electricity from geothermal energy at four to six cents per kilowatt-hour (ref. 8). In their report on non-utility electricity producers, the Investor Responsibility Research Center (IRRC) states that geothermal energy can be employed to produce power for "... as little as 4.5 cents per kilowatt-hour" (ref. 1). Finally, the California Energy Commission (CEC) estimates the levelized cost of generating electricity from geothermal energy at four to ten cents per kilowatt-hour (ref. 17). This range compares to the CEC estimates of four to six cents per kilowatt-hour for electricity production from gas and four to ten cents per kilowatt-hour when coal or nuclear fuel are employed. These data are summarized in Table 1.

Table 1: Estimates of the Cost to Produce Electricity

	Non-Renewable	Geothermal
EPRI	12 ¢/kW·hr	15 ¢/kW·hr
SAIC	coal: 6 ¢/kW·hr	8 ¢/kW·hr
DOE Labs		4-6 ¢/kW·hr
IRRC		4.5 ¢/kW·hr
CEC	gas: 4-6 ¢/kW·hr coal: 4-10 ¢/kW·hr nuclear: 4-10 ¢/kW·hr	4-10 ¢/kW·hr

Three of the studies cited in Table 1 indicate that it should be possible to produce electricity from geothermal energy for a cost in the range of four to five cents per kilowatt-hour. This is true for production from the dry steam resource at the Geysers. However, for electricity production from

hot-water resources, the minimum necessary price, given a relatively clean resource located in a geological setting that does not introduce extraordinary drilling problems, is probably closer to six cents per kilowatt-hour.

Even at a price in the neighborhood of six cents per kilowatt-hour, the studies cited above indicate that the production of electricity from geothermal energy is generally competitive with the available options. Based on this information, it would be concluded that cost should not be a major obstacle to expansion of the geothermal industry.

Utility Contracts for the Purchase of Electricity

Additional insight into the cost of producing electricity can be gained by comparing pricing for recent power purchases. Data on seven power purchase contracts negotiated by Sierra Pacific Power Company and four contracts negotiated by Nevada Power Company were obtained and analyzed. These contracts involve three gas cogeneration facilities, one coal-burning plant, six geothermal plants, and a generating station that employs tires for fuel.

Though the price of electricity is often discussed in terms of cost per kilowatt-hour, power purchase contracts are not negotiated on this basis. In power purchase contracts, one price is specified for installed capacity and another for energy delivered. It is these prices that were obtained from the Nevada utility companies. These data are given in Appendix B. The characteristics of each of the power plants and the assumptions required to derive a cost for delivered electricity are also discussed in the appendix.

Figures 5 and 6 show the projected energy and capacity prices for the power purchase contracts. In these figures, the prices for the geothermal plants and the gas cogeneration facilities have been averaged. The averaging was done to reduce clutter and confusion in the graphical presentation. The data for individual contracts are given in Appendix B.

Energy Prices

The assumed inflation rate for the contracts with the geothermal plants is between four and five percent, whereas the assumed inflation rate for the contracts with the gas cogeneration plants is four percent. However, the energy price for the gas cogeneration plants is tied to 120% of the indicated inflation rate. Hence, the geothermal and gas cogeneration energy prices are nearly identical. The data for the tire burning plant shows the effect on energy prices tied to a four percent inflation with no other multipliers. The energy rates for the coal plant are lower than those for the gas cogeneration or geothermal facilities, but follow the same general trend.

Capacity Prices

The contracts for capacity prices for the gas cogeneration and tire plants have either a fixed escalation or are tied to a fraction of some general inflation indicator. After an initial surge, the escalation of the capacity price for the coal plant is on the order of two and three-quarter percent. Only the capacity payments for the geothermal plants do not include an escalator.

Figure 5: Projected Energy Prices
Source: Nevada Utility Contracts

In most of the contracts for capacity prices, there is a reduction in the price paid for capacity at some point. This is the sharp drop in the capacity price for the tire plant in 2014. Similar reductions in individual contracts resulted in the discontinuities in the average capacity prices for the gas cogeneration and geothermal plants. This price reduction is meant to coincide with the retirement of the debt incurred in plant construction.

Some insight into the incurred debt can be gained by examining the capital costs. Table 2 gives estimates of capital costs for various types of power plants (ref. 4). The payments for capacity are meant to help the operator recover the costs of bringing the power plant on line. The total capital costs include plant construction, interconnection, drilling, etc. From the data in Table 2, it would be expected that geothermal plants would receive the highest capacity payments, coal plants the second highest, and gas facilities would receive the lowest capacity payments. Such expectations are not supported by the projected capacity prices in Figure 6. The initial capacity prices for the gas cogeneration and the geothermal plants are essentially the same with the capacity price for the coal plant somewhat lower. However, eventually, the gas-burning facilities will receive the largest capacity payments and the geothermal plants will receive the lowest.

Figure 6: Projected Capacity Prices
Source: Nevada Utility Contracts

Table 2: Capital Cost for Selected Generating Technologies

Plant Type	Base Cost	Maximum Cost
Natural Gas Boilers	\$829/kW	\$860/kW
Coal Boilers	\$1293/kW	\$1807/kW
Natural Gas Combined Cycle	\$506/kW	\$520/kW
Geothermal Flash	\$1692/kW	\$2125/kW
Geothermal Binary	\$2392/kW	\$2498/kW

Source: W.P. Short III, GRC Bulletin, October 1991

Based on a comparison of the data in Figure 6 with that in Table 2, it appears that geothermal plants cost more and receive lower capacity payments than other facilities. Such conditions

would be definite disincentives to the development of geothermal energy for the production of electricity. It can only be assumed that there is more to the determination of capacity prices than the capital cost of initially bringing a power plant on line.

Electricity Prices

Under the assumptions discussed in Appendix B, the projected capacity and energy prices are combined in Figure 7 to yield the price per kilowatt-hour of delivered electricity. Again, the gas cogeneration and geothermal data are averaged. The data for the individual contracts are given in the appendix.

Figure 7: Projected Electricity Prices

Source: Nevada Utility Contracts

Initially, the prices for electricity from the gas cogeneration plants, the geothermal plants, and the tire burner are nearly identical, while electricity from the coal plant is significantly cheaper. While the initial price for electricity from the geothermal plants, the tire burners, and the gas cogeneration facilities are comparable; the predicted increases in the prices from the geothermal plants are lower than the predicted increases from any of the other contracts. The lower

predicted late-year prices for the geothermal plants are directly attributable to the differences in the capacity pricing discussed above and shown in Figure 6. Within three years of initial operation, the price for electricity from the geothermal plants is below that for either the tire burner or the gas cogeneration plants. After the turn of the century, the price for electricity from the geothermal plants is predicted to be below that for electricity from the coal facility.

Gas cogeneration plants are generally considered the primary competition for geothermal plants in the market for electric power contracts. Because of this, the primary interest in the costs discussed in the previous paragraphs is a comparison between the costs for these two options. Before making this comparison, there is another point to be considered. Nevada Power Company did a first order analysis of the feasibility of developing a tieline with Sierra Pacific Power Company to purchase electricity from geothermal facilities in northern Nevada (ref. 22). The study concluded that even at a purchase price of four cents per kilowatt-hour, line losses and interconnection charges would drive the price to Nevada Power Company significantly above avoided costs.

The following points summarize the analysis of power purchase contracts in the state of Nevada:

1. With the exception of the first years of the contract with the coal plant at Craig, Colorado, the capacity price negotiated with geothermal facilities is below the capacity prices negotiated with the other facilities.
2. The energy price for electricity from geothermal facilities in northern Nevada is essentially the same as the energy price for electricity from gas cogeneration facilities in southern Nevada.
3. Assuming similar capacity factors, the contract price per kilowatt-hour of delivered electricity from the geothermal plants in northern Nevada is lower than the price for delivered electricity from gas cogeneration plants in southern Nevada.
4. However, the difference in the price of electricity produced at geothermal plants when compared to the price of electricity produced at gas cogeneration facilities is not sufficient to offset the cost of power transmission from northern to southern Nevada.

From the above points, it can be concluded that given a relatively clean resource in the local vicinity, production of electricity from geothermal energy is competitive with the available options. As was found in the overview of the analytical studies of the cost of electricity, it must be concluded that cost should not be a major impediment to the expansion of the geothermal industry.

Drilling Cost and Time

A major element in the cost of producing power from geothermal energy is the cost of drilling and completing the wells. Figures 8 through 15 are time and cost charts for geothermal wells drilled in the Imperial Valley, California; at the Geysers, California; at Roosevelt Hot Springs,

Utah; and at Baca Ranch, Valles Caldera, New Mexico. The information displayed in these charts was derived from models developed by Carson, Lin, and Livesay (ref. 23). These models were constructed to represent trouble-free, non-optimal wells. Being trouble-free, no estimates of the costs due to commonly encountered drilling problems, such as lost circulation, stuck pipe, etc., are included in the models.

The cost estimates from these models are now outdated due to inflation and there have been technical advances in the drilling and completion of geothermal wells since Carson, Lin, and Livesay completed this work. However, there have been no major innovations in the drilling industry that would invalidate a high-level analysis based on the relative costs estimated by these models. For analyses of where time and resources are spent in normal drilling and completion activities, these models are the best available information. The casing programs for the well models are given in Table 3.

As shown in Table 3, the casing programs at Roosevelt Hot Springs and Baca Ranch are essentially the same. The program employed in the Imperial Valley model uses 20-inch, instead of 30-inch, conductor pipe, and reduces the number of casing strings and set points by one. The program at the Geysers employs a barefoot finish through the production zone instead of hanging a 7-inch slotted liner. When compared to the Baca Ranch and Roosevelt Hot Springs casing programs, both the reduced number of casing strings in the Imperial Valley and the barefoot finish at the Geysers tend to reduce the cost of well completion relative to other costs associated with drilling a production well.

As shown in Figures 10 and 12, the Geysers' and Roosevelt Hot Springs' models indicate a larger portion of cost due to drilling than does either of the other models. In the Geysers' model, this is due to the last 2500 feet of the well being finished barefoot whereas the other models assumed a 7-inch slotted liner is hung through the production zone. This difference reduces the relative contribution of casing in the Geysers' model and emphasizes the drilling costs.

In the Roosevelt Hot Springs' model, the relatively large portion of the time spent drilling is due to an average rate-of-penetration (ROP) of less than nine feet-per-hour. This compares to about twelve feet-per-hour for the Geysers and Baca models and twenty-two feet-per-hour in the Imperial Valley model. As a consequence of this relatively slow ROP, the drilling time and costs are emphasized in the Roosevelt Hot Springs' model. Some indication of the effect of ROP on well cost can be achieved by comparing the Roosevelt Hot Springs with the Imperial Valley models. It is estimated that it costs 60% more to drill and complete a well at Roosevelt Hot Springs than it does in the Imperial Valley. Three-fourths of this increased cost can be contributed directly to the harder rock and more severe drilling conditions which result in the slower ROP at Roosevelt Hot Springs.

As shown in Figures 10 and 12, the Geysers' and Roosevelt Hot Springs' models indicate a larger portion of cost due to drilling than does either of the other models. In the Geysers' model, this is due to the last 2500 feet of the well being finished barefoot whereas the other models assumed a 7-inch slotted liner is hung through the production zone. This difference reduces the relative contribution of casing in the Geysers' model and emphasizes the drilling costs.

Table 3: Casing Schedules for Well Models

Imperial Valley, CA:

Conductor	26-in hole, 20-in pipe to 100 ft
Surface Casing	17 1/2-in hole, 13 3/8-in pipe to 1600 ft
Intermediate Casing	12 1/4-in hole, 9 5/8-in pipe to 5300 ft
Production Casing	8 1/2-in hole, 7-in pipe to 7200 ft

Geysers, CA:

Conductor	42-in hole, 30-in pipe to 50 ft
Surface Casing	26-in hole, 20-in pipe to 350 ft
First Intermediate	17 1/2-in hole, 13 3/8-in pipe to 1900 ft
Second Intermediate	12 1/4-in hole, 9 5/8-in pipe to 5500 ft with 10 3/4-in tieback to surface
Production Casing	8 3/4-in hole, barefoot to 8000 ft

Roosevelt Hot Springs, UT:

Conductor	36-in hole, 30-in pipe to 30 ft
Surface Casing	26-in hole, 20-in pipe to 200 ft
First Intermediate	17 1/2-in hole, 13 3/8-in pipe to 800 ft
Second Intermediate	12 1/4-in hole, 9 5/8-in pipe to 3400 ft
Production Casing	8 1/2-in hole, 7-in slotted liner to 7500 ft

Baca Ranch, Valles Caldera, NM

Conductor	36-in hole, 30-in pipe to 50 ft
Surface Casing	26-in hole, 20-in pipe to 200 ft
First Intermediate	17 1/2-in hole, 13 3/8-in pipe to 1500 ft
Second Intermediate	12 1/4-in hole, 9 5/8-in pipe to 3000 ft with 9 5/8-in tieback to surface
Production Casing	8 1/2-in hole, 7-in slotted liner to 6000 ft

In the Roosevelt Hot Springs' model, the relatively large portion of the time spent drilling is due to an average rate-of-penetration (ROP) of less than nine feet-per-hour. This compares to about twelve feet-per-hour for the Geysers and Baca models and twenty-two feet-per-hour in the Imperial Valley model. As a consequence of this relatively slow ROP, the drilling time and costs are emphasized in the Roosevelt Hot Springs' model. Some indication of the effect of ROP on well cost can be achieved by comparing the Roosevelt Hot Springs with the Imperial Valley models. It is estimated that it costs 60% more to drill and complete a well at Roosevelt Hot Springs than it does in the Imperial Valley. Three-fourths of this increased cost can be contributed directly to the harder rock and more severe drilling conditions which result in the slower ROP at Roosevelt Hot Springs.

**Figure 8: Well Costs
Imperial Valley, CA**

**Figure 9: Expenditure of Time
Imperial Valley, CA**

**Figure 10: Well Costs
Geysers, CA**

**Figure 11: Expenditure of Time
Geysers, CA**

**Figure 12: Well Costs
Roosevelt Hot Springs, UT**

**Figure 13: Expenditure of Time
Roosevelt Hot Springs, UT**

**Figure 14: Well Costs
Baca Ranch, Valles Caldera, NM**

**Figure 15: Expenditure of Time
Baca Ranch, Valles Caldera, NM**

As shown in Figures 10 and 12, the Geysers' and Roosevelt Hot Springs' models indicate a larger portion of cost due to drilling than does either of the other models. In the Geysers' model, this is due to the last 2500 feet of the well being finished barefoot whereas the other models assumed a 7-inch slotted liner is hung through the production zone. This difference reduces the relative contribution of casing in the Geysers' model and emphasizes the drilling costs.

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The portions of the charts in Figures 8 through 15 labeled 'drilling' include expenses and time spent with the bit turning on bottom. The drilling category then represents primarily time-related charges. Similarly, the tripping category is time spent extracting the drill string from the hole or returning it to the bottom and, thus, also represents primarily time-related charges. As a general rule, the percentage of total cost due to drilling and tripping is about one-half the percentage of total time spent on these activities. This implies a multiplier of about 50% for innovations reducing the time associated with completing the well. For example, if some new method or technology results in increasing the rate-of-penetration such that the time spent drilling is reduced by 20%, it would be expected that the cost of the well would be reduced by about 10%.

The 50% multiplier discussed in the previous paragraph also implies that about half of the current cost of a well is due to direct charges for materials. The models estimate that the proportion of total cost due to direct charges range from just over 50% at the Geysers and Roosevelt Hot Springs to about 60% in the Imperial Valley. A majority of the direct charges are tied to completion practices. The current practice in completing geothermal wells is to cement the casing from the top of the production zone to the surface. The portion of the well cost due to the casing, the cement, and the wellhead range from about 35% at the Geysers to about 45% in the Imperial Valley. These percentages represent a practical limit on the cost reduction possible without major changes in well completion methods and technology.

The Relationship of Factors Effecting the Cost of Power

A reduction in the cost of drilling will result in a reduction in the cost of producing electricity from geothermal energy. However, because there are a number of other factors in addition to drilling that also influence the cost of electricity, the translation from drilling costs to power costs is not one-to-one. The additional factors include capital costs associated with developing the resource and power plant as well as operating and maintenance (O&M) costs associated with

power production and maintaining the plant and well field.

The best available information concerning how each of these factors effect the cost of power can be obtained through the use of the IM-GEO code (refs. 24 and 25). This code estimates the return, in cents per kilowatt-hour of electricity, necessary to recover the costs of building and operating a geothermal plant from initial resource exploration until plant retirement. Not included in IM-GEO are costs associated with building or maintaining a power transmission system.

IM-GEO estimates the costs associated with both binary and flash plant development for four geologic regions: the Imperial Valley, the Basin and Range, the Cascades, and Young Volcanics. Based on the predictions of IM-GEO, Table 4 gives the proportion of the necessary return due to a number of factors.

The categories in Table 4 are not mutually exclusive. For example, the well costs include drilling trouble and testing. Similarly, the exploration and confirmation costs include drilling costs. Therefore, it should not be expected that the columns would sum to 100%.

However, the costs for wells and plant core are mutually exclusive. In six of the eight cases, these costs are predicted to account for more than 80% of the cost of producing power. Only for flash plants in the Imperial Valley and the Young Volcanics regions, where chemical costs are estimated to be proportionally high, do the combined costs of wells and plant core constitute less than 80% of total costs.

Half of the chemical costs in the Imperial Valley are for sludge disposal. In the Young Volcanics, the chemical costs are primarily due to handling of the precipitate and hydrogen sulfide control. Except for sludge disposal, chemical costs in the Young Volcanics region are predicted to require about the same percentage of total costs as in the Imperial Valley. Both of these regions are predicted to have proportionally greater chemical problems than either the Basin and Range or the Cascades.

