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Energy

GEOTHERMAL

NEW MEXICO STATE UNIVERSITY CAMPUS GEOTHERMAL DEMONSTRATION PROJECT

Technical Completion Report

By
Roy A. Cunniff
Kevin P. Fisher
Prasan Chintawongvanich

April 1984

Work Performed Under Contract No. FC07-80ID12137

Physical Science Laboratory
Las Cruces, New Mexico

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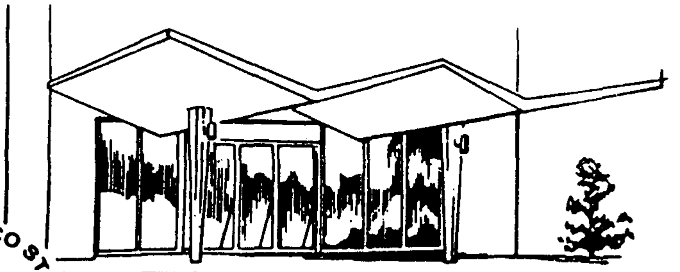

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ABSTRACT

This report presents the design, construction highlights, and performance of the New Mexico State University Campus Geothermal Demonstration Project at Las Cruces, New Mexico. The installed system was funded by the New Mexico Legislature and the Department of Energy under a cooperative agreement. Construction started in July 1981, first system use was January 1982, and the system was dedicated on April 21, 1982. Included herein are summary observations after two years of use.

The geothermal hot water from New Mexico State University wells is used to heat potable water, which in turn provides 83 percent of the domestic hot water on the New Mexico State University campus, as well as space heat to two buildings, and for two heated swimming pools. The original system is providing service to 30 total buildings, with two additional buildings (150,000 square feet) in process of geothermal conversion.

The system overall performance has been excellent, except for geothermal well pump problems. In terms of operating efficiency, the system has exceeded the design parameters. In spite of abnormally high costs for well and pump repairs, the system has shown a positive cost avoidance of more than $118,000 for the first year of operation. For the first two full years of operation, the system has produced a net positive cost avoidance of more than $200,000. Payback on the total investment of $1,670,000 is projected to be 6 to 10 years, depending on the future prices of natural gas and electricity.

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1. INTRODUCTION

On the New Mexico State University campus at Las Cruces, New Mexico a large scale geothermal system has been successfully constructed, tested, and used. The system provides domestic hot water to eleven user complexes of university buildings, including the dormatories, student athletic facilities, and the natatorium complex which contains two swimming pools. Currently, the system also provides space heating for 30,000 square feet in two buildings, and construction is underway to expand the system to add 150,000 square feet of heated space in two additional buildings. There will be 32 buildings supported by the geothermal resource. Formal dedication was April 21, 1982, following a seven-month construction program and a three-month operational check-in period. This construction was the culmination of a progressive series of studies, feasibility and research followed by a detailed geothermal acquifer evaluation. Design and construction were initiated after determination was made that on a long-term basis, the aquifer could supply the necessary quantity of water at sufficient temperature.

This project was constructed using $829,000 construction funding from a special appropriation of the New Mexico Legislature, $70,000 of New Mexico funding for a new disposal well, supplemented by $336,000 from U.S. Department of Energy for well drilling and project management. The installed system has the capability to supply 15 million BTU per hour of geothermal heat, and in the initial phase described herein the system is supplying a peak load of 3.5 million BTU per hour.

Operation of the system has demonstrated an overall highly successful use of geothermal energy. In the first 18 full months of operation, the system displaced more than 75,000,000 cubic feet of natural gas, and generated a fuel offset of more than $400,000. Operations were constrained by difficulties with production wells and production well pumps. Follow-on support costs to provide well repair and replacement pumps reduced the 18-month total net positive cost offset to $118,000. For 24 months of service, total favorable cost offset is $200,000.

Problems experienced in production, including large amounts of sand and highly corrosive hydrogen sulfide have largely been resolved. A new production well is being designed to intersect the deeper fractured carbonate rocks, to avoid the sand problem. Well pump problems have been resolved by switching to a new vertical shaft turbine pump to replace short-lived submersible pumps.

1.1 Objectives

The primary objectives of this project were to provide a successful, large scale geothermal direct heat development in New Mexico, and demonstrate the successful application of large scale commercial usage of low temperature geothermal water in New Mexico. To accomplish these general objectives, this project also had to demonstrate the useability of a geothermal resource that has no surface manifestations, and to demonstrate that the resource was environmentally safe to use. Moreover, the project had to demonstrate that proven technology existed to produce the geothermal resource, and that adequate commercial technology existed to use the geothermal water without special research equipment.

1.1.1 Department of Energy Project Opportunity Notice Program

The use of geothermal energy for direct heat purposes by the private sector within the United States has been quite limited to date, yet there is a large potential market for thermal energy in such areas as industrial processing, agribusiness, and space/water heating of commercial and residential buildings. Technical and economic information is needed to assist in identifying prospective direct heat users and to match their energy needs to specific geothermal reservoirs.

In September 1977 and April 1978, the Department of Energy, Division of Geothermal Energy (now the Division of Geothermal and Hydropower Technologies), issued two Program Opportunity Notices. These solicitations were part of DOE's national geothermal energy program plan, which had as its goal the near-term research and development of hydrothermal resources by the private sector. Although this NMSU Geothermal Demonstration Project was funded by a New Mexico appropriation, the basic cooperative agreement contract with DOE was funded for well drilling and project management by the DOE PON program. Accordingly, reporting guidelines for the PON program were incorporated within the NMSU contractual terms with DOE.

1.1.2 Demonstration Project

Demonstration projects receiving financial support under the DOE's PON program must resolve a number of technical and institutional problems ranging from resource exploration to retrofit and operation of the plant on geothermal energy. The technology developed in these initial projects is being made available to the general public and to stimulate the development of geothermal energy.

1.2 Pre-Project Background

From 1974 to 1979 NMSU had experienced a 4,600 percent increase in the cost of natural gas. Moreover, the NMSU gas supply was interruptible; which meant the gas supply could be discontinued during peak usage periods if a prolonged period of cold weather occurred. The compound problem of escalating costs and the increasing probability of gas supply disruption was expected to continue indefinitely into the future. Research funded by New Mexico and DOE had provided evidence that a potentially usable geothermal resource existed underneath NMSU-owned land. This research started with evidence that a few warmer-than-normal shallow wells existed. A comprehensive series of geophysical investigations were conducted which culminated in two deep geothermal gradient wells completed in early 1979. These gradient wells established the existence of a resource with a probable temperature of at least 140°F, and possible flow rates of up to 200 gpm.

In August, 1979, NMSU drilled the first geothermal production well to a depth of 850 feet (NMSU PG-1). Subsequent limited flow testing showed evidence of 200 gpm potential, with well-head water temperature of 142°F. A second shallow production well was drilled later in 1979 to serve as the heating source for the University Center and President's house. This well (NMSU PG-2) is 600 feet deep and produces water at 118°F.

Based on the successful well drilling, New Mexico Energy and Minerals Department provided funding for a detailed aquifer evaluation and design of a geothermal system. The design phase was intermeshed with the DOE funding under the cooperative agreement, and also served as the scientific basis for the construction appropriation by the New Mexico Legislature in March 1981.

As defined for back-up data to the appropriation, the proposed NMSU Geothermal Energy Application Project would use geothermally heated domestic hot water to supplement the central steam space heating system, and provide domestic hot water to campus buildings to replace an estimated 50,000 MCF (roughly equivalent to 50,000 million BTU) per year of scarce and costly natural gas consumption. Moreover, the natural gas replaced by geothermally heated water would be available to Las Cruces to provide additional space heating for the rapidly expanding residential sector.

1.3 Project Scope

1.3.1 Initial Scope

Based on the engineering design feasibility study, the project was defined in scope to include domestic hot water to five NMSU dormatories, and four other buildings, along with heat for the indoor swimming pool. The conceptual design provided for one primary production well, with a single back-up well, and one disposal well. Proposed design heating load was a peak load of 7.5 million BTU per hour. To meet this load, the hot water storage tank was conceptually sized to hold 50,000 gallons of water. Expected geothermally heated domestic water supply temperature was 125°F, with probable minimum temperature of 115°F. Peak flow rate (normalized at 105°F) was expected to be 300 gpm. To support this load, a single heat exchanger was specified, which was to be titanium clad to avoid expected corrosion problems.

1.3.2 Final Scope

The completed project is shown in site context in Figure 1-1, and a more detailed schematic portrayal is shown in Figure 2-1.

