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PLEASANT BAYOU OPERATIONS
BRAZORIA COUNTY, TEXAS

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ABSTRACT

A. Hybrid Power Systems (HPS)

This project will demonstrate the Hybrid Cycle Concept for electricity generation using geopressured-geothermal resources. The test is scheduled to be a minimum of one year, which may be extended. The majority of the equipment came from the DOE facility at East Mesa, CA. The hybrid cycle has been designed for 10,000 BPD brine and 220,000 SCFD of gas. The power output will be about one megawatt, which will be sold to Houston Lighting and Power Company.

B. Production

An important research objective is to determine the size and ultimate production capability of the geopressured-geothermal reservoir. The long-term deliverability of these type reservoirs is a significant factor in determining the ultimate economic capability of these systems.

C. Controlling Factors

Some of the significant controlling factors of this project are:

1. Pressure, deliverability, and long-term life of the reservoir.
2. Injection pressures and volumes of the disposal well.
3. Turbine life.
4. Scaling and corrosion.

INTRODUCTION

The Pleasant Bayou No. 2 well (drilled and completed in 1979) represented the first full scale production test of a geopressured-geothermal aquifer in the United States by DOE. The initial production tests were divided into four phases. The first phase (0) was conducted to measure both the surface and bottom hole pressures as the well was flowed at various rates between 1,500 BPD and 17,000 BPD (July 1979 - December 1979). Phase I (September - October 1980) was from 8,000 BPD to 12,000 BPD. Phase II-A (July - October 1980) was intended, initially, to measure both the bottom hole and surface pressures while the well flowed at its maximum deliverability. Shortly after the test began, the bottom hole gauge and nearly all of the wireline was lost in the hole. This was pushed to bottom, and Phase II-B test was continued without a bottom hole pressure measuring device. The Phase II-B test (September - October 1982) recorded only the surface flowing pressures with a less accurate, continuously recording meter. Continuation of

Phase II-B (October 1982 - April 1983) was discontinued prematurely due to failure of the production tubing. A total of about 4,500,000 Bbl of brine and 99 MMCF of gas had been produced. The well experienced severe scaling during production. A workover to clean out the well was suspended.

The site was placed on standby status until September 1985, when Eaton Operating Company assumed operation of the site. Plans had been made by DOE to clean out the well and install a Hybrid Power System in fiscal year 1986. Due to budget restraints, the production well was cleaned out in FY 1986 and placed on production in FY 1988. The well has been flowed at a rate of 15-20,000 BPD since. The HPS is presently being installed, to be operational about the end of May 1989. This system will be tested for at least one year.

DISCUSSION

Hybrid Power Systems (HPS) (1)

Two primary objectives of the HPS are:

1. To demonstrate the generation of electricity from geopressured-geothermal resources (i.e., hot brine and natural gas).
2. To operate the test system over a wide range of conditions to obtain data that will be helpful for future commercial installations.

As shown on the Electrical Generating System Hybrid Cycle Flow diagram (Figure 1), electricity will be produced from a binary cycle unit, operating on heat from the geopressured-geothermal brine, augmented by engine exhaust heat from two gas engines that are used to drive generators. The gas engines' fuel will be natural gas, separated from the brine, through the production system shown.

Additional power will also be available from the hydraulic energy in the high pressure wellhead fluid. A pressure reduction turbine will not be installed, but calculations will be made during testing to determine what power could have been generated with a turbine.

Most of the equipment for this project is used equipment from DOE's Direct Contact Heat Exchange (DCHX) facility at East Mesa, California. The DCHX facility was a nominal 500 KW binary cycle plant with isobutane as the working fluid. The DCHX facility differed from conventional binary cycle plants in that heat transfer from the geothermal brine to the isobutane occurred in a direct contact heat exchanger. Direct contact heat exchangers will not be used in the Pleasant Bayou unit. Shell-and-tube heat exchangers will be used. The Hybrid

gas, not used in the engine, will be sold.