Further inspection of the data in Table 4 reveals a number of other areas where a specific region is predicted to have proportionally higher costs in a given category. Exploration costs are high for flash plants in the Basin and Range and the Cascades. The Cascades are also predicted to require an especially large proportion, approximately two-thirds, of total costs for wells and drilling trouble. Plant core constitutes 60% or more of the cost of producing power through binary processes in all regions. Binary plants are predicted to be more costly than flash plants by two to three times.

Proportionally high costs within a region indicate opportunities for research directed toward specific problems in specific regions. Currently, there is significant interest in developing the geothermal potential in the Cascades. As shown in Table 4, 14% of the cost of producing power from flash plants in this region is estimated to be due to exploration and reservoir confirmation costs. Furthermore, IM-GEO estimates that 90% of these costs are associated with drilling and completion of wells. Thus, it is predicted that 13% of the cost of generating electricity from

Table 4: The Cost of Power Apportioned to Influencing Factors

	Imperial Valley	Basin and Range	Cascades	Young Volcanics
Exploration and Confirmation:				
Flash	7%	13%	14%	9%
Binary	7%	3%	5%	5%
Wells (Capital and O&M):				
Flash	33%	29%	59%	32%
Binary	22%	25%	23%	10%
Drilling Trouble:				
Flash	4%	3%	9%	6%
Binary	2%	2%	4%	2%
Well Testing:				
Flash	3%	4%	5%	4%
Binary	4%	5%	4%	3%
Testing Uncertainty:				
Flash	5%	6%	10%	5%
Binary	6%	9%	5%	1%
Plant Core (Capital and O&M):				
Flash	28%	54%	27%	39%
Binary	62%	58%	62%	76%
Chemical:				
(Sludge, Scale, Flash	28%	4%	2%	13%
H ₂ S, Corrosion) Binary	< 0.5%	< 0.5%	< 0.5%	< 0.5%

Notes:

1. Source: IM-GEO Version 3.05
2. The categories are not mutually exclusive; the columns will not sum to 100%.

flash plants in the Cascades will be due to well drilling and completion costs during the exploration and reservoir confirmation phases.

The portion of the cost of producing power that is due to well costs appears to be exceptionally high for flash plants in the Cascades. The cost of drilling for binary plants in the Cascades is comparable to the cost in the other regions. However, the cost of drilling for flash plants in the Cascades is estimated to be from 1.7 to 2.2 times as expensive as drilling for flash plants in any other region. Though IM-GEO does not explain the cause of this difference; this difference is the cause of the relatively high proportion of the cost of power in the Cascades due to wells. Thus, data derived from IM-GEO indicate that R&D into drilling methods and exploration have

the greatest chances of having a significant impact on the cost of producing power in the Cascades region.

In all regions, exploration costs for flash plants are estimated to constitute from 15% to 23% of the total capital costs. For binary plants, exploration costs are estimated to constitute from 5% to 12% of total capital costs. A closer examination of the costs of exploration and reservoir confirmation reveals that, depending on geologic region, from 75% to 90% of the exploration costs are predicted to be due to well drilling and completion. This is strong evidence that the key to reducing exploration and confirmation costs is to reduce the costs of drilling and completing exploratory wells.

As shown in Table 4, exploration costs for binary plants are proportionally less than for flash plants. Furthermore, with the exception of the Imperial Valley, IM-GEO estimates that due to higher temperature requirements resulting in extra expenses and necessitating deeper drilling, wells for flash plants will cost at least twice as much as wells for binary plants. In all regions, the differences in exploration and resource confirmation costs, between binary and flash technologies, are due to the differences in drilling costs.

With the exception of the Cascades, wells account for about 30% of the cost of producing power from flash plants. As a result, for these regions, the effects of programs to reduce the costs of wells have a multiplier of about three-tenths. For example, if an R&D program is expected to reduce the cost of drilling and well completion by 10%, it would be expected that the cost of producing power would be reduced by about 3%.

Comparison of the costs due to testing with those due to uncertainty in testing reveals that in all cases except binary plants in the Young Volcanics, testing uncertainty costs more than the tests themselves¹. The difference between testing and uncertainty costs provides leverage for the development of instrumentation. If testing uncertainty could be halved, even at a 25% increase in the cost of testing, IM-GEO predicts that the net effect would be lower power costs by an average of more than 2%. Even if testing costs double in achieving a 50% decrease in uncertainty, IM-GEO predicts that the overall effect would be essentially nil. And a side benefit of reducing measurement uncertainty would be better data, better knowledge, and a better understanding of reservoir phenomena.

For the Imperial Valley and Young Volcanics regions, IM-GEO indicates that research into problems associated with sludge, scale, hydrogen sulfide, and corrosion could have significant effects on the cost of power. As a final point, it is obvious from the data in Table 4 that reduction in the cost of plant core is the key to reducing the cost of power produced at binary facilities.

¹Costs due to testing uncertainty were derived from information provided in *Research Objectives of the Geothermal Research Program*, Appendix B, D. J. Entingh, Meridian Corporation, Alexandria, VA, March 1989, revised: March 1992.

Problems Encountered in Drilling Geothermal Wells

The geothermal industry uses oil and gas technology for exploration, drilling, and completion. However, a typical geothermal well costs significantly more than a typical oil and gas well. Some of this difference is due simply to the difference in the size of the wells. Geothermal wells are larger than oil and gas wells and thus have higher capital costs due to increased casing sizes and larger wellheads.

However, there is more than just increased size driving the higher costs associated with geothermal wells. Due to the fractured formations drilled in geothermal applications, lost circulation is a significantly larger problem than in the sedimentary regions typical of oil and gas drilling. Furthermore, much of the equipment and materials used in geothermal wells has premium costs due to the high temperatures experienced. Some standard instrumentation and logging techniques employed in the oil and gas industry can not be used in geothermal wells because of the higher temperatures. In other cases, oil and gas logs are not applicable to the geothermal industry. Geothermal resources are generally located in regions dominated by igneous or metamorphic rock. These hard formations result in high drill string wear rates and relatively slow drilling progress when compared to oil and gas wells. Finally, the corrosive fluids encountered in geothermal drilling cause problems peculiar to this industry, and these problems are further aggravated and accelerated by the high temperatures encountered.

In the following sections, the effects of lost circulation, high temperatures, hard rock, and corrosive chemicals on the drilling and completion of geothermal wells is discussed in more detail.

Lost Circulation Effects

Drilling fluids are an essential part of drilling any well. Because they generally consist of a clay suspended in water, drilling fluids are commonly called mud. The mud performs a number of functions during drilling including cooling the bit and lubricating the drill-string; however, the most important functions of the mud system involve removal of the cuttings, stabilization of the well bore, and pressure control of formation fluids. Lost circulation is the loss of drilling fluids to the formation during drilling. Some fluid is lost during almost all drilling. The fluid loss may be slow, one to two barrels per hour, or it may be severe, no mud returns to the surface regardless of the pumping rate. When fluid losses become large enough, the mud can no longer adequately perform its intended functions, resulting in serious consequences up to and including loss of the well. With large losses, the cost of make-up fluids can become prohibitive. Even if the cost of make-up fluids can be justified, the unsolved lost circulation problem can prevent other drilling and completion activities from being performed.

When severe lost circulation occurs, there is a direct cost due to lost drilling time and the materials, equipment, and services necessary to restore circulation. These costs are estimated in a later section of this report. There are also a number of secondary costs due to lost circulation. Lost circulation can cause problems such as stuck pipe, loss of control of formation fluids, and failure to properly complete the primary cement job. Also, the prevalence and severity of lost

circulation in geothermal drilling have resulted in a number of modifications to well design, drilling procedures, and completion practices. Though difficult to quantify, these secondary costs of lost circulation are also discussed in the following sections.

Lost Circulation Effects on Cuttings Removal

In severe cases of lost circulation, there is no return flow to the surface. When this occurs, the cuttings are no longer being removed from the hole. The mud pumps can continue to work and remove the cuttings from around the bit, but the cuttings have no path out of the well. When fluid losses are large, at least some of the cuttings will be carried away with the mud into the formation. In geothermal drilling, the lost circulation zones are often open enough to accept both cuttings and drilling fluid. However, it is almost certain that some cuttings will be suspended in the fluid column in the well bore. This load, along with new cuttings being generated, are a mechanism for sticking the drilling assembly. When pressure is reduced or the mud pumps are shut down, cuttings carried into the formation can also return to the well bore providing additional material to clog the well and prevent the drill string from either turning or being removed from the well.

When the drill pipe becomes stuck, the first action is generally to attempt to free it with drilling fluid. Pumping the drilling fluid at a high rate may loosen material around the bottom hole assembly enough to allow movement of the drill pipe. If high flow rates help, the driller can continue to pump and simultaneously work the drill pipe out of the hole. If pumping fluid at a high rate does not free the drill pipe, the driller can attempt to loosen the material around the bottom hole assembly by pumping twenty to fifty barrels of a high viscosity fluid. Chemicals which alter the filter cake characteristics can also be added. If the high viscosity mud or chemical treatment helps, the strategy is the same as when high flow rates loosen the pipe: continue to pump and work the drill pipe out of the hole.

If pumping does not free the drill pipe, the next option is to attempt to jar it loose. To be able to jar the pipe, drilling jars need to have been included in the drill string; however, the inclusion of jars in the drilling assembly is fairly common. Drilling jars allow the use of elastic energy to impart an axial impulse to the drill string. It is sometimes possible to free a stuck drill string by jarring it either up or down.

If neither pumping nor jarring will free a stuck drill string, the only option left is to attempt to wash over it. This requires disconnecting from the stuck pipe, tripping out, and returning with a larger pipe to work over the stuck pipe while flowing mud. When washing over the stuck pipe, there needs to be a way to remove material from the well to prevent the wash-over pipe from becoming stuck. If the initial stuck pipe is due to lost circulation, the lost circulation problem may need to be solved before a wash over can be attempted. The wash-over operation usually necessitates the use of the specialized skills of a fishing hand. In fact, it is not uncommon to hire a fishing hand whenever stuck pipe occurs. Costs due to stuck pipe include time lost from drilling, the cost of lost drilling fluids, the cost of specialized equipment, and possibly the charges for the skills of a fishing hand.

Lost Circulation Effects on Bore-Hole Stability

Lost circulation also affects bore-hole stability. Relatively slow losses of mud are thought to result in a filtration process during which a filter cake is formed on the hole wall. Fluid pressure against this filter cake is believed by many to be a mechanism enhancing bore-hole stability. However, the fluid filtrate entering the formation can reduce the stability of water-sensitive shales and clays. A lack of stability in the formation materials adjacent to the well bore can result in the portions of the wall sloughing into the well. This will cause problems with circulation and can trap the drill string.

An increase in the severity of lost circulation after a period of relatively slow losses can also affect well bore stability by reversing the pressure balance in the well. An increase in fluid loss can reduce the pressure in the well bore above the loss zone. Such a reduction can result in a well-bore pressure that is lower than the formation pressure. Under these conditions, fluids previously lost to the formation will flow back into the well, carrying cuttings and formation materials. The well bore will be altered by the flow of fluids toward the hole and the structure can be weakened enough to cause whole sections of the well bore to collapse. Thus, lost circulation decreases well bore stability through both fluid chemistry affecting the strength of the formation materials and differential pressure resulting in flow into the well.

Lost Circulation Effects on Primary Pressure Control

In addition to removing the cuttings and enhancing bore-hole stability, the drilling fluid is the primary well control mechanism. The fluid column in the well bore exerts pressure against the wall preventing formation fluids from entering the hole. Fluids more dense than water are often used to increase the pressure of the fluid column on the well bore. If fluid losses are severe enough to prevent returns to the surface, the height of the fluid column will be reduced. The reduction in fluid column height reduces the control pressure above the loss zone. Any time that the mud column pressure is less than the pore fluid pressure, there is a chance that a quantity of formation fluid will enter the well-bore. This influx of formation fluids is referred to as a kick.

If the entering fluids are gas or high-temperature liquids, the overall density of the fluids in the well bore will be further reduced, diminishing the well-control capability of the drilling mud. As the formation fluids rise in the well, high-temperature liquids can flash when they reach a depth such that the pressure exerted by the drilling fluids is below the boiling pressure at the temperature of the formation fluids.

There are techniques to handle a kick. If the kick is liquid, control of the invading fluid is fairly simple since the density of the fluid is not greatly different from that of the drilling mud. But if the kick is gas or steam, control will be more difficult. If the kick is steam, it may be controlled by pumping cold water to reduce the temperature and condense the steam thus reducing the problem to the control of a liquid kick. From indications at the surface, the difference between a steam kick and a gas kick are not always obvious so any indication of gas rising in the well-bore is often treated as a gas kick. Procedures to control a gas kick are well established. However, controlling a kick while continuing to drill can be difficult and risky. The

minimum cost of an influx of formation fluids is the cost of an idle drilling rig for the time spent controlling the kick.

Lost Circulation Effects on Cementing Procedures

The previous discussion has concerned lost circulation as a drilling problem. Lost circulation can also cause major problems during cementing. Oil and gas wells are usually located in sedimentary regions with generally moderate temperature and chemical environments. Because of these characteristics, oil and gas wells are often completed by cementing the casing at the bottom and/or top only. Conversely, geothermal wells are drilled through igneous or metamorphic rock often containing high temperature, highly corrosive fluids. For protection from these fluids and for protection from buckling due to thermal expansion during production, the casing-to-formation interface in geothermal wells is commonly cemented from the top of the production zone to the surface.

Common densities for drilling fluids in geothermal operations range from 8.6- to 10.6-pounds per gallon (ppg). This compares to common fluid cement densities of 12.6-ppg to 16.2-ppg. As a result, the pressures on the formation during cementing significantly exceed those during drilling. Under these conditions, it is almost certain that cement will flow into any lost circulation zones that were not fixed during drilling. Also, because of the higher pressures during cementing, relatively minor loss zones during drilling can become major loss zones during cementing.

If material is lost to the formation at a significant rate, it may not be possible to get cement returns at the surface to assure the primary cement job. Failure to properly complete the primary cement job can result in loss of the well or, at minimum, costly remedial cementing procedures which are often unsuccessful. Because of the possibility of loss of the well, a number of procedures have been developed for remedial cement jobs. However, no strategy for remedial cementing has been developed that will, with high probability, repair the integrity of a sub-standard primary cement job.

A major problem with remedial cement jobs is that it is difficult to guarantee that formation fluids and/or drilling fluids are not trapped behind the casing. Fluids trapped behind the casing will heat up and attempt to expand when high-temperature fluids flow through the casing during production. Because of the resultant pressures, either the casing or the cement must yield. Thus, if the casing does not collapse, the cement sheath behind it will be fractured. Fractured cement destroys the integrity of the seal of the primary cement job and exposes the casing to the formation fluids.

Exposure of the casing to formation fluids can shorten the well life, but it will not result in immediate casing failure even in a highly corrosive environment. However, the entrapment of fluids between casing strings can have immediate and severe consequences when production is initiated. Since the outer casing string is supported by the formation, fluid trapped between casing strings has no volume in which to expand. Thus when the well heats up, fluids trapped between casing strings will almost certainly result in collapse of the inner casing string. The repair of collapsed casing is costly, time consuming, and often unsuccessful. Unsuccessful

rework causes problems during production and limits other repairs and operations in the well bore. Thus, significant effort is warranted to avoid trapping fluid between casing strings.

Lost Circulation Effects on Well Design Criteria

Lost circulation not only causes problems during the drilling and completion of a well, but the awareness of these problems also causes modifications in the design of the casing string. The use of liners and tieback strings in the casing design is a common method of reducing the fluid pressure and, therefore, the possibility of lost circulation problems during cementing. The liner is suspended from the lower end of the previous casing string and cemented in place. After the liner cement sets, the tieback string is run from the top of the liner to the surface and cemented.

Casing designs employing liners and tieback strings reduce the possibility of problems due to lost circulation in two ways. By hanging the liner at the previous casing shoe, the pressure on the formation during cementing is minimized because the cement column need only come up to the previous casing shoe instead of completely to the surface. Minimizing the pressure reduces the chance of losing significant amounts of cement to the formation. Also, if a remedial cement job is necessary, minimizing the overlap between the liner and the previous casing string reduces the chance of trapping fluids between the casing strings. If done with care, a good cement job on the tieback string can almost be guaranteed since the cement is between casing strings and not between casing and formation. While the use of liners and tieback strings does reduce the possibility of problems with lost circulation during cementing, it also requires additional equipment to hang the liner and additional time to allow cement to set twice: once for the liner and again for the tieback string. Also, liner hangers have been known to trap fluids.

Lost circulation not only affects casing design through the use of liners and tieback strings, but it also results in the use of a conservative approach when determining casing depths. Geothermal reservoirs must be highly permeable to be capable of sufficient production to support a power plant. Also, geothermal reservoirs are generally under-pressured, i.e. below the pressure exerted by a static water column of the depth of the reservoir. This combination of high permeability and under-pressured fluids almost guarantees that circulation will be lost when the reservoir is penetrated.

Upon reservoir penetration, the height of the drilling fluids in the well bore will drop to equilibrate with the reservoir pressure. The pressure gradient within the reservoir will be different from that of the drilling fluid. This makes it difficult or impossible to balance the pressure of the mud column with two or more openings into the reservoir. When the well-bore penetrates the reservoir in more than one place, drilling fluids can be lost to one fracture while another fracture begins to produce. The hot fluids entering the well will rise and expand. Because of the lost circulation, the driller cannot depend on a full column of drilling fluids to control the kick. Therefore, in the casing program, the drilling engineer will normally assume that the last casing shoe can be exposed to the full pressure of any reservoir fluids that are encountered. When compared to oil and gas practices, this results in setting conservative casing depths.