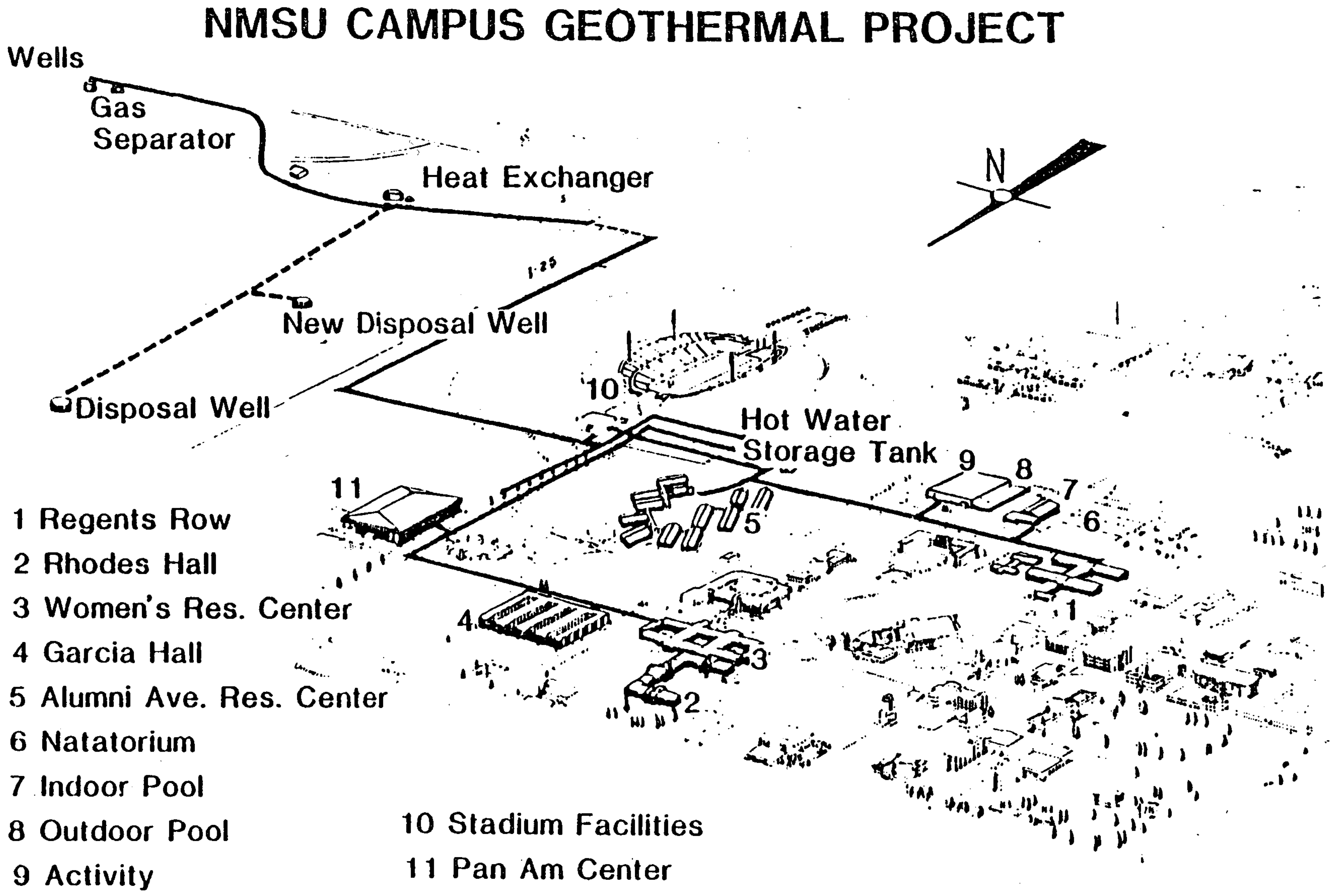


Figure 1-1 NMSU Campus Geothermal Project.

The production well field contains two production wells, each capable of supplying twice the required heat load.

- Disposal operations encompass two disposal wells, each capable of handling twice the current geothermal production volume.
- Two identical primary heat exchangers were installed, each capable of handling 200 gpm flow rate. The exchangers are stainless steel (Type 316 L) plate and frame exchangers.
- The hot water storage tank has a capacity of 60,000 gallons of hot water.
- Installed heat load capacity is 15.0 million BTU per hour, and current peak load supplied is 3.5 million BTU per hour.
- Peak hot water flow is 400 gpm.
- The installed system provides domestic hot water to eleven building complexes (32 total buildings) provides heat for the indoor swimming pool (270,000 gallon pool) and the outdoor pool (500,000 gallon pool) and provides space heat for the the Natatorium complex and the Football Stadium Office. (30,000 square feet of heated space).

1.4 Growth Potential

1.4.1 Future Possible Expansion

The engineering design phase for the currently installed system addressed only domestic hot water consumption as the primary use of the geothermal water. During that study, however, evidence was accummulated that some space heating also was possible. Subsequently, the constructed system included space heating application for two buildings, plus a type of space heating for the two swimming pools. The engineering study also identified future space heating targets if the developed system resulted in sufficient confidence in the resource and resource application to warrant expansion. Figure 1-2 is the buildings which are candidates for near-term future conversion to geothermal heating.

FUTURE EXPANSION

OPTION		SAVINGS
Two buildings under design for Geothermal Heating:		
	Ft^2	
O'Donnell Hall	54,000	2-year payoff of capital costs of $65,000
Breland Hall	94,000	2-year payoff of capital costs of $75,000
Total	148,000	Will use part of installed capacity
Add space heating to 8 currently-served buildings		$70,000/year
Convert 24 other buildings		$250,000/year
Add future new buildings (Business Building and other new buildings)		

Figure 1-2

1.4.2 Near-Term Future Expansion

Expansion of geothermal service to the following buildings, all on Stewart Street, is recommended to provide capability to discontinue steam service totally on the south steam pipeline from the Central Plant to the Alumni Dormatories mechanical equipment room during the five-month "summer" condition. Normally from mid-April to mid-October, the Central Steam Plant is switched to the small boiler, and the steam system is operated in the 50 psig mode.

Activity Center
Breland Hall
O'Donnell Hall
Anderson Hall (Physical Science Laboratory)

1.4.3 Current Expansion

A modification currently is under construction, scheduled to be completed in mid 1984, to provide geothermal space heating to O'Donnell and Breland Halls. This modification is funded by a cost-sharing agreement between NMSU and the Energy Conservation Program for public schools. The project entails a pipeline extension to both buildings, as well as building retrofit for both space heating and domestic hot water

1.4.3 New Deep Production Well

A decision is pending for a new 2,400-feet deep production well. Much preliminary work has been conducted to determine a suitable location for the exploratory well site. A site in the vicinity of a likely fault-intersected zone has been selected based on surface geophysical work conducted as part of the production well decision process.

Geological data obtained from self potential, soil helium and soil mercury surveys, coupled with temperature gradients and electrical resistivity studies provide information needed for the site selection. These studies were used to supplement data from a refraction and reflection seismic survey which covered 4.7 line-miles.

2. SUMMARY

The overall system operation is illustrated in Figure 2-1. Either of two production wells in the well field can supply the required production rate of 100-200 gpm, at a temperature of 141-145°F, to the primary heat exchangers after the dissolved CO_2 has been stripped off by the gas separator. The gas separator is located at the well head and the heat exchangers are 6,200 feet away, adjacent to the main campus domestic water storage tank. Water from the main campus water tank is heated in the primary heat exchangers and then supplied through 6,000 feet of buried pipeline to the hot water storage tank for distribution to system users. This storage tank is located on the main campus, adjacent to two of the primary users of domestic hot water.

The cooled geothermal fluid is routed to the disposal wells located one-half mile from the heat exchangers, and reinjected into the geothermal aquifer. The hot water storage tank provides domestic hot water at peak flow rate of up to 400 gpm, and provides a short-term storage capability in the event of temporary system outages. The system components have been sized to provide a built-in capacity for future expansion. The system controls and instrumentation are an integral part of the NMSU Campus Energy Management System (EMS) which is designed to provide remote monitoring and centralized computer control of energy consumption.

During 24 months of operation, the system has operated relatively trouble-free for most of the system components. The Heat Exchangers have been disassembled for inspection three times, and no fouling or scaling has been present. The Gas Separator has worked as designed, and provided a simple, but effective, way to get rid of troublesome dissolved gases. The Hot Water Storage Tank has performed as designed to maintain temperature for peak flow needs, and the control point of the on-campus distribution system. Moreover, it was used as a short-term back-up source during six unplanned system outages caused by electrical malfunctions (one operator error and five weather-induced). In addition, the tank has provided a capability to maintain a usable temperature for longer-term outages of up to 72 hours. The installed system demonstrated a capability of providing domestic hot water at 138°F to the campus, starting with a geothermal resource temperature of 142-144°F with only a four to six-degree loss in temperature through four miles of pipeline and the heat exchangers.

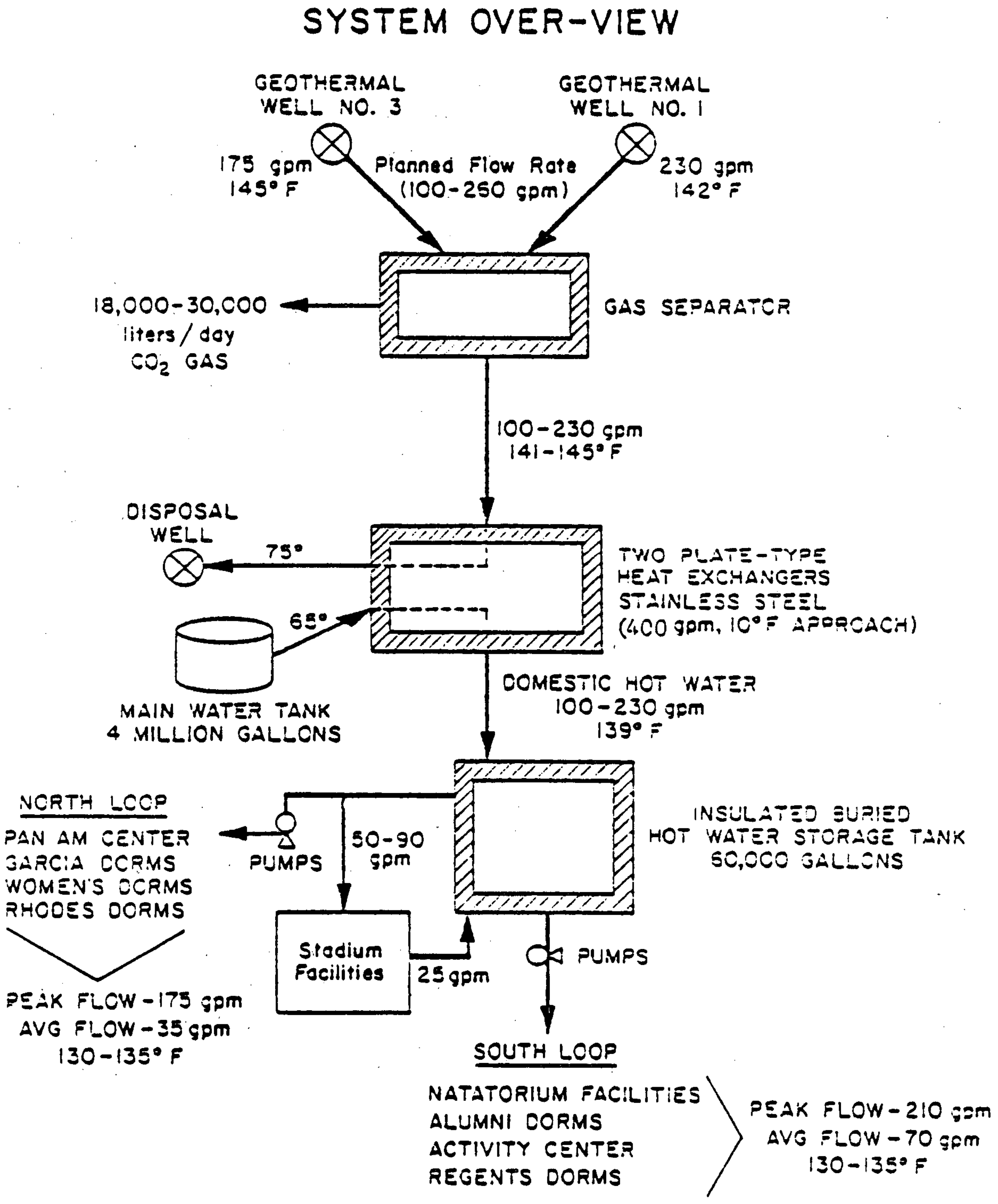


Figure 2-1 NMSU Campus Geothermal System

2.1 Project Development

Construction of the geothermal system was funded by a special appropriation of $829,000 to New Mexico State University from the New Mexico State Legislature in 1981. Funding for the well field expansion completed in January 1981, Project Management and system monitoring was provided by a grant from the U.S. Department of Energy through the Idaho Operations Office. Follow-on funding by the New Mexico Energy and Minerals Department was provided to drill and complete a second disposal well, completed in October 1982. An additional grant from New Mexico Energy and Minerals Department was used to conduct detailed geophysical studies leading to a new deep, production geothermal well expected to be drilled and completed in 1984. Concurrently, New Mexico State University funds have been used to cost-match other funds used to expand the system to provide space heat to two additional buildings (Breland Hall and O'Donnell Hall with a combined total of 150,000 square feet of heated space.)

