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**The Learning Curve Concept Applied to the
Development of a Hydrothermal Resource**

by Dr. James H. Barkman

THE LEARNING CURVE CONCEPT APPLIED TO THE DEVELOPMENT OF A HYDROTHERMAL RESOURCE

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ABSTRACT

The geothermal industry has been slow in developing hydrothermal resources for a variety of reasons. These include institutional barriers, marginal economics and technical uncertainties. Conservative investors and utilities have been reluctant to proceed until perceived problems are resolved and solutions are demonstrated. This paper argues that the industry is in fact on a learning curve and that significant advances in knowledge, technology and economics will be made as projects move forward. The learning curve concept is illustrated with actual examples taken from Republic's early development experience in the East Mesa field and its related engineering design of a flashed steam power plant.

INTRODUCTION

The learning curve concept is well understood by people in manufacturing and in petroleum exploration, although these two industries might seem to have little in common.

Taking the latter industry as an example, a petroleum company commonly begins a project with only sketchy geophysical data and perhaps one untested wildcat well. Based on this limited information, field development scenarios must be written and pro forma economics run in order to decide whether or not to proceed.

As additional drilling is carried out, the reservoir properties are revised to fit the new data. Estimates of well productivity are made based on drill stem tests and well logs. In some offshore fields, billion dollar commitments to build platforms and flowlines have been made based on short-term flow tests and geophysical data.

A learning curve effect enables the operator to improve his cost estimates and to optimize his drilling and completion practices. He makes mistakes along the way, but applies what he learns to improve future results. This process is so familiar to experts in the business that it hardly needs explanation. Management is concerned with the question of economic viability but does not expect that the final details of the field development will match the original plan.

EXAMPLES OF THE LEARNING CURVE EFFECT

The learning curve applies to the development of a geothermal field in much the same way it does for a petroleum reservoir. Republic has drilled and extensively tested seven wells at East Mesa and has designed a flashed steam power plant for this application through General Electric Company and The Rust Engineering Company. Several examples from this experience are presented to illustrate the concept.

Well output, measured in megawatts, is dependent on the productivity index (PI) as shown in figure 1. The PI is determined by the undamaged permeability-thickness of the reservoir and by the condition of the wellbore which penetrates that reservoir. Residual drilling mud or filtrate invasion may reduce the effective well PI below that of an undamaged formation.

At East Mesa, a PI of 2000 lb/hr-psi was originally assumed for planning purposes. This value has been exceeded, on the average, by the seven wells Republic has drilled to date. However, two early wells suffered wellbore impairment and exhibited an initial PI of only 800. Now that the cause has been identified, future wells can be drilled which will approach the target (undamaged) productivity.

The PI scale is equivalent to a time scale, where the PI of each successive well tends to improve as more information is obtained. In effect, figure 1 represents a learning curve, whereby well output improves with time and additional knowledge.

Another place where experience has led to improvements at East Mesa is in the area of well pumping. It was originally planned to flash flow the wells since the power plant was to be a dual-flash, direct steam cycle. Detailed studies and field testing lead to the conclusion that high volume downhole pumps (either shaft driven or electric submersible) could be utilized to more than double the output of each well over what would be possible with natural or flashing flow. This is illustrated in figure 2 for typical East Mesa conditions. The increase of 2 MW in well output by pumping is more than adequate to justify the cost of a downhole pump. The concurrent power plant study showed that the resultant single-phase gathering lines would save \$6,000,000

Dr. Barkman

compared to the cost of two-phase lines that would be required if the wells were flash-flowed. At the beginning of development it was not suspected that the advantage of pumping would be so great.

A third example of the learning curve relates to the decision of how low a resource temperature is acceptable. The East Mesa reservoir contains at shallow depths, higher permeability sands but lower temperature water. In effect, by completing wells higher up the hole, the well deliverability can be greatly increased at the expense of producing cooler water.

This is a difficult optimization problem that must consider power plant performance, casing designs, well productivity, downhole pumps and economics. In the past it has been suggested that a definite cut-off temperature (such as 350°F or 380°F, etc.) exists, below which it was not economic to produce electricity by a direct steam cycle. This view is an over-simplification, which does not take into account a total systems approach. Flash steam plants, such as the one Republic will build at East Mesa, can be designed to operate over a broad range of temperature. This range includes resource temperatures as low as 300°F and as high as 400°F or even greater.

Figure 3 illustrates how the well flow rate increases as the completion interval is expanded to include shallower sands. The rate levels off due to the assumed pump horsepower limitation of 1000 HP. The resultant power output increases to a point, and then it declines mainly due to cooler temperatures. The flowing resource temperature corresponding to the maximum power output is approximately 325°F. The optimum temperature may be somewhat higher than this when power plant economics are accounted for. Nevertheless, this illustrates that the original choice of a completion interval probably was too restrictive. By attempting to restrict production to high temperatures, one actually pays a penalty of lower megawatt output.

Numerous other examples at East Mesa could be cited where system improvements to the original plan were made as new knowledge was acquired. These include a determination of the degree of filtration and other treatment necessary to successfully reinject the geothermal fluid. This is an example of technology that can only be acquired by actual practice.

SOME POSSIBLE MISCONCEPTIONS

Since the hot water geothermal industry in the United States has very little real experience, it is not surprising that a body of opinion has grown up which is supported mainly by conjecture. As a result of several developing projects, our national understanding of the real issues and their significance has improved.

It is commonly thought that the higher the temperature, the more favorable the economics of

development. In reality, higher temperature geothermal reservoirs may sometimes (although not always) be accompanied by: (a) higher salinity, (b) more scaling, (c) more corrosion, (d) more noncondensables, and (e) lower well productivities. All of these factors add to the cost of operation and offset the benefits of higher temperature. Therefore, the cost of electricity, which is the "bottom line" may in some cases be lower with a 340°F reservoir than with a 400°F reservoir.

The use of a flashed steam power cycle does not necessarily favor free flowing wells. As a general rule, lower temperature, higher productivity wells should be pumped. Their net megawatt output can often be doubled, which will more than compensate for the cost of the pump and for a larger casing design. Low productivity, hot wells cannot always be pumped because of the temperature limitations of pump technology and the deep setting depth required.

Wells drilled into fractured reservoirs (such as Roosevelt and the Geysers) often have very high initial flow rates. Such reservoirs are not, a priori, more desirable than reservoirs which produce from matrix porosity (such as Heber and East Mesa). It is much more difficult to estimate reserves or to predict future performance in fractured reservoirs than in matrix type reservoirs. Pressure maintenance in a matrix reservoir is generally easier to carry out because of better sweep efficiency.

FUTURE DEVELOPMENTS

The most promising prospects for extending the learning curve and improving future economics at East Mesa are the following:

- a. Future wells and recompletions should have productivities approaching that of the undamaged reservoir, which is very high.
- b. Downhole pump efficiency, reliability, and cost will improve as manufacturers see a real market developing. Pumps are being developed which offer the possibility of a major breakthrough.
- c. New power conversion technologies (binary organic cycles, etc.) will likely increase the kwh output of each pound of hot water produced.
- d. Well productivity will benefit from hydraulic fracturing or explosive stimulation. Hot dry rock technology could open up very large incremental reserves below 8000 feet in the Imperial Valley.
- e. Operating costs in constant dollars will decrease as new techniques are developed for controlling scale and other potential problems.
- f. Actual operating experience with one or more hydrothermal fields will serve to narrow the band of uncertainty which now exists about costs and other economic factors.