Lost Circulation Direct Costs

From the discussion in the previous paragraphs, it is clear that in addition to the cost of lost drilling fluid, there are a number of secondary costs such as those due to the use of liners, tieback strings, and conservative casing depths that are a result of lost circulation in geothermal drilling. Degradation of formation stabilization and well control capabilities due to lost circulation also result in costs controlling kicks and freeing stuck drill strings. Many problems encountered when attempting to complete a primary cement job are also due to lost circulation. Problems with the primary cement job can result in loss of the well.

Even when fluid losses become significant, it is often possible to continue drilling. Even with complete loss of fluid, it is generally possible to drill blind, i.e. without returns, for some distance. However, because of the severe consequences that can result, most drillers do not hesitate to interrupt drilling to combat lost circulation. There are a number of lost-circulation materials (LCM's) available for the driller to attempt to plug a loss zone and some LCM's are routinely added to the drilling mud. However, when severe losses occur, few drillers resort to LCM's. Almost universally, cement is employed to combat severe lost circulation.

Glowka (ref. 26) developed a cost model for a conventional cement treatment for lost circulation. This model assumes that the lost circulation event occurs at a depth of four-thousand feet. Tables 5 and 6 (next page) summarize Glowka's model. Table 5 gives estimates of the time required to set either a single or a double cement plug. Table 6 gives the resultant cost at bottom-hole temperatures of 200°F and 400°F. The justification for the time and cost estimates in Tables 5 and 6 are given in the reference and are repeated in Appendix C.

As shown in Tables 5 and 6, a single lost circulation event can easily cost a day's drilling time and twenty thousand dollars. It is also worth noting that the cost estimate increased by a third with a temperature increase from 200°F to 400°F. The cost of combatting lost circulation in drilling a particular well depends on the number and severity of lost circulation events. Lost circulation is not considered as severe a problem in the Imperial Valley as it is in other locations. For example, in the first phase of drilling the Long Valley well near Mammoth Lakes, California, circulation was lost twenty-nine times in the first twenty-five hundred feet. There is no doubt that tools and procedures to reduce the cost of combatting lost circulation will lower the cost of drilling geothermal wells.

High Temperatures in Geothermal Operations

As discussed in the previous sections, conditions leading to lost circulation are an expected characteristic of the geology where geothermal drilling is attempted. Another expected characteristic of geothermal operations is high temperature. The effects of high temperatures on the drilling and completion of geothermal wells are nearly all secondary: special tools and insulated instruments are needed, drilling muds and cements require particular additives, material strengths are reduced, and corrosion is accelerated. As shown in the previous section, even the cost of combatting lost circulation increases dramatically with temperature. The effects and costs of high temperatures on geothermal operations are discussed in the following sections.

**Table 5: Time Estimates for a Conventional Cement
Treatment for Lost Circulation Control**

Activity	Estimated Time (hours)	
	One Cement Plug	Two Cement Plugs
1. Mud circulation/flow testing	1.5	1.5
2. Trip out bottom-hole assembly	2.0	2.0
3. Trip in open drill pipe	2.0	2.0
4. Cement Preparation and mixing	1.0	1.0
5. Rig-up and pump cement	1.5	1.5
6. Wait on cement	8.0	6.0
6a. Test cement plug hardness		1.0
6b. Rig-up and pump cement (plug 2)		1.5
6c. Wait on cement		8.0
7. Test cement plug hardness	1.0	1.0
8. Trip out open drill pipe	2.0	2.0
9. Trip in bottom-hole assembly	2.0	2.0
10. Drill cement	2.0	2.0
Total	23.0	31.5

**Table 6: Cost Estimates for a Conventional Cement
Treatment for Lost Circulation Control**

Item	Quantity for		Unit Cost	Cost for	
	One Plug	Two Plugs		One Plug	Two Plugs
Time	23 hrs	31.5 hrs	\$10k/day	\$9.6k	\$11.9k
Cement Service					
at 200°F	300 ft ³	600 ft ³	\$9/ft ³	\$2.7k	\$5.4k
at 400°F			\$13/ft ³	\$3.9k	\$7.8k
Mud Lost					
at 200°F	500 bbl	500 bbl	\$7/bbl	\$3.5k	\$3.5k
at 400°F			\$9/bbl	\$4.5k	\$4.5k
Mud Conditioning					
at 200°F	400 bbl	400 bbl	\$7/bbl	\$2.8k	\$2.8k
at 400°F	800 bbl	800 bbl	\$9/bbl	\$7.2k	\$7.2k
Total			at 200°F	\$18.6k	\$23.6k
			at 400°F	\$25.2k	\$31.4k

Temperature Effects on Instrumentation

The high temperatures experienced in drilling geothermal wells have detrimental effects on the availability, operation, and cost of instrumentation. Electronic components are currently limited to maximum temperatures in the range from 350°F to 425°F. However, operations in this range are possible only after high-temperature screening of individual devices. Some components may survive higher temperatures, but any system that employs standard silicon-based chips will begin to experience problems at about 270°F.

The tolerance of instrumentation to high temperatures can be extended through the use of heat shielding. Nearly all down-hole logging tools available to the oil and gas industry can be made to function in the geothermal environment by providing a heat shield for the electronics. However, heat shielding does not allow the user to be entirely unconcerned with down-hole conditions. Even with heat shielding, the time an instrument can be operated in a given environment is limited by the time it takes the internal components to reach their design limit. This time is dependent on the temperature of the external environment, the leakage into the instrumentation package through the walls, the leakage at the signal and sensor inputs, and the internal heat generated by the electronics. The current state of the art in heat shielding of drilling instrumentation allows electronics to survive about ten to twelve hours in a 600°F environment.

When operating instrumentation, the ability to provide real-time readings at the surface is limited by the temperature tolerance of the electrical insulation on the wire-line. Extruded teflon insulation on the wire-line can be used to temperatures on the order of 550°F. Wrapped teflon (TFE) insulation extends wire-line use to about 600°F. New, higher temperature wire-line insulations are being developed. Magnesium oxide cables can withstand temperatures above 600°F, but are impractical for ordinary use. At temperatures above the wire-line limits in down-hole logging operations, on-board memory must be employed in addition to heat shielding.

While few well logging tools are marketed specifically for high-temperature operation, the technology to provide heat shielding and/or on-board memory is currently available. Tools to operate in high temperature environments are provided on special order. Tools that have been heat shielded include pressure-temperature and pressure-temperature-spinner combinations, natural gamma ray detectors, bore-hole calipers, and the bore-hole televiewer. Acoustic tools, such as the bore-hole televiewer, require a compliant window through which to work. The materials to provide this window exist and thermal insulation can be maintained. However, the ability to build tools to survive the environment does not remove all impediments to high-temperature well testing.

In oil and gas wells, it is routine to employ memory tools to record pressure and temperature during production draw-down and shut-in or pressure build-up testing. The tool is placed in the well and the test period is begun. The on-board electronics can be programmed to collect data for thirty to forty-five days. Data is collected based on time or signal variation and stored in memory. At the end of the test period, the tool is retrieved and the data downloaded for analyses.

As discussed previously, the high-temperature capability of electronic instruments, even with heat shielding, is measured in hours. This time-at-temperature limitation makes heat-shielded memory tools impractical for long-term testing in geothermal wells. Some instruments not employing electronics have inherent high-temperature capabilities. Spinners to measure flow rate can be operated to the temperature limit of the wire-line. However, the cost of high-temperature, hydrogen-sulfide tolerant, wire-line is on the order of three to four dollars per foot. Thus a flow log to 8000 feet in a high-temperature geothermal well can cost upwards from \$25k for wire-line alone.

Figure 16: Temperature and Logging Costs
Source: Various Logging Co.

Much of the additional cost for logging services at high temperatures is due to wire-line charge. Typically, at temperatures exceeding 300°F, there is an additional 25% charge for logging a well, and, at temperatures exceeding 450°F, another 25% is charged. Thus, for geothermal wells, the basic well logging cost has a 25% to 50% additional charge due primarily to the need for high-temperature wire-line. The relationship between temperature and logging costs is illustrated in Figure 16.

Temperature measurements employing a thermocouple can be performed to the tolerance of the thermocouple wire. Pressure tools to operate at 600°F have been advertised. However, commonly employed instruments limit pressure measurements to about 350°F for long-term testing. There are capillary tubing techniques and temperature sensors using thermocouple wire encased in capillary tubing that can be employed for continuous down-hole pressure and temperature sensing if recording equipment is maintained at the surface. The necessary memory for long-term testing is available on a new digital logging truck, but the cost of such a truck exceeds a quarter of a million dollars. Thus, it is not financially reasonable to conduct long-term measurements of down-hole functions in geothermal wells on a regular basis if a digital logging truck is required continuously at the wellhead.

Because casing inspection and cement evaluation tools have not been adapted to operate at high temperature, these logs are run only after the well has been cooled to such a degree that the instruments will survive. If a casing or cement log is needed after the power plant is on-line, production must be interrupted to cool the well. There is some uncertainty in evaluating the capability of materials and interfaces to function at high temperature from the results of tests conducted at low temperature. However, as discussed in a subsequent section, there is little uncertainty that subjecting the materials and interfaces in a geothermal well to thermal cycling can only cause degradation.

Temperature Effects in Drilling

The high temperatures encountered in geothermal wells affect the drilling operation in a number of ways. The drilling fluid properties of density, plastic viscosity, and yield point are all dependent on temperature. Changes in density affect the mud's well-control capabilities. The yield point is correlated with the ability of the mud to carry cuttings out of the hole and the mud's ability to suspend solids when circulation is stopped or lost. The changes in mud density with increasing temperature are minor, however, the effects of high temperature on viscosity and yield point are not. High temperature problems are further complicated by the fact that many of the materials added to drilling fluids to maintain physical properties are organic; and high temperatures generally reduce the effectiveness of organic additives.

The effects of high temperature on the properties of the drilling fluids can be offset, but at some cost. For temperatures below 300°F, a low-lime mud runs about six to seven dollars per barrel. At temperatures above 300°F, additives such as Therma-Check, Therma-Thin, SB111, and Torq-Ease are employed to maintain fluid properties. These additives are viscosifiers and thinners developed primarily to offset the effects of temperature on viscosity and yield point. At 400°F, 500°F, and 600°F, the corresponding mud costs are about nine, twelve, and fifteen dollars per barrel. As shown in Figure 17, the cost of the drilling fluid can more than double for a high-temperature well.

In addition to drilling fluid, high temperatures also have detrimental effects on drill bits. The sealed roller or journal bearings in rotary drill bits are seldom designed to operate at the high temperatures encountered in geothermal wells. The failure rates for sealed bearings are thus higher in geothermal drilling than in drilling for oil or gas. To circumvent this problem, open

Figure 17: Temperature and Mud Costs

Source: Desert Mud

roller bearings have been used with some success in geothermal applications. However, open roller bearings have higher failure rates in geothermal drilling than the sealed bearings common in oil and gas drilling.

High temperatures also reduce bit life by degrading seals and lubricants. The performance of all elastomers is degraded with increasing temperature. The temperatures encountered in geothermal wells degrade the performance of the seals in shock subs and jars. Sliding or rotary seals for applications at temperatures above 550°F do not exist. In general, all seal applications are compromised by the lack of an adequate high-temperature elastomer. This includes bit seals, actuators, sliding seals in shock subs and jars, and seals in any other tool that must operate in the down-hole environment.

Though mud coolers are seldom used on oil and gas rigs, they are commonly employed in geothermal drilling to combat the detrimental effects of high temperatures on the drilling fluids and the drill string by removing heat from the system. The present cost of an enclosed mud cooler, that does not introduce additional oxygen into the drilling fluid, is \$290 per day with a

twenty-one day minimum charge.

Temperature Effects on Directional Drilling

It is sometimes economically and environmentally advantageous to use directional drilling to complete multiple wells from a single pad. The most important advancement in directional drilling came with the development of the positive displacement mud motor (PDM) in the mid 1960's. PDM's operate on the Moineau principle. The stator in Moineau motors is a cast elastomer. There is a project through the Geothermal Drillers Organization to develop a high-temperature Moineau motor, however, the currently available motors have temperature limitations of about 300°F.

To circumvent problems due to high temperature limitations on PDM's, directional drilling practices have been modified for geothermal operations. When compared to practices in oil and gas drilling, the directional change, requiring the use of a drilling motor, is completed relatively close to the surface in geothermal wells, before high temperatures are encountered. Once the necessary angle is achieved, the remainder of the well can be drilled with rotary bits using azimuth and inclination measurements to assure that the desired direction is maintained. Instrumentation to measure azimuth and inclination and to perform the end-of-interval survey can be heat shielded. Problems do arise when hole deviations require plug back and redrill or when directional corrections require motor runs. When motor runs are required, the first attempt is generally to cool the well before using the PDM.

The use of air as a drilling fluid is common at the Geysers and has also been employed at other sites to avoid some of the cost of lost circulation. Directional drilling on air is costly and difficult. The rate of tool wear when drilling with air or aerated mud is very high. As long as the hole temperature is not too high, Moineau motors will operate satisfactorily with misted air. They will operate on air as well, but the presence of mists help cool the motor. Nonetheless, it is generally felt that directional drilling in the air portion of a well is best avoided.

Temperature Effects on Well Design

The increased temperatures encountered in geothermal wells not only affect drilling materials and instrumentation, but also cause special considerations in well design. High temperatures affect the materials employed in the well. The collapse ratings for casing weights and grades decrease significantly with increasing temperature. In considering elastic collapse, the casing design must allow for the reduction of the modulus of elasticity with increasing temperature. In considering plastic collapse, the casing design must allow for the reduction of yield strength with increasing temperature. Geothermal wells have generally higher production requirements than oil and gas wells and thus are drilled to larger diameters and employ larger production casing strings. The detrimental effects of high temperatures on the physical properties of the casing require even heavier and stronger casing designs.

During well completion, specific additives must be included in the cement for geothermal wells to prevent premature setting and degradation at high temperature. High temperatures can increase

the cost of cement by 60% or more. For temperatures below 230°F, neat cement, costing about nine dollars per cubic foot, can be used. Above 230°F, SSA-1 (silica flour), costing an additional dollar per cubic foot, is added. Additionally at increased temperatures, agents to retard setting, to prevent dehydration, and to reduce the apparent viscosity of the cement must be used. These agents cost about one, two, and three dollars per cubic foot respectively. The resultant charge for a 15.5-pound-per-gallon cement for use at 550°F is about sixteen dollars per cubic foot. The cost of cement as a function of temperature is shown in Figure 18. As shown, high temperatures can increase cement costs by two-thirds.

Figure 18: Temperature and Cement Costs

Source: Halliburton Services

The possibility of temperature induced buckling causes design modifications in the completion of the well. Oil and gas wells are often completed by cementing the casing at the bottom and/or top only. Such a completion in a geothermal well would risk casing collapse due to temperature induced buckling. To preclude casing collapse, and to protect the casing from corrosive formation fluids, the casing-to-formation interface in geothermal wells is cemented from the top of the production zone to the surface. Besides the increased cost of cement due to additives and extra volume, the requirement to cement from the production zone to the surface causes other problems as discussed in the sections on lost circulation.

The high temperatures experienced in geothermal wells result in two modifications to the wellhead when compared to oil and gas wells. Due to the larger production requirements of geothermal wells, generally larger wellheads and valves are employed. In addition, wellhead equipment ratings are strongly affected by temperature. This derating with increased temperature requires the use of even stronger wellhead equipment for geothermal wells.

Consideration of thermal expansion of the casing in geothermal wells has also resulted in modifications to the standard oil and gas wellhead. On oil and gas wells, the casing is stressed in tension during wellhead installation. Upon completion of installation, this tension is maintained by a set of slips in the wellhead. The temperature excursions experienced in oil and gas wells result in variations in the tension in the casing but no movement of the wellhead.

However, the temperature excursions experienced in geothermal wells prevent a similar approach. A 300°F temperature increase with initiation of production is not unusual for a geothermal well. Such a temperature excursion will result in a foot of expansion for every five-hundred feet of unrestrained casing. An initial tension of 60,000 psi would be necessary to prevent movement of the casing under these conditions. This exceeds the yield strength of most common steels and nickel alloys. To prevent stressing the casing beyond its limit and to allow for motion of the casing, expansion spools are employed between the wellhead and the valves on geothermal wells. The expansion spool is designed to allow the casing to expand without moving the wellhead.

Wellhead and completion costs increase with temperature. For example, the cost for the wellhead, expansion spool, and ten-inch master and operating valves for use in a 200°F environment is about fifty thousand dollars. For 500°F fluids, the cost of a similar completion is about ninety thousand dollars. At 625°F, the cost increases to around one-hundred twenty thousand dollars, more than twice the cost for the same equipment to operate in a low-temperature environment.

It should be noted that in practice, casing expansion is never as great in geothermal wells as is predicted by theoretical calculations. It is believed that this is due to the cement at the casing-to-formation interface preventing motion of the casing for some distance up from the bottom of the well. In spite of this difference between theory and practice, expansion spools are still used.

Down-hole pumps for producing reservoir fluids to the surface are currently limited to temperatures below 400°F. This is not now a serious problem since down-hole pumps are currently used only on relatively low temperature resources. However, before the exploitation of deep geothermal resources can be pursued, some additional boost may be needed to produce the fluids to the surface; and this mechanism is most likely a high-temperature down-hole pump. The problem of a high-temperature production mechanism could also eventually face the hot-dry rock and magma resource developments.