The parasitic loads for this system will consume a larger percentage of generated output than would be expected in a commercial power plant. These are made up of the following:

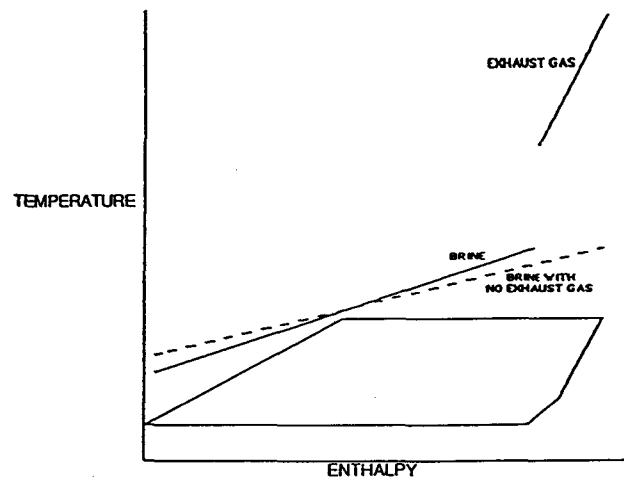
1. Condensers (75 KW) - This includes water pumps (one each for the four Baltimore Aircoil condensers) and eight fan motors.
2. Circulating Pump (74 KW) - The pump used to pump the isobutane liquid into the high pressure exchangers.
3. Miscellaneous Loads (60 KW) - These include the utility cooler, lube oil pumps, air conditioning, compressing air for the trailers and instruments, control power and lighting.

The binary cycle portion of the hybrid plant will use isobutane as the working fluid. This will be pressurized to 330 psi by a multi-stage, vertical turbine pump (P-1-E). It will then be heated to its bubble point in the first shell-and-tube heat exchanger (E-1-N) by warm brine from a previous exchanger (E-2-N). After leaving the exchanger (E-1-N), the isobutane flow will split, with some of the isobutane being boiled by exhaust heat from the gas engines in the third heat exchanger (E-3-N), and the remainder being boiled in the second heat exchanger (E-2-N). Isobutane vapor from the two latter exchangers (E-2-N and E-3-N) will be combined, then passed through a separator (to remove any remaining liquid). It will then expand through the turbine (T-1-E) to generate electricity. The exhaust isobutane leaving the turbine will be recondensed in four Baltimore Aircoil condensers. The condensed isobutane will enter the accumulator (V-1-E) and will be pumped back through the loop, completing the cycle.

Isobutane is not the optimum working fluid for a standard binary cycle on a resource with the relatively low temperature of the Pleasant Bayou well (wellhead $\pm 290^{\circ}\text{F}$). For a new unit, propane with a higher vapor pressure could be used to generate more power, but the existing equipment is not rated to high enough pressures to utilize propane. A comparison was made that indicated propane would yield about 5% more net power than isobutane. This small advantage was not considered significant enough to justify the purchase of all new equipment, especially since the additional amount available by the use of the propane can be calculated. The goals of the test, to demonstrate the hybrid cycle using the geopressured-geothermal resources and gaining operating data over an extended period, can be met even if the net power is slightly less than it would be using propane.

The wellhead gas will be used to power two Caterpillar Model 398 engines which will produce 650 KW total. The engines' exhaust gas ($1,130^{\circ}\text{F}$) will be used to boil 14% of the isobutane in the third heat exchanger (E-3-N). The remainder of the isobutane will be boiled in the second exchanger (E-2-N) by hot brine from the separators. The brine which will leave the separator at 278°F will be cooled to 220°F in this second heat exchanger (E-2-N). The cooler brine will then be used for preheating of the full flow of isobutane in the first exchanger (E-1-N), as described above.

Even though the engine exhaust only heats and vaporizes 14% of the total isobutane (exchanger E-3-N), the addition of this heat will be important to the overall cycle efficiency. Figure 3 is a temperature enthalpy diagram of the binary cycle portion of the hybrid plant, showing the cooling curves for brine and exhaust as solid lines. The dotted line is the cooling curve for the brine if there is no exhaust heat available. Note that the reject brine for the case with no exhaust heat added is at a higher temperature than the reject brine when the exhaust gas is used. Rejecting brine at a higher temperature means that less heat is provided to the cycle by the brine, so less power would be produced. For this pilot plant, only eight percent of the total heat will be from the exhaust gas, but the improvement in overall efficiency will be substantial. An optimized system would also recover the jacket heat from the gas engines, but ebullient-cooled engines were not available for this project.