The Geothermal Demonstration System has resulted in a considerable saving; this saving is developed in detail in Section 33.0. The natural gas displaced is available to the City of Las Cruces for residential or other use. In addition to a secure, economical source of heat, there are many other benefits generated from the geothermal project.

The engineering construction, design, and economic evaluation document for this project, Report EMD 2-68-2207, provides a complete guide for design and construction of similar projects. A detailed study and analysis of campus energy requirements and methodology to gather required data is given. Detailed design criteria are listed for each of the major components of the geothermal system. The cost/benefit analysis is an excellent guide for economic evaluation of other projects.

A low temperature aquifer having considerable production capability has been identified; work continues to identify the full extent and production capability of this aquifer. Successful exploitation of this aquifer has encouraged geothermal work in the Rio Grande Rift in particular, and in general, in other geothermal areas. The installed system is a built-in visitor show piece. In the past 24 months, more than 175 groups of businessmen, students, and civic leaders have toured the project, in addition to representatives from foreign nations.

A brochure has been prepared to provide the geothermal developer with a simplified guide and checklist to aid in completing the permitting process in the State of New Mexico. Detailed instructions are given to guide the developer through the technical process necessary to acquire permits for a geothermal well. For each progressive step which involves state and federal agencies, the regulatory process is detailed. The brochure also provides sample completed forms and instructions for completing these forms.

2.2 Economic Result

The system provides heated water to eleven building complexes on the NMSU campus. Heat sources are provided to a total of 32 buildings including space heating, domestic hot water, and heating of the indoor and outdoor swimming pools. This geothermally heated water displaces steam from the Central Heating Plant and consequently reduces natural gas consumption. The payback period for this project is estimated to be 6 to 10 years depending on the future costs of natural gas and electricity. Current gross annual savings are estimated to be at least $250,000. See section 33 (System Economics) for further details.

2.3 Net Energy Analysis

2.3.1 General

A method of assessing the comparative advantage of energy replacement system is so-called net energy analysis. In this still new method of project evaluation, the total energy for all materials and energy expended over the life of project is calculated for each of the alternatives. It is noted that the net energy analysis is somewhat limited in that the energy of certain maintenance and operations over the project life is only crudely known. The great advantage is that the method is entirely independent of monetary inflation and variable cost escalation of alternative fuel and materials.

For this particular project, the errors introduced by estimation are rather small, because the large portion of the energy is readily calculated generating energy. (Approximately 95 percent of the total project expended energy is for pumping).

2.3.2 Methodology

The net energy analysis of the NMSU Geothermal Project was conducted for domestic hot water heating. Geothermal fluid at 142°F was taken as free good, but all items of energy involved in constructing and generating the system were taken as an energy cost. The energy which would not be used in the existing Central Heating Plant was taken as an energy credit. The net benefit over a 15 year life, in BTU and as a percent of energy now being expended, was then calculated.

The following method was used to determine energy of construction:

(1) Well drilling; information from a drilling contractor on fuel expenditure per 100 feet of depth in the type of formation represented by the NMSU geothermal aquifer.

(2) Well completion; published figures on energy consumption for iron and steel making, plus design weight of metal used to fabricate well casing, pump bowl, pump column, etc. (Omitted: Energy & mining and transporting ore and coal).

(3) Pipe fabrication; the system pipeline consists of both steel pipes and asbestos pipes. Energy consumption for pipe fabricating was based on the published figures on energy for steel and asbestos making.

(4) Heat exchanger, gas separator, and hot water storage tank; same as item (2).

(5) Insulation; heat of formation of design amount of insulating material.

(6) Installation; approximate figures on hourly fuel consumption of trenching and welding machinery, plus the total hours of operation in completing the system.

(7) Maintenance and operations; record of wells and well pumps repairing, plus fuel consumption for vehicle used to maintain the system operation.

The system operating energy was based on the actual data of annual electricity consumption for well pumping. The BTU equivalent of electrical energy was computed at 30% overall efficiency of electrical generation.

Table 2-2 shows the net energy analysis for domestic hot water to the eleven building complexes over a 15-year period, assumming no change in present demand. Calculation is detailed in Section 33.10. The calculation was for; (1) a geothermal fluid of 142°F which adds 75°F to heat the supply domestic water on the average flow rate of 100 gpm and a 240-day per year basis, (2) the system overall efficiency of 52 percent (80 percent Central Plant efficiency, and 65 percent end-use efficiency). A net saving of 85.6 percent of natural gas now being used is predicted, this amounts to over one-half billion cubic feet of natural gas saved over a 15-year period. (The natural gas saved was based on an assumed heat content of one million BTU per MCF).

Table 2-2

NET ENERGY ANALYSIS--DOMESTIC HOT WATER HEATING

Total energy expended on project, by category, in 15 years. The geothermal resource is considered free and reusable.

Component	Million BTU
Well Drilling	211
Well Completion	651
Pipe Fabrication	1,059
Heat Exchanger	84
Gas Separator	70
Hot Water Storage Tank	252
Insulation	15
Installation	885
Maintenance and Operations	1,473
Energy for well pumping	83,325
Total Expended Energy	90,025
Natural Gas Use Replaced	623,080

Net Energy Saving: 85.56%, or 0.533 billion cubic feet of natural gas saved over a 15-year period.

3. CONCLUSIONS AND RECOMMENDATIONS

3.1 Technical

3.1.1 Overall Conclusions

The project has proved to be a technical success, and has been a highly successful demonstration of large-scale geothermal operation. It has served as a focal point of New Mexico State University alternative energy research, and many useful applied research lessons have been learned to be transferred to other private sector applications. At the same time, the project has permitted a detailed assessment to be performed of the Las Cruces geothermal anomaly, and quite possibly will pave the way for a very large city heating district project. More than 175 different groups from this county and six foreign nations have toured the project. In spite of less than satisfactory well pump life, the project has operated successfully for two years, and is being expanded. It will serve as a viable and expanding project for many years.

On the financial side, the project is commendable because such a large project was constructed with a relatively small capital outlay in comparison with other geothermal projects. The greatly truncated well pump life has caused NMSU expenditures to support the system operation to be much larger than forecast. In the first 18 months of operation, support costs have been four-fold larger than anticipated. Overall, natural gas savings have more than covered these support costs, however, and the project shows a net favorable cost variance of more than $200,000 for the first two years of operation.

3.1.2 Dissolved Gas Control

In the earlier stages of aquifer evaluation, the focus of research was on the gross parameters of fluid extraction rates, reservoir performance, likely life and other information. After the first permanent pump was installed, however, the problem of dissolved gases became a concern. The vendor of the first pump attributed substandard pump performance to the presence of dissolved gases in the water. Partly to assess the legitimacy of that claim, but also to gain a better understanding and control of the geothermal fluid, a program of focused research was started. Initially, a small test apparatus was designed and constructed at the well head to accummulate gases and measure the dissolved gas content. This program, coupled with detailed water analyses, enabled the team to determine gross gas parameters. It was soon recognized that dissolved carbon dioxide was the potentially largest source of problems. At the same time, the program benefited from a research program conducted by Carl Bernhart of New Mexico Tech under the guidance of Dr. Norman. Their research was an attempt to devise a new gas geothermometer, and the program involved acquiring and meticulously analysing water samples from geothermal wells and springs to measure gas content. The samples obtained from our wells provided the first complete analytical data for dissolved gases.

Based on the field data from the test apparatus, and Carl Bernhart's analyses, the large scale gas separator was designed and built. Subsequently, a series of follow-on gas analyses were done, and these analyses confirmed that the gas separator was performing to design specifications. More than one-half of the dissolved carbon dioxide, and most of the dissolved nitrogen was separated by simply expanding the pumped fluid to atmospheric pressure in a large surge vessel.

Because of the corrosive nature of the geothermal water, coupled with the very high fluid velocity resulting from this rapid expansion, stainless steel fittings were used in the final valve and the piping interconnects. At the time of initial construction, however, an artificial constraint was imposed by procurement rules so that the valve body was mild steel so as to keep the valve cost within artificial cost limits. As a consequence, the valve failed after only 1,000 hours of operation. It was replaced by the correct stainless valve body, which now has more than 15,000 hours of operation.

As an important side benefit of the dissolved gas control program, the analytical work also facilitated calculations for the partial (vapor) pressure of the gasses. In turn, this information provided guidelines for pump setting levels and dynamic draw-down levels to assure sufficient water head was in the well bore to keep pump section pressure higher than the dissolved gas partial pressures.

3.1.3 Materials Selection

Based on an active program of literature research and laboratory testing, an early determination was made that selection of materials to combat expected corrosion problems was a key decision. From the analysis of dissolved minerals, gases, pH, and temperature of the geothermal water, the research team had confidence that stainless steel type 316L was probably most compatible with the fluid. Further, the pipeline should be epoxy lined, as would be the large tanks used for the gas separator and the 60,000 gallon hot water storage tank. Moreover critical control valves would have either a stainless steel body, or stainless steel trim with epoxy coating on the surfaces exposed to geothermal fluid.

Other than the one valve failure identified earlier, there have been no system surface components which have failed due to corrosion in more than 15,000 hours of operation. The stainless steel heat exchangers have been dismantled three times for inspection, and show no evidence of fouling or corrosion. The down hole equipment has not faired nearly as well, even though the pump columns have been coated with epoxy on the exterior surfaces. The corrosion problem in the wells has resulted from an unexpectedly high level of hydrogen sulfide gas which has caused sulfide embrittlement and consequent severe pitting, scaling, and attack of threaded portions of the pump column. This latter problem possibly is amenable to control with flanged column pipe with special O-ring grooved fittings and epoxy coating on column pipe interior and exterior surfaces.

These latter measures were used on the last pump setting on the primary production well, PG-1. The protective features are not yet field tested, because the well produced so much sand during initial pump testing that the pump was removed. It will be re-installed in mid-1984, and long-term use will dictate how successful the new protective measures are in controlling sulfide embrittlement.