Temperature and Corrosion

High temperatures aggravate problems associated with corrosive fluids by increasing chemical reaction rates. The rate of a chemical reaction may be affected by temperature in a number of

ways, but the most common model describing the effect of temperature on reaction rate is the Arrhenius function (ref. 27), in which reaction rates are exponentially dependent on the inverse of the absolute temperature. A common rule of thumb in accelerated aging programs is that reaction rates double for every ten Celsius above ambient temperature. Regardless of the exact relationship between corrosion rate and temperature, reaction rates at geothermal temperatures can be orders of magnitude faster than at ambient temperature. Thus, a reaction that takes years at room temperature might be complete in a matter of weeks or months at the temperature encountered in a geothermal production well.

The Effects of Thermal Cycling

To this point the discussion of temperature has concentrated strictly on its magnitude in geothermal wells. In a number of places it has been noted that in order to avoid the detrimental effects of high temperatures, the well is cooled before some operation is conducted. During cooling, thermal stresses are developed that can cause the well bore to slough into the hole. A worse situation occurs when the well bore is merely weakened and sloughs after drilling is resumed resulting in a stuck drilling assembly.

If thermal cycling occurs after the initiation of production, the open portion of the well, or production interval, will be weakened by thermal stresses. In addition, all materials employed in the well, including the wellhead, valves, casing, and cement, are subjected to stress cycling in conjunction with the thermal cycling. Thermal cycling can also cause stresses at the interface of dissimilar materials including the casing-to-cement and the cement-to-formation interfaces. At the cement-to-formation interface, either the cement or the formation will be damaged to some degree.

The detrimental effects of thermal cycling have led to a number of programs to develop procedures to perform periodic maintenance and clean-out without the necessity of stopping production and cooling the well.

Effects of Hard Rock

Hard rock is another expected characteristic of geothermal operations. Oil and gas drilling is most often done in sedimentary formations, whereas geothermal drilling is almost entirely in the harder igneous and metamorphic rock. The harder rock encountered in geothermal drilling results in shorter life for nearly all drill string components. The shortened life is due both to the increased forces necessary to cut hard rock and to the increased abrasiveness of the rock itself. Additionally, the high temperatures encountered in geothermal wells aggravate the abrasive wear problems by reducing the lubricating characteristics of the drilling fluids.

Drill String Wear

Since the tool joints have larger diameters than the drill pipe itself, it is expected that they will contact the formation walls during drilling. Consequently, tool joint surfaces are treated during manufacture to reduce abrasive wear. However, when compared to oil and gas drilling, wear at

the tool joints is increased during geothermal drilling due to the more abrasive nature of the rock. Hole deviations, whether due to directional drilling or bit wander, can cause the drill pipe itself to contact the rock. However, unlike the tool joints, the manufacture of drill pipe does not include hardening or otherwise protecting it from abrasive wear. Consequently, when the pipe contacts hard rock, the wear rate can be quite rapid. If this wear is not detected and the worn pipe removed, drill string failure can result.

Drill string stabilizers rub against the wall of the hole during drilling. Roller-reamers, essentially stabilizers with a rolling element in contact with the hole wall, are sometimes used to reduce abrasive wear. The use of a roller-reamer will also reduce the torsional drag on the drill string. However, roller-reamers are not used universally in hard-rock applications. The alternative to employing a roller-reamer is to use a conventional stabilizer with sliding contact. The wear on conventional stabilizers in hard-rock drilling can be extremely high necessitating frequent rotation of the stabilizers in the string and removal of those exhibiting excessive wear.

Bit Design

Drilling in hard-rock formations also requires modifications to the bits that are employed. Drag bits employing polycrystalline diamond compact cutters are used extensively in soft to medium hard formations to attain relatively high rates of penetration. However, no drag bit can withstand the mechanical and thermal stresses experienced in hard-rock drilling. As a result, nearly all geothermal drilling is accomplished with roller-cone bits, but even these bits must be designed specifically for the hard-rock conditions. Neither milled-tooth nor insert bits can be as aggressive in attacking hard rock as is possible in softer formations. Hence, hard-rock bits employ harder teeth and less offset of the roller cone axes. The harder teeth are manufactured using high carbon content in the near surface of milled-tooth cutters and harder grades of carbide in bit inserts. The increased hardness results in increased brittleness and sensitivity to impact.

Bit Wear

The rate of hard-rock penetration is greatly influenced by the force applied at the bit. To increase this force, or weight-on-bit (WOB), more and larger drill collars are employed. The larger collars are more expensive and more difficult to handle on the rig floor. Heavy drill pipe may also be employed. All of this results in increased handling time when changing the bottom-hole assembly. However, the major effect is that under the increased load, bits wear faster and bearings fail sooner. The increased WOB also results in increased failure rates for other drill string components.

Bit center section wear is accelerated during hard-rock drilling due to the increased WOB and the lack of redundancy of the cutters. Generally there are only a few cutters to cover the center section. In the center of the hole there is no relative motion to bring more cutters into play. Failure of a single tooth in the center will stop bit advance and require a trip to change the bit.

Excessive heel row wear on bits when drilling hard rock causes under-gauge hole. Reaming is required to correct this loss of gauge diameter. The required reaming can either be accomplished

with a reamer or with the heel row of a new bit. The use of a reamer requires two extra trips and results in time spent correcting the hole without increasing depth and is thus inefficient. The alternative to using a reamer is to change the bit and use the heel row of the new bit to ream the hole during the return trip. When compared to the use of a reamer, reaming with the heel row of a new bit results in a shorter time before drilling to increase hole depth resumes; however, it also results in wear on the heel row. Inevitably reaming with the heel row causes quicker loss of gauge diameter thus requiring either reaming or another new bit.

Casing and Cement

The hard rock encountered in geothermal drilling can also cause problems in running casing. When running casing in deviated holes, the casing can drag against the wall during installation. When this occurs, the increased frictional drag due to the hard formation can make it difficult to get the casing to the bottom. Once the casing reaches the bottom, it is nearly impossible to complete the cement sheath around the casing when one side is against the formation.

Directional Drilling

Hard rock also presents extra problems during directional drilling. As discussed previously, hard-rock bits are designed with less offset than bits designed for drilling in softer formations. This makes it more difficult to influence the direction of the bit through bit forces during drilling. Bent subs and bent housings, which influence bit tilt, are commonly employed with down-hole motors to sidetrack in hard rock. Additionally, bent subs with much higher build angles are often required to achieve the desired angle than is the case in softer formations.

After the initial direction is achieved, minor corrections to the angle are often needed. Because of the design of the heel row and the cone angle-of-attack, there is not much tendency for hard-rock bits to change direction. Thus the side forces required for lateral penetration are higher for hard-rock bits than for bits designed for use in soft to medium hard formations. Widely spaced stabilizers can be used to increase angle; however, the design of hard-rock bits fights against attempts to decrease angle. Decreasing the angle often requires a bent sub and down-hole motor.

Chemical and Corrosion Problems

Chemical and corrosion problems are also common in geothermal drilling, completion, and production. There are five major causes of these problems: carbon dioxide, hydrogen sulfide, chemical salts and dissolved solids, water, and oxygen (ref. 28). These same agents are present to some degree in most oil and gas drilling also, however, high temperature accelerates the chemical reactions and aggravates the corrosion and chemical problems in geothermal wells.

Carbon dioxide reacts with water to form carbonate and bicarbonate ions. The presence of these ions reduces the filtration and gelation characteristics of the mud. Furthermore, the filtration and gelation degradation cannot be corrected until the carbonate and bicarbonate ions are removed. Removal of these ions is generally accomplished through the addition of calcium hydroxide to the mud, and some operators routinely add calcium hydroxide to counteract carbon dioxide.

However, excess calcium in the mud causes flocculation, an unacceptable aggregation or local thickening of the drilling fluid.

Hydrogen sulfide is a toxic, foul smelling gas. The presence of hydrogen sulfide can lead to hydrogen embrittlement of the drill string and casing as well as physical harm to the drilling crew. When hydrogen sulfide enters the mud system, free hydrogen, sulfite, and sulfate ions are produced. Hydrogen ions will penetrate high strength steels interstitially resulting in a loss of ductility and susceptibility to brittle failure. Stress corrosion cracking resulting from hydrogen embrittlement reduces the utility of high-strength and corrosion-resistant steels in geothermal wells. One method of treating for hydrogen sulfide is through the addition of sodium hydroxide to the drilling fluids. This results in the formation of sodium bisulfite, sodium sulfide, and water. Free sodium ions can be removed from the mud through the addition of zinc.

Excess oxygen in the drilling fluid leads to an accelerated corrosion rate. The corrosion causes pitting and loss of metal in the pipe and casing. Corrosion rings and galvanic probes are used to detect the corrosion. Most oxygen enters the drilling fluid at the surface. The rate of oxygen entrainment can generally be controlled through proper operation of the surface equipment associated with the mud system. When necessary, sodium sulfite can be added to the mud to remove excess oxygen molecules.

The presence of oxygen, carbon dioxide, and hydrogen sulfide not only result in degradation of the drill pipe, but also cause corrosion of the casing. The use of sacrificial liners is not an unusual tactic to reduce the corrosion of the casing in geothermal wells. Experiments with cement-lined pipe and titanium casing have also been conducted.

There are also problems due to dissolved solids and chemical salts in the reservoir fluids. These materials can come out of solution and are deposited wherever pressure and temperature changes are significant. If flashing occurs in the reservoir, the resultant deposits can alter production characteristics. Flashing in the well-bore can lead to reduced flow due to chemical deposits and can require interrupting production to rework the well. Mechanical scraping and chemical attack are the common methods of removing scale and chemical deposits in production wells. In addition to removing deposits, mechanical scraping does some damage to the casing. Unless provisions have been made during well completion, the addition of chemicals to attack the deposits requires killing the well. In flash plants, some provisions must be made to handle the solids that are deposited in the flashing stages. And finally, the solids and chemical salts also work to plug injection wells.

As with lost circulation, high temperature, and hard rock, corrosive fluids and chemical problems are endemic to geothermal drilling, completion, and production. These problems cannot be solved; they cannot be made to go away. They must be dealt with. The tools, materials, and procedures to operate in the presence of lost circulation, high temperature, hard rock, and corrosive fluids and chemicals must be devised and employed. With corrosive fluids, these methods generally employ using some chemical to neutralize the undesirable affect. As discussed, it is then sometimes necessary to add a second chemical to remove the first. As with methods employed to counteract the effects of lost circulation, high temperature, and hard rock,

combatting corrosion and chemical problems increases the cost of geothermal operations.

Conclusions

Resource Definition

In the discussion of the history of geothermal development, the current state of the electrical generation industry in general, and the geothermal industry in particular, the following points were made:

1. The geothermal industry is not strong;
2. The production of electricity from geothermal energy can be cost competitive with the available options;
3. The excess electrical generating capacity that existed through the late 1970's and 1980's is fading and the demand for new generating capacity will increase in the next decade; and
4. The obvious sources of geothermal energy in the United States have either been exploited or are protected.

The geothermal industry is in a period of contraction. DOE support for geothermal energy programs peaked in 1979 and then declined throughout the 1980's (ref. 1). The early growth of the geothermal industry was almost entirely in California and was supported by the California SO4 contracts in the 1980's. These contracts, of which new issuance was suspended in 1985, were essentially price supports. Under these circumstances, over-stimulation of the industry, followed by a period of contraction, would be expected. But for whatever reason, as stated in the first point, the geothermal industry is not strong. DOE support is necessary to conduct any significant research, development, or expansion effort at this time.

For the production of electricity from geothermal energy to be cost competitive, the resource must be relatively clean and not present extreme drilling or fluid extraction problems. What is 'relatively clean' and what constitutes 'extreme problems' are debatable topics. However, the contracts with Sierra Pacific Power Company in Nevada imply the existence of such resources. Reservoirs in the Imperial Valley and at Coso Hot Springs are also examples of such resources.

Even though competitive, geothermal energy is not currently the cheapest alternative for new electrical production capacity. The use of gas turbines can provide power at a lower levelized cost than geothermal plants and will probably continue to be able to do so at least into the next decade. Conservation programs may also prove to offset the demand for new generating capacity at less cost than geothermal plants. However, gas turbines and demand-side programs will not satisfy all demand for generating capacity in the near future; and, in the vicinity of known resources, the use of geothermal energy is a viable and competitive option for new electrical generating capacity.

The third point above concerns demand for new generating capacity. The United States in general and the western part of the country in particular over-built electrical generating capacity in the 1970's and had excess reserve margin through the 1980's. However, that excess margin now appears to be fading. The Sacramento Municipal Utility District (SMUD) recently decided to proceed with contracts and construction of four cogeneration projects totaling 465 MW. SMUD also plans to proceed with a 50-MW wind project, to purchase 255 MW from power producers in British Columbia, and to initiate programs to develop 350 MW of power from renewable energy sources (ref. 29). Nevada utilities also have a number of new contracts for the purchase of electricity. The California Energy Commission (CEC) has predicted the need for some 10 GW of new generating capacity within ten years. The Bonneville Power Administration (BPA) is predicting firm energy shortages in the Pacific northwest. And BPA shortages will not just affect the northwest, but all areas tied to the northwest power grid, which includes most of the western part of the country.

The use of geothermal energy will be investigated as a means to offset at least a portion of the needed capacity expansion in the next decade. Sierra Pacific Power Company has contracts to purchase power from six new geothermal plants being developed in northern Nevada. The CEC has recommended that Southern California Edison eventually purchase all of the power that can be produced at Coso Hot Springs and in the Imperial Valley. The BPA has a program with the goal of establishing a minimum of 300 MW of geothermal capability in the Cascades. Each of these projects and plans will result in additional electrical production from geothermal energy, provided that adequate and reliable resources can be demonstrated.

To date all major geothermal developments have occurred in areas characterized by obvious manifestations of geothermal energy: hot water or steam at the surface. However, these obvious sources of geothermal energy have either been exploited or are protected. In order for the geothermal industry to expand and make an increased contribution to the nation's electric power requirements, less obvious areas must be explored and defined. A relatively inexpensive method to conduct such wide-scale exploration is needed.

Activity at the Geysers

Another trend that became apparent in the study of the historical developments of the use of geothermal energy for the production of electricity is that while the industry began at the Geysers, it is now moving away from that area. It is obvious that the future of the geothermal industry is not at the Geysers. There are significant problems with the apparent field depletion at the Geysers; and it is likely that specifically targeted research could help alleviate these problems. However, the Geysers resource is unique in this country. Lessons learned and procedures developed at the Geysers may not be directly applicable to the more common hot brine resources. Additionally, there is no reason to believe that the Geysers resource will support any more than the current generating capacity, if that much.

Based on the discussion in the previous paragraph, it could be concluded that there is little justification for expending effort at the Geysers. However, a better understanding of the depletion at the Geysers will lead to a better understanding of geothermal resources and may lead

to more accurate predictions of the depletion of other resources. Also, some people will point to the Geysers as an example of the unreliability of geothermal resources, in spite of the thirty-year history of power production at the Geysers.

Regional Characteristics of the Cost of Power

A program to aid in exploration and resource definition is the greatest need of the geothermal industry. A concerted effort in this area will result in increased production of electricity from geothermal energy. It will also reduce the expected cost of power, especially in the Cascades and Young Volcanics regions. However, it should not be expected that an exploration program will have as great an effect on the cost of power from the Imperial Valley. Other avenues must be explored for cost reductions in the Imperial Valley.

IM-GEO estimates that about a fourth of the cost of power produced in the Imperial Valley is due to the high salinity of the brine in this area. A program to reduce the costs associated with the handling and disposal of the solids that precipitate from the brine during production could have a significant impact on the cost of power. Such a program should also reduce the cost of power in the Young Volcanics.

The only aspect of the geothermal industry in the United States that is currently expanding and demonstrating health is the use of binary technology to produce power from relatively low temperature resources in the Basin and Range. For binary plants, the wells are generally not deep and, as discussed, the cost of the wells is not the major part of the cost of producing electricity. In most regions, the binary plants themselves represent about 60% of the cost of producing power with this technology. In the Young Volcanics, the cost of the plants is estimated to run to 75% of the cost of producing power using binary technology. Significant reductions in the cost of power from binary technology will be difficult without reducing the cost of binary power plants.

Capital Expenditures

Power plant costs, including the core and auxiliary units, along with costs of developing and maintaining the well field, account for 85% to 90% of the costs of producing power from geothermal energy. Furthermore, the costs of a power plant, whether it employs either binary or flash technology, are about three-fourths capital. Similarly, more than half of the costs of a geothermal well are capital expenditures; and a large majority of those expenditures are for cement, casing, and hardware for well completion. Overall, one-half to three-fifths of the cost of power from a flash plant is due to capital expenditures. For a binary plant and well field, capital expenditures can account for two-thirds of total costs.

Capital expenditures are for materials and machinery. It is difficult to reduce these costs. For geothermal plants, about the only leverage in capital expenditures is in processing of the dissolved solids that precipitate from the brine and reducing the costs due to the corrosive liquids and chemical abatement, primarily hydrogen sulfide. Programs in these areas could have noticeable effects on the cost of power in the Imperial Valley and in the Young Volcanics region.

Opportunities for Well Cost Reduction

In addition to operations and maintenance, exploration and drilling costs are major areas of expense outside of capital purchases. The majority, 75% to 90%, of exploration costs are due to wells. Thus a program to reduce drilling costs will also help reduce exploration costs. The 75% to 90% figures assume no differences exist in well size, drilling practices, or completion methods between exploration and production wells. However, it is not certain that exploration wells need to be as large as production wells. Additionally, unlike production wells, exploration wells do not need to be completed in a manner to guarantee long life. Thus, so long as the wells are considered expendable, even capital expenditures associated with completion practices of exploration wells could be reduced. Therefore, while a program to reduce costs in exploratory drilling may have some elements in common with a program to reduce costs in production drilling, production and exploratory drilling programs can be quite different in technical approaches and program goals.