Heat Curve for Binary Cycle Portion of Hybrid Power Plant

Figure 3

Eaton Operating Company, Inc. (Houston, Texas) has overall responsibility for this project and operates the producing and disposal wells. They have delegated duties to the Institute of Gas Technology (IGT) (Chicago, Illinois) for fluid handling, gas separation and drying, and collection and evaluation of production data for reservoir analysis. The Ben Holt Co. (Pasadena, California) designed the system for EPRI and will construct and operate the system under Eaton's direction for DOE.

Hot brine, dried methane and cooling water makeup will be provided to the power plant by IGT and Eaton. The spent brine and cooling water blowdown will be taken by IGT and Eaton at the plant boundary and injected into the disposal well. The brine will be recombined with the production brine, bypassing the unit, and injected into the Eaton disposal well.

The present Draft Test Plan envisions the following test runs, during the first three months of operations. The remaining nine months (or more, if extended) will be for continuous operation as close as possible to a commercial facility.

Test #1 - Design (iC4) Flow

Isobutane (iC4) will be flowed at a rate as close as possible to its design value. Exhaust gas flow will also be at design value. The brine and gas flows will be regulated to whatever amount is required to maintain isobutane levels in the reboilers. This will determine the required brine flow rate corresponding to the hybrid cycle as built. Since the hybrid plant was designed to use only half of the well flow rate, there will be no problem if more than 10,000 BPD is required.

Test #2 - Design Brine Flow (10,000 BPD)

The system will be operated on 10,000 BPD of brine and design exhaust gas flow. This will establish performance at the design input levels of the binary cycle.

Test #3 - Maximum Brine

With exhaust gas flow set at the maximum available from the gas engines, brine flow will be increased until isobutane flow is the limiting factor (this will probably be the maximum power case, also).

Test #4A - Low Exhaust Gas (100%-0%) (10,000 BPD)

Fuel gas to the engines will be reduced in stages to 75%, 50%, 25% and 0% values of design flow (reducing heat from the exhausts). Brine flow will be maintained at 10,000 BPD.

Test #4B - Low Exhaust Gas (100%-0%)

Gas flow to the engines will be reduced to zero in 25% increments. The plant will operate at the brine flow rate of Test #1.

Test #5A - Low Brine Flow (7,500 BPD)

The brine flow rate will be reduced to 7,500 BPD. Isobutane flow will be adjusted accordingly. Gas flow to the engines will be maintained at design values.

Test #5B - Low Brine Flow (5,000 BPD)

Flow will be reduced to 5,000 BPD of brine input into the plant. Isobutane flow will be adjusted accordingly. Gas flow to the engines will be maintained at design values.

Test #5C - Low Brine Flow (2,500 BPD)

Flow will be reduced to 2,500 Bbl of brine into the plant. Isobutane flow will be adjusted accordingly. Gas flow to the engines will be maintained at design values.

Test #6 - Maximum Power

Brine flow will gradually be reduced from Run #3 value to determine if maximum net power production is at maximum isobutane flow rate or a lesser flow rate. These optimum conditions will be the target for continuous operation during the last nine

months (or more) of the program. This is the point of most interest to a commercial operation.

Before the final optimum conditions are selected for continuous operation, all equipment will be inspected to insure that none is overloaded. The most critical item is the binary cycle turbine. Checks will be made for bearings running hot, etc. and to insure that manufacturers' recommendations for maximum operating levels are not exceeded.

Start-up, shakedown and testing are scheduled for the first three months of system operation. If all of the off-design tests have not been completed within the first three months of operation, the continuous operation phase will be delayed until testing is completed. The system will not be shut down during any of the testing, so the objective of demonstrating long-term operation is not compromised.

Operator requirements during the start-up, shakedown and testing will be two operators around-the-clock, plus a plant manager. The plant manager will remain throughout the operation, but plans are made to cut down to one operator around-the-clock during the continuous operation phase. Four operators, working eight hour shifts, will be used to provide one operator on the site at all times. Every effort will be made to cross-train with Eaton and IGT production operation personnel for future possible total staff reduction at the site.

The primary responsibilities of the operators will be to inspect equipment, collect data, and to make process adjustments for such things as changes in weather, fluid and/or gas availability, or equipment performance. A full-time maintenance staff will not be employed. Contract personnel will be utilized. Initial analysis of the operational data will be done in part by the plant manager and operators, then transmitted to The Ben Holt Co. home office for final analysis and evaluation.