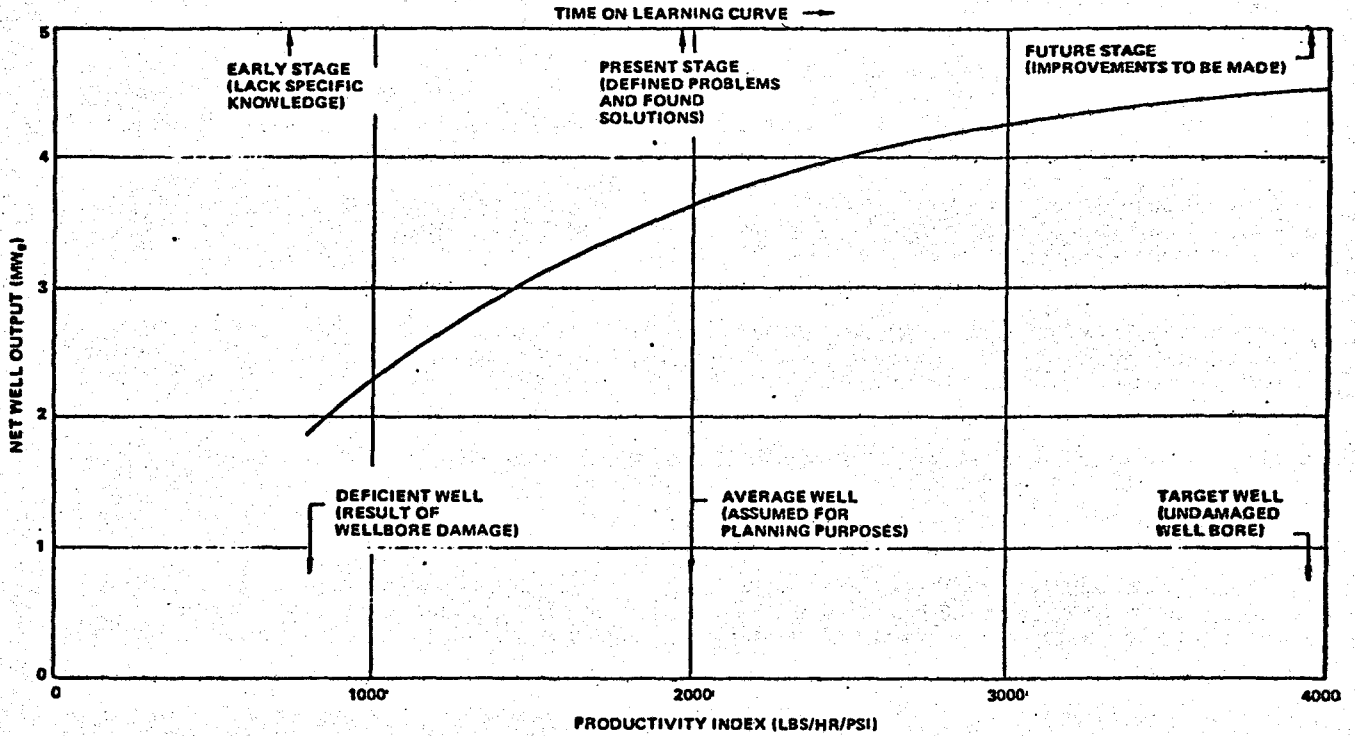


FIGURE 1. EXAMPLE OF THE LEARNING CURVE EFFECT APPLIED TO EAST MESA WELL PRODUCTIVITY

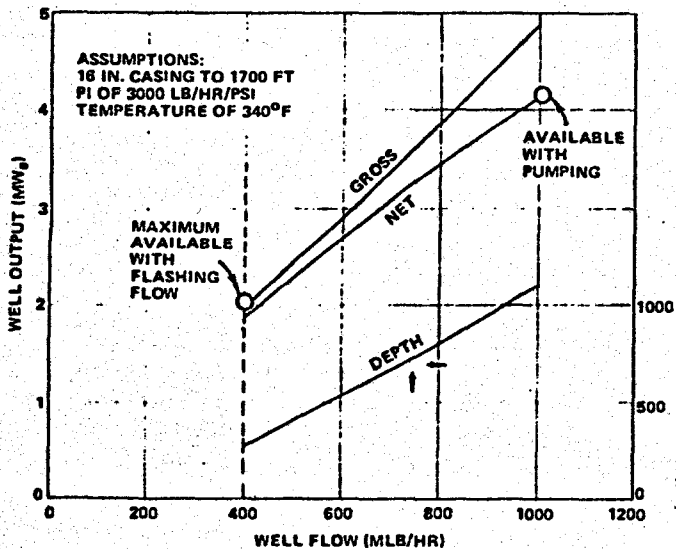


FIGURE 2. IMPROVED WELL POWER OUTPUT AVAILABLE FROM USE OF DOWNHOLE WELL PUMPS VERSUS FLASHING FLOW

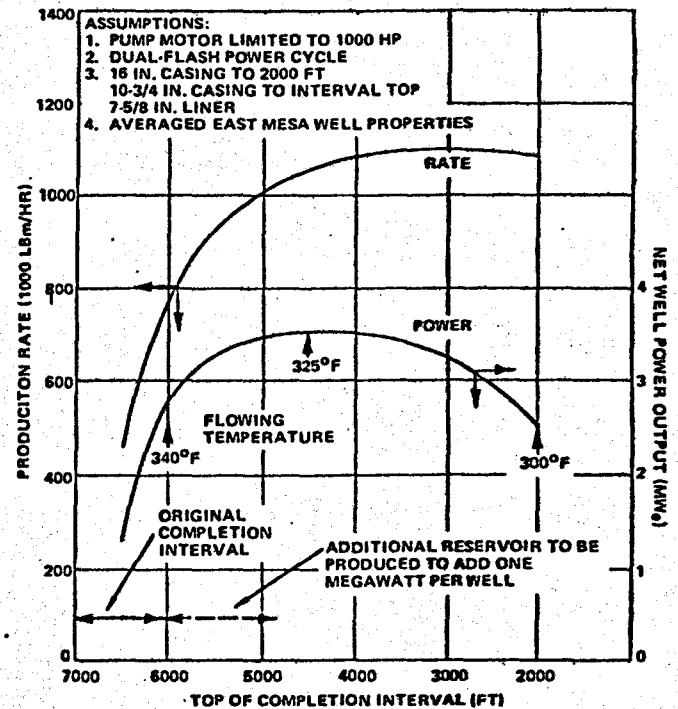


FIGURE 3. EFFECT OF COMPLETION INTERVAL ON POWER OUTPUT AT EAST MESA

Drilling Fluid Formation Damage in Geothermal Wells

by Dr. Robert W. Nicholson

DRILLING FLUID FORMATION DAMAGE IN GEOTHERMAL WELLS

Dr. Robert W. Nicholson

Republic Geothermal, Inc.

ABSTRACT

Matrix type hot water reservoirs are highly susceptible to near well bore permeability impairment due to drilling fluid filtrate and particle invasion. The drilling fluids must be properly formulated to allow an efficient drilling operation and yet neither interact with the formation and in-situ fluids nor permanently plug the formation. Examination of the unique factors in matrix type geothermal reservoirs leads to steps which can be taken to alleviate formation damage problems during drilling.

Highly productive wells are critical to the economic viability of hot water dominated reservoirs. Severe formation damage near the well bore by the drilling fluids can significantly reduce well productivity when production is primarily from matrix flow. Avoiding serious damage during the drilling operation is far more economical than trying to restore the damaged well bore. Generally, drilling fluids and drilling techniques are used which yield the most economic drilling operation, however, drilling cannot be considered successful if the resulting well is severely impaired. Proper design of the drilling fluid and implementation of good drilling procedures can limit the damage during drilling operations.

The basic factors unique to matrix type hot water reservoirs which make them susceptible to drilling fluid damage are:

- A. Highly permeable formations which are usually normally pressured.
- B. Formation fluids which contain many different solutes.
- C. Temperatures usually in excess of 300°F.

Drilling fluids are formulated from a liquid phase containing dissolved solids and a solid phase which provides viscosity and fluid loss control. Since most hot water matrix type reservoirs are normally pressured (0.433 psi/ft) the pressure exerted by the mud (drilling fluid) column will be greater than the formation. This is desirable to keep the well from flowing and the formation from caving while drilling. However, this differential pressure forces particles and filtrate into the

formation.

The basic concept of filtration and the development of a filter cake on the well bore is depicted in Fig. 1. As virgin formation is exposed by the drill bit, mud particles and filtrate rapidly enter the pores and plugging begins. With time, particles consolidate to form an inner filter cake (Fig. 1.b) and eventually a dynamically stable (during mud flow) outer mud cake (Fig. 1.c) develops and the filtration rate reaches a constant minimum.

Thus, after drilling has been completed, the formation near the well bore contains drilling mud particles and filtrate. If reverse flow during production does not remove all the invaded liquid and solids, the pores will remain plugged and the well productivity will be greatly reduced.

Severe damage due to mud filtrate was suspected in a well near Westmorland in the Imperial Valley. Permeability measurements made on plugs from cores cut in the production zone showed this to be the case. Fig. 2 illustrates the severity of mud filtrate damage even though particles above 0.45 microns in the filtrate had been removed. Reverse flow did not restore the permeability and there appears to be a permanent 20% reduction in permeability. A number of such tests were conducted and in many cases much more severe damage occurred and some cores did not recover any permeability on reverse flow.

The liquid phase which contains solutes must be compatible with the formation and formation fluids. Clay minerals contained in the matrix may be sensitive to certain ionic atmospheres and may disaggregate, or swell, when exposed to the liquid phase of the drilling fluid. Figs. 3 and 4 illustrate core tests from the same well as in Fig. 2. It is apparent that ionic concentrations on these particular cores greatly effects the permeability. Additionally, the formation fluids may contain anions or cations, which in contact with anions or cations from the liquid phase of the drilling fluid, may cause insoluble precipitates. Some formation fluids in the Imperial Valley contain free barium. Sulphates in the make-up water of the drilling fluid, or chemical additives, may cause a very insoluble precipitate, barium sulphate, to be formed in the pore channels causing permeability reduction.

Clay solids are used in making up drilling fluids to increase the viscosity for hole stability and to suspend the drilled cuttings. These solids

also form the filter cake to reduce filtrate invasion. The high temperatures encountered in geothermal drilling greatly effect montmorillonite type clays which have historically been used for oil and gas drilling. However, increased temperature causes suspensions of montmorillonite to form very high gel strengths (measurement of force needed to initiate flow). A reasonable gel strength is necessary to suspend cuttings when fluid circulation stops during connections and when pulling the drill string for a bit change. However, excessive gel strengths cause very high surge pressures from the well bore to the formation when the drill string is run in the hole. Also, after the fluid has been quiescent, very high pressures must be used to initiate flow if the gel strength is very high. These high pressures cause deeper invasion and a deep damaged zone around the well bore.

Fig. 5 illustrates the high temperature gelation tendency of montmorillonite clay suspensions¹. Dramatic increases occur above 250°F with concentrations above 18 pounds per barrel (typical concentrations used in actual drilling vary from 15 to 24 ppb). Also, gel strengths continue to increase with prolonged exposure at high temperatures as shown in Fig. 6 and actual solidification will occur. Calcium montmorillonites can form a low grade cement in the 300°F temperature range. The montmorillonitic particles which have invaded the matrix near the well bore will continue to consolidate with time. After cessation of drilling the formation near the well bore, cooled during drilling operations, will increase to its original temperature further enhancing the solidification of the invaded particles.

Experience with two wells drilled successively in the Imperial Valley illustrate the severity of productivity damage due to montmorillonite solidification. The mud systems were very similar, both containing high concentrations of montmorillonite. The first well was flowed extensively almost immediately after drilling stopped and has been a fairly productive well. The second well was flowed for a very short period of time and shut-in due to restrictions by the water control regulations. This well was tested several months later and had very low productivity, however the first short flow indicated a highly productive well. Several attempts were made to increase the productivity, none were successful. X-ray diffraction analysis of core material showed no montmorillonite but much illite and amorphous clays. After a hydrochloric-hydrofluoric acid treatment a large amount of fines came out of the well. An analysis of these fines showed high percents of montmorillonite and amorphous clays and no illite. It was concluded that initial flow was not long enough, or early enough, to remove the drilling particles and filtrate before solidification which severely damaged the near well bore permeability.

For drilling operations in a matrix type hot water reservoir, the following general steps should be taken to help reduce formation damage:

- A. Use drilling fluid materials which do not have adverse high temperature properties.

- B. Analyze the formation solids and fluids to formulate the liquid phase to be compatible with both.
- C. Coordinate the mud properties and drilling techniques to reduce the well bore to formation pressure differential.
- D. Flow sufficient volumes from the well as soon as possible after drilling to remove invaded particles and filtrate.

Very encouraging developments^{2,3} in high temperature drilling fluids have been made recently and field experience with these have been quite favorable. Sepiolite clays have replaced montmorillonite. These clay suspensions build reasonable viscosity and do not form excessive gel strengths at high temperatures. Also, these fluids are not very susceptible to contaminants. Usually a polymer, such as sodium polyacrylate is added to increase viscosity and help reduce filtrate loss. Adequate filtration control is still a problem with many of the sepiolite formulations.

Formulation of the drilling fluid liquid phase to be compatible with formation solids and liquids can be done where such data are available. However, for exploratory drilling no data exists and an inhibitive type system should be used such as potassium chloride. Reducing the invasion with low differential pressures also helps reduce the depth of any plugging due to noncompatibility.

Drilling practices in the production zone should be employed to limit the differential pressures into the formation. Circulation rates and mud properties (viscosity and yield point) should be coordinated to produce a low annulus pressure loss and still clean the hole properly. Gel strengths and yield points should be used to estimate a maximum speed of running the pipe in the hole to help reduce high pressure surges. Mud weights should be kept as low as possible utilizing all mud cleaning equipment available.

As discussed above, once a well has been completed, early flow of sufficient quantities of formation fluid will help remove filtrate and particles from the well bore and formation, reducing the possible time and temperature reactions which may cause plugging. Monitoring the produced fluids and solids can indicate when all the drilling fluids have been removed which can be removed by reverse flow.

1. Annis, Max R., "High-Temperature Flow Properties of Water-Base Drilling Fluids", SPE preprint 1698, 1967.
2. Carney, L.L. and Meyer, R.L., "A New Approach to High Temperature Drilling Fluids", SPE preprint 6025, 1976.
3. Bannerman, J.K. and Davis, N., "Sepiolite Muds Used for Hot Wells, Deep Drilling", Oil and Gas J., Feb. 27, 1978.