As indicated in the previous paragraph, the opportunities for reductions in the cost of production wells are not as great as the opportunities for reductions in the cost of exploratory wells. The difference is due to completion requirements. The casing, cement, and wellhead for completion can account for up to 45% of the cost of a production well. These costs represent a limit on the possible cost reduction in production drilling without significant innovation in completion practices.

Factors in the Cost of Geothermal Wells

There are four factors common to geothermal drilling that result in increased cost when compared to oil and gas drilling. These four factors are lost circulation, high temperature, hard rock, and corrosive fluid. A complete program to reduce the cost of drilling should contain elements targeted at reducing costs and problems in each of these areas.

If we define drilling problems as being only those situations or events that require interruptions in the normal drilling and completion processes; then, of the four factors listed in the previous paragraph, only lost circulation is a drilling problem. Other examples of drilling problems are well kicks or blowouts, stuck pipe, broken or twisted drill strings, materials or tools lost in the hole, incomplete cementing, and unusual bit wear resulting in under-gauge cutting or premature failure. The primary figure of merit for any tools or procedures developed to attack drilling problems is the time necessary to return to normal drilling and completion processes.

The high temperatures encountered in geothermal wells directly affect instrumentation and testing capabilities. Long term flow and draw-down tests, common in oil and gas wells, cannot be conducted with down-hole instrumentation in geothermal wells due to the inability of electronic instruments to withstand the temperatures. The resultant lack of long-term pressure, temperature, and flow data from geothermal wells limits our knowledge of geothermal reservoirs and restricts our ability to predict reservoir behavior. Because of the inability to operate at high temperature, bond logs and cement evaluation tools can be run only after cooling the well, with the resultant dangers associated with thermal cycling. Instrumentation developed to operate for longer periods

at higher temperatures could alleviate these shortcomings.

High temperatures cause changes in fluid properties. The ability of the drilling fluid to remove cuttings, control formation fluids, and stabilize the well bore is decreased at elevated temperatures. Also, cementing problems are encountered at high temperatures. Not only are retardants necessary to prevent premature setting, but special additives must also be employed to prevent the cement slurry from dehydrating at high temperature.

The high temperatures encountered in drilling geothermal wells also tend to increase the severity of other problems. Material strengths decrease with increasing temperature, thus tools wear faster and fail at lower stress levels when subjected to high temperatures. High temperatures aggravate problems associated with corrosive fluids by increasing chemical reaction rates. These are problems that can be attacked through advances in material science; such as the development of affordable, high-strength and/or corrosion-resistant materials. One geothermal reservoir near Niland, California, has temperatures in excess of 500°F. However, the brine measures 275,000 ppm dissolved solids and is highly acidic with a pH of 3.2. Every advance in the development of methods to handle brines that are highly acidic and brines with a high concentration of dissolved solids will improve the chances of developing this resource.

As discussed above, high temperatures aggravate problems associated with corrosive brines and any program set up to combat the corrosive nature of the brine must also consider the temperatures of operation. The other major chemical related problem is the dissolved solids and chemical salts in some brines. According to IM-GEO, there is a significant portion of the cost of power in the Imperial Valley and Young Volcanics regions that is due to chemical problems. Chemical deposits in the well bore require interrupting production to rework the well. The utility of the use of jets for rework has been questioned, but the alternative, mechanical rework, cannot be good for the casing.

The hard, abrasive rock encountered in geothermal drilling causes accelerated wear on bits and drill string components due to both the increased abrasiveness of the rock itself and to the increased forces necessary to cut the rock. Programs in materials science to improve the ability of drill string components to withstand these conditions might be attractive.

The hard rock also significantly decreases the rate of penetration (ROP) during drilling. In oil and gas drilling, twenty-five feet-per-hour is a common ROP. In geothermal drilling a ROP of twenty-five feet-per-hour is approached only in the Imperial Valley. In other areas, a ROP of ten to fifteen feet-per-hour is more typical. The relatively high ROP's possible in oil and gas drilling are due not only to the softer rock encountered, but also to the use of polycrystalline diamond compact (PDC) drag bits. While PDC bits significantly out-perform roller cone bits in medium hard formations, neither PDC nor any other drag bit developed to date can withstand the increased temperatures, shock, and loading associated with hard rock cutting. Considering that about half of the time and a fourth of the cost of a geothermal well is spent with the bit turning on bottom, the development of a hard rock drag bit has strong possibilities for reducing geothermal drilling costs.

As a final word, while a set of programs to reduce the cost of production drilling holds as much or more promise for reducing the cost of power as any other R&D program, caution should be employed concerning expectations of these programs. For example, a new bit technology that would increase rate of penetration in hard rock and thus reduce drilling time by 20% would be a major accomplishment. If this hypothetical bit is not significantly more expensive than those currently employed, such a development would be expected to reduce the cost of a geothermal well by about 10%. This, in turn, would result in a reduction in the cost of power of about 3%. Thus, large cost-of-power reductions should not be expected; changes on the order of a few percent are much more reasonable objectives.

However, changes of a few percent are significant. Geothermal drilling and power production are relatively mature industries. As stated previously, the production of electricity from geothermal power is locally cost-competitive. Being competitive implies that changes of a few percent in the cost of production can make significant changes in the penetration of the use of geothermal energy in the electrical production market.

Projects

Exploration and Resource Definition

The primary need of the geothermal industry is the identification and definition of geothermal resources for development. There are any number of possible programs that could be instituted to accomplish a goal of resource identification and definition. For example, the DOE could fund, through the U.S. Geological Survey, a program to explore specific regions of the country in detail and map the geothermal resources. While such a program could accomplish the end of resource definition, it would not improve the geothermal industry's ability to expand and explore new areas. A better approach might be to develop tools and procedures that reduce the cost of geothermal exploration.

The cost of exploration is estimated to be in excess of 10% of the cost of producing electricity from geothermal energy in the Cascades and Basin and Range regions. Furthermore, by far the largest portion, 75% to 90%, of the cost of exploration and reservoir confirmation is estimated to be due to the cost of drilling exploratory wells. So it follows that there is significant leverage for reducing the cost of power through reductions in the cost of exploration; and the greatest opportunity to reduce the cost of exploration is through a reduction in the cost of exploratory wells.

One method for reducing the costs of exploratory wells that is currently being studied employs relatively small-diameter wells, or slim-holes, instead of production-size wells in the exploration process. It should not be as expensive to drill a small-diameter hole as it is to drill a production-size well, especially if the hole is considered expendable; i.e. it is expected that upon test completion the casing will be pulled and the well cemented. Petty and Entingh estimate that the use of slim-holes in the exploration process could reduce the cost of power by six percent on average (ref. 30). They also showed that it may be possible to reduce the financial risk associated with geothermal exploration by a quarter. Finally, they found that the use of slim-

holes would "... shift the burden of cost away from the early phases of the project with the highest risk and the largest percentage of developer investment", thus encouraging geothermal exploration and development.

There are at least three areas that require some work or definition before a slim-hole exploration program can be fielded:

1. The measurement and analysis techniques to characterize a geothermal reservoir with other than flow tests of production-size wells must be developed,
2. The instrumentation to support reservoir assessment and evaluation is needed, and
3. The methods to efficiently drill and complete small-diameter holes for geothermal assessment should be improved.

In the oil and gas industry, small-diameter holes can be drilled quickly and efficiently using PDC drag bits. However, neither PDC bits nor any other drag bit currently available can withstand the thermal and mechanical stresses imposed during drilling the hard igneous and metamorphic rock encountered in geothermal operations. For larger diameter holes, the geothermal industry employs roller cone bits. However, problems with high-temperature seals limit the use of journal bearings in geothermal applications and roller bearings for small-diameter tri-cone bits cannot withstand the forces necessary to crush hard rock. With drag bits eliminated and roller cones of limited use, diamond impregnated core bits are the most efficient cutters currently available for drilling small-diameter holes in hard rock.

Then, using currently available bits and technology, the general consensus is that the optimum slim-hole drill rig would be either a coring rig or a coring-rotary hybrid. However, it should be remembered that the object is to get a hole in the ground, not to obtain core. A slim-hole drilling program should search for the most efficient method of drilling the hole.

If coring were to be employed, there may be some advantage or information gained by analyzing and/or preserving the core. The core is probably the best geological data that will be obtained. However, this does not imply that the costs associated with coring or preserving the core can be recovered through core analyses. There has been significant discussion of core testing, cataloging, measurement, and data storage and manipulation. Amoco has developed a transportable lab for core analysis in oil and gas drilling; and discussions with Amoco personnel have indicated a desire to transfer this technology to a service company. However, to date there are no known proposals concerning how core data and information could be employed to increase the efficiency or decrease the cost of identifying and defining geothermal resources.

Besides drilling methodology, another area that needs attention in the development of a slim-hole program is instrumentation. A slim-hole program cannot be successful without instrumentation to make measurements in small-diameter wells. Though some of the currently available tools and instruments may be adaptable, they were not developed to work in small-diameter holes. More importantly, as a slim-hole program matures, new requirements for instrumentation will

almost certainly develop. There is also a side benefit of establishing an instrumentation program in support of slim-hole exploration: it is certain that technology developed in support of a slim-hole program would result in better instrumentation for production-size wells.

The major uncertainty in the concept of slim-hole exploration is that it is not entirely clear that the necessary information to characterize a reservoir can be obtained without tests conducted in wells capable of production-level flow. The primary information needed for reservoir characterization includes the following:

1. production temperature,
2. brine chemistry,
3. well productivity, and
4. reservoir capacity.

It is current practice to estimate well productivity and reservoir capacity from flow tests of production-size wells. In small-diameter holes, choke flow may occur near or below the kill pressure. Thus achieving any flow may be difficult, let alone sufficient flow to adequately stress the reservoir to indicate reservoir boundaries or to estimate storage capacity.

The problems with flowing a small-diameter hole do not imply that the necessary information cannot be obtained. The required information for reservoir characterization needs to be precisely defined. The tests and procedures necessary to obtain this information need to be specified. The required stimuli need to be determined and the expected response to these stimuli need to be predicted. In summary, individuals with knowledge of geology, geophysics, and reservoir mechanics need to establish, define, and develop models to determine if and how a geothermal reservoir can be characterized from tests in other than production-size wells.

Discussions with geologists and reservoir engineers concerning reservoir characterization almost invariably return to discussions of the possibility of obtaining flow from small-diameter holes. Often it seems that there is an implicit assumption that reservoir characterization requires flow testing. Are there no other ways to estimate reservoir transmissivity and storage capacity? The question should not be whether it is possible to characterize a reservoir from tests in a small-diameter well; but whether it is possible to characterize a geothermal reservoir from tests other than in production-size wells.

The success of a slim-hole exploration program hinges on the answer to the characterization question. If it is concluded that a geothermal reservoir cannot be adequately defined without flow tests of production-size wells, then the efficacy of slim-hole exploration is greatly diminished. In this case, only static reservoir temperature and brine chemistry can be learned without a production-size well. This can already be accomplished. Under this limitation, the most that can be achieved from a slim-hole program is the development of an initial filter to eliminate some regions from further consideration.

In addition to possible savings in exploration and resource definition, the development of a slim-hole drilling program would have another benefit. If the theory, methodology, and instrumentation necessary to define a geothermal reservoir through information available from means other than production-size wells are developed, then it should be possible to employ this same technology for diagnostic purposes in known regions. This would yield a better understanding of reservoir dynamics and, hence, make possible a better job of reservoir management.

As a final note, an evaluation of deep gas drilling was recently completed for the Gas Research Institute (GRI) (ref. 31). This study concluded that, if the primary interest is large scale impact on deep drilling operations, GRI should focus their efforts on supporting research in the area of slim-hole drilling technology. Thus, the pursuit of a slim-hole drilling program could have applications in the gas industry, as well as in the geothermal industry.

In summary, a program to develop slim-hole exploration technology involves significant effort in at least three fields: drilling technology, instrumentation, and reservoir mechanics. If successful, a slim-hole program will have a number of benefits:

1. The cost of drilling exploratory wells and the financial risk associated with geothermal exploration could be reduced significantly,
2. A major cost in geothermal development could be shifted from the early phases of the project, thus encouraging exploration,
3. Instrumentation programs developed in support of a slim-hole program would also result in higher-quality instrumentation for testing in production-size wells,
4. A better understanding of the geothermal resource and reservoir mechanics would be attained, thus allowing better management of the resources currently being exploited, and finally
5. Technology developed in support of a slim-hole program would not only have cross-applications in the drilling and monitoring of geothermal production wells, but also in the drilling for deep gas reservoirs.

Lost Circulation Control

Lost circulation is the most costly problem encountered in geothermal drilling. Not only can the loss of drilling fluids present serious problems to the driller without other complications, but lost circulation can also be the cause of a number of other drilling problems such as stuck drilling assemblies, well sloughing, and incomplete primary cement jobs.

Lost circulation materials (LCM's) are routinely added to drilling muds. However, once lost circulation becomes a problem, there is little or no use of LCM's when attempting to plug the loss zone and prevent further losses. Cement is used almost exclusively to combat lost

circulation in geothermal drilling. The primary reasons for this are the possible consequences of failure to stop the lost circulation (loss of the well) and a general lack of faith in the ability of LCM's to perform reliably. This lack of faith could be the result of the fact that, because of the temperatures encountered, many of the LCM's developed and used in oil and gas drilling are not effective in geothermal wells.

The primary incentive for continuing with an LCM program is the possible cost savings over a standard cement treatment of lost circulation. Glowka (ref. 26) estimates that LCM's could reduce the cost of combatting a lost circulation problem by as much as 50% to 80%.

Aside from the development of LCM's, there are at least four programs that could reduce the impact of lost circulation on well costs:

1. The development of methods and tools to identify and locate lost circulation zones as soon as possible,
2. The development of tools and procedures for placing cement in the lost circulation zone,
3. The development of cements or cementitious muds that can be placed through the bit nozzles, and
4. The development of quick-setting cements or materials that can be drilled in less than the normal six to eight hours hardening time for conventional cements.

Methods and tools to identify and locate lost circulation zones would increase the efficiency of the methods used to combat the problem. Also, quick identification and knowledge of the loss zone should reduce other problems, such as stuck pipe and incomplete cement jobs, that are associated with lost circulation. The development of tools and procedures for directing and placing cement would increase the efficiency of using cement to plug the loss zone and also reduce the amount of cement required. The development of materials that can be placed through the bit nozzles would reduce the time spent combatting the problem. With the daily rate on the order of \$10k, the eight hours required for cement to set costs \$3,000 to \$4,000 for the drill rig alone. The development of cements or materials with shorter setting times would directly reduce this cost and allow a quicker return to drilling.

Lost Circulation and Cementing

When lost circulation is encountered, it is sometimes possible to drill ahead blind, i.e. without returns to the surface. At other times it is possible to continue drilling using a foamed or aerated mud. At the Geysers, it is common practice to drill the production interval using air as a drilling fluid. These are all methods to circumvent lost circulation as a problem while drilling. However, if casing must be set, an uncorrected loss zone will cause problems during cementing even if drilling can continue. Because an improper primary cement job can result in loss of the well, few drillers hesitate to spend the time and resources to combat lost circulation when it is

encountered, even if it might be possible to continue drilling.

The development of methods or materials that would allow completion of the primary cement job through a loss zone would reduce the stature of lost circulation as a drilling problem. One suggestion for cementing through loss zones involves the use of foam cement. Foam cement can be formulated to be as light as four pounds per gallon. The use of a light-weight cement should reduce the losses to the formation and increase the chances of completing the cement sheath.

There is an impression in the geothermal industry that foam cement is experimental in some sense. However, the Bakersfield office of Halliburton has been employing foam cement in oil and gas wells for forty years. Still, individuals in the geothermal industry have a number of concerns about the use of foam cement:

1. There are questions concerning the stability of the foamed slurry at high temperature,
2. There are questions about the strength of foam cement and its ability to support the casing, and
3. There are questions about the impermeability of foam cement and whether it will adequately protect the casing from formation fluids.

There are varying opinions about the answers to each of the above concerns. These answers will come only with a properly structured test and investigation program. Finally, even individuals that question the use of foam cement for the primary cement job, concede that it might be a useful tool for plugging lost circulation zones.

Bit Development

In addition to lost circulation control, another area for reducing drilling costs is bit design. As discussed in the text, about 50% of the time and 25% of the cost associated with drilling and completing a geothermal well is spent with the bit turning on bottom. Additionally, the rate of penetration (ROP) common to geothermal drilling is slow when compared to oil and gas drilling. These facts indicate that there is leverage for reducing the cost of geothermal wells in the development of bits capable of higher ROP's in hard rock.

The oil and gas industry uses PDC bits to achieve relatively high ROP's in medium hard rock. PDC bits will also out-perform roller cone bits in hard rock, they simply will not do it for very long. Neither PDC's nor any other drag bit available today can withstand the frictional heating and impact loading encountered in drilling hard rock.

It is not at all certain that the development of a hard-rock drag bit is possible. Such a development would likely require significant effort in materials technology, stress modeling, and failure analysis in addition to bit design. However, there are bit companies working to extend drag bits to harder formations and there is leverage for reducing the cost of geothermal wells in bit development. The feasibility of developing a hard-rock drag bit should be investigated.