This will be a very interesting and worthwhile research project. Hopefully, additional funds will be made available to extend the test period for more than the one year period presently scheduled.

Production

In addition to the operation of the HPS, another important research objective is to determine the size and ultimate production capability of the geopressured-geothermal reservoir. As shown on Figure 4, the productive sand was perforated from 14,644 to 14,704 feet (60'). The well has been tested at rates in excess of 20,000 BPD (limited by size of production separators).

This is a much higher rate than conventional oil and gas production rates in the U. S. Gulf Coast region. The long-term ability of the reservoir to maintain adequate flowing pressures, while producing at these high flow rates, is a significant factor in determining the ultimate economic capability of these systems. Production rates of 15-20,000 BPD will provide 1½ to 2 times the capacity of the HPS and minimize fluctuations to it. The high rates will adequately stress the reservoir and assist in determining its ultimate production life.

As outlined in the introduction, a total of about 4,534,000 Bbl of brine and 99 MMCF of gas was produced

in earlier testing from 1979-1983. As shown on Figures 5 and 6, additional amounts of 4,213,123 Bbl of brine and 82,298,000 SCF of gas have been produced since March 1988, when the well was put back on production, through January 31, 1989. This has been at flow rates averaging 17-20,000 BPD.

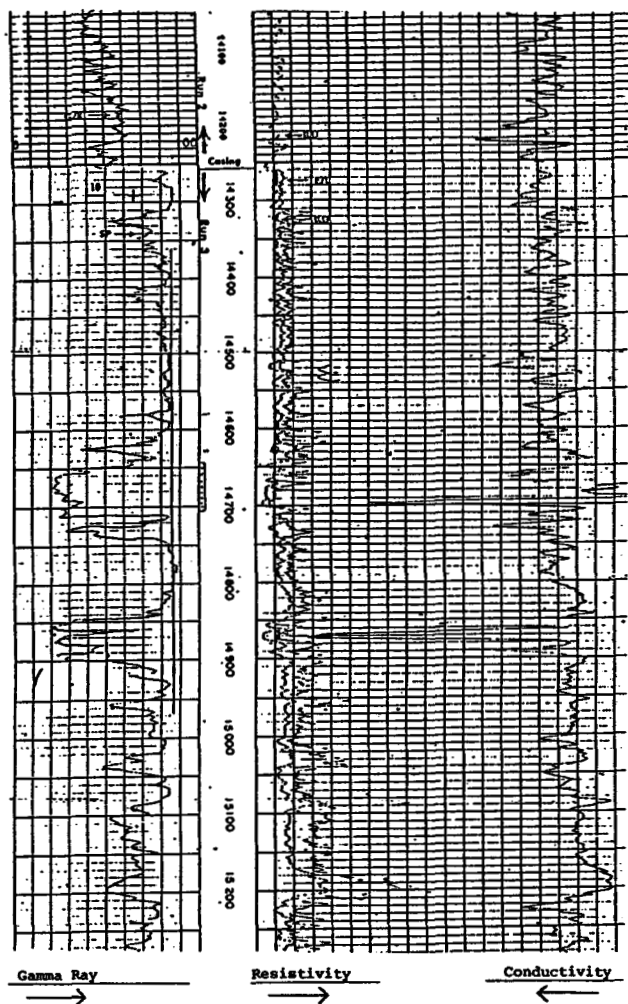


Figure 4

The previous reservoir testing by other contractors provided data on permeability/thickness product (Kh) of the target sand, lack of barriers to flow near the well bore, and fluid chemistry.

The actual drawdown of the reservoir pressure, near the end of the prior production in 1983, now appears to have been less than thought at the time. Wellhead pressures were depressed due to scale and resultant high pressure drop across a ball of wireline in the flow loop, as well as scale in the tubing (approximately a 3/8" layer of scale was found in the tubing fish when it was removed during the Eaton recompletion in 1986). The previous data collected suggested very little, if any, change in brine chemistry or gas/brine ratio. The scale inhibitor squeeze technique appears to have solved the scaling problem, though it may be necessary to repeat it.