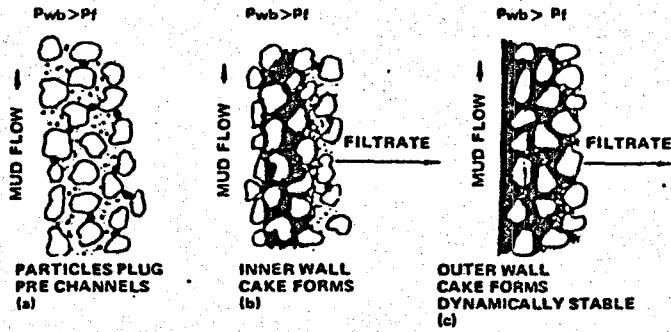


FIGURE 1. STAGES OF FILTRATION AND WALL CAKE BUILDUP ON THE WELLBORE

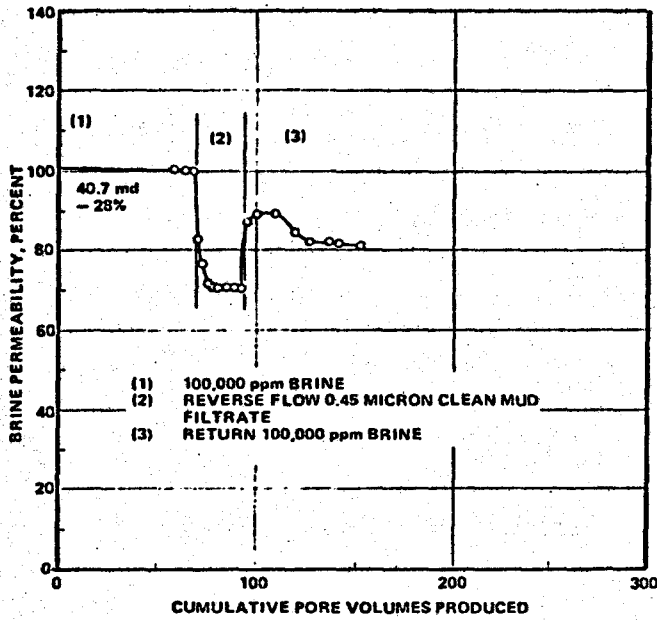


FIGURE 2. FLUID SENSIBILITY - WESTMORELAND CORE PLUG

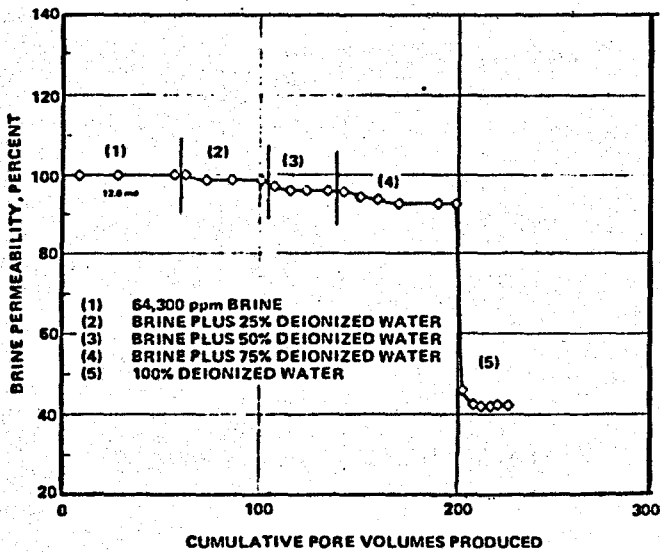


FIGURE 3. FLUID SENSIBILITY - WESTMORELAND CORE PLUG

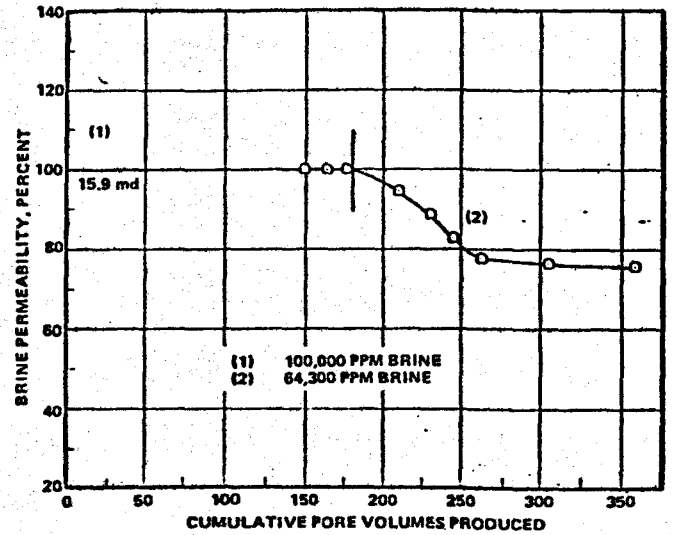


FIGURE 4. FLUID SENSIBILITY - WESTMORELAND CORE PLUG

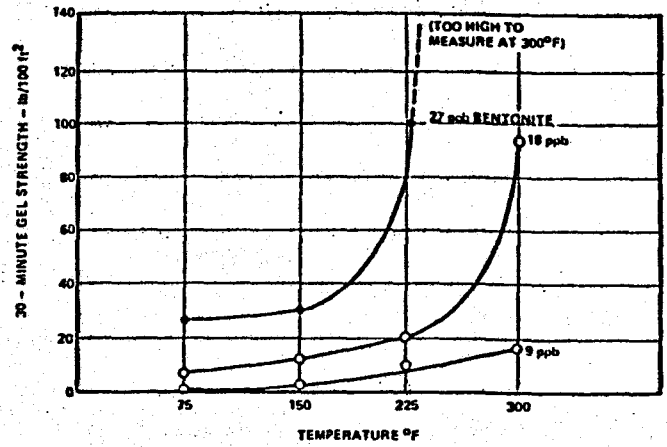


FIGURE 5. EFFECTS OF TEMPERATURE AND BENTONITE CONCENTRATION ON 30 MIN. GEL STRENGTH (FROM REF. 1)

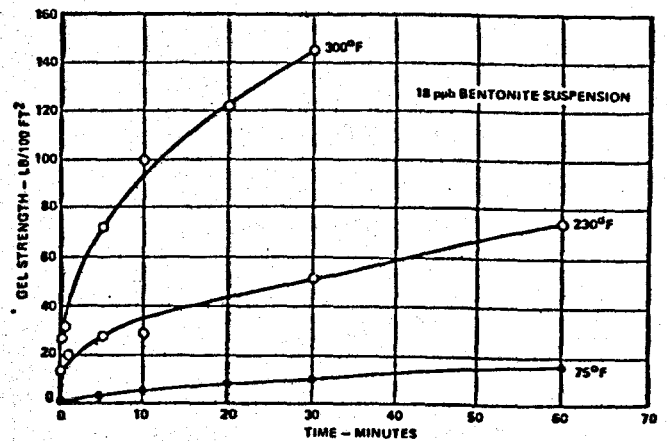


FIGURE 6. EFFECTS OF TIME AND TEMPERATURE ON GEL STRENGTH (FROM REF. 1)

**Geothermal Fluid Investigations at
Republic's East Mesa Test Site**

by O. J. Vetter, D. A. Campbell and M. J. Walker

GEOHERMAL FLUID INVESTIGATIONS
AT REPUBLIC'S EAST MESA TEST SITE

by O.J. Vetter*, D.A. Campbell** and M.J. Walker**

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ABSTRACT

This paper summarizes some of the experiments and tests performed thus far in the Northern part of the East Mesa Geothermal Field operated by REPUBLIC GEOTHERMAL, INC. (RGI). The investigations described concern only the fluid characteristics pertinent to future power plant design and operations. Test facilities including test loops, fluid composition, scaling tendencies, pH control experiments and gas behavior ("noncondensables") are briefly reviewed. The data available thus far indicate that the geothermal fluids will present no significant technical problems in a conventional flashed steam power cycle.

1.0 INTRODUCTION

REPUBLIC GEOTHERMAL, INC. is currently conducting extensive test and evaluation work at its East Mesa site. A 48 Mw (net) power plant is now in the final design stage. The current work includes reservoir evaluation as well as a study of the fluid characteristics under simulated power plant conditions.

The present paper describes the fluid study in a summary form. Three additional detailed papers are being prepared under a Department of Energy (DOE) contract. These three reports^{1,2,3} will be published within the next few months.

The study was performed jointly by RGI and VETTER RESEARCH. BATELLE PNL⁴ provided valuable support for some later phases of the study with expertise, manpower and instrumentation.

2.0 TEST OBJECTIVES

The main objectives of the tests were to: (1) Determine if there would be problems in a power plant due to scale formation; (2) Predict any problems in the planned flashed steam plant which might be caused by noncondensables; and (3) Suggest technically and economically feasible ways and means to overcome any scale and/or noncondensable problems indicated.

In order to achieve the above goals, it was necessary to conduct a comprehensive study of the geothermal fluids under actual field conditions.

This required the design and construction of equipment at the well sites that allowed simulation of the flow conditions encountered in an actual power plant and also, measurements of the pertinent properties and characteristics of the fluids. Of particular interest were the fluid chemistry and phase separation data (e.g., the formation of non-condensables) at different temperature, pressure and flow conditions. In addition, the test equipment had to be designed so that it would not interfere with concurrent field testing.

3.0 TEST LOOPS

In most geothermal testing, the critical fluid characteristics are supposedly determined by utilizing side streams. The main flow line is tapped and a small stream of fluid is diverted into a "test device" to evaluate a number of characteristics such as corrosion or scaling tendencies. It is then concluded that the reactions observed in the device can be related to similar reactions in the main stream. The general validity of these methods is questionable for the following reasons: (1) It is impossible - in most cases - to draw a representative portion of the fluid into the side stream. This would be possible only if the fluid in the main line is homogenous, i.e., no separate phases are present (suspended particles, liquid drops, and/or gas bubbles); (2) The flow characteristics of the fluids in the main stream and those in the side stream may be different, leading to a change of the fluid properties; and, finally, (3) The devices themselves may not allow the proper evaluation of fluid properties for an actual power plant. For example, scaling and corrosion properties are different in the devices than they are in various components of a power plant. It is doubtful that even relative comparisons yield valid data, because it is almost impossible to duplicate all the pertinent flow conditions (thermodynamic and hydrodynamic) in such devices.

Pilot plants of any size offer similar problems in investigating fluid characteristics. In addition, a full-fledged pilot plant is much too expensive to build if valid data on the brine characteristics are not available in advance.

In order to overcome many of these problems, it was decided to add test loops to the standard test facilities. As shown in Figure 1 the test loop is simply an attachment to the flow line leading from the production well to the separation facilities. This device, constructed of common valves and pipe fittings, allows the diversion or by-pass of the total geothermal fluid steam at various flow rates into an area where accurate pressure, temperature and fluid chemistry measurements can be obtained without affecting the well flow. Orifice plates of predetermined size are inserted at various points in the loop in order to simulate the desired pressure or temperature conditions. Valves are provided which enable the loop to be isolated from the well stream for modification, cleaning, or visual inspection.

Such facilities have a number of advantages in that: (1) Their cost of construction is relatively low; (2) They can be run with little extra expense; (3) They are portable and can be moved easily from well to well; (4) They can be operated without interfering with other reservoir or well test work; (5) They can simulate almost all operations of future power plants using flashed steam power cycles; (6) They can easily be adapted for evaluation of other power plant cycle types; (7) They can be utilized to investigate scaling and corrosion; (8) They allow evaluation of the effects of fluid alteration by the addition of chemicals (continuous or batch) at any temperature and pressure; (9) They permit obtaining information on the fluid properties at various temperatures and pressures in order to extrapolate the measured data to reservoir conditions (producer or injector); (10) They can be used for evaluation work regarding mineral recovery; and, finally (11) They offer a means of evaluating various types of instrumentation and process control equipment under field conditions.

4.0 TEST FACILITY INSTRUMENTATION

Conventional liquid filled bourdon tube pressure gauges and bimetallic thermometers, are used throughout the test loop. Two orifice meters and an automatic level controller are used to measure and control flow rates of the fluids in the liquid and steam exit lines of the separator. This type of instrumentation is generally adequate for evaluation of the data and control of the test facility. However, the accuracy of the gauges is inadequate for some purposes. During the later phases of testing, additional instrumentation was supplied by BATTTELLE PNL; e.g., thermoelements, pressure transducers, conductivity cells and pH monitors. The signals from each of these instruments are fed into an automatic data logger. The conductivity cells need further improvement, but the other instrumentation provide valuable data.

5.0 FLUID COMPOSITION

Samples of fluids were collected from the test facility at various times and locations using a variety of sampling methods. These samples were

collected in plastic bottles, glass containers and/or stainless steel bombs, with and without, sample preservation. Thousands of samples were analyzed for a large number of chemical constituents by VETTER RESEARCH. Instrumental methods (various types of AA, UV/VIS, GC) and wet procedures were used. The volume of the gathered data is too large to be discussed in detail in this summary.

The composition of the unflashed liquid varies slightly from well to well. A typical example is given in Table I.

TABLE I
COMPOSITION OF UNFLASHED GEOTHERMAL WATER
(Well No. 38-30, September 1977)

CONSTITUENT	MG/LITER	CONSTITUENT	MG/LITER
Ag	<0.06	Ba	<0.20
Pb	<0.50	Al	<0.30
Mn	<0.06	Mg	0.06
Zn	0.50	SiO ₂	172.0
Hg	0.0008	K	30.0
Fe	0.20	Na	660.0
Cd	<0.03	Ca	2.50
Li	0.92	Cl	535.0
Sr	0.80	TDS	1804.0
B	1.50		

Carbon dioxide constitutes 90± percent of the non-condensables present in the vapor phase. The balance is nitrogen, methane and traces of other gases. No H₂S has been detected. The CO₂ concentration in the single phase water is on the order of 1000 mg/liter. After flashing, non-condensables amount to approximately 0.5 percent of the vapor phase.

6.0 SCALING TENDENCY

The scaling tendency of the fluid is low, but could cause problems in a power plant if not handled properly. Two types of scale are possible, calcium carbonate and silica. Approximately 1.5 mg CaCO₃ per liter of unflashed water can form. No measureable amounts of CaCO₃ are found if the pressure of the fluid is kept above 60 psig, even though a large percentage of the carbon dioxide is already flashed at this pressure. The majority of the CaCO₃ scale (more than 50%) is formed at pressures below 25 psig. The CaCO₃ deposited at these low pressures is a very fluffy porous material, whereas, the CaCO₃ formed between 25 and 60 psig is dense and exhibits well formed crystals. The silica forms in measureable amounts below pressures of 25 psig and is masked by the CaCO₃ scale. Approximately 1 percent SiO₂ is dispersed in the fluffy CaCO₃ scale. No other type of scale has been detected in the test facilities.