Besides ROP, another major bit problem in hard-rock drilling is premature wear resulting in under-gauge cutting. Under-gauge cutting requires reaming before the hole can be deepened. The models developed by Carson, Lin, and Livesay (ref. 23) estimate that, after the initiation of air drilling at the Geysers, reaming adds 25% to the drilling time. Advances in bit design to reduce under-gauge cutting would reduce the time and money spent reaming the hole.

Instrumentation

For well logging, the geothermal industry depends on the oil and gas service companies. Many of the instruments and logs developed for oil and gas drilling are not applicable to the geothermal industry and others will not survive the geothermal environment. There is industry interest in the development of newer and higher quality instrumentation for geothermal applications. The questions concern what needs to be known, what measurements will yield or imply the necessary information, and what instruments are required to make the measurements.

Instrumentation does not directly influence either the recovery of heat from a geothermal reservoir or the production of electricity from that heat. Whether or not a specific reservoir parameter is measured does not effect the value of the parameter; or, for that matter, the brine effectiveness, the plant efficiency, or the power output. The function of instrumentation in the geothermal industry is to provide information to allow more efficient and more economical recovery of heat and conversion of that heat to electricity. Thus instrumentation and measurement are secondary functions in that they support other activities in the exploitation of geothermal resources. The justification of a specific instrumentation program must be on this basis.

Possible Approaches

More instrumentation is used and more logs are run in the oil and gas industry than in the geothermal industry. There are a number of reasons for this, but primary is the fact that the correlation between specific measurements and knowledge of the resource has not been demonstrated to as great a degree in the geothermal industry as it has in oil and gas exploration and production. Neither instruments designed to estimate previously unmeasured quantities nor instruments designed to yield higher quality measurements will receive much use unless some correlation between the measurement and the resource can be demonstrated. There are two ways of demonstrating such a correlation:

1. Design and build the instrument, make the measurements, and search for the correlation; or
2. Develop the theory and build the instrumentation program from the resultant data requirements.

The ideal approach is the second one: develop the theory and learn what needs to be measured before developing the instrument. When possible, this approach should be employed; however, no model or analysis is exact so the relationships are not always obvious. Though there is danger

of working on that which is fun and developing that which is easy, it is likely that more has been accomplished with the first approach: build a device and then try to determine how it can be used.

The first step in any instrumentation program is to determine the current state of the available tools and their limitations. As a starting point, Table 7 gives a simplified summary of the status of the logs currently run or available in geothermal drilling and production.

Table 7: Currently Available Tools

<u>Measurement</u>	<u>Status</u>	<u>Operating Limit</u>
Temperature	Current	600°F
Pressure	Current	600°F
Fluid Velocity	Current	600°F
Natural Gamma	Current	600°F
Collar Locator	Current	600°F
Bore-hole Caliper	Development	600°F
Tracer/Gamma Ray	Development	600°F
Bore-hole Televiwer	Development	530°F

As discussed in the text, any instrument containing silicon-based chips must be contained in heat shields for measurements in the neighborhood of 300°F or above. Thermocouples for temperature measurement and mechanical spinners for flow velocity can operate at temperatures higher than 300°F; and one vendor claims to have developed a pressure tool for use to 600°F without shielding. The 600°F limitation given in Table 7 is due to the capability of the wire-line insulation. The 530°F limitation on the bore-hole televiwer is due to the compliant window for the acoustic sensor.

Resource Evaluation

A major failure in geothermal instrumentation and data analysis is the inability to accurately measure and predict reservoir parameters and resource performance. The Geysers is suffering from an apparent field depletion. There are concerns about the capacity of the resource at Coso Hot Springs. The majority of the activity in recent years at Coso has been to maintain current production capability. When the Heber binary plant is in operation, the Heber flash plant suffers. It is not clear that the resource is adequate to support both facilities. Events such as these reduce the general confidence in geothermal energy as a valid alternative for the production of electricity and magnify the difficulty of penetrating the power production market.

In cooperation with geologists, geophysicists, and reservoir engineers, new avenues of resource

evaluation should be investigated. In particular, emphasis should be placed on reducing the uncertainty in resource characterization. These are goals to be pursued in support of a slim-hole program, but a program to achieve a better understanding of the geothermal resource should proceed even in the absence of a slim-hole project.

Some of the difficulty in predicting resource performance is due to the inability to perform long-term tests. As discussed in the text, long-term production and shut-in tests running thirty to forty-five days are not uncommon in the oil and gas industry. Because of the nature of the environment, such tests are generally not feasible in geothermal wells. The ability to economically perform long-term tests in geothermal wells would be a major step leading to a better understanding of reservoir dynamics.

Memory Tools

Wire-line charges are a primary cause of increasing logging costs with increasing temperature. The necessity for wire-line can be eliminated through the use of memory tools. Some people believe that the logging companies are not anxious to develop memory tools even though the technology exists. The reason for this reluctance is a fear that the operators will then run their own logs. Based on the experience with mechanical memory tools for recording data, there is some basis for such a fear on the part of the logging companies.

Even though they lack precision, mechanical memory tools have received a degree of acceptance in the geothermal industry. Electronic memory tools can be developed for any operator that indicates an interest and there is no doubt that electronic memory tools can out perform mechanical memory tools. However, some operators that have employed mechanical memory tools continue to do so because of concerns with reliability and repair of electronics-based devices. There are two criteria that must be met before wide acceptance of electronic memory tools can occur:

1. The operators must be assured of the reliability of electronics-based devices in the geothermal environment and
2. The need for the better performance characteristics of electronic memory tools, when compared to mechanical memory tools, must be demonstrated or convincingly argued.

Transmission Line

High temperature wire-line is expensive, costing three to four dollars per foot. It has been suggested that fiber optic cable could replace wire-line. Two advantages of fiber optic cables are higher temperature capabilities and greater corrosion resistance. There are definitely reservoirs where the corrosion resistance would be advantageous and the ability to operate at temperatures greater than 600°F could be useful in some instances, though temperatures exceeding 600°F are not the norm.

The major questions concerning the use of fiber optic cables for data transmission are cost and

the adaptation of sensors. The development of fiber optic sensors to eliminate the use of down-hole electronics would be a major advance in testing and logging geothermal wells. Fiber optic temperature and pressure sensors have been developed for other applications. The costs and advantages of further development of fiber optic cables and sensors for geothermal data logging should be investigated.

Specific Instruments

There is significant dissatisfaction in the industry with the use of spinners for flow velocity measurement. Due to their tendency to jam, spinners must be monitored continuously during use. The accuracy of spinner measurements is not considered sufficient for resource evaluation needs. At best, spinners give the flow velocity in a small region; they do not yield any information concerning the velocity profile. Assumptions concerning the shape of the profile and its relationship to the spinner data must be made before estimates of the mass or volumetric flow rates can be attained.

It is almost certain that a better device for measuring brine flow can be developed. An instrument based on acoustics is one possibility. Any new instrument for flow measurement should allow better estimates of the mass, or at least the volumetric, flow rate and flow contribution. Additionally, interest in the detection and measurement of two-phase flow has been indicated. This would ultimately lead to the development of a steam quality tool. There are conflicting opinions concerning the need for down-hole steam quality measurement, but there is interest.

Another possibility for acoustic instrumentation is the development of an acoustic or transit-time log. During drilling, such a log could be used to measure formation density and porosity. During production, an acoustic log could be used to evaluate formation damage due to solids deposition. Some of this same information can be determined from nuclear logs; however, the use of radioactive materials make these devices less attractive.

An acoustic transit-time log is the basis for the cement evaluation tool. However, there is significant dissatisfaction with both the current cement evaluation tools and the current bond logs. A lot of people run them, but few believe them. The occurrence of false positives, the instrument indicating a void in the cement sheath when none can be found, is a common complaint. The unnecessary attempt to perforate the casing and squeeze cement not only costs money to perform, but also results in permanently damaged casing.

Additionally, bond logs and cement evaluation tools require that the well be cooled before operation. As discussed in the text, this thermal cycling can only have negative effects on materials and interfaces in the well. There is also the question of evaluating the capability of the cement and casing at production temperatures from tests at low temperature. In addition to qualitative data, quantitative data is also desired. In other words, knowing not only that a void exists, but also the size of the void, would be helpful in determining what, if any, remedial action should be taken.

In the industry interviews, the only positive comment concerning bond logs was from an engineer that believes the major problems with these devices is in data interpretation. There is some logic to this argument. The device returns a signal; it is the interpretation of that signal that yields predictions of the condition of the cement and casing. If data interpretation is the problem, then the development of calibration procedures and standards for signal interpretation could resolve the majority of complaints with bond logs. This experience with bond logs points to the importance of the specification of measurement standards and calibration routines, and the development of data analyses procedures, as part of any instrumentation program.

One final suggestion for an instrumentation program. It is generally believed that geothermal reservoirs consist of a system of fractures. Furthermore, it is believed and that the fractures or fracture cloud that determine a specific reservoir have some general orientation. One engineer stated that if he could determine fracture direction, he could "save gobs of money". By knowing fracture direction, the wells could be drilled to efficiently intersect the reservoir thus increasing the average well productivity. It has been suggested that the bore-hole televiewer could be used to determine fracture direction. If so, the methods and procedures to accomplish this have not been prominently advertised. The development of tools or procedures to detect fractures and determine fracture direction would be welcome.

Appendix A

Summary of Industry Interviews

Over a period of several months during 1991, the authors conducted a series of discussions with individuals in the geothermal industry. Representatives of operating companies, service companies, and private contractors were interviewed. The main subjects during these discussions were the current state of the geothermal industry, the major problems being encountered, and the direction for DOE programs to have maximum impact.

There was a provincial nature to many of the interviews. People around Santa Rosa were concerned with the apparent depletion of the Geysers. Those working in the Imperial Valley expressed more concern about corrosion and scale build-up. And, reflecting the current emphasis and main activity in the geothermal industry, drilling-related problems were discounted in comparison to production-related concerns.

In spite of the narrow focus and variety of the opinions expressed during the discussions, a number of areas were repeatedly mentioned as presenting significant obstacles or problems to the industry. Judging by the number of times each was introduced into conversation and the opinions concerning the relative magnitude of the various problems, the following areas can be considered of primary concern to the geothermal drilling industry:

1. Lost circulation and cementing,
2. High-temperature tools and instrumentation, and
3. Exploration and resource definition.

In addition to those listed above, the following areas of interest also received multiple mention:

1. Fishing and fishing-related problems,
2. Information access and transfer,
3. Corrosion and scale build-up, and
4. Data reduction and interpretation.

In the following paragraphs, the authors' interpretation and summary of the problems discussed in the interviews are presented.

Lost Circulation and Cementing

Lost circulation and cementing problems are the most frequent trouble areas encountered in developing a well for production; however, they are not independent of one another. There does

not seem to be great concern with lost circulation as a drilling problem, but if circulation is not maintained, a good primary cement job cannot be achieved and the well will be lost.

Though lost circulation materials (LCM) are added routinely to drilling muds, there is little or no support for the use of LCM once problems with lost circulation have been encountered. A major concern with LCM as a lost circulation fix is that, though circulation may be restored while drilling, it cannot be certain that the LCM will hold up when running cement. Because of this uncertainty with LCM as a lost-circulation fix, several drilling engineers and supervisors indicated that when lost circulation is encountered, cement is employed.

Given the relationship between lost circulation and the primary cement job, there are at least two ways to reduce the impact of problems caused by lost circulation:

1. Develop methods to satisfactorily complete the primary cement job past loss zones and
2. Develop aids in plugging loss zones as they are encountered.

The first suggestion would be a significant development since it would decouple drilling from running casing when completing a well. During drilling, lost circulation would be a problem only so far as it complicated the task of getting the hole to the desired depth. Once the desired depth was attained, the casing would be run. While the idea of completing the primary cement job through loss zones is attractive, no proposals concerning how this could be accomplished have been advanced. It is suspected that completion of the well past loss zones will be accomplished only with the introduction of methods of sealing the formation and protecting the casing that employ some new sealant either prior to, or instead of, cement.

Aids in plugging loss zones include methods and tools to place cement at the desired depth. One such aid would be an open-hole packer that could be placed below or straddling the zone. Such a packer would direct the cement to the zone of interest and prevent it from sinking to the bottom of the well. A packer placed above, or straddling, the loss zone would allow squeezing cement into the zone.

Another possible method for directing placement is through the use of light-weight cements that can be floated into place. Foam cement has been suggested for this purpose. While foam cement has not been widely used in geothermal applications, Halliburton has been using foam cements in oil and gas wells for nearly forty years. Cements as light as four pounds-per-gallon are possible, however, approximately seven to eight pounds-per-gallon is the minimum to assure an impermeable set. This is an adequate density range to handle nearly all geothermal applications. The strength of a light-weight material could be questioned, but as a lost circulation fix, high strength may not be necessary. The major uncertainty concerning the use of foam cement in geothermal wells is the high-temperature stability of the foam.

Instrumentation

There is significant interest in a reliable method to evaluate the casing-to-cement interface. There is nearly universal distrust of bond logs. Everybody runs them, but nobody believes them. The most positive comments concerning bond logs were from an engineer who thought the problems are the interpretation of the output. He suggested that the instrument returns an electronic signal, but there is no standard by which to interpret this signal. He believed that if calibration standards for good casing-to-cement bonds, as well as casing-to-cement decoupling, were developed; then consistent interpretation of the bond logs would result and the expressed concerns with these measurements would disappear.

Even if the main problem with bond logs is interpretation, there is also dissatisfaction that bond logs cannot be run at high temperature. The lack of a high-temperature capability was also expressed concerning cement evaluation and casing inspection tools. Cooling the well to run these instruments induces stresses in the formation and the materials and interfaces in the well. In addition to the stresses induced by thermal cycling the well, there are also questions concerning evaluation of the capabilities of casing and cement at high temperature from data collected at low temperature.

The ability to make direct measurements down-hole would be an improvement over the currently available casing and cement evaluation tools. The interest in measurements of the casing and cement is quantitative as well as qualitative. Not only is it important to know if gaps exist at the casing-to-cement interface, but a measurement of the magnitude of any gaps would aid in determining what action, if any, is necessary.

In addition to bond logs and cement evaluation tools there is also strong support for improvements in other instruments. Better down-hole temperature measurements and instruments with quicker response times would be welcome; so too would be the capability to measure or infer steam quality and enthalpy. A desire for "a sampler that works" has been expressed, as has a desire for a flow measurement more accurate than the spinner yet, capable of high-temperature operation. Finally, there is general interest in instruments capable of withstanding higher temperatures for longer periods of time.

Performance Specifications

While there is a significant interest in evaluating the casing-to-cement and cement-to-formation interfaces, it does not appear that anyone has performed any work to determine specifications for cement or casing. Other than a general statement of its function, no one is able to specify what is required of the cement and casing or how much degradation can be tolerated before some remedial action is necessary. This is also true for other tools and instruments. It is often stated that some current measurement is not good enough, but no statement is made concerning what would be adequate. There is need for work in developing specifications and functional requirements for cement and casing as well as for instrumentation.

The development of specifications and functional requirements prior to initiating a development

program for instrumentation or materials would yield several positive results. A generally better understanding of the production mechanism and down-hole functions would be achieved. It would define the requirements and, therefore, make the development of tools, materials, and instruments clearer, easier, and cheaper. It would result in better benchmarks by which to judge the progress of the development. And finally, by defining the goals in advance of the development, the performance expectations for the end product would be as universally understood as possible, thus avoiding misunderstandings concerning expected results.

Exploration and Resource Definition

There is considerable interest in the development of tools and methods to explore for new geothermal resources and to better define known reservoirs. One engineer stated that he "knew of two or three projects that are dead in the water, because no one will go out and define the resource". By far the greatest portion of the development of geothermal energy has occurred in areas of gross physical manifestations: hot water or steam vented at the surface. These obvious sources of geothermal energy have either been exploited or are protected. For any significant expansion of the use of geothermal energy for electricity production, less obvious areas must be explored and new resources found and defined.

There are at least two areas in which DOE could assist the effort to explore and define new geothermal resources:

1. The development of methods to define promising areas and search intelligently and
2. The development of methods to reduce the cost of exploratory drilling.

No strategies rooted in geology or geophysics have been developed to explore and define geothermal resources. There has been limited success employing geochemistry to determine where not to search. But the primary mode of exploration for geothermal energy resources is to drill holes and test for heat and liquid. The development of methods to narrow the search could save exploration funds.

Not only are there no general strategies to aid in exploration for geothermal resources, but no one is currently attempting to develop such a strategy either. However, there is effort being expended toward reducing the cost of exploratory drilling through the development of slim-hole drilling technology.

The use of small-diameter wells for exploration could reduce costs in two ways. First, it should not be as expensive to drill a small-diameter hole as it is to drill a production-size well, especially if the hole is considered a "throw away"; i.e. it is expected that upon test completion the casing will be pulled and the well cemented. Also, further savings from the development of small-hole technology would be realized by reducing the size of the exploration debt to be carried until initial production.

There are at least three areas that require some work or definition before a slim-hole exploration

program can be fielded:

1. It has not been determined if the necessary information to characterize a reservoir can be obtained without a production-size well,
2. Instrumentation to support the slim-hole program will be needed, and
3. The optimal method to drill small-diameter holes has yet to be specified.

The general consensus among those with whom we spoke is that the optimum slim-hole drill rig would be either a coring rig or a coring-rotary hybrid. Given that coring is employed, there is some discussion concerning whether it would be practical to preserve the cores. The core has been described as the best geological data that can be obtained; but this does not imply that the expense of preserving and saving the cores could be recovered. However, as more than one geologist noted, there is a significant amount of information that can be obtained if the cores are simply cataloged and boxed without expending extra effort for preservation.