3.1.3 Primary Heat Exchangers

During the design stages of this project, the primary heat exchangers were sized for an expected peak demand of 250 gpm. As the project end-use boundaries expanded, and as better data became available for likely peak and average hot water demands, a need was foreseen for expanded capacity. Moreover, titanium-clad heat exchangers initially were being considered to combat expected serious corrosion problems. As indicated previously, the on-going research suggested that type 316L stainless steel would be adequate. It was also foreseen that a need would exist to inspect the heat exchangers on a regular basis, and a capability was required to keep the system in operation during the expected one-week duration inspection and cleaning process. Accordingly, at a cost equal to one titanium exchanger, two stainless steel exchangers were purchased and installed. Each is rated at 200 gpm capacity with a 10°F approach temperature, for a total installed capacity of 400 gpm. With two exchangers installed, in operation the system uses both, with the flow equally distributed. As a result, the exchangers (because of the doubled heat exchanger surface) are capable of a one-to-two degree approach temperature. The overall system then is able to deliver up to 200 gpm of consumptive hot water to the campus end-points, at a total heat loss of only 3 to 5 degrees from the well head through the entire four miles of pipeline, through the heat exchangers, and through the hot water storage tank. This performance exceeds design parameter, which allowed a 17-degree temperature drop, and which also considered as much as a 27-degree temperature drop as adequate for intended system use. One major result of this performance has been high confidence levels in the system, and concurrent expansion plans for space heating applications which can use the 136 - 138°F delivered temperature.

3.1.4 Outdoor Pool Heat Exchanger

This smaller unit is also a plate-and-frame exchanger, which was sized for a 10°F approach at a balanced flow of 80 gpm on both cold and hot sides. The cold side is swimming pool water, which requires chemical temperature (effectively chlorination) to meet health standards. The team explored the possibility of directly mixing potable hot water with pool water to heat the pool. The cost of chemical treatment far outweighs the cost of heating. Hence, a heat exchanger is required. The unit worked as designed, but a problem occurred because the hot side reinjection temperature was 95°F or better at flow rates above 40 gpm. This temperature resulted from the highly efficient system performance in delivering hot water to the campus. Original design was to reinject the cooled hot side water back into the domestic (cold) water drinking supply, but the elevated temperature excessively warmed the cold water supply for adjacent buildings. The problem was solved by adding additional plates to the exchanger, so that its net output increased by 50 percent, which at the same time produced a 4°F approach temperature. Cost of the change was only 10 percent of exchanger costs, and was accomplished very easily.

3.1.5 Hot Water Storage Tank

The system design considered a 50,000 gallon tank to be adequate, and also envisioned a large 35 Hp circulation pump which would operate through a 3-way valve to keep the tank contents thoroughly mixed to control expected temperature stratification in the tank. This large pump was to be supplemented by smaller in-line pumps. Design changes increased the capacity to 60,000 gallons, which was installed. A more cost-effective alternative was designed and built to control temperature stratification. To minimize circulating pump needs if water was withdrawn from the top of the tank, both inlet and outlet ports are in the lower part of the tank. In turn, each is connected to a perforated pipe which runs the length of the tank (72 feet). The two perforated pipes are three feet apart. Inlet water at 136 - 138°F blends with tank water, and the outlet draws from the same general horizon throughout the tank. Even after prolonged shutdown, outlet temperature is within four degrees of inlet.

Because the tank is insulated, and buried so that the top is three feet below ground level, the tank has a very low rate of heat loss. In controlled testing, the tank lost less than 1°F in 24 hours under lock-up conditions, and still provided a 125°F usable temperature after lock-up of 120 hours. The tank also serves to provide in-place capacity for up to 400 gpm peak demand, with a six-hour reserve, or 250 gpm peak demand with a 16-hour reserve. During six unplanned power outages, the tank has provided all required hot water demands. The tank is replenished by a 100-gpm constant inflow. As system demand increases for follow-on use, the inflow rate will be increased. Total system distribution system pumping needs are met using one 3 Hp, one 5 Hp circulating pump and one 7.5 Hp pump. The smaller pumps have decreased system operating costs by more than $10,000 per year at current electricity costs, in comparison with the single large pump originally envisioned.

The tank was emplaced by using a sand cement foundation which was poured after the tank had been installed and connected to the system, and the tank had been insulated. This method was very cost effective compared with poured concrete, and also avoided differential settling which would have cracked connecting fixtures. The design and installation proved to be very effective.

3.1.6 Space Heating for the Football Stadium Building

This building heating system was designed for 180°F circulating hot water, with the energy supplied by a buried steam line and condensate return line 1,200 feet long. The original design considered supplying only geothermally heated domestic hot water, by a separate small feed line from the primary distribution system pipeline some 400 feet away. After performing tests to determine heat load in the building, and heat loss from the steam and condensate lines, a change was engineered to supply building heat by using the 135°F water piped to and from the building using the existing steam/condensate lines. Initial calculation indicated a rate of 50 gpm would be required under peak winter load. Subsequent system testing showed that the actual load was met by 30 gpm, with a heat loss in the overall loop from hot water storage tank to the stadium and return, of only 200,000 Btu per hour. The original steam system was providing more than over 500,000 Btu per hour. The difference between the two values represents wasted energy. The system proved so efficient that the stadium and other facilities satellited on the geothermally installed hot water storage tank are supplied by circulating hot water during those periods of time when the geothermal system is shut down. If necessary, the steam system could be reinstalled by merely opening and closing appropriate valves.

3.1.7 After the procurement bidding process had resulted in selection of Johns-Manville TEMPTITE as the pipeline material, detailed heat balance calculations were made. This analysis suggested that the uninsulated couplings normally installed (which amount for roughly 8 percent of total pipeline length) could result in a loss of several degrees of temperature in the overall system. Moreover, at that point in the design process, concern existed that the pessimistic design case (120 - 127°F delivered water temperature) possibly would occur. The team felt that the uninsulated couplings temperature loss was unacceptable. Accordingly, a field insulation was applied to every coupling during installation of the pipeline. The insulation consisted of 5/8-inch Armoflex, fixed into and around the coupling. A vapor barier consisting of two sheets of 4 mil polyethylene was then taped tightly around the coupling. After the system was installed, field trials verified that at least 2.5°F temperature loss was avoided. Based on material and labor costs, the incremental cost for this insulation was $0.50 per foot, with a resultant total additional pipeline cost of approximately $7,500.

3.1.8 Back-up Production and Reinjection Wells

Early in the design phase, the team recognized that major uncertainties existed concerning life of the resource, equipment performance, and equipment life. Since this was a demonstration project, additional measures were necessary to assure redundancy in critical system components. For these reasons, the system installed contained two production wells, each equipped with a pump, and two disposal wells. (The second disposal well was drilled and completed as a New Mexico funded project after the system was dedicated). The wisdom of this decision is best evidenced by the fact that the system has been supplied only by the secondary production well (PG-3) for a 12-month period starting in March 1983. In that time, a series of pump failures and other well problems have caused the primary production well (PG-1) to be out-of-service. Moreover, the system has been successfully adjusted and modified numerous times without terminating service because back-ups and by-pass systems are available.

3.1.9 Geothermal Well Design

The major conclusion reached after testing and using the geothermal wells for almost four years is that a severe penalty has been incurred for the original decisions made on well casing diameter, and well screen material. Both production wells have a 10-inch inside diameter. A vertical shaft turbine pump for dynamic pumping conditions is then limited to a maximum size of 235 gpm. It is true that a submersible pump could be purchased to provide 350 gpm under larger draw-down conditions, and submersible pumps initially were used. However, the high speed, and light weight construction of the submersible pumps makes them vulnerable to short lives if measureable sand is present in the pumped fluid. Thus, possible aquifer production was constrained by casing diameter.

This under-sized casing also caused other problems. The large amount of dissolved carbon dioxide in the fluid could be controlled by reinjecting a bypass stream into the well. This also would help to control carbonate scale build-up on the well screen. There is inadequate clearance between the pump column and casing to permit any realistic size of reinjection tube. Another constraint occurred when the team investigated the feasibility of using an eductor-type, down hole sand separator to remove the sand before it damaged the pump, and to discharge the sand at the surface so that the well did not sand-in. Here, again, the concept is feasible, but cannot be done in current wells because there is insufficient clearance between the eductor assembly and the well casing. Throughout the testing and use cycle, the undersized casing also has hampered efforts to insert down-hole instruments to measure and record subsurface events.

Concerning well screen material, two years of full-scale production usage have confirmed the existence of a highly corrosive environment, with hydrogen sulfide a major factor. There is considerable evidence that the primary production well (PG-1) drilled and completed in late 1979, reached its usable life in less than four years. The well screen is slotted carbon steel, and down-hole video cameras show a pattern of enlarged slots and slot corrosion which is contributing heavily to sand infiltration problems.

For the new disposal well (GD-2), the well screen is a wire-around stainless steel screen; this is expected to be much easier to clean, and should have a much longer life than the carbon steel screen. Any future production well completed in the hot, saline, and hydrogen sulfide environment should use stainless steel screen.

After the well problem became critical for PG-1, an attempt was made to see if the observation well could be placed into service as a production well. However, the original well engineer had specified a 4-inch casing (even though a 6-inch casing would have added less than 4 percent to the well cost). Although numerous pump alternatives were examined, the team could find no pump that would fit inside the 4-inch casing. We did find numerous pumps, with a capacity for almost all of the required production rate, which would be usable inside a 6-inside casing.

3.1.10 System Installed Capacity

As previously indicated, the installed system had redundant capability for operational readiness. This extra capability is also translated into extra installed capacity. Each production well had twice the capacity of average load conditions. The primary heat exchangers have four times the current average flow capacity (100 gpm), or an installed capacity of 400 gpm. The connecting pipelines and dual-installed circulating pumps have four times the safe capacity of current average flow needs of 100 gpm. In terms of installed load capacity, the system can deliver almost 16 million Btu per hour, whereas the current load is only 3.5 million Btu per hour. This extra capacity is a result of conservative engineering to guard against uncertainties.

This load includes the two space-heating loads (30,000 square feet) plus the outdoor swimming pool heating which represent expansion over the original design concept. Thus, the constructed system is bigger and more efficient, and the accelerated construction meant the system was in-service far earlier than the required operational date.

Now, however, with two years of operational experience, the extra capacity represents built-in capability for incremental system expansion which is occurring. This expansion, however, is hampered by the lack of a usable primary well, and NMSU currently is planning a new 2,400-feet deep production well which will intersect a fractured linestone formation, with expected yield of up to 750 gpm.