7.0 pH CONTROL OF SCALING

A major effort was made to investigate the feasibility of controlling the pH by continuous injection of acid at various production rates.

A pH of approximately 6.0 is considered sufficient to keep all the calcium carbonate in solution. A pH of 4.5 or lower may be sufficient to retard (not prevent) the silica precipitation. Figure 2 shows the effect of acid (HCl) addition on the water pH at approximately 25 psig pressure. This figure clearly indicates that the buffer capacity of this water - even at 25 psig - is still too high to make the continuous pH control with HCl an economical method. These pH control experiments proved that most of the acid is utilized to titrate the bicarbonate under line pressure, or, in other words, the first and major portion of the acid drives off the CO₂ instead of lowering the pH.

It should not be concluded that all fluids behave similarly when acid is added. Fluids having a different composition may act differently. These experiments show, however, that effective and economical pH control by continuous injection of acid is not possible at East Mesa.

In contrast, a batch addition of acid can be used to remove the formed CaCO₃ without a shut-down of the facilities. Small slugs of acid applied at regular intervals proved to be a much more economical method of scale control. The power plant design will incorporate appropriate provisions to allow for batch acid treatment if it proves to be the preferred method of control.

The cost of acid required to maintain scale-free lines and equipment by batch acid treatment would be less than 0.5 mills/kwh. This is a very small percentage of total plant operating costs and would be entirely acceptable. Concurrently, high temperature scale inhibitors are being tested which may control scale at a cost even less than the batch acid treatment method. By contrast, continuous injection of acid, if it were feasible, would cost on the order of 33 mills/kwh.

8.0 CO₂ VENTING

Another problem in a flashed steam power cycle may be caused by the non-condensable. Gases (mainly CO₂, methane and nitrogen) will break out of solution and enter the turbines and condensers with the steam. The more gas there is, the more costly the power plant becomes due to the larger capital investment and power requirements for vacuum pumps and/or steam ejectors. The actual plant design will utilize vacuum pumps to handle the relatively small amount of CO₂.

The field experiments show that the CO₂ can be handled in another fairly simple and economical way. The main portion of all gases may be vented from the geothermal fluids before these fluids enter the first steam flash stage. Computer modeling of the East Mesa fluids show that almost 50 percent of the CO₂ (capable of forming non-condensables) can be vented by pressure decreases before a 0.1 percent steam flash is experienced. Thus, major portions of the gases can be kept from entering the turbines and condensers. This method of CO₂ venting is favored by economics in fields

with high CO₂ content. At East Mesa the more straight forward use of vacuum pumps is preferred because of the low CO₂ content.

9.0 MAJOR CONCLUSIONS

It can be concluded from the collected data that: (1) The liquid in the reservoir is low in TDS and is not saturated with carbon dioxide; (2) Calcium carbonate and small amounts of silica scale can occur in surface installations unless preventive action is taken; (3) No scale problems are expected in pumped producing wells; (4) The boron, H₂S and heavy metal ion content are too low to cause any serious environmental or operational problems; (5) No significant corrosion will occur if oxygen is kept out of the system; (6) Continuous pH control of the fluids by the addition of acid to prevent scale deposition is not economically feasible; (7) Removal of deposited CaCO₃ at regular intervals by batch acid treatment is economically feasible; (8) Scale control by chemical inhibitors may be a viable alternative to batch acid treatment; (9) Venting of the CO₂ before steam flash occurs can prevent a major portion of the non-condensables from entering the turbines and is feasible in fields with high CO₂ content; (10) The test facilities with the test loops proved to be an excellent means of studying the behavior of the geothermal fluid.

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11.0 ACKNOWLEDGEMENT

We wish to express our thanks to RGI, BATTELLE PNL and the U.S. Department of Energy (DGE) for their support of this work.

Figure 1. TEST LOOP CONFIGURATION USED AT EAST MESA WELL NUMBER 38-30.

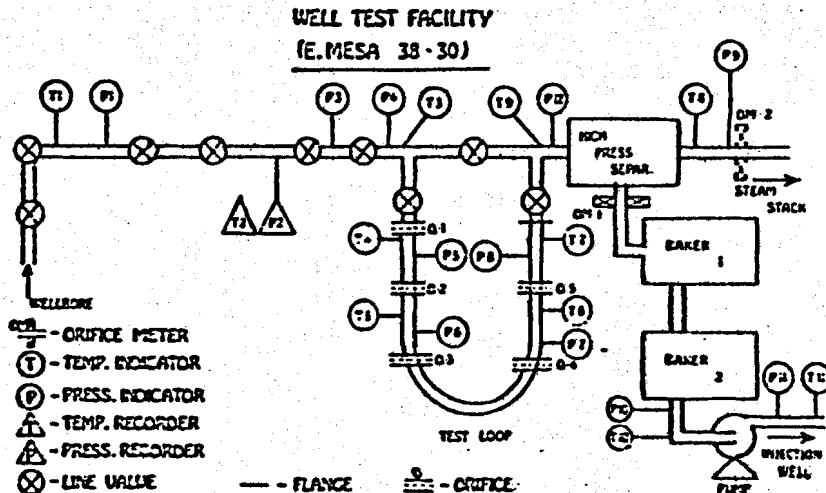
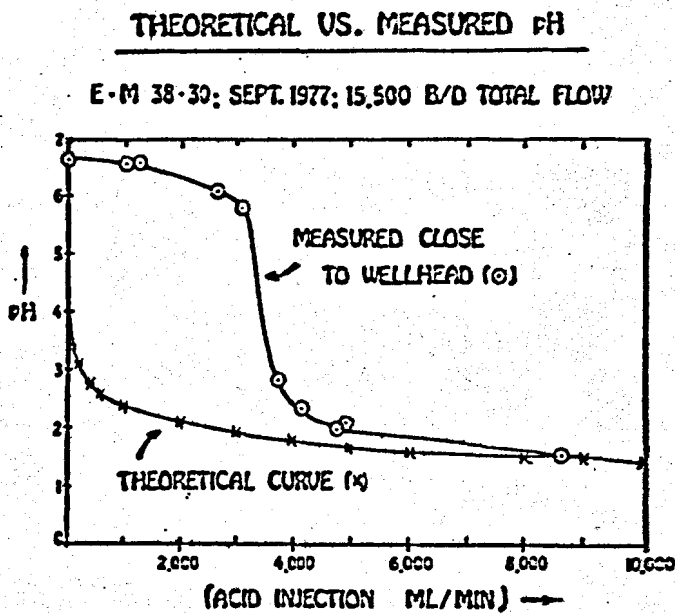


Figure 2. EFFECT OF HCl ON THE FLUID pH AT EAST MESA WELL NUMBER 38-30.



Pumping Experience in Geothermal Wells at East Mesa

by Robert V. Verity and Carl E. Fisher

PUMPING EXPERIENCE IN GEOTHERMAL WELLS AT EAST MESA

Robert V. Verity and Carl E. Fisher

Republic Geothermal, Inc.

ABSTRACT

Republic Geothermal, Inc. is presently carrying out extensive well testing in the East Mesa Field. The testing and development of geothermal well pumps is one important phase of this testing. The intent is two-fold: 1) to test the deliverability of the wells under high rate pumping conditions and 2) to guide the economic selection of well pumps for production to the future power plant. To date, two types of pumps have been tested, a lineshaft turbine pump and an electric submersible pump.

Testing Summary

The two types of pumps undergoing testing differ primarily in the means of transmitting power down the well to the pump. The lineshaft turbine is a downhole multistage turbine pump driven by a motor or engine on the surface through a rotating shaft. The pump is suspended from the surface on a pipe called the pump column through which fluids are pumped to the surface. Control of pump output is achieved by throttling the discharge at the surface or by rpm control with the prime mover or gearbox. The electric submersible is also a turbine pump; however, it is driven directly by a downhole motor(s). Power is transmitted to the motor(s) by an electric cable banded to the side of the pipe on which the pump and motor assembly is suspended. This pipe, or tubing, also conducts the pumped fluid to the surface. Control of pump output is achieved by throttling the discharge at the surface.

Table 1 is a summary of test conditions. The lineshaft turbine pump has been tested for 39 days and 27 days respectively in each of two wells. The pump completed both tests successfully but required extensive repairs after the first run. The electric submersible pump ran 5 days in one well, then failed, was pulled and repaired and is currently running in another well. In both cases the failures are attributable to factors which can be corrected and do not negate the basic ability of the systems to perform in the geothermal well environment.

In the case of the electric submersible, the principal question is whether or not the electric motors and cable will withstand the geothermal well temperatures for extended runs. The first test was

terminated after 5 days by a nonelectrical failure, so the durability of the motors and cable in the high temperature environment has not been adequately tested. The failure was a bearing seizure in the seal assembly caused by excessive thrust loads when the producing rate fell below the recommended operating range for the pump.

The principal operating problems with the lineshaft turbine have been associated with the lineshaft bearings and bearing flush water. With results from two tests and competitor experience, the solutions to these problems appear to be virtually in hand. The pump is an enclosed lineshaft design of standard water well construction except that it has increased bearing clearances and carbon-filled Teflon lineshaft bearings. In the first test, in well No. 38-30, severe wear to the lineshaft, bearings and impellers resulted from the fact that initial bearing clearances were too small to offset thermal expansion and the filtered geothermal water used as bearing flush water, carried suspended solids and formed precipitates which abraded the bearings and shaft. In the East Mesa 56-30 installation, lineshaft bearing clearances were increased and a softened flush water filtered with 10-micron filters was used. Some carbonate scale was formed on the shaft because of hardness leakage through the softeners but bearing wear was minimal, i.e. 0.002-0.003 inches. Recent experience of another operator with water lubricated bronze bearings as well as the carbon-filled Teflon bearings has been good.

Technical Applicability of Pumping

In general, pumping is advantageous in a moderate temperature resource where a substantial gain in production over flashing flow can be achieved. Additional advantages of reduced well bore scaling and single-phase surface gathering lines may alone justify pumping in some projects.

East Mesa, a moderate temperature resource with a relatively low noncondensable gas content, is well suited to pumping production. Substantial production increases of 2-3 fold over flashing flow are economically achievable. Also, carbonate scale deposition, although not severe, has been observed to be primarily coincident with steam flash. Pumping with a surface discharge pressure above flash pressure appears to have virtually eliminated well bore scale deposition.

In order to evaluate the technical applicability of pumping to a hot water resource, one must

Robert V. Verity

know the resource temperature, the free gas content and scaling tendency of the geothermal fluid as a function of pressure and the inflow performance of the wells, i.e. producing rate as a function of bottom-hole pressure. For acceptable pump life and efficiency the pump intake must, of course, be set below the depth of steam flashing. Where substantial free noncondensable gas evolves below the flash point, the pump setting depth must be even deeper to avoid cavitation. Further, to avoid scaling in or above the pump, the surface discharge pressure must normally be above steam flash pressure, but in some cases much higher. Where a high surface discharge pressure is required, the energy requirement alone may rule out pumping as a means of controlling scale deposition.

The lineshaft turbine has the following specific advantages over the electric submersible pump:

1. Standard water well pumps can be used with relatively few modifications.
2. It operates over a broader range of rates than electric submersibles at a given rpm. This advantage is further enhanced by the potential of rpm control at the surface which would allow matching well production to plant demand without wasteful throttling.
3. Its lower rpm probably makes it less susceptible to erosion than a submersible.
4. Its temperature capability is probably quite high since only metal parts are required downhole.

Its principal disadvantage is high capital cost for a deep-set pump due to the high cost of the column and lineshaft assembly. The principal advantages of the electric submersible over the lineshaft turbine are:

1. Standard pumps, motors and cable are applicable to geothermal with minor modifications.
2. Capital cost is substantially lower than lineshaft turbines for deep settings.

Its principal disadvantages as mentioned above are susceptibility to erosion in the pump and its relatively narrow operating range. If sustained sand production is not a problem and if the pump capacity is properly matched to the well productivity, then these disadvantages become unimportant. The principal unknown is the ability of the electrical components to withstand the geothermal temperatures for long periods.

Based on published performance data, energy requirements for lineshaft turbine and submersible pumps are quite comparable. The goals of testing are to confirm the published performance in a geothermal application and to estimate the long-term repair and maintenance expense for the two types of pumps. The testing program is beginning to develop this information.