Besides drilling methodology, another area that needs attention in the development of a slim-hole program is instrumentation. Though some of the currently available instrumentation may be adaptable, it was generally not developed to work in small-diameter holes. Additionally, as a slim-hole program matures, new requirements for instrumentation will almost certainly develop. There is an additional benefit of establishing an instrumentation program in support of slim-hole exploration: it is certain that technology developed to support such a program would result in better instrumentation for production-size wells as well.

The major uncertainty in the concept of slim-hole exploration is that it is not clear that the necessary information to characterize a reservoir can be obtained without production-size holes. The primary information needed includes fluid chemistry, production temperature, well productivity, and reservoir capacity. It is current practice to estimate well productivity and reservoir capacity from flow tests of production-size wells. In small-diameter holes, choked flow may occur near or below the pressure at which the reservoir will not flow at all. Thus achieving any flow may be difficult, let alone sufficient flow to adequately stress the reservoir to indicate boundaries or to estimate storage capacity.

The problems with flowing small-diameter holes do not mean that the necessary information cannot be obtained; it must simply be obtained through new or more sophisticated means. The information required for reservoir characterization must be precisely defined. The tests and methodologies to obtain this information need to be determined. The test stimuli need to be specified and the expected responses of the reservoir to these stimuli need to be predicted. In summary, individuals with knowledge of geology and geophysics need to establish, define, and develop models to determine if and how a reservoir can be characterized from tests in other than production-size wells.

If it is concluded that a reservoir cannot be adequately defined without flow tests of production-size wells, then there is little need to expend significant resources developing slim-hole drilling

technology as an exploration tool. If a reservoir productivity and size cannot be adequately estimated without tests in production-size wells, then all that can be learned from small-diameter wells is static temperature and liquid chemistry.

Fishing

Interest has been indicated in two areas associated with fishing. First, there is interest in the development of a diagnostic tool to evaluate the fish prior to attempted retrieval. It is not unusual for some doubt to exist concerning the exact nature of the fish. And, even if the nature of the fish is fairly well known, its orientation in the hole may not be certain. An instrument to determine the nature and orientation of the fish prior to attempting retrieval would increase the probability of successful recovery.

The second area of interest associated with fishing concerns when it is economical to continue to attempt recovery and when it would be better to pour cement and either grind the fish up or bypass it. This decision should depend on the value of the fish as compared to the cost of continuing to attempt recovery. If data are available, it is expected that an analysis would indicate that the probability of successful recovery decreases as the number of attempts at recovery increase. Then for a given fish, it should be possible to determine a number of attempts or a time after which the expected return is less than the cost of continuing to attempt recovery. We were told that ARCO has an equation or algorithm to determine when to discontinue fishing. If so, all that may be necessary is to make this information generally known.

Information Clearinghouse

There are indications that a technical information service could be of significant use. For example, ARCO supposedly possesses an algorithm to determine when to continue fishing, yet we talked with a drilling engineer employed by another company who suggested that DOE sponsor a study to develop this same information. In another instance an engineer with one of the operating companies stated that foam cements were experimental and he didn't believe the service companies had the technology to properly use them. However, discussions with Halliburton led to the discovery that they have been using foam cements for nearly forty years and, when they are busy, the Bakersfield office alone does "four or five foam jobs a week". While it may be that ARCO is in no hurry to divulge their methods to their competitors, it is certain that Halliburton is not trying to hide their expertise and experience in foam cements. The mechanisms for the dissemination of information in the geothermal drilling industry are less than perfect.

There are a number of ways in which DOE could support and encourage information transfer within the geothermal community. One way would be to sponsor regular seminars and colloquia with invitations to specific companies for papers on certain topics. A geothermal "trade show" could be held. One drilling engineer stated that a clearinghouse for information and data on topics of interest to the industry would be useful. The recommendation was for a service to provide references and abstracts on topics of interest to the geothermal community. The Geothermal Resources Council (GRC) currently provides many of these functions. DOE

programs could be designed to compliment and assist similar GRC programs.

Probably of greater use than a technical information service would be a "Thomas Register" for companies involved in geothermal energy exploration and production. One way to initiate such a service would be for DOE to publish the initial volume and then turn it over to an outside organization such as the GRC for update and further publication. The listing could be organized similarly to the Yellow Pages. Companies interested in being listed could be allowed to compose their own advertisements and, after the initial publication, be charged accordingly.

Public Relations

There is opposition to geothermal energy development. There is an organized group opposing the development in Hawaii. Anyone associated with the nuclear power industry can attest to the capabilities of organized opposition and the implications of eroding public opinion. The California Energy Commission stated:

"In many cases, poor public opinion has a greater influence over technology use than more substantial economic and environmental constraints" (ref. 17).

There should be some effort to counter the opposition to geothermal energy development or at least a central organization should be established for disseminating accurate information about geothermal energy.

The opposition to geothermal development in Hawaii appears to be primarily a local organization, however, the Sierra Club and Audubon Society have also been active. Additionally, there has been some opposition from native Hawaiians on religious grounds, claiming geothermal steam to be in the domain of the goddess Pele. However, there is also some dispute among native Hawaiians concerning the validity of this claim.

The local opposition to the Puna and True Mid-Pacific geothermal developments has concentrated on three main issues:

1. Excessive noise and general inconvenience or negative impact on local residents,
2. Emission of toxic or noxious substances in general and hydrogen sulfide in particular, and
3. Possible pollution of drinking water sources.

In articles in the local newspapers, the facts concerning these issues have either been misunderstood or misrepresented by the authors. Scare tactics, referring to hydrogen sulfide as "a highly toxic powerful oxidant that can cause rapid death or serious physical disorders" (ref. 32), have been employed, while no mention of hydrogen sulfide abatement was made. While this description of hydrogen sulfide cannot be disputed, its use in this manner is meant not to educate but to terrorize. Even the concept of avoided cost has been used to argue that the developers are

taking advantage of the local population and "stand to make billions over time". It is not clear that either the state or any other organization has made a serious effort to provide accurate information about geothermal development in general or these issues in particular.

A peculiar aspect of the Hawaiian opposition is that they have neither taken a stand nor made any strong opposition to the development of a coal-fired plant on the island of Oahu. There have even been reports of support for the coal plant from the same people that oppose geothermal development. These actions imply a very localized opposition with a self-centered aim of preventing development in the immediate vicinity.

There is a segment of society that will oppose any industrial or centralized development. Tactics to be expected include delays through legal action, demands for more tests and more comprehensive environmental studies, and insistence of proof of safe operation. At public hearings and local meetings, supporters of development will find it difficult to express their views. It should not be expected that the opinions of these people can be influenced. However, they will not be able to significantly influence the development of geothermal energy without broader public backing. It is this broader support that must be prevented. The developer cannot be expected to act as 'point man' in shaping public opinion on a specific project. It is too easy to discredit the developer as having a financial motive. There needs to be a separate organization with access to the necessary technical information and knowledge of the expected tactics of those opposing geothermal development.

There are a number of positive aspects to geothermal energy use that can be emphasized. This is especially true when geothermal energy use is compared to the use of fossil fuels. Direct use applications reduce consumption of other energy sources. For electrical generation, geothermal energy can provide baseload power; it is a viable alternative and direct substitute for the use of coal, oil, gas, and nuclear power. In terms of environmental impact, emissions from geothermal power plants do not contribute to smog or acid rain and carbon dioxide emissions are generally an order of magnitude lower than from a typical coal plant. These comparisons should appeal to sensible people, however, a system to disseminate this information is needed.

Other Perceptions

Emissions from geothermal power plants are not just a concern of those opposing development. The CEC's technology evaluation indicates that environmental issues could have a significant impact for flash plants; however, environmental considerations are not emphasized for binary plants. This implies that the concern is emissions, since other environmental issues, such as degradation of scenic values or wildlife management, would be common to both technologies. Disposal of sludge in the Imperial Valley has also been indicated as a concern. It is important to note that these issues were not raised by those opposing geothermal development.

Besides waste and emissions, there are other concerns that could limit the expansion of the geothermal industry. Investors view geothermal technology as high risk due to a lack of reliable estimates of reservoir productivity and the inability to assure long production periods. These same factors are also indicated as reasons that utility companies are reluctant to purchase power

from independent geothermal producers. The apparent depletion of the Geysers only helps to reinforce this view.

The reliability of geothermal production facilities is also an issue within the geothermal industry. A degree of concern with the long-term integrity of production wells was noted in discussions with individuals involved in the operation of generating facilities, especially in the Imperial Valley. There were no discussions of major problems currently being encountered. However, the impression was that if major problems with scale build-up or corrosion do occur, it will not take those in the industry by surprise. Significant scale and corrosion problems will be expensive to combat; and, if these problems result in reduced power delivery, there will be further questions about the reliability of geothermal energy. Effort expended toward developing methods to prevent or remove scale, and research into affordable corrosion resistant materials and coatings, could pay significant returns and enhance the general perception concerning the geothermal industry.

Data Reduction

Several individuals indicated an interest in applying improved data reduction techniques to geothermal drilling. This has ranged from applying simple regression and correlation techniques on currently available data to developing expert systems. In the oil and gas industry, there has been significant interest and effort in this area over the past ten to twelve years. However, industry expectations have generally not been realized. Simple statistical techniques and processes have not yielded satisfactory results. Some physical models have demonstrated promise in predicting down-hole conditions. However, these models have required more information than is available from surface measurements alone; and the computational capacity necessary to run these models has not traditionally been available at the drill site.

In general, MWD and data reduction systems developed for the oil and gas industry have not been applied to geothermal drilling. Two reasons have been advanced to explain this:

1. The systems are expensive and geothermal operators have been reluctant to spend the money without demonstrated results, and
2. The systems were developed for oil and gas drilling conditions and would experience reduced life in the geothermal environment.

While it may be possible to modify existing systems to operate in the geothermal environment, the service companies have considered the market too small to warrant the expense.

It is likely that available information can be better employed and it may be possible to reduce the problems encountered in drilling through the use of data reduction and modelling techniques. Also, the advent of PC's coupled with hard disk data storage has greatly expanded the computational capacity available at the drill site. However, before embarking on a major program in this area, it is recommended that a survey of the oil and gas industry be conducted to determine the currently available equipment, models, and analysis techniques.

Appendix B

Nevada Power Purchase Contracts

Data concerning a number of recent power purchase contracts negotiated by utility companies in Nevada have been obtained. Information concerning contracts with six geothermal facilities in northern Nevada and one coal-burning facility in Colorado was obtained from Sierra Pacific Power Company. Similar information concerning contracts with three gas cogeneration plants and one tire-burning facility in the southern part of the state was obtained from Nevada Power Company.

A summary of plant characteristics for the contracts is given in Table 8. Four of the plants, the three gas cogeneration units and the plant designed to burn tires, will provide electricity to Nevada Power Company in southern Nevada. The coal facility at Craig, Colorado, and the six geothermal plants will sell electricity to Sierra Pacific Power Company in northern Nevada.

Table 8: Plant Characteristics and Data

Bonneville A and B	Saguaro
Purchaser: Nevada Power	Purchaser: Nevada Power
Gross Capacity: 85 MW each	Gross Capacity: 90 MW
Fuel: Gas cogeneration	Fuel: Gas cogeneration
Oxford	Craig, Colorado (3 plants)
Purchaser: Nevada Power	Purchaser: Sierra Pacific Power
Gross Capacity: 45 MW	Gross Capacity: 446 MW each
Fuel: Tires	Fuel: Coal
Steamboat II and III	Ormat A and B
Purchaser: Sierra Pacific Power	Purchaser: Sierra Pacific Power
Gross Capacity: 13.5 MW each	Gross Capacity: 14.3 MW each
Fuel: Geothermal	Fuel: Geothermal
San Emidio 1 and 2	
Purchaser: Sierra Pacific Power	
Gross Capacity: 5.4 MW and 21.6 MW	
Fuel: Geothermal	

Of the eleven contracts with plants in Table 8, ten are with qualifying facilities (QF's) as defined in the Public Utilities Regulatory Policies Act (PURPA). The only non-QF is the coal facility at Craig, Colorado. It is almost certain that this difference in status has some effect on the price of electricity; however, neither the magnitude of such an effect nor whether it tends to increase or decrease the price is known.

There are three coal plants at Craig, each with 446 MW gross generating capacity. The Colorado Ute Electric Association, which built the Craig facilities, filed bankruptcy in 1991. Effective

April 1, 1992, Public Service Company of Colorado, PacifiCorp, and Tri-State Generation and Transmission Association divided the assets and customers of Colorado Ute Electric Association. PacifiCorp and Tri-State each obtained portions of the coal facilities at Craig. It is not expected that this action will affect the contract with Sierra Pacific Power Company.

When power purchases are cited, the price is often discussed in terms of cents-per-kilowatt-hour of delivered electricity. However, contracts for the purchase of electricity are not negotiated on this basis. Purchase contracts for electricity specify a price for installed capacity and another price for energy delivered. Data concerning negotiated capacity and energy prices were obtained for each of the facilities of Table 8. The energy and capacity price information received from Sierra Pacific Power Company is given in Table 9. The information received from Nevada Power Company is summarized in Table 10. For the Nevada Power Company contracts, the summer season is defined as the months from May through September inclusive. The summer on-peak hours are defined as the time between 10:00 am and 10:00 pm. The winter season is the remaining seven months; and the winter on-peak hours are from 5:00 am to 10:00 am and from 4:00 pm until midnight.

In order to derive the price for delivered electricity from the information in Tables 9 and 10 some assumptions must be made. All energy prices, and some capacity prices, are tied to either the CPI or the GNP deflator. The data received from Sierra Pacific Power Company projected the energy and capacity prices beyond 2020. These projections include assumptions of four to five percent inflation as measured by the specified indicator. As given in Table 10, Nevada Power Company provided an algorithm, but did not project the energy and capacity prices into the future. To project prices for Nevada Power Company contracts into the future, a four percent inflation rate was assumed. Averaging the capacity and energy prices in Table 10 over time and assuming four percent inflation, the projected capacity and energy prices for the Bonneville A, Bonneville B, Saguaro, and Oxford contracts are given in Table 11.

Capacity and energy prices are roughly analogous to fixed and variable costs. The actual price paid per kilowatt-hour of delivered electricity depends on the amount delivered. For this study, it was assumed that each facility would deliver 90% of the negotiated capacity. Some of the contracts specify penalties for delivery of less than 95% of negotiated capacity. Such penalties were not considered in determining the projected prices for delivered electricity.

Finally, it is noted that the capacity and energy prices depend on the facilities beginning operation on the specified date. It is not clear that this will be accomplished in every case.

In summary, in order to predict future prices for electricity from the information of Tables 9 through 11, the following assumptions were made:

1. Each facility will begin to deliver power on the date specified in the contract,
2. Each facility will deliver 90% of contracted capacity,
3. There are no penalties for delivery of less than 100% of specified capacity,

4. The capacity and energy prices provided by Nevada Power Company are averaged over time to attain single capacity and energy prices for a given year, and
5. The general inflation rate, as indicated by the CPI and GNP deflator, is 4% per year for the Bonneville, Saguaro, and Oxford contracts. The assumed inflation rates for the Colorado Ute, Steamboat, Ormat, and San Emidio contracts were incorporated in the data provided by Sierra Pacific Power Company and are between four and five percent.

There are a couple of additional points concerning the above assumptions that should be made. The second assumption is a 90% capacity factor for all plants. For coal-burning plants in general, average delivery of 90% of rated capacity would be exceptional. Also, there are a number of people that will argue that a 90% capacity factor is too low for geothermal plants. It is not known how to incorporate different capacity factors for the various technologies without at least the appearance of bias. So while it is understood that any single capacity factor for all plants will not reflect reality, the use of a single capacity factor avoids the problems of setting and justifying individual capacity factors for each technology. Also, the conclusions discussed in this report are not sensitive to any reasonable differences in capacity factor among the technologies.

Second, it should be noted that the assumptions concerning inflation rate, discussed in (4) above, are not the same for all facilities. The prices for electricity from the coal and geothermal plants assume a higher inflation rate than do the prices from the gas cogeneration and tire burning facilities. This will tend to over-estimate the price of electricity from the coal and geothermal plants when compared to the gas cogeneration and tire-burning facilities.

Finally, based on the above assumptions and discussion, the projected costs per kilowatt-hour of delivered electricity from each of the facilities are given in Table 12.