3.2 Institutional

3.2.1 Contruction Management

The initial system design had a construction cost estimate which appeared to be unrealistically low. However, this cost estimate, prepared before the design process was complete, formed the basis of the appropriation request to the New Mexico Legislature. It was not possible to get an increase in the appropriation, so the next best thing was to attempt a less costly construction option. Accordingly, a team was formed from Physical Science Laboratory engineers, supplemented by expertise from the Civil Engineering Department. A construction crew was assembled, consisting of a blend of upper division engineering students and professional construction technicians. This crew was organized, trained and equipped, and proceeded to build the system. The system design was an evolving process, which proceeded from system component design, construction, and test on a sequential basis working through the system from wells to gas separators, to primary heat exchangers, hot water storage tank, end-use distribution system and retrofit. As tests demonstrated performance criteria in one segment, the results were fed back to allow appropriate adjustments in other segments. Because there was total control of the labor force, and material acquisition, the team was able to orchestrate cost and schedule adjustments with maximum flexibility. This method proved to be highly effective for this system, and more than one hundred major and minor changes were incorporated "on the fly." The normal construction bidding process, which predicates a fully completed design, would have resulted in a much more costly construction program, as well as one which would have taken at least one year longer to complete.

3.2.2 Documentation

Because detailed engineering design drawings were not required, a concerted effort was made to document the construction and test results as construction proceeded. A comprehensive procedures manual was assembled, consisting of "as-built" isometric sketches, valve labeling and identification, technical literature for all key components, and detailed written procedures. Also prepared was an "as-built" pipeline layout, which contains field routes and surveyed locations for all buried pipelines. In spite of the availability of this type of documentation, operational errors have occurred by personnel now operating the system. In part, these errors are simply an unwillingness to read and follow the existing procedures. In other cases, adjustments are made without fully comprehending the consequence. After two years of operation, however, an effective operating procedure has evolved, based almost exclusively on memorized sequences. One major failing of the evolved documentation is the lack of blueprint quality, "as-built" schematics. No time or money was available to fill this need, and the deficiency should be corrected before too much time elapses, and while key members of the geothermal team are still available.

3.2.3 Permits

One useful side benefit of the project was the evolution of a comprehensive written guide for geothermal development. When the project was conceived, there was no procedure for large scale geothermal direct use development in New Mexico. The Union Geothermal/DOE Baca project was an electricity project, and existing New Mexico Geothermal rules had been developed for geothermal steam wells. Moreover, New Mexico has shared jusisdiction on geothermal water wells. (State Engineer for consumptive water rights, and the Geothermal Division of the Oil Conservation Division of Energy and Minerals Department for geothermal correlative rights.) This problem is compounded by dual jurisdiction with the Federal Government (Bureau of Land Management) where surface ownership is private or state ownership, and subsurface mineral rights are in the federal domain. The Guide to Geothermal Well Drilling, written as part of the project, represented a "lesson learned" guide to developers and operators for permit application and processing, and was complete with properly completed examples of all forms and permits used to construct the NMSU Demonstration Project.

3.2.4 Instrumentation System

Although technical in nature, a discussion of this type is included within the institutional section because the primary problems were institutional in nature. An instrumentation scheme had been included in the original engineering design, but this scheme was discarded because the university chose instead to apply a module from the Energy Management System (EMS) which was being installed simultaneously with construction of the geothermal system. Hence geothermal instrumentation became a constructive add-on to the new EMS System, to be added after everything else was done. Flow and temperature sensors were selected by the EMS contractor, and the software for system control and columns was to be provided for by the EMS contractor. The EMS System (installed cost for geothermal almost $45,000) has not worked properly. Two years later, the geothermal system requires manual monitoring to verify conditions. When critical data on flow or temperature are required, it is necessary to use external information to acquire system intelligence. The lack of a good instrumentation system has resulted in confusion, uncertainty, and lack of operator trust in the installed system.

3.3 Economic

3.3.1 Cost Accounting and Control System

Because the team recognized an austere construction budget, at the onset a very detailed cost accounting system was installed. The system was in addition to the mechanized accounting system used by PSL, which is excellent but which has a 30- to 60-day delay for material acquisition. The mechanized system was overlaid with a manual purchase order system so that bi-weekly, then weekly, and finally daily fund status was always available. Although costly in terms of manpower and effort, this system enabled the team to schedule manpower costs and to perform cost trade-offs in real time.

For the actual construction, which followed the engineering design concept for the most part, a design to cost philosophy was followed. Under this concept, the total installed cost was used instead of only material cost. Accordingly, trade-offs could consider labor costs as well as material costs, and time factors. Not only did this philosophy enable the team to meet construction cost goals, it also provided flexibility to accommodate the one hundred or so change orders that were made. Moreover, this concept allowed contingency funds to be freed to allow the constructed system to serve more users (space heating applications) as well as provide installed reserve capacity.

3.3.2 Economic Benefits

Although the installed system represents a success from an operational ready date, capacity, and cost basis, it is not as successful on the same basis concerning benefits. The major problem is one of a lack of conclusive evidence as to system cost savings. This problem stems from a steam-heating system which has almost no metered users. Hence, when the steam service was displaced by geothermal energy, there is technical debate concerning the steam (hence natural gas) displaced by geothermal. Even from an overall perspective, consensus has not been attained on overall benefits. An increased non-heating system steam energy usage (up 24 percent), coupled with a winter which was 22 percent colder than the previous winter, caused natural gas consumption to remain essentially unchanged from previous years. Thus, there is no way to absolutely prove the savings, and no way to disprove them. The system economics section of this report (Section 33) contains a detailed analysis of the procedures used by the geothermal team to calculate and estimate geothermal savings. In the absence of any evidence to the contrary, this report contains the author's conclusions that the geothermal system is cost effective, and has saved considerable money for New Mexico State University and the State of New Mexico. This saving is over and above the extraordinarily high operating costs that have resulted from premature production pump and well failures.

4. PROJECT DESCRIPTION

Construction of the Geothermal Demonstration System was performed under cooperative agreement DE-FC07-80ID-12137. The initiation date was 1 July 1981 and the required completion date was 30 June 1982. Construction was started on time and completed five months ahead of schedule and within the budget. The following Table 4-1 reviews the pre-construction and construction highlights of the Geothermal Demonstration Project. Operational status (test mode) was reached by 15 February 1982 and by 29 March 1982 the complete system was fully operational. The budgeted and actual costs are compared in Table 31-1 for major system elements.

Table 4-1
PRE-CONSTRUCTION HIGHLIGHTS

1949	Clary drills wildcat oil well and leaves unsupported reports of steam and hot water, but no oil or gas.
1956	Emmett Nations drills a well for water--it comes up rusty and warm (95°F).
1959	Tellyer drills a well--it is salty and warm (85°F).
1961	NMSU drills a well for the Golf Course--it is not unusually warm but is salty.
1976	Electrical resistivity work is performed by Stone and Jiracek--outlining a large area of potentially warm water.
June 1978	Morgan and Swanberg drill six 100-feet deep gradient wells. Find temperature gradients up to ten times higher than normal.
Dec-Jan 1978-79	Two 1,000 feet gradient wells are drilled-geophysical logs confirm water, and temperature logs show 60°C (140°F) potential.

Table 4-1 (Cont'd)
PRE-CONSTRUCTION HIGHLIGHTS

Oct 1979	First production well (PG-1) is drilled, and flow tested at 142°F and 200 gpm.
1980	Shallower well (PG-2) is drilled for University Center--120°F
March 1981	Legislature approves $829,000 for construction of project.

Table 4-2
CONSTRUCTION HIGHLIGHTS

WELLFIELD EXPANSION

- PG-3 completed January, 1981
- Observation Well completed November, 1980
- Pumps installed July, 1981, and February, 1982

DISPOSAL

- Disposal Pipeline installed October, 1981
- Old Golf Course Well renovated as disposal well, December, 1981
- New Disposal Well completed October, 1982

SYSTEM FACILITIES

- Pump Houses completed June, 1980, and March, 1981
- Transmission Power Line completed June, 1981
- Buried Pipelines completed August, 1981
- Gas Separator completed September, 1981
- Heat Exchanger Building completed October, 1981
- Hot Water Storage Tank completed January, 1982
- Four complexes retrofitted January, 1982

Table 4-2 (Cont'd)
PRE-CONSTRUCTION HIGHLIGHTS

- Partial System Use January, 1982 (six months ahead of schedule)
- Tunnel Pipeline completed February, 1982
- Retrofit completed March, 1982
- Swimming Pools on-line March, 1982
- System Tests
    - Gas Separator (September, 1981)
    - Heat Exchanger (November, 1981)
    - Disposal Well (December, 1981)
    - Hot Water Storage Tank (January, 1982)
    - Full System (January - March, 1982)
- Instrumentation (April, 1982)
- Dedication (April, 1982)

4.1 Task Breakdown

The project was divided into three main groups; the production well field, the disposal system, and the system facilities.

However, before actual construction of the project was started, several design problems were confronted. The following outline was constructed as a guide to the design scheduling and construction of the project.

Table 4-3
CONCEPTUAL TASK LIST
NMSU CAMPUS GEOTHERMAL PROJECT

Basic Tasks

I. Existing Production Well
    Develop pump criteria
        Depth, Type, Size for Aquifer evaluation

Table 4-3 (Cont'd)
CONCEPTUAL TASK LIST
NMSU CAMPUS GEOTHERMAL PROJECT

Select pump (contract specifications)

Electricity supply

Procure pump

Install pump (procurement specifications)

  a. Pump mounting system

  b. Pump house

Conduct 10-day test; retest as necessary

  a. Revetment (Impoundment) vs. natural discharge

  b. Water sampling

Reevaluate aquifer and water quality

II. Geothermal Water System

Identify conceptual supply alternatives

Select transmission piping route and perform cost/benefit analysis on alternate materials

  a. Pipeline route

  b. Storage tank location

  b. Pumping requirements

Evaluate requirements

Design storage tanks (In conjunction with number and flow rate of wells and hot water demand)

  a. Size

  b. Insulation type, thickness, cost

  c. Heat losses

Design/select heat exchanger

  a. Efficiency

  b. Heat exchanger method

  c. Cost (Installation and maintenance)

Design reinjection well

  a. Pumping requirements

  b. Depth

Table 4-3 (Cont'd)
CONCEPTUAL TASK LIST
NMSU CAMPUS GEOTHERMAL PROJECT

- c. Site
- d. Cost

Procurement Specifications

- a. Pipeline material
- b. Heat exchanger
- c. Storage Tank
- d. Pumps
- e. Instruments/recorders

Contracts

- a. Pipeline installation
- b. Storage tank construction
- c. Heat exchanger construction
- d. Reinjection well drilling/casing/screening/testing
- e. Pump installation
- f. Install instrumentation/recorders

III. Hot Water System

Evaluate hot water capabilities

- a. Prepare master data worksheet
- b. Establish hot water usage data
- c. Determine units to be serviced
- d. Instrumentation/recording required

Develop conceptual supply methods

Select pipeline route

- a. Pipeline route
- b. Evaluate utility tunnel vs. direct buried
- c. Evaluate pipe/insulation combinations/options
- d. Instrumentation/monitoring locations
- e. Determine if storage needed at user locations (heat losses?)