Pump Performance Monitoring

A nitrogen-filled "bubble" tube has been

used to measure downhole pressure at the pump during production. (Refer to Figure 1.) These data are essential for monitoring pump performance and can be used to calculate the well productivity index (PI).

The first two attempts to install a bubble tube failed. In both these attempts, in East Mesa 38-30 and one previous well, a 1/4" O.D. stainless steel tube was banded to the outside of the lineshaft turbine pump column as it was being run in the well. In both cases, contact with the well casing crimped the tube and made it unusable. For the East Mesa 56-30 installation, the pump discharge head was modified so that a string of 1/4" line pipe could be run after the pump was installed. This procedure was successful.

In the submersible pump installations, a 1/8" O.D. stainless steel tube was banded to the outside of the 7" O.D. tubing on which the pump was run. The armored electrical cable (~1-1/4" O.D.) was then banded on beside the bubble tube, providing protection from contact with the well casing. Both installations were successful.

Surface bubble tube pressure readings, combined with normal flow rate, temperature and pressure data are used to calculate pump intake pressure, pump submergence, total pumping head and well PI. These calculations, assuming negligible kinetic energy effects, are outlined below.

Pump Intake Pressure

$$P_{in} = P_b + (z_{in} - z_b) \gamma_f$$

where $\gamma_f = \frac{G z_b}{53.3 \text{ Tav}_g Z}$ (1)

$$P_b = P_{bs} e^{-\frac{G z_b}{53.3 \text{ Tav}_g Z}}$$

Pump Submergence

$$z_f = \frac{P_{bs} - P_a}{\gamma_f}$$

This assumes that the density of gas in the casing annulus equals that in the bubble tube. In fact, the densities of the two gases are probably not equal, but the calculation provides at least an estimate of submergence to protect the pump against cavitation.

Total Pumping Head

$$h = \frac{P_s - P_{in} + \Delta p_{fc} + z_p}{\gamma_f}$$

Productivity Index

$$J = \frac{q}{P_e - P_{wf}} \quad (2)$$

where

$$P_{wf} = P_{in} + \gamma_f (z_d - z_{in}) + P_{fw}$$

Future Testing

Future pumping tests at East Mesa are aimed at testing the durability of lineshaft turbine and electric submersible pumps and projecting operating and maintenance expenses to guide the economic selection. Larger capacity pumps capable of 800,000 - 900,000 lb/hr will be tested. One lineshaft turbine of this size is scheduled for delivery in June, 1978. If results with the present submersible pump are sufficiently encouraging, a larger submersible probably will be ordered and tested.

NOMENCLATURE

- G = gas gravity relative to air = 0.967 for nitrogen
 h = head, feet
 J = productivity index, lb/hr/psi
 P_a = casing annulus pressure at surface
 P_b = pressure at bottom of nitrogen-filled bubble tube, psia
 P_e = external boundary pressure in the reservoir, psia
 P_s = pump discharge pressure at surface, psia
 P_{in} = pump intake pressure, psia
 P_{bs} = surface bubble tube pressure, psia
 P_{wf} = bottom-hole flowing pressure at z_d , psia
 ΔP_{fc} = pressure loss due to friction in the column or tubing above the pump, psi
 ΔP_{fw} = pressure loss due to friction in the well casing below the pump, psi
 q = well producing rate, lb_m/hr
 T_{avg} = average temperature of nitrogen in bubble tube, °R. Assume equal to temperature of pumped fluid.
 z_b = depth to bottom of bubble tube, feet
 z_f = depth to liquid level, feet
 z_{in} = depth to pump intake, feet
 z_p = depth to top of pump, feet
 z_d = datum depth in producing interval
 Z = gas compressibility factor
 γ_f = static pressure gradient of the produced fluid at flowing conditions, psi/foot.

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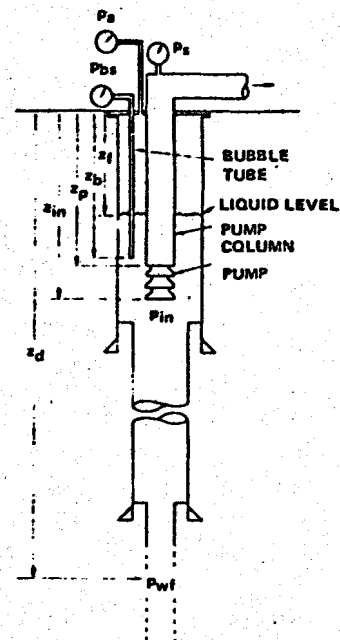


FIGURE 1. PUMP AND WELL SCHEMATIC

TABLE 1 - SUMMARY OF PUMPING TESTS

Well No.	Type of Pump	Pump Setting Depth (feet) (1)	Test Duration (days)	Range of Producing Rates (M lb/hr)	Optimum Capacity Range of Pump (M lb/hr)
38-30	lineshaft turbine	400	39	170-350	230-590(3)
56-30	lineshaft turbine	840	27	207-520	230-590(3)
78-30	electric submersible	1203	5	276-440	320-515(4)
16-29	electric submersible	1319	7+(2)	320-440	320-515(4)

(1) Depth from surface to top of pump.

(2) Test in progress

(3) Range for pump efficiency $\geq 70\%$

(4) Range in which thrust loads are properly balanced in pump

Analysis of Geothermal Well Pumping

by Thomas A. Campbell

ANALYSIS OF GEOTHERMAL WELL PUMPING

Thomas A. Campbell

Republic Geothermal, Inc.

ABSTRACT

A system study of geothermal well pumping includes the evaluation of the problems of how to determine the net power output of pumped wells for various productivity indices. The principal parameters needed are presented and the present value income of two common well casing programs are compared.

ANALYSIS APPROACH:

Net power output of a pumped well and the identification of the principal pump parameters are determined by estimating the maximum pump setting depth and the pump power requirements as a function of well flow rate. Maximum pump setting depth for a vertical lineshaft turbine pump is presently 1200 ft. The only setting depth constraint on a submersible electric pump is that the casing be large enough (11-3/4" casing or greater) at depth. The maximum power for both pumps is 1000 Hp (750 KW_e). For this paper the lineshaft pump was chosen; however, the results also apply to the submersible pump for the equivalent setting depth. Thus within the bounds of setting depth and power, maximum flow rates can be determined for various productivity indices (P.I.) of the well. The productivity index is the amount of flow (lbs/hr) that the formation can produce into the well for a given well drawdown (psi). Based upon a given flow rate, a fluid temperature, and the brine rate per kw required by the geothermal turbine-generator, gross power per well can be determined. Net power per well is defined as the gross power output minus the required pumping power. For this analysis a two stage flashed steam turbine-generator is used to compute gross power per well.

When comparing two wells with different dimensions, the principal factor will be the power losses due to friction of the fluid with the casing. The dollar costs of friction losses can override the initial drilling costs over a period of time.

PUMPING ANALYSIS:

The equation used to determine a pump

setting depth is given by the following sum of fluid heads (ft).

$$Z_{in} = Z_f + h_{sv} \quad (1)$$

$$Z_f = (Z_d - P_e / \gamma_f) + (Q/J) / \gamma_f + \Delta P_{fw} / \gamma_f + P_a \quad (2)$$

Where

- Z_{in} = pump setting depth, ft
- Z_f = depth to the fluid level in the annulus between the well casing and pump column, ft
- h_{sv} = net positive suction head, ft
- Z_d = depth to a datum level in the well production zone, ft
- P_e = external boundary pressure in the reservoir, psia
- γ_f = static pressure gradient of the produced fluid at flowing conditions, psi/ft
- Q = well flowing rate, lb/hr
- J = productivity index, lb/hr/psi
- ΔP_{fw} = pressure loss due to friction in the well casing below the pump, psi
- P_a = annulus pressure at the surface of the gas/fluid level at the depth Z_f

The friction loss head, $\Delta P_{fw} / \gamma_f$ is determined from:

$$\Delta P_{fw} = L \cdot 2.16 \cdot 10^{-4} \cdot f \cdot \rho \cdot q^2 / d^5 \quad (3)$$

- Where L = length of pipe section with inner diameter d , ft
- q = flow rate, gpm
- d = inner diameter of pipe, in
- f = friction factor for pipe section

The friction factor can be determined from: (1)

$$\frac{1}{\sqrt{f}} = -2 \log \left(\frac{2.51}{R \sqrt{f}} + \frac{E}{3.7D} \right) \quad (4)$$

- Where R = Reynolds number
- E = absolute roughness of the pipe, ft
- D = inner diameter of the pipe, ft

$$\text{and } R = \frac{50.56 \cdot q \cdot \rho}{\mu \cdot 12 \cdot D}$$

- Where μ = fluid viscosity in centipoise
- ρ = fluid density, lb/ft³

Over the temperature range of 300°F to 360°F, the viscosity of water ranges from .18 to .15 centipoise and up to .38 centipoise for 26% NaCl at 300°F. The value for f varies around 2% of a nominal value at 335° for these conditions. A typical value for E is .00015 ft, which is representative of commercial steel.

The required pump setting depth for a specific well design can be determined using equations (1) through (5). In the following analysis a standard casing depth program will be used and only the casing diameters will be varied. The surface casing will be set from the surface to 1700 ft, the intermediate liner from 1500 ft to 5750 ft, and the production liner from 5550 ft to 7500 ft. Production is assumed to originate between 6000 ft and 7000 ft. Friction losses in the production liner are determined by distributing the flow uniformly over the production interval (7000 ft to 6000 ft) and at the full flow rate above 6000 ft. Other values held constant are:

- h_{sv} = 50 ft
- Z_d = 6100 ft
- P_e = 2570 psia
- γ_f = .3896 psi per ft (value at 335°F, fresh water)
- P_a = 110 psia (saturation pressure of fresh water at 335°F)
- J = 800 to 3000 lb/hr/psi
- M = .16 centipoise (335°F, fresh water)

The case example to be considered has the following dimensions: surface casing, 16" - 75 lb/ft; intermediate liner, 11 3/4" - 54 lb/ft; production liner, 8 5/8" - 32 lb/ft. Figure 1 shows the results of the analysis for three values of P.I. From Figure 1, the pump specification of flow rate and required setting depth can be determined within the setting depth and power boundaries. From the required setting depth the pump column costs can be determined (approximately \$60/ft). Note that for P.I.'s greater than 2000, the required setting depths will be less than 1200 ft due to the power boundary.

Required pump power is determined from the total dynamic head, h , as follows:

$$h = Z_f + \Delta P_{fc} / \gamma_f + P_1 \quad (6)$$

ΔP_{fc} = pressure loss due to friction in the annulus between the pump column and the tubing enclosing the shaft, psi

P_{s1} = incremental pressure above the saturation pressure of the fluid at the surface discharge of the pump, psi

The column size for the pump is 10 3/4" with a 3 1/2" tube enclosing the shaft. The head, ΔP_{fc} , is a function of flow rate and is generally supplied by the pump manufacturer. P_{s1} was chosen as 50 psi to account for any losses in the pipeline between the wellhead and the plant.

Required pump power is determined using the following:

$$\text{Pump power (hp)} = \frac{(h \cdot q \cdot S_g / (3960 \cdot E_p) + Z_{in} \cdot L_s) / (E_g \cdot E_n)}$$

- Where q = flow rate, gpm
- E_g = gearbox efficiency
- E_n = engine efficiency
- S_g = fluid specific gravity relative to fresh water at 60°F
- L_s = shaft horsepower loss per ft
- E_p = pump efficiency

Values used in the analysis to determine pump power are:

- E_g = .97
- E_m = .93
- S_g = .90
- L_s = .023 hp/ft
- E_p = .75

Although for any given pump, the pump efficiency, E_p , varies with pumping rate, it is assumed for this analysis that at some fixed rate this efficiency could be achieved through proper pump selection.

Figure 2 shows the required pumping power vs. flow rate for the 16" well. Required pump horsepower is used to size the pump motor, gearbox, and the shaft size. Total dynamic head is used to compute the number of pump stages (h/head per pump stage = number of pump stages) and determines the cost of the bowl assembly.

For a given turbine-generator unit, net well output for the well can be given as shown in Figure 3. Of interest are the maximum power values possible for the fluid temperature of 335°F. For P.I.'s of 2000 to 3000 they range from 3.65 MW to 4.4 MW. For P.I.'s of 1000, the 750 KW boundary occurs at 690,000 lbs/hr. Since the net power is still increasing at that point, it is indicated that electric submersible pumps with their deeper setting depth capability could increase the net power of the 1000 P.I. case from 1.9 MW to 2.4 MW.