EOC/DOE 2-Pleasant Bayou

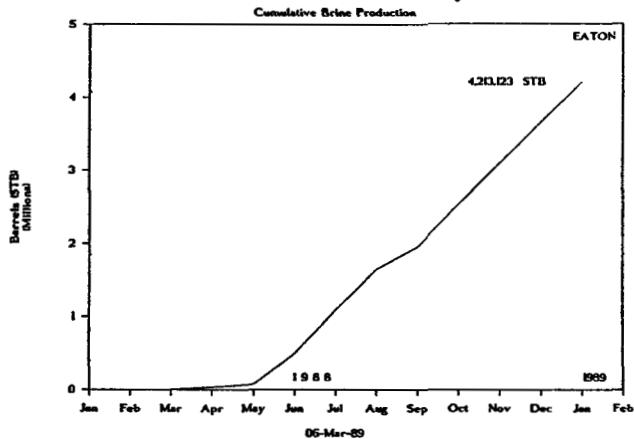


Figure 5

EOC/DOE 2-Pleasant Bayou

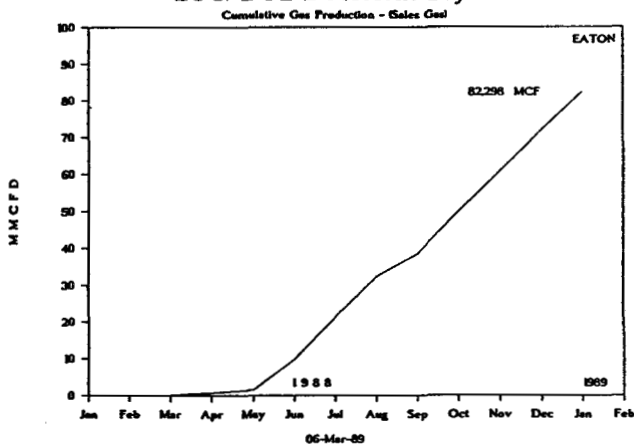


Figure 6

It appears that the disposal well will require clean-out and possible perforating of additional intervals to maintain production rates of 20,000+ BPD. This will probably be done when the well is shut in to hook up the HPS.

Some of the reservoir areas of interest in this testing are:

- o Are skin effects rate dependent? If so, why?
- o What is the effect of the scale inhibitor pill on Kh?
- o What is the maximum life of the scale inhibitor squeeze? When will another be required?
- o Is there any hydraulic communication with any oil or gas reservoirs?
- o Is shale dewatering a significant reservoir drive mechanism?
- o Is compaction occurring in the formation from reservoir pressure depletion?
- o Where does significant corrosion occur?
- o Where is the sand in the disposal well coming from? Can it be controlled?

- o What are the contributions of: (1) loss of Kh, (2) skin, and (3) charging of the finite reservoir volume to the increasing injection pressures in the disposal well?

Some possible areas of change that might require plan adjustment are:

- o Significantly increasing gas-water ratios.
- o Significant oil production.
- o Evidence of significant scaling or corrosion, especially in the production tubing.
- o Major changes in brine chemistry.
- o Changes in the mechanical condition of the production well, production facilities, and/or injection well.
- o Excessive disposal well injection pressures.

Controlling Factors

As outlined in the sections above, the primary controlling factors of this project are:

- o Maintaining pressure and deliverability of the producing well, and long-term life of the producing reservoir.
- o Injection pressures and fluid volume accepted by the disposal well.
- o Turbine life and long-term mechanical reliability of the HPS.
- o Scaling and corrosion.

Conclusions

This is an exciting and challenging research project. If adequately funded, extension of the test period by at least another year could yield significantly more results, both for the HPS and reservoir analysis. One goal is to improve the HPS technology to the point where electricity could be produced commercially from a substantial number of geopressured resource sites via "Wells of Opportunity". Another goal is to be able to predict reservoir size and longevity, hydrocarbon content, salinity, etc. with 90% confidence, over a ten year period, by 1992. The same is true of the injection well performance. Scale inhibition treatments will continue to be improved, overcoming one of the major obstacles to long-term production in the past.

Other research, such as coring to determine formation alteration from production (compared to original cores) and residual effects of scaling inhibitor squeeze, can also be done if funding is available.

References

- (1) "EPRI Draft Test Plan", Evan Hughes - EPRI, February 8, 1989 (includes test plan written for EPRI report by Richard Campbell - The Ben Holt Co.)