Design pipeline

- a. Heat, head losses
- b. Pumping requirements?

Table 4-3 (Cont'd)
CONCEPTUAL TASK LIST
NMSU CAMPUS GEOTHERMAL PROJECT

c. Storage requirements?
d. Cost/material trade offs

Design storage facilities if needed

Design instrumentation/monitoring installations

Procurement specifications
a. Pipe
b. Storage units
c. Pumps (if required)
d. Instrumentation/recorders

Contract specifications
a. Pipeline installations
b. Storage installation (if required)
c. Pumps (if required)
d. Instrumentation installation

IV. Evaluation of Geothermal Potential

Geothermal Well
a. Need More than one well at current temperature?
b. Deeper - hotter (do we attempt deep exploratory drilling to see if water is warmer at depth? How deep?)
c. Closer to energy end point use?
1. Same temperature?
2. Higher temperature?

Geothermal Water
a. Heat capability
1. Fully used (extract all water temperature differences)
2. Under-used (do not take advantage of all available wells)
3. Insufficient heat available (reduce user connections)
b. Heat demand
1. Equals availability
2. Surplus available
3. Exceeds available supply

4.2 Organization and Participants

Construction was primarily done by NMSU-PSL labor team; some contract work was, of necessity, required for various reasons. See Figure 4-3 for the organization of project personnel.

4.3 Cost Breakdown

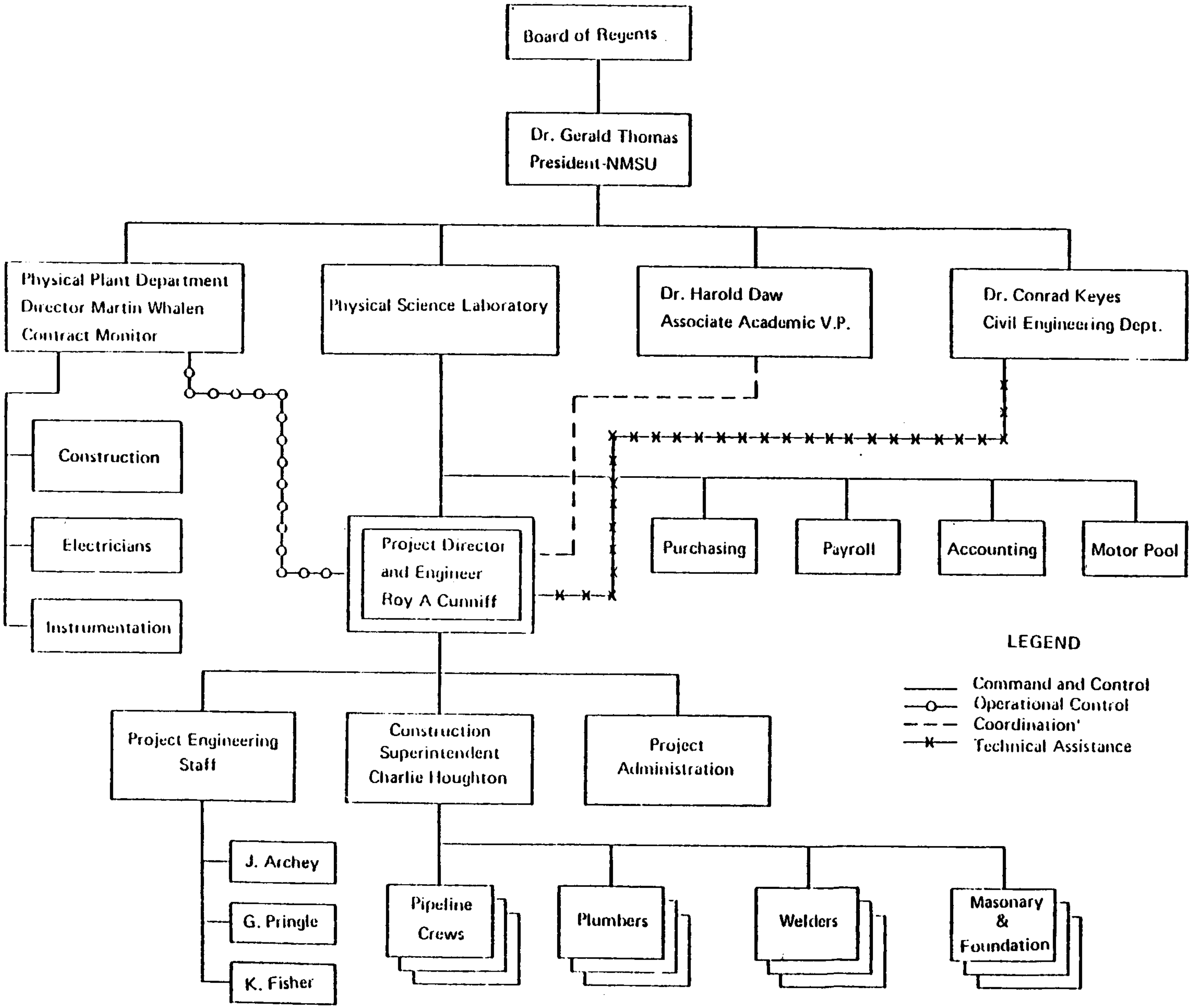
Table 4-4

TOTAL COST OF NMSU CAMPUS GEOTHERMAL PROJECT
AND FUND SOURCE

CATEGORY	NEW MEXICO	NMSU	DOE	TOTAL
Basic Research	$ 30,000		$ 70,000	$ 100,000
Development	$ 54,000		$126,000	$ 180,000
Demonstration and Application	$ 954,000*		$336,000*	$1,290,000*
Disposal Well	$ 70,000*			$ 70,000*
New Deep Production Well	$ 90,000	(to be determined)		$ 90,000
System Expansion (Breland & O'Donnell)		$122,000	$120,000	$ 242,000
	$1,198,000*	$122,000	$652,000	$1,972,000

For further detail see Section 33.1

*NOTE: This report concerns the New Mexico appropriation of $829,000 for system construction, plus the $70,000 for the new disposal well, together with the $336,000 from DOE. (Report is then focused on the results from expenditures of $1,235,000, or 63 percent of total estimated capital expenditures on this project from 1976 through 1984.)



PROJECT ORGANIZATION

Figure 4-5

5.0 RESOURCE ASSESSMENT

5.1 Pre-Project Assessment

The New Mexico State University campus is located adjacent to Las Cruces on the south-east side of the city, and immediately west of Tortugas Mountain in central Dona Ana County, New Mexico (see Figure 5-1). The geothermal anomaly used as source for the NMSU geothermal system is part of the southern Rio Grande rift system at the eastern margin of the "Basin and Range" province.

As described by Seager (1975), three major stages are recognized in the Cenezoic tectonic evolution of the area:

(1) Laramide uplift: The deeply eroded structually highest folds of this uplift approximately underlie the present course of the Rio Grande.

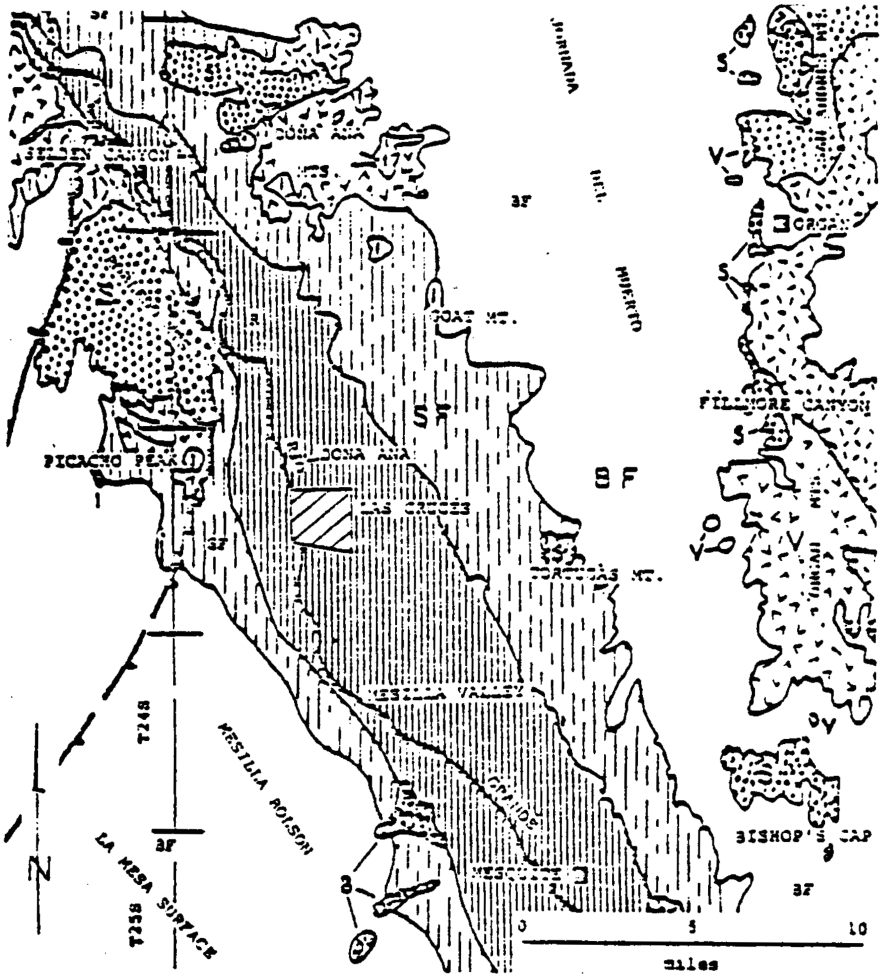
(2) Eocene-Oligocene andesite and rhyolite volcanism: These silicic volcanic sequences overlie the eroded laramide uplifts and basins. Immediately east of the anomaly area is Tortugas Mountain, an uplifted block of Paleozoic limestone which is thought to be a remnant part of the rim of the Organ Caldera (Seager and Brown, 1978). The caldera is described as a "trap-door" type; 16 to 19 kms in diameter and hinged along its northern margin extending east to the Organ Mountains. Two sheets of ash flow tuff (up to 600m. thick), the Cueve tuff and the Cox Ranch tuff, (Dunham, 1935; Seager, 1978), have spread beyond the caldera boundaries and are considered to be representative of the eruption prior to the major cauldron subsidence. One of the sheets of the Cueva tuff has been K-Ar dated at 32 my. Another 2150m. (7000 ft.) of ash flow tuff later erupted (which was the cause of the cauldron subsidence) and was contained by the walls of the caldera. Because no major unconformities have been recognized throughout the sequence, the date of 32 my. (mid-Oligocene) is thought to be representative of the whole structure. Furthermore, the organ batholith which appears to have intruded the caldera on its eastern margin is also dated at 32 my. and has been interpreted to be probably the magma chamber from which the caldera volcanics were erupted. It has been uplifted by block faulting on the rim of the caldera during the Rio Grande rift movements.