WELL DIMENSION COMPARISONS

The previously analysed 16" well will be compared against a smaller well. The smaller diameter well has 13 3/8" - 54.5 lb/ft surface casing, 9 5/8" - 40 lb/ft intermediate liner, and 7" - 23 lb/ft production liner. Figure 4 shows the comparison of maximum flow rates possible in each well for a given P.I. For P.I.'s in the neighborhood of 1000, the maximum flow rates are low and friction losses are not a significant factor. The 16" well shows a 16% increase in flow rate over the 13 3/8" well for a P.I. of 2000. This implies that for a field development with a fixed gross input flow rate to a plant, that fewer 16" wells would be needed than 13 3/8" wells.

In Figure 5, the two well sizes are compared against their differential economic values. The value of a well is defined for this analysis as the present value well income over a 15 year period minus the present value drilling cost. The present value well income equals net power (KW) x power value to the field developer (mills/KW-hr) x present value time factor for the for the income stream over 15 years with a 10% discount rate and a power value escalation of 6% per year. The differential value approach quantifies the comparison of the two wells on the basis of dollars. For example, using a P.I. of 2000, and 20 mills/KWHR, the 16" has a present value income (15 yrs) of \$700,000 more than the 13 3/8" well.

The differential value analysis compares wells on a one to one basis at maximum flow rates. It is apparent from the large differential value that the income from reduced friction losses can be substantial. Thus, from a total field development point of view, it may be advantageous to the operator in the case of a fixed plant size, to decrease the friction losses by drilling bigger (and higher cost) wells, or alternatively to drill a larger number of smaller wells and operate them at lower flow rates to maximize well value.

CONCLUSION

Geothermal well pumping is a technological opportunity available at temperatures below 350°F to 400°F. A wide choice of well and pump sizes as well as well spacing makes it appropriate to carry out a system evaluation of trade-offs. A system study has shown significant advantages for close matching well productivity and well and pump sizes.

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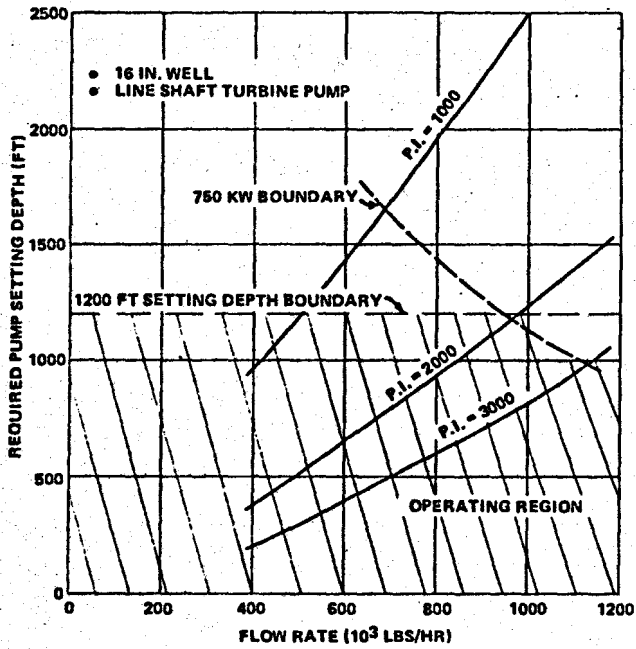


FIGURE 1. REQUIRED PUMP SETTING DEPTH VERSUS FLOW RATE

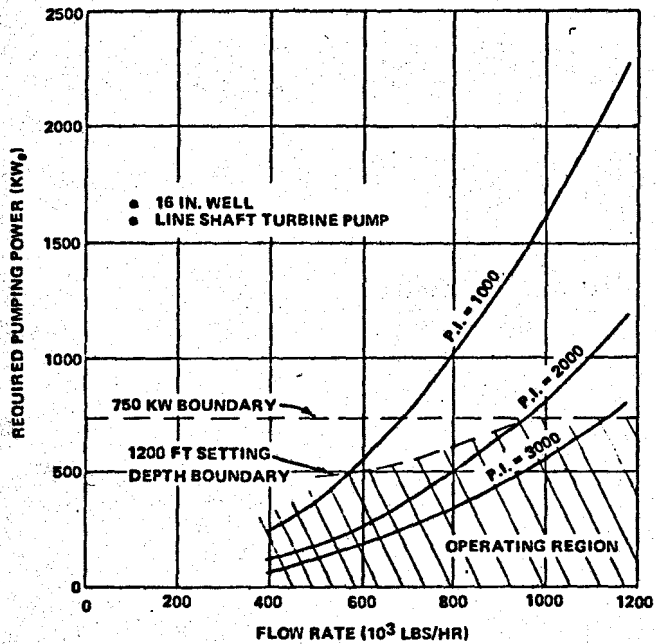


FIGURE 2. REQUIRED PUMPING POWER VERSUS FLOW RATE

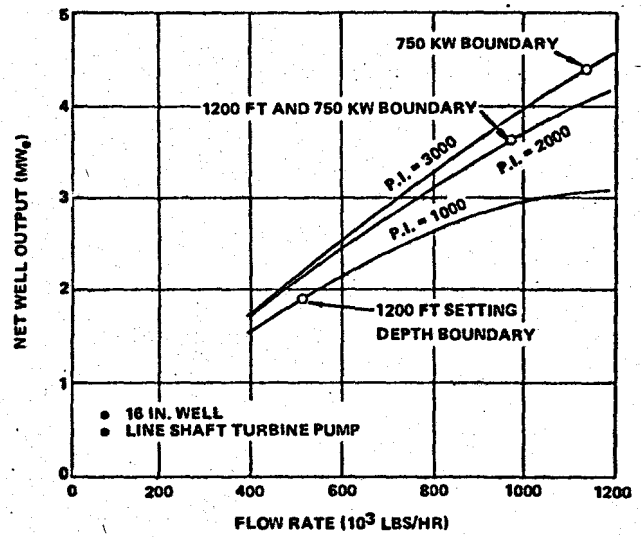


FIGURE 3. NET WELL OUTPUT VERSUS FLOW RATE

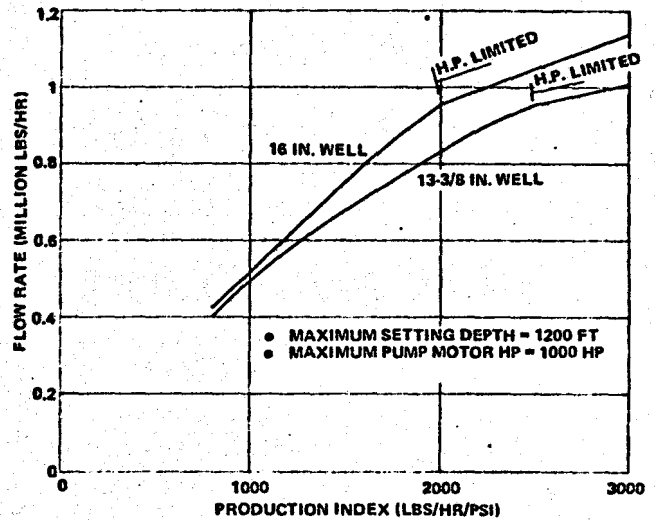


FIGURE 4. MAXIMUM FLOW RATES VERSUS WELL PRODUCTIVITY

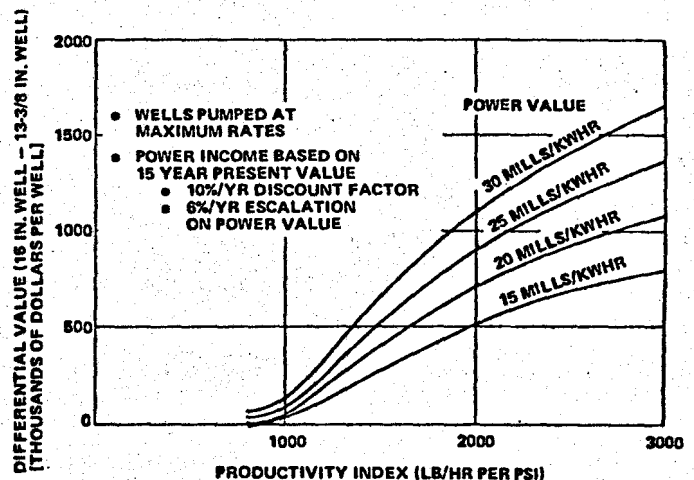


FIGURE 5. WELL SIZE COMPARISON

CO₂ in Geothermal Steam
A Rapid, Precise, and Accurate Field Assay Technique

by Dr. Donald E. Michels

CO₂ IN GEOTHERMAL STEAM
A RAPID, PRECISE, AND ACCURATE FIELD ASSAY TECHNIQUE

Dr. Donald E. Michels

Republic Geothermal, Inc.

ABSTRACT

A system for sampling and measuring noncondensable gases in steam has been devised for field use, giving results for CO₂ and non-CO₂ fractions as weight percent in steam. Six to eight determinations can be made per hour with a precision better than ± 0.04 of the measured value, providing a way to examine short-period patterns in gas contents as well as finding concentrations needed for engineering design.

In this assay-type method condensate and noncondensable are collected together in a calibrated syringe at a precisely measured pressure and at ice water temperature. Henry's law is applied to compute the portion of the total gas which is dissolved in the condensate.

Hardware is designed around 1/8" O.D. stainless steel tubing which solves in a simple way sampling problems that otherwise tend to give serious inaccuracies. Several additional advantages flowing from the use of small-diameter tubing make the system especially serviceable in the field.

INTRODUCTION:

Henry's law describes the solubility of gases in water, providing a basis for measuring the concentration of those gases in geothermal steam. The method described here is convenient for low-pressure steamlines leading out of separators. There, a sample can be extracted from the line through a small diameter stainless steel tubing and condensed while maintaining association between the condensate and the noncondensables. By equilibrating a known volume of the mixture in both thermal and chemical senses one can set up a condition to which Henry's law applies and then calculate the % CO₂, etc.

Measurements of gas volume, condensate volume, and pressure are used to calculate the noncondensable concentration in the original steam. These measures are simplified by using a syringe for collecting and equilibrating the sample and using a manometer to measure pressure. Knowledge of the absolute pressure at the time of collection is needed for the calculations; for precise work it should be known within about 1 cm of Hg. Since necessary measurements are made at the time of sampling there is no requirement to remove samples from the field. Calculations can be made in the field as well.

Collection and equilibration of a sample takes 7 to 10 minutes. For CO₂ mixed with other gases two samples must be taken to make one determination. One of these is collected into a NaOH solution to convert CO₂ to an ionic form. Syringes used for collection and equilibration of samples can be used also to transport them for further study, as, for example, if separate measures of noncondensables other than CO₂ are desired, perhaps by GC or MS.

The method is especially practical for steam which contains less than 5% noncondensables. Mixed noncondensable gases in which CO₂ is a major constituent are readily quantified separately, in the field, as CO₂ and non-CO₂ fractions. Precision of the method is better than ± 0.04 of the measured value.

The high precision of the method and the relatively fast real-time results (6 to 8 determination per hour) make the method useful for studying subtle behaviors of geothermal wells. The method should be applied with caution if CO₂ concentration in the steam is smaller than about 0.3 weight % yet is still the most prominent noncondensable.

METHOD

Principles

Gas solubility in water is remarkably linear with respect to pressure. Such is true even for CO₂ if pH is less than 4.0 which corresponds to a CO₂ partial pressure of 0.1 atmosphere or more. Gas solubilities are strongly dependent on temperature, but collection in a bath of ice water can eliminate that complication.

It is intended in this method to collect the noncondensable gases and equilibrate them with the condensate at ice temperature so that a well-defined solubility coefficient applies. The steamline pressure is used to drive the sample into the syringe and hold it during equilibration. Thus, the absolute pressure of the steamline is the correct value to use for the calculations. By collecting the sample in a calibrated syringe, equipped so as to limit the extension of the plunger, both the liquid volume and the volume of the undissolved (excess) gas can be measured. The collected noncondensable gases and especially CO₂, are present in both liquid and gaseous compartments of the syringe. The amounts in each compartment are calculated separately and the results summed to complete the analysis.