Table 9: Projected Pricing for Sierra Pacific Power Contracts

year	Craig Coal		Steamboat II		Steamboat III		Ormat A		Ormat B		San Emidio 1		San Emidio 2	
	capcty	enrgy	capcty	enrgy	capcty	enrgy	capcty	enrgy	capcty	enrgy	capcty	enrgy	capcty	enrgy
1991	12.42	18.49												
1992	14.32	19.63	19.01	24.24			26.73	19.00			19.21	22.50		
1993	16.30	20.35	19.01	25.24	19.01	25.00	26.73	19.86	26.73	19.00	19.21	23.60		
1994	16.72	21.07	19.01	26.28	19.01	26.03	26.73	20.75	26.73	19.86	19.21	24.78		
1995	18.80	21.97	19.01	27.36	19.01	27.10	26.73	21.70	26.73	20.77	19.21	26.10	23.73	25.50
1996	22.60	22.92	19.01	28.49	19.01	28.22	26.73	22.74	26.73	21.76	19.21	27.51	23.73	26.88
1997	23.18	23.90	19.01	29.66	19.01	29.38	26.73	23.84	26.73	22.81	19.21	28.99	23.73	28.33
1998	23.78	24.93	19.01	30.88	19.01	30.59	26.73	25.02	26.73	23.94	19.21	30.59	23.73	29.39
1999	24.42	26.00	19.01	32.16	19.01	31.85	26.73	26.28	26.73	25.15	19.21	32.33	23.73	31.59
2000	25.08	27.12	19.01	33.48	19.01	33.16	26.73	27.61	26.73	26.42	19.21	34.17	23.73	33.39
2001	25.75	28.29	19.01	34.86	19.01	34.53	26.73	28.97	26.73	27.73	19.21	36.12	23.73	35.29
2002	26.46	29.51	19.01	36.30	19.01	35.95	26.73	30.41	26.73	29.10	19.21	38.14	23.73	37.27
2003	27.18	30.78	19.01	37.79	19.01	37.44	26.73	31.89	26.73	30.51	19.21	40.24	23.73	39.32
2004	27.92	32.10	19.01	39.35	19.01	38.98	26.73	33.41	26.73	31.97	19.21	42.41	23.73	41.44
2005	28.70	33.48	19.01	40.97	19.01	40.58	26.73	35.00	26.73	33.49	19.21	44.70	23.73	43.68
2006	29.50	34.92	19.01	42.66	19.01	42.26	26.73	36.64	26.73	35.06	19.21	47.07	23.73	46.00
2007	30.32	36.42	14.00	44.42	19.01	44.00	26.73	38.35	26.73	36.70	19.21	49.57	23.73	48.43
2008			14.00	45.75	14.00	45.81	26.73	40.15	26.73	38.42	19.21	52.14	23.73	50.95
2009			14.00	47.12	14.00	47.18	26.73	42.03	26.73	40.22	19.21	54.86	23.73	53.60
2010			14.00	48.54	14.00	48.60	26.73	43.99	26.73	42.10	19.21	57.71	23.73	56.39
2011			14.00	49.99	14.00	50.06	26.73	46.05	26.73	44.07	19.21	60.71	23.73	59.32
2012			14.00	51.49	14.00	51.56	26.73	48.21	26.73	46.13	7.52	63.87	23.73	62.42
2013			14.00	53.04	14.00	53.11	26.73	50.46	26.73	48.29	7.52	67.19	23.73	65.65
2014			14.00	54.63	14.00	54.70	18.71	52.82	26.73	50.55	7.52	70.68	23.73	69.07
2015			14.00	56.67	14.00	55.30	18.71	55.30	18.71	52.92	7.52	74.36	9.49	72.66
2016			14.00	57.95	14.00	58.03	18.71	57.88	18.71	55.39	7.52	78.22	9.49	76.44
2017			14.00	59.69	14.00	59.77	18.71	60.59	18.71	57.98	7.52	82.29	9.49	80.41
2018			14.00	61.56	14.00	61.56	18.71	63.43	18.71	60.70	7.52	86.57	9.49	84.59
2019			14.00	63.33	14.00	63.41	18.71	66.40	18.71	63.54	7.52	91.07	9.49	88.99
2020			14.00	65.23	14.00	65.31	18.71	69.51	18.71	66.51	7.52	95.81	9.49	93.62
2021			14.00	67.18	14.00	67.27	18.71	72.76	18.71	69.63	7.52	100.8	9.49	98.49
2022					14.00	69.29			18.71	72.88			9.49	103.6
2023	Notes: 1. capacity data are in \$/kW·mo 2. energy data are in \$/MW·hr												9.49	109.0
2024													9.49	114.7

Table 10: Provisions of Power Purchase Contracts with Nevada Power Co.**Bonneville A (\$/kW-hr):**

	Summer On-Peak	Summer Off-Peak	Winter On-Peak	Winter Off-Peak
Capacity	0.05430	0.02084	0.03180	0.02084
Energy	0.02070	0.02070	0.02070	0.02070

- Notes: 1. Beginning May 1, 1991, and ending May 1, 2022, the capacity rates will be adjusted annually by two per-cent per annum.
2. Beginning May 1, 1991, and ending May 1, 2022, the energy rates will be adjusted annually by one-hundred twenty per-cent of the change in the Consumer Price Index for all urban consumers during the preceding year.

Bonneville B (\$/kW-hr):

	Summer On-Peak	Summer Off-Peak	Winter On-Peak	Winter Off-Peak
Capacity	0.05410	0.02060	0.03170	0.02060
Energy	0.02310	0.02120	0.02120	0.02120

- Notes: 1. Beginning May 1, 1991, and ending May 1, 1998, the capacity rates will be adjusted annually by zero per-cent per annum.
2. Beginning May 1, 1999, and ending May 1, 2007, the capacity rates will be adjusted annually by two and one-half per-cent per annum.
3. On May 1, 2008, the capacity rates will be reduced to:

	Summer On-Peak	Summer Off-Peak	Winter On-Peak	Winter Off-Peak
Capacity	0.04100	0.01480	0.02250	0.01480

4. Beginning May 1, 2009, and ending May 1, 2022, the capacity rates will be adjusted by two per-cent per annum.
5. Beginning May 1, 1991, and ending May 1, 2022, the energy rates will be adjusted annually by one-hundred twenty per-cent of the change in the Consumer Price Index for all urban consumers during the preceding year.

Saguaro (\$/kW-hr):

	Summer On-Peak	Summer Off-Peak	Winter On-Peak	Winter Off-Peak
Capacity	0.05551	0.01386	0.02710	0.01386
Energy	0.01990	0.01990	0.01990	0.01990

- Notes: 1. Beginning May 1, 1991, and ending May 1, 1994, the capacity and energy rates will be adjusted annually by five per-cent per annum.

2. Beginning May 1, 1995, and ending May 1, 2020, the capacity and energy rates will be adjusted annually by one-hundred per-cent of the change in the Consumer Price Index for all urban consumers during the preceding year.
3. During the period from May 1, 2011, through April 30, 2021, the capacity payments will be reduced by twenty-five per-cent from the amount that would otherwise be paid.

Oxford (\$/kW-hr):

	Summer On-Peak	Summer Off-Peak	Winter On-Peak	Winter Off-Peak
Capacity	0.05837	0.01917	0.03519	0.01945
Energy	0.02041	0.02041	0.02041	0.02041

- Notes:
1. Beginning May 1, 1991, and ending May 1, 1993, the capacity and energy rates will be adjusted annually by five per-cent per annum.
 2. Beginning May 1, 1994, and ending May 1, 2022, the capacity and energy rates will be adjusted annually by seventy-two and one-half per-cent of the change in the Consumer Price Index for all urban consumers during the preceding year.
 3. During the period from May 1, 2013, through April 30, 2023, the capacity payments will be reduced by twenty-two and one-half per-cent from the amount that would otherwise be paid.

Table 11: Projected Capacity and Energy Prices for Nevada Power Company Contracts (all data in ¢/kW·hr)								
	Bonneville A		Bonneville B		Saguaro		Oxford	
year	capacity	energy	capacity	energy	capacity	energy	capacity	energy
1991	3.13	2.07	3.11	2.16	2.66	1.99	3.25	2.04
1992	3.19	2.17	3.11	2.26	2.80	2.09	3.41	2.14
1993	3.25	2.27	3.11	2.37	2.94	2.19	3.58	2.25
1994	3.32	2.38	3.11	2.49	3.08	2.30	3.68	2.31
1995	3.38	2.50	3.11	2.61	3.21	2.40	3.79	2.38
1996	3.45	2.62	3.11	2.73	3.34	2.49	3.90	2.45
1997	3.52	2.74	3.11	2.86	3.47	2.59	4.01	2.52
1998	3.59	2.87	3.11	3.00	3.61	2.69	4.13	2.60
1999	3.66	3.01	3.09	3.04	3.75	2.80	4.25	2.67
2000	3.74	3.16	3.27	3.29	3.90	2.91	4.37	2.75
2001	3.81	3.31	3.35	3.45	4.06	3.03	4.50	2.83
2002	3.89	3.47	3.43	3.62	4.22	3.15	4.63	2.91
2003	3.97	3.63	3.52	3.79	4.39	3.28	4.76	2.99
2004	4.05	3.81	3.61	3.97	4.56	3.41	4.90	3.08
2005	4.13	3.99	3.70	4.16	4.75	3.55	5.04	3.17
2006	4.21	4.18	3.79	4.36	4.94	3.69	5.19	3.26
2007	4.29	4.38	3.88	4.57	5.13	3.84	5.34	3.36
2008	4.38	4.59	2.27	4.79	5.34	3.99	5.50	3.46
2009	4.47	4.81	2.31	5.02	5.55	4.15	5.66	3.56
2010	4.56	5.04	2.36	5.26	5.78	4.31	5.82	3.66
2011	4.65	5.29	2.41	5.52	4.50	4.49	5.99	3.76
2012	4.74	5.54	2.46	5.78	4.68	4.67	6.16	3.87
2013	4.83	5.81	2.51	6.06	4.87	4.85	4.92	3.99
2014	4.93	6.09	2.56	6.35	5.07	5.05	5.06	4.10
2015	5.03	6.38	2.61	6.65	5.27	5.25	5.20	4.22
2016	5.13	6.68	2.66	6.97	5.48	5.46	5.36	4.34
2017	5.23	7.00	2.71	7.31	5.70	5.68	5.51	4.47
2018	5.34	7.34	2.77	7.66	5.93	5.91	5.67	4.60
2019	5.44	7.69	2.82	8.03	6.17	6.14	5.83	4.73
2020	5.55	8.06	2.88	8.41	6.41	6.39	6.00	4.87
2021	5.66	8.45	2.94	8.82	6.67	6.64	6.18	5.01
2022	5.78	8.85	2.99	9.24			6.36	5.16

Table 12: Projected Prices for Power Purchases in the State of Nevada (\$/kW·hr)

year	Bonneville		Saguaro	Oxford	Craig Coal	Steamboat		Ormat		San Emidio	
	A	B				II	III	A	B	1	2
1991	5.5	5.6	4.9	5.6	3.7						
1992	5.7	5.7	5.2	5.9	4.1	5.3		6.0		5.2	
1993	5.9	5.8	5.5	6.2	4.5	5.4	5.4	6.1	6.0	5.3	
1994	6.1	5.9	5.7	6.4	4.7	5.5	5.5	6.1	6.1	5.4	
1995	6.3	6.1	6.0	6.6	5.1	5.6	5.6	6.2	6.1	5.5	6.2
1996	6.5	6.2	6.2	6.8	5.7	5.7	5.7	6.3	6.2	5.7	6.3
1997	6.7	6.3	6.4	7.0	5.9	5.9	5.8	6.5	6.3	5.8	6.4
1998	6.9	6.5	6.7	7.2	6.1	6.0	6.0	6.6	6.5	6.0	6.6
1999	7.1	6.7	7.0	7.4	6.3	6.1	6.1	6.7	6.6	6.2	6.8
2000	7.3	6.9	7.2	7.6	6.5	6.2	6.2	6.8	6.7	6.3	7.0
2001	7.5	7.2	7.5	7.8	6.7	6.4	6.3	7.0	6.8	6.5	7.1
2002	7.8	7.4	7.8	8.1	7.0	6.5	6.5	7.1	7.0	6.7	7.3
2003	8.0	7.7	8.2	8.3	7.2	6.7	6.6	7.3	7.1	6.9	7.5
2004	8.3	8.0	8.5	8.5	7.5	6.8	6.8	7.4	7.3	7.2	7.8
2005	8.6	8.3	8.8	8.8	7.7	7.0	7.0	7.6	7.4	7.4	8.0
2006	8.9	8.6	9.2	9.0	8.0	7.2	7.1	7.7	7.6	7.6	8.2
2007	9.2	8.9	9.5	9.3	8.4	6.6	7.3	7.9	7.7	7.9	8.5
2008	9.5	7.3	9.9	9.6		6.7	6.7	8.1	7.9	8.1	8.7
2009	9.8	7.6	10.3	9.8		6.8	6.8	8.3	8.1	8.4	9.0
2010	10.1	7.9	10.7	10.1		7.0	7.0	8.5	8.3	8.7	9.3
2011	10.5	8.2	11.2	10.4		7.1	7.1	8.7	8.5	9.0	9.5
2012	10.8	8.5	9.9	10.7		7.3	7.3	8.9	8.7	7.5	9.9
2013	11.2	8.8	10.3	11.0		7.4	7.4	9.1	8.9	7.9	10.2
2014	11.6	9.2	10.7	9.7		7.6	7.6	8.1	9.1	8.2	10.5
2015	12.0	9.5	11.1	10.0		7.8	7.8	8.4	8.1	8.6	8.7
2016	12.4	9.9	11.5	10.3		7.9	7.9	8.6	8.4	9.0	9.1
2017	12.8	10.3	12.0	10.6		8.1	8.1	8.9	8.6	9.4	9.5
2018	13.3	10.7	12.5	10.9		8.3	8.3	9.2	8.9	9.8	9.9
2019	13.7	11.2	13.0	11.2		8.5	8.5	9.5	9.2	10.3	10.3
2020	14.2	11.6	13.5	11.5		8.7	8.7	9.8	9.5	10.7	10.8
2021	14.7	12.1	14.1	11.9		8.8	8.9	10.1	9.8	11.2	11.3
2022	15.3	12.6		12.2			9.1		10.1		11.8
2023											12.3
2024											12.9

Appendix C

Justification of Time and Cost Estimates for Lost Circulation Control

The time and cost estimates for a conventional cement treatment of lost circulation are given in Tables 5 and 6 respectively. These estimates are generally taken without variation from Glowka (ref. 26). The following list gives the differences between the reference and the model used here:

1. Two hours were added for waiting for the first plug of the two-plug treatment to set before testing (Activity 6, Table 5),
2. One hour was added for testing the first plug in the two-plug model (Activity 6a, Table 5),
3. Cement and cement service were decreased from \$15/ft³ in the reference to either \$9/ft³ or \$13/ft³ depending on temperature (Item 2, Table 6),
4. The cost of lost drilling fluids was increased from \$5/bbl in the reference to either \$7/bbl or \$9/bbl depending on temperature (Item 3, Table 6), and
5. A quantity of drilling fluid, either 400 or 800 barrels, depending on temperature, was considered lost due to the need to condition and clean the mud after cementing and prior to commencing drilling (Item 4, Table 6).

The overall effect of the modifications to Glowka's model are three additional hours in the two-plug treatment and additional cement and drilling fluid costs in both the one-plug and the two-plug treatments.

Time Estimates

The first activity listed in Table 5 is fluid circulation to clean out the hole and determine the rate of fluid loss. This is assumed to take 1.5 hours. The next activities are to remove the bottom-hole assembly (BHA). Tripping the drill-string requires about one-half hour per thousand feet. Thus, for a 4000-foot hole, two hours are required for tripping in each direction. No extra time was considered for removal of the BHA.

Cement preparation and mixing typically requires about one hour. While there is no reason that this activity cannot be accomplished during the time that the BHA is being removed, a more conservative approach of allowing explicitly for cement preparation was employed here.

The next activity is rigging and pumping cement. Rigging takes about one-half hour. Pumping 300 ft³ (53 bbl) of cement takes a little more than ten minutes at a pump rate of five barrels per minute. There will be another twenty to forty minutes of pumping to insure complete displacement of the cement from the drill-string. Another quarter of an hour is required to pull

the drill-string up far enough to be out of the cement. Thus for a 300 ft³ cement plug, one and a half hours was allowed for rigging and pumping cement.

Waiting for the cement to set is the longest activity required in a conventional cement treatment of lost circulation. About eight hours is generally necessary before the cement is hard enough to drill. This is the time used in the one-plug treatment. In the two-plug treatment, it is assumed that a test of the seal conducted after six hours fails and the necessity of a second plug is determined. One and a half hours is again allowed for rigging and pumping the second plug; and then eight hours is allowed for the second plug to set.

After allowing the cement to set, it is common practice to test the hardness of the plug prior to tripping out of the hole. This test is done with the open drill pipe and requires about an hour. Once it is determined that the cement is sufficiently hard, the open drill pipe is tripped out of the hole (2 hours) and the BHA or drilling assembly is tripped back in (another 2 hours). Finally, two hours are allowed for drilling cement for both the one-plug and two-plug treatments. For the two-plug treatment, this assumes that most of the first plug flowed out of the well-bore into the lost circulation zone.

Adding the times for each activity results in 23 hours for a single plug and 31.5 hours for two-plugs.

Cost Estimates

Item 1 in Table 6 is the time lost while combatting the lost circulation and is taken from Table 5. This time is charged at the daily rate for the drill rig and services. A rate of \$10,000 per day is not unusual.

The second item in Table 6 involves the costs of cement and cement services. Jerry Evanoff, Halliburton Services, gave estimates of \$9/ft³ of neat cement for use below a temperature of 230°F. The need to include additives to prevent dehydration, maintain the apparent viscosity, and prevent premature setting at elevated temperatures results in an estimated cost of \$13/ft³ at a bottom-hole temperature of 400°F.

The third item in Table 6 is mud lost to the formation. A flow rate on the order of 600 gpm would not be unusual in a 14-inch hole. Then if drilling proceeded for 30 minutes to an hour after the initial encounter with the lost-circulation zone, between 400 and 900 barrels of drilling fluid would be pumped. A figure of 500 barrels was taken from this range as the amount of fluid lost to the formation. Gene Polk, Desert Mud, estimated drilling fluid costs of \$6 to \$7 per barrel for low lime mud suitable for use at temperatures below 300°F. The need for viscosifiers and thinners to maintain fluid properties result in an estimate of \$9/bbl at 400°F.

Gene Polk also indicated the need to condition the mud after running and drilling cement. The estimates of 400 and 800 barrels of mud are the amounts considered necessary for conditioning the mud and returning the fluid properties of viscosity and yield point to values acceptable for drilling.

Based on the model and data presented in Tables 5 and 6, a day's drilling time can be lost and costs of \$20,000 to \$30,000 can easily accrue during an attempt to plug a lost-circulation zone with cement.

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