(3) Late Tertiary block faulting: 26 my. marked the transition to active rifting shown by a halting of the silicic volcanism. After a period of quiescence, alkali olivine basalts appeared around 13 my. Ramberg and Smithson (1975) suggest that bidirectional fault patterns may be inherited from pre-existing structural grains. This rifting has created local basins separated by ranges which have now been partly buried in their own debris. The Organ Mountains are representative of the late Tertiary fault block that extends north-south for over 160 km. Uplift has been principally along the boundary fault on the eastern side of the block. Gravity and topographical data indicate a total throw of more than 3000m. Piedmont scarps indicate movement has continued into the late Quaternary.

The area of the geothermal anomaly is characterized by valley fill deposits which increase in depth away from Tortugas Mountain (King and Hawley, 1975). There is no surface manifestation of the anomaly. The only indication of geothermal activity resulted from private drilling while intersected shallow deposits of warm water in the temperature ranges of 95 to 110°F.

The Las Cruces area is a zone of unusually high heat flow as compared to adjacent "Basin and Range" and "High Plains" areas (Cook et al. 1979; Reiter et al. 1979). A prominent north to northwest trend of high geochemical temperatures passes through the Las Alturas area (Swanberg, 1979) and follows the general trend of a major northwest, southeast trending fault believed to be located in the western base of the Tortugas Peak Jackson. Silica and the Na-K-Ca geothermometers indicate temperatures around 150°C, (Swanberg, 1975).

Previous surface exploration work includes electrical resistivity (dipole-dipole) survey (Smith, 1976) and (Jiracek, 1978), and subsequent two-dimensional modelling (Jiracek and Gerety, 1978). This work produced evidence of a low resistivity layer interpreted to be the geothermal reservoir, and also indications of the presence of a high resistivity barrier to the east, possibly a fault striking north to northeast. The authors considered that this fault may be a primary structural control governing the rising hot water, see Figure 5-2.



EXPLANATION

R	Valley-fill alluvium, late Quaternary; clay to gravel, less than 80 ft thick.
B	Olivine basalt flows and volcanic cones; Quaternary, generally post date the Santa Fe Group.
BF	Basin-fill surface. Santa Fe Group, with discontinuous overlay (generally less than 25 ft thick) of younger alluvial, eolian and minor lacustrine deposits.
SF	Santa Fe Group Basin fill; Miocene to middle Pleistocene; clay to gravel; locally as much as 4,000 ft thick. Also discontinuous overlay (generally less than 100 ft thick) of younger valley slope deposits.
V	Volcanic rocks, and associated clastic sedimentary rocks, undifferentiated; early and middle Tertiary.
S	Sedimentary rocks, undifferentiated; Paleozoic, Cretaceous and early Tertiary.
I	Intrusive rocks, undifferentiated, and associated metamorphics; Precambrian and Tertiary.
—	Faults involving significant displacements of basin fill.

Figure 5-1. Geologic map of Las Cruces area.
(From King and Hawley, 1975)

5.2 Pre-Drilling Assessment

Based on the assembled evidence, a decision was made in 1978 to drill six shallow geothermal gradient wells to map the heat flow for that part of the NMSU Campus located to the east of Interstate Highway 25. These wells (approximately 300 feet deep) gave evidence of very high temperature gradients, of a magnitude of 400°C/km of depth. (Swanberg and Morgan, 1979).

The enormously high heat flow formed the basis for a follow-on exploratory drilling program.

In November, 1978, the decision was made to drill two exploratory wells, 1000 to 1500 ft. deep, to gather information regarding the subsurface conditions -- stratigraphy, temperature gradients and hydrology. Location of the two wells was determined on the basis of previous work completed, primarily electric resistivity and the shallow temperature gradient survey. The wells were drilled about 0.6 mile and 1 mile east respectively from the NMSU solar houses south of NMSU golf course along the dirt road going towards Tortugas Mountain. Location of the two wells is shown in Figure 5-2.

The two wells, numbered NMSU-DT-1 and NMSU-DT-2 (New Mexico State University - Deep Geothermal Wells 1 and 2) were drilled during December 27, 1978 to January 3, 1979, by Johnson Drilling Company of Las Cruces, using a rotary drilling rig. Well DT-1 is located at 52 feet higher ground elevation compared to well DT-2 (4163 ft. and 4111 ft. above M.S.L. respectively). The bottom hole temperature in DT-1 was approximately 63°C, and in DT-2 the temperature was 52°C. (Swanberg and Morgan, 1979). Formation and electrical logs of both wells gave evidence that a production well should be able to produce 100 to 200 gpm of geothermal water. (Chaturvedi, 1979).

In 1979, Dicey performed a series of surface geophysical investigations under the supervision of Morgan. The work included gravity, magnetic, seismic refraction and seismic reflection profiling in an attempt to delineate structure related to the geothermal anomaly. (Dicey and Morgan, 1979).

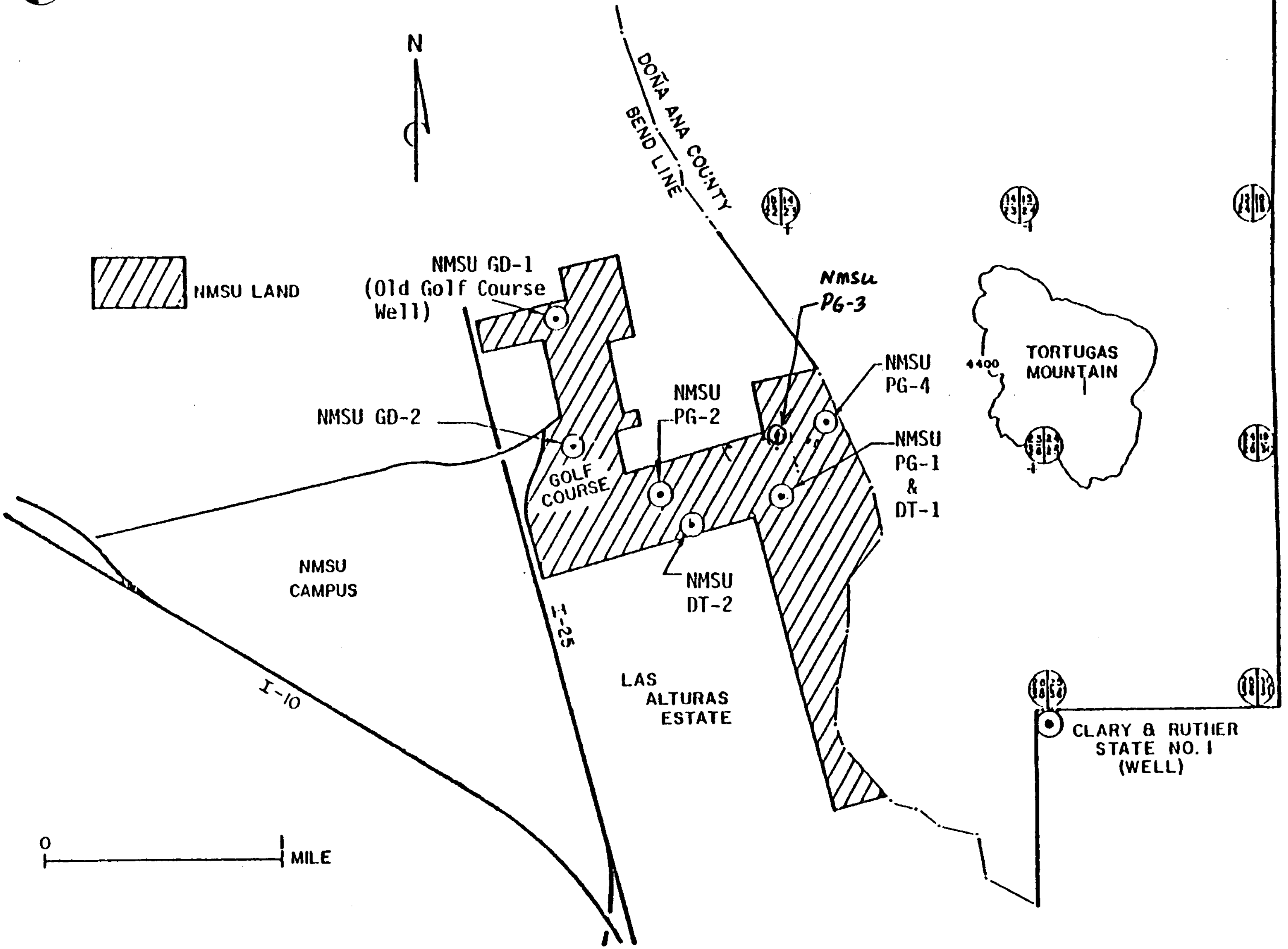


Figure 5-2 Location of NMSU Geothermal Wells

5.3 Drill Site Selections:

Based on the favorable showing from DT-1 exploratory well, the first production well PG-1 was drilled within 20 feet of DT-1. Rationale for this location was that a proved resource existed, that the resource was fault dominated, and moving to a location significantly removed from DT-1 would cause unacceptable risk. Such a close proximity, however, resulted in a situation in which the DT-1 well could not be used as a monitoring well. This in turn forced the drilling of a new observation well, OW-1, which was drilled 280 feet away in 1981.

Similarly, PG-2 was sited near DT-2, closer to the point of intended use of the confirmed geothermal water to heat the University Center (President's House).

Both of the above two wells were drilled and completed prior to the NMSU-DOE Cooperative Agreement concerning the construction of the end-use system. After the agreement was signed, three additional wells were drilled under the terms of the agreement. An observation well was drilled, with its location picked to be within 280 feet of PG-1, so as to perform a more methodical reservoir hydrology assessment. Based on the results from that assessment, technical information indicated that the location for the new production well should be more than 1,000 feet from PG-1 so as to minimize pumping interference between the wells. Accordingly, PG-3 was sited and completed.