If CO₂ is present two gas collections must be made. One, when the syringe holds a few ml of NaOH solution, enough to totally solubilize the CO₂. In this second collection there is no partial pressure of CO₂. This step provides for both a direct measure of non-CO₂ noncondensables and a means to accurately estimate the CO₂ partial pressure in the other sample.

Hardware

The major parts of the setup shown in fig. 1 are: (1) a small-diameter metal tubing to extract a representative sample from the steamline and assure that it remains representative. The tubing also serves as a cooling coil, (2) ice and water bath for temperature equilibration, (3) a calibrated syringe to measure gas and liquid volumes, and (4) a manometer to measure steamline pressure. As a practical measure, one needs also a sensitive means to detect when a solubility equilibrium has been reached.

The sampler design assures that several important functions are served.

The small-diameter tubing is used as a probe to go deep into the steamline in order to avoid problems of condensate on the pipe walls. Additionally its small diameter assures the continued integrity of the steam sample during condensation by maintaining the noncondensables in intimate association with their respective volumes of condensate. The small diameter tubing allows the surface tension of the condensate to maintain a droplet of water entirely across the tubing diameter, trapping a bubble of noncondensable in front of it early in the condensation stage. This arrangement of small-scale bubble and liquid drop persists until the sample emerges in the syringe. These essential effects are absent in tubing larger than about 1/8 inch I.D.

Most of the length of the stainless steel tubing is arranged into 2 coiled portions so that condensation (high heat load operation) is well separated from where the temperature equilibration takes place (low heat load operation). Length of the stainless steel tubing is chosen so that the flow rate through it is made small by viscous relationships to the fluid. In this way the flow

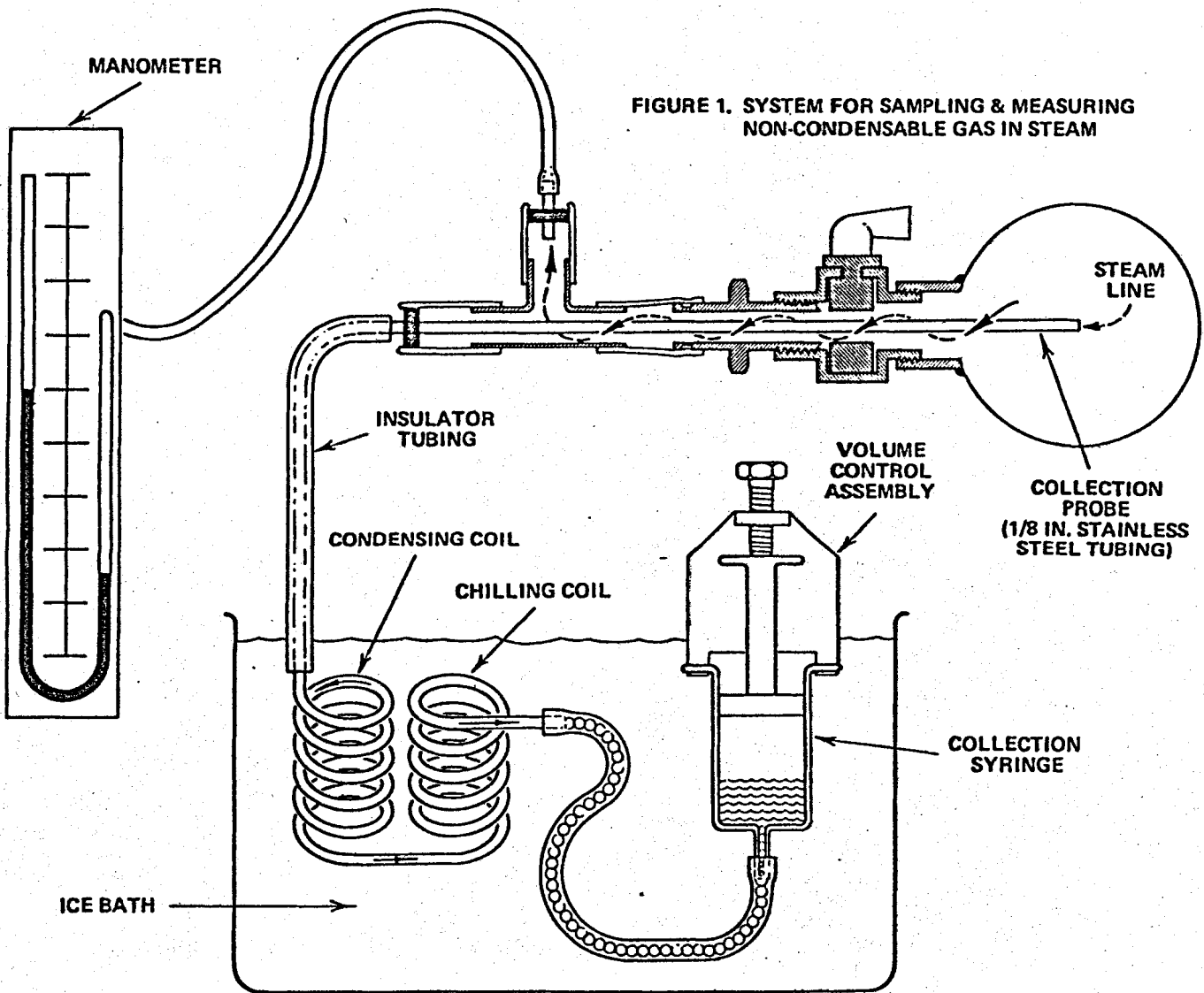


FIGURE 1. SYSTEM FOR SAMPLING & MEASURING NON-CONDENSABLE GAS IN STEAM

rate is kept low and smooth without valves. Thermal equilibration occurs inside the tubing, rather than inside the syringe.

A flexible transparent/translucent tubing connects the stainless steel tubing with the syringe, providing a window for monitoring the progress of fluid into the syringe. Equilibrium is judged to exist when bubbles no longer leave the stainless steel tubing while the syringe is being shaken in the ice bath.

The syringe has the attribute of possessing essentially zero volume at the start of the sample collection. After a stable flow is established through the tubing and the tubing is well flushed the collapsed syringe can be connected to the flexible tubing without interrupting flow and without introducing air into the syringe. Subsequently, the steamline pressure, transmitted through the sample as it is being collected, moves the plunger of the syringe until a mechanical stop arrests the plunger at a desired total volume. Fluid continues to enter the syringe until equilibration is achieved with both the steamline pressure and the gas solubility. The dissolution of CO₂ is moderately slow at ice temperature, thus, it speeds things up to shake the syringe during the pressurization stage.

The absolute pressure inside the syringe is required for calculations. This has been obtained by combining a manometer reading made at the time of sampling, with a barometric pressure obtained from a nearby airport. The manometer must be arranged so that neither the volume of the syringe nor its contents are disturbed by the shifting of fluids in the manometer. Thus, it is practical to connect the manometer separately, yet nearby the place where the sampling probe enters the steamline. Since streaming velocities inside steamlines are fairly high some aerodynamic effects cause differences between the pressure existing on the probe end of the sampler and on the manometer. These factors must be worked out for each case in order to accurately assess the pressure inside the syringe.

Calculations

Two sample collections, one with and one without NaOH in the syringe, yield the 5 items of data required for the calculations:

$$V_{L1}, V_{G1}, V_{L2}, V_{G2}, P_{T1}$$

V and P refer to volume and pressure, L and G refer to liquid and gaseous phase, and 1 and 2 refer to the collections, specifically, 2 refers to that one involving NaOH. The subscript T on the pressure refers to the total absolute pressure inside the syringe at the time equilibrium is reached, that is, it is the sum of barometer and manometer indications, the latter adjusted for aerodynamic influences associated with the connections to the steamline.

$$\%CO_2 = KP_{T1} \left(\frac{V_{G1}}{V_{L1}} \right) \left(1 + \frac{M_C V_{L1}}{V_{G1}} \right) \left[1 - \underbrace{\left(\frac{V_{G2}}{V_{G1}} \right) \left(\frac{V_{L1}}{V_{L2} V_{NaOH}} \right) \left(1 + \frac{M_N V_{L2}}{V_{G2}} \right)}_{F_1} \right]_{F_2}$$

Where the terms are as defined above with the additions that constant K = .00256 involves the formula weight for CO₂, gas constant, temperature, and fluid density appropriate for pressure measured in cmHg, volumes in ml, and density in grams per ml. The term V_{NaOH} presumes that in the second collection NaOH is added before-hand as a water solution.

The equation above has been arranged so that the special significances of some portions are easier to see.

F₁ represents the fraction of P_{T1}, which is due to non-CO₂ gases. The factor M_N suggests nitrogen in the case at hand, in the presumption that nitrogen dominates the non-CO₂ suite, a presumption that would be assessed independently.

F₂ represents the virtual pressure fraction for CO₂. The mathematics treats the dissolved CO₂ as if it were added to the gas phase compartment; this virtual pressure fraction is larger for larger V_{L1} and generally exceeds the value 1.

The non-CO₂ fraction of the noncondensable gas is given by

$$\text{non-CO}_2 \text{ fraction} = \frac{F_1}{F_1 + F_2}$$

RESULTS:

This method has been applied to wells of Republic's development at East Mesa. Besides seeking the CO₂ content for use in engineering design, we also were interested in identifying trends.

Figure 2 shows an absence of trends in well FS between 4 and 8 hours after turn-on. Later measurements show that the concentration of CO₂ in well FS remained in that same narrow range throughout the 500-hour test period.

Figure 3 shows the trend observed for well SE. The change of concentration toward an asymptote suggests a contribution from unequal portions of the reservoir and their approach to a steady state situation. The decrease in CO₂ content in the first few hours after turn-on can be interpreted in various ways. One is that it is a consequence of cross-flow phenomena that occurred upon shut-in after a previous test.

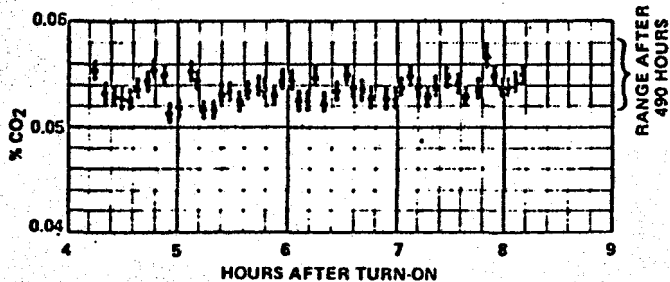


FIGURE 2. CO₂ IN TOTAL FLOW WELL FS

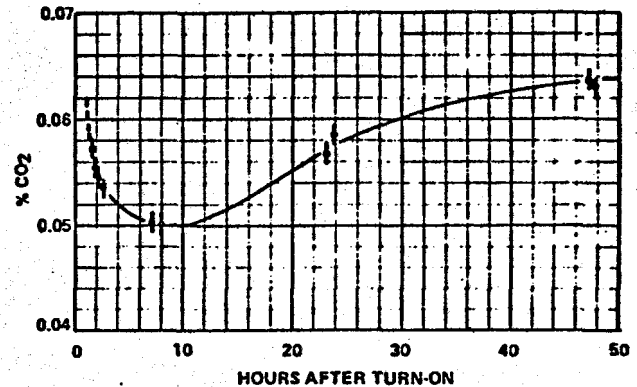


Figure 3. CO₂ IN TOTAL FLOW WELL SE

SUMMARY

A precise and rapid field method for measuring noncondensable gases in geothermal steam has been developed and used. The method is based on Henry's law and involves a direct measure of gas volumes, yielding a nondestructive assay-type analysis. The hardware that was developed in order to apply the Henry's law principle avoids two problems that are at risk in any sampling for noncondensables: (1) using a probe to withdraw the steam sample from deep within a steamline to avoid its being affected by condensate that might exist on the walls and (2) preventing a separation of condensate and noncondensable in a condensing coil that can lead to wrong proportions being introduced into the collection vessel. Calculations for the CO₂ and non-CO₂ components of the steam depend on five quantities measured in the field plus a barometric reading. The sample need not be removed from the field so requirements for transport and preservation are avoided. However, the sample is captured in a way convenient for removal from the field in case additional study is desired, and then the same material would be involved in both studies. The method can be used to study variations over time of noncondensable gases during production, leading to insight about reservoir conditions as well as providing data for engineering design.

In the field, precision has been in the range of .02 to .04 of the amount of noncondensable collected. Theoretical accuracy due to limitations in measuring pressure and volume and in determining when solubility equilibrium has been reached, is in the range of .005. Pressure uncertainties need be no worse than 0.3 cm Hg per 100 cm Hg; volumes are readable to ± 0.2 ml in 20 in standardized plastic syringes that yield a flat meniscus; and the approach to equilibrium can be followed readily in 5 to 10 minutes with shaking to rates as small as 8×10^{-6} moles per second which corresponds to a solubility reaction better than 99.99% complete. Uncertainties in the Henry's law coefficients for mixed gases may be the major factor which limits accuracy.

**A Practical Hydrogen Sulfide Abatement Process
for Air Drilling and Venting Geothermal Steam Wells**

by Thomas A. Turner and Dr. R. W. Rex

A PRACTICAL HYDROGEN SULFIDE ABATEMENT PROCESS FOR
AIR DRILLING AND VENTING GEOTHERMAL STEAM WELLS

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ABSTRACT

A simple, economic process has been developed and applied to full scale operations for the abatement of hydrogen sulfide emissions while air drilling and venting geothermal steam wells. The process consists of blooie line injection of sodium hydroxide and hydrogen peroxide. 91-98% of hydrogen sulfide emissions can be abated during the drilling of a typical geothermal steam well for a cost of less than \$10,000.

INTRODUCTION

Hydrogen sulfide is an odorous gaseous pollutant generally present in geothermal steam. When the first geothermal steam well was drilled at the Geysers in 1922, the presence of hydrogen sulfide odor was accepted as a naturally occurring phenomena associated with fumarolic activity. Most of the fumarolic activity has declined during the ensuing years due to man's modifications to harness this natural energy source for electrical power generation.

The majority of today's hydrogen sulfide emissions entering the atmosphere from the Geysers are from man-made devices. Increased environmental awareness in recent years has resulted in a legislative standard for hydrogen sulfide based on the threshold of smell. This standard of 30 ppb has been exceeded on occasion as a result of Geysers emissions. New source review rules promulgated by the California Air Resources Board were recently adopted as regulation in Lake County, CA. The rule requires that the respective air pollution control officer review any proposed new source of pollutant in excess of 20 pounds/hour and deny a construction permit if there is substantial evidence that the new source will prevent attainment of the ambient hydrogen sulfide standard.

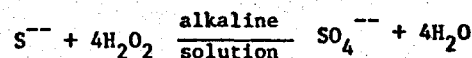
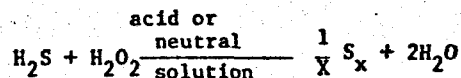
Some geothermal well drilling activity, even though it constitutes a minor transitory source of emission, has been constrained as a result of these new regulations. The response has been the development of a process - using blooie line injection of hydrogen peroxide and sodium hydroxide to abate the hydrogen sulfide emissions during drilling, plant gathering line venting and well bleeding operations in order to prevent future

violations of point source emission rules or the ambient air quality standard. From preliminary laboratory work performed by FMC Corporation, a manufacturer of hydrogen peroxide, at the request of Dr. R. W. Rex, it was determined that field drilling conditions could not, economically, be lab simulated. Republic Geothermal, in August of 1976, then designed and constructed a pilot sized geothermal muffler unit for use in California's high pressure steam field, the Geysers. The muffler unit was designed to dynamically simulate flow conditions present in conventional mufflers used to suppress noise and control particulates. Steam for the field trial was supplied by Magma Power Company and at Magma's request, field and technical assistance was furnished by their operator, Union Oil's Geothermal Division.

The process involves the continuous injection of aqueous hydrogen peroxide and sodium hydroxide solutions into the geothermal steam. Injection is made into the blooie line upstream from the muffler. The principal product of the oxidation is sodium sulfate, a neutral salt. During preliminary testing, sulfide abatement of 91% was achieved at a 4:1 weight ratio of hydrogen peroxide to hydrogen sulfide and 2.8:1 weight ratio of sodium hydroxide to hydrogen sulfide.

CHEMISTRY

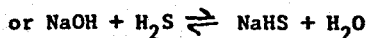
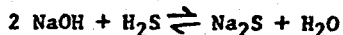
The products of sulfide oxidation are controlled by pH and the chemical reactions that take place with hydrogen peroxide are illustrated by the simplified equations:



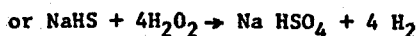
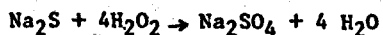
At ambient temperatures a period of 5 to 20 minutes is generally needed for hydrogen peroxide to completely react with sulfide in aqueous solution. This range has led some investigators to conclude that indigenous catalysts are operating. At 122°F the reaction is complete in 15 seconds. Rates in water solutions at still higher temperatures should be extremely fast. The presence of heavy metal ions will increase reaction rates even further. Reactions in the pilot system proceeded

to completion in less than 4 seconds.

In detail the reactions proceed at more rapid rate in the liquid phase and H₂S assimilation into the liquid phase is accelerated by an increased liquid phase pH as follows:



plus Peroxide



The reaction products Na₂SO₄ and NaHSO₄ are stable salts and will not revert to hydrogen sulfide in the sump during neutralization activities upon completion of drilling.

Analysis of test muffler condensate reaction products performed for Republic by Quality Water Laboratory, Inc. identified trace amounts of SO₃, SO₂ and elemental sulphur, and it is probably due to the catalytic action of iron and trace heavy metals that the reaction does not proceed in precise stoichiometric proportions as displayed in the simplified equations above. Although not field tested, many other combinations of oxidants, and pH modifiers can be utilized to effect similar results. However, since hydrogen peroxide is a readily available, inexpensive industrial chemical and strong reagent solutions can be prepared with NaOH, sodium is the preferred cation for creating a strong alkaline environment for the practical disassociation and oxidation of H₂S.

Measurements made of the resultant steam emitted to the atmosphere indicate no caustic or peroxide carryover to the atmosphere.

OPERATING PROCEDURES

In field practice, implementation of the system is very straightforward. Caustic and peroxide injection points should be separate and located as closely as practical to the banjo box in order to provide maximum system residence time for the reaction to proceed to completion and maximum exposure to high Reynolds, Froude, & Webber number flow regimes for optimal mixing. Vacuum sampling points should be provided both upstream of the injection point and on the muffler stack in order to control abatement levels and optimize process efficiencies.

Hydrogen peroxide storage and transfer lines should be 304 or 316 passified stainless steel using low volume positive displacement chemical metering pumps for injection such as Pulsa Feeder Model 7120 4.2 to 42 GPH electric driven pumps. Care should be taken that storage tanks are protected by anti-siphon valves and that all hydrogen peroxide handling equipment has been passified with 68% Nitric Acid for ± 24 hours.

Caustic storage and handling facilities can be mild steel and require no special handling procedures other than adequate containment provisions for personnel safety and anti-siphon valves to avoid storage contamination. If the system is to be utilized during cold weather conditions, a 25% aqueous solution of sodium hydroxide is recommended in that its freezing point is 0°F where 50% solutions freeze at 50°F.

For a typical geysers production well ± 2000 gallons of storage should be provided for each chemical depending on delivery problems at the specific location.

Injection points should be provided with high energy spray nozzles for improved mixing and dispersion in the blooie line. In line strainers are recommended in that the nozzles will tend to plug with foreign material. Provisions should be made for removal and cleaning of spray nozzles which provide minimum down time and personnel exposure.

The scope of this presentation is necessarily limited to the initial development phases of the abatement process and the construction aspects of full scale facilities. Republic Geothermal has not had the occasion to implement the process on a full scale operational basis, however, this sulfide abatement process has been utilized by other operators with reported attainable field abatement levels of up to 95% with per well costs averaging \$6500. An additional important advantage of this blooie line abatement process is that atmospheric pollution can be mitigated continuously, independent of drilling operations. Previously tested systems, relying on drill string injection, necessarily preclude abatement during all rig operations other than drilling. This new method results in significant reductions in abatement efficiencies and undesirable pollution of the atmosphere.

Republic currently has its hydrogen sulfide process equipment leased to Phillips Petroleum Co. and it is being operated for Phillips by the R. F. Smith Corporation. The R. F. Smith Corp., a geological services corp. specializing in the provision of well mud logging services, also provides rig floor compressor breathing equipment, Scott Air Packs, blooie line vacuum sampling devices, hydrogen sulfide monitoring equipment and intends to provide and operate the hydrogen sulfide abatement process described in this paper as a service to operators in the Geysers area.

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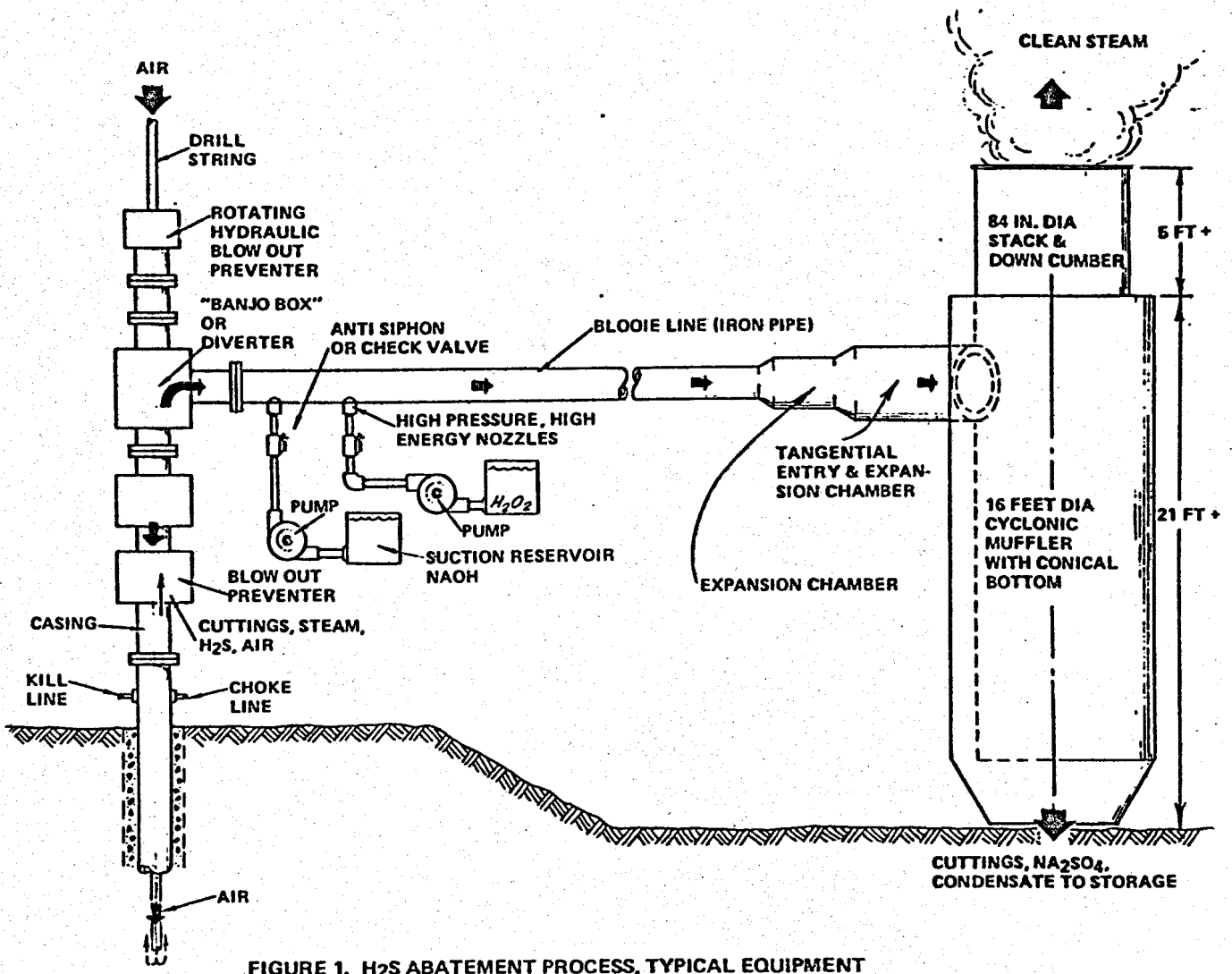


FIGURE 1. H₂S ABATEMENT PROCESS, TYPICAL EQUIPMENT