The third well drilled under the agreement was a new disposal well. This location was dictated by reservoir conditions as well as engineering considerations. Funding for this new disposal well was provided by the New Mexico Energy and Minerals Department.

5.3.1 Site Locations

(See Figure 5-2)

5.3.2 Selection Criteria

All wells were sited on land owned by NMSU. In addition to the obvious need to reduce long term costs by avoiding royalty payments, the locations were governed by geothermal aquifer hydrology factors as well as engineering considerations in terms of distance and cost to connect users with the production well field.

From best available geological and geophysical information several years ago, the best primary locations were believed to be one to two miles closer to Tortugas Peak, one mile east of NMSU boundary line. However, the land is BLM administered, and is placed in a special category. The land (some 12,000 acres which includes Tortugas Peak) was withdrawn from public use and placed in a "withhold" status with sole usage consisting of telescopes, radar antenna, and other structures built to serve NASA and other national defense needs. Advice from the BLM was to the effect that drilling could not be authorized on the withheld land without first cancelling the withheld status. This would have resulted in open bidding for the land, and loss of control over the sensitive scientific installations. Accordingly, well locations were constrained solely to NMSU land. This constraint, however, did not cause any sacrifice of potential geothermal resources, because the most useful indicators (heatflow and temperature gradients) indicated NMSU land was the best available location.

5.4 Post Drilling Assessment

5.4.1 Concerning PG-1, two years of production experience has clearly shown that a geothermal well completed with a screen section in the water-bearing fine sand strata can cause severe operational problems, which are covered in more detail in 5.4.2. As to PG-3, the drilling record and subsequent methodical research, indicates the well in its most productive zone (770 to 780 feet of depth), probably intersected a fault gouge of a relatively recent fault which occurred after the Santa Rosa alluvial sequence was deposited. This well was completed as an open hole, gravel packed. However, after the premature failure of the first well pump in that well, the system operator chose to fill the open hole with a cement plug "to stop sand formation".

The cement filled in the looser aggregate located at the fault zone, and production was severely curtailed.

5.4.3 The new disposal well, GD-2, has performed as projected based on the drilling record. If funding were not a constraint, it appears that a higher capacity disposal well would have to be drilled much deeper than 1,000 feet.

5.5 Operational Assessment

5.5.1 PG-1 Assessment

This well was drilled and completed in late 1979, and apparently was developed initially by bailing for 24 hours. The engineers on this well had estimated from the suite of electrical logs that the well would produce economically 100 to 200 gpm. (Chaturvedi, 1979) A chronological well history is contained in the following sub-paragraphs.

In February 1980, a 24-hour pump test was conducted on that well. The pump intake was set slightly below 510 feet, but the pump cavitated when 200 gpm flow rate was attempted. The pump was able to operate on the ragged edge of cavitation at a rate from 189 to 200 gpm. No draw-down measurements are available, but the cavitation suggests the draw-down level was at least 190 feet below the static water level at 322 feet. This is a specific yield of roughly 1.0 gpm per foot of draw-down. (This is also close to the specific yield of PG-3, which indicates an approximate aquifer potential for the wells completed in the tight alluvial formations).

Later in February 1980, a seismic experiment was conducted by detonating explosives in the DT-1 well, which was located about 15 feet from PG-1. OT-1 was destroyed by dynamite. From the written report of this experiment, at least four separate charges were detonated. (This seismic experiment was not known by the project geothermal team until November 1980).

In June 1980 a permanent pump was set in PG-1, and a controlled 10-day pumping test was conducted. A marked change in specific yield was noted. Draw-down stabilized at 474 feet (or a draw-down of 152 feet for a 200 gpm flow rate). This is a specific yield of 1.3 gpm per foot of draw-down, or 30% larger than the February test. With the advantage of hind site, it would seem evident that the dynamite charges possibly loosened the gravel pack, and also possibly fractured the screen, which is the damage detected by video camera in April 1982.

During the period July - November 1980, a series of flow tests were conducted on PG-1. In aggregate, a total of perhaps 500 hours of well pumping was conducted. Draw-down and specific yield parameters remained unchanged from the July 1980 values.

When the dynamite experiment was discovered, the project geothermal team attempted to determine the possibility of damage to PG-1. From the written report filed by the seismic researchers to the New Mexico Oil Conservation Division (OCD), the deepest charge was detonated at or near 550 feet. By pressuring the well to 125 psi, the water level was depressed to 610 feet. Since no loss of air pressure was detected, the assumption appeared valid that the casing was intact to at least that depth. One worrisome factor, however, was that the damaged DT-1 well casing, exposed 15 feet away, had observable movement when air pressure was increased or decreased.

In June 1981 after the permanent pump was installed in PG-3, a combined flow test was conducted on the two wells. PG-3 was pumped at 275 gpm, and PG-1 was pumped at 280 gpm with rates up to 320 gpm. This test was designed to stress the aquifer as much as practical to assess the effects of the interference between the wells. During the test, PG-1 suddenly started producing large amounts of mud and sand, which persisted for 45 minutes. The 50-hp Peerless pump subsequently failed, and the test was terminated.

In August 1981, the 100-hp TRW-REDA pump was relocated from PG-3 to PG-1. A series of controlled flow tests were made, with the flow gradually increased from 150 to 320 gpm. Only small amounts of sand were produced at any time.

From September 1982 through May 1982, the TRW-REDA pump in PG-1 was operated for roughly 2,500 hours. The pump failed in May 1982, and in the late stages, sand production showed an increasing trend.

After the break in the screen section was detected, repairs were made by cementing the lowest 50 feet of the screen section. A new test pump was acquired, and a controlled flow test was conducted. In spite of a one-third decrease in screen section, no observable changes were noted in specific yield or draw-down. In retrospect, this was not a good sign because it suggested the bulk of the production was from the apparently undamaged screen section.

This could be true only if the gravel pack was deteriorated so that higher than desired screen intake velocities were being used. If the screen inlet velocity exceeds 0.1 fps, channeling can occur in the formation and the gravel pack. This test pumping produced excessive amounts of sand, so the pump was removed and the well was air-jetted for 5 days. This air-jetting removed large amounts of sand.

A new 60-hp REDA pump was reinstalled in September 1982. This pump had a casting flaw and failed after 60 hours of operation. During the short period of operation, the well did not produce significant amounts of sand.

A new Johnston vertical shaft turbine pump was installed in November, 1982, and operated successfully for 3,500 hours. In late March, 1983, a noticeable increase in sand production was noted. Controlled testing indicated that the well was producing excessive sand at a flow rate of 220 gpm, the desired production rate, but that the sand formation was greatly reduced if production rate was held below 150 gpm. Because production had declined, the pump was removed and inspected. Loss of production was attributed to hydrogen sulfide attack on the column pipe which resulted in complete penetration of the column pipe at the three lowest joints, and serious erosion of the threaded portion of 80 percent of the column pipe. The pump had suffered damage from sand, which eroded the throttle bushing and allowed geothermal water to enter the oil tubing.

The well was again air-jetted for five days, and excessive amounts of sand were removed. The air-jetting produced some gravel believed to be representative of the original gravel pack. Accordingly, a new TV log was acquired. This log showed major plugging of the well screen (an estimated 65-75 percent of the screen was plugged with carbonate deposits) and some slot enlargement. A strong likelihood was noted that the gravel pack apparently no longer was intact at the 740-750 foot horizon.

The well condition resulted in a decision to attempt to solve the problem by deepening the well to a sand-free horizon, and a bid invitation was advertised. In mid-June, the bids were open and no responsive bids were received.

At this point, only two options were apparently available. Drill a new well, or attempt to treat the well with chemicals to clean the screen section and also attempt hydrogen sulfide abatement. The least costly choice was well treatment, coupled with design changes on the pump and pump column to make them as sand and hydrogen sulfide resistant as possible. The well was treated with hydrochloric acid to dissolve the carbonate, in the hope that the increase in screen openings would result in lower screen inlet velocity, and less sand production. For hydrogen sulfide abatement, the well was treated with sodium hypochlorite, to test the theory that hydrogen sulfide was caused by anaerobic bacterial action. See Table 5-4 for a record of hydrogen sulfide analysis for NMSU geothermal wells.

A follow-on controlled flow test was conducted in December, 1983, in which a tightly controlled 24-hour step flow test was conducted to see if the sand could be pumped out, and to determine if the chemical treatment was effective.
That test indicated the well would likely produce an excessive amount of sand.

5.5.1.1 Chemical Analysis of Water Samples

The data for pH and conductivity measurements shown in Table 5-3 indicate that much of the chemical residues resulted from the acid treatment of PG-1 in August, 1983, were still in the aquifer supplying water to PG-1 at the beginning of the flow test. However, these chemical residues decreased as pumping progressed, and only negligible traces of the chemical residues were found at the end of the flow test.

Initially, pH of the solution was 6.5. The pH continued to decrease during pumping until it reached a minimum of 6.0 after four hours of pumping. Then, the pH of the solution increased gradually to a maximum of 6.8 after 12 hours of pumping; thereafter, the pH gradually decreased to 6.5 at the end of the flow test. Conductivity of the solution, however, started out as low as 2840 μmhos at the beginning. It rapidly increased to the maximum of 7,200 μmhos after 4 hours of pumping; thereafter, the conductivity gradually decreased to a stable level of 3,170 μmhos at the end of the flow test.

A total of 10 water samples were taken during the flow test at a rate of one sample every two hours. On the basis of the conductivity measurements data,

TABLE 5-3

CHEMICAL ANALYSIS

		µmhos/cm	mg/l					
Sample	pH	EC	Na	K	Ca	Mg	Cl	CO_3
PG-1 #4	6.17	6.59	627.2	80.5	538.4	108.0	1714.8	0
#7	6.60	4.51	536.3	61.1	325.9	60.4	1123.2	0
#8	6.64	4.05	504.6	55.2	267.6	49.4	963.0	0
#10	6.45	3.72	500.7	54.1	232.7	43.2	847.1	0
PG-3								
PG-1 (1980)	6.30	3.11	488	54	143	18.6	584	0
PG-3 (1980)	6.25	3.13	488	52	141	18.8	546	0

	mg/l						
Sample	HCO_3	SO_4	TDS	Fe	Mn	NO_3-N	F
PG-1 #4	134.2	645	4220	81.6	5.37	.04	3.51
#7	341.7	402.5	2868	13.03	2.11	<.01	2.70
#8	422.2	292.5	2416	9.31	1.43	.02	2.41
#10	458.8	308	2044	7.71	1.11	<.01	2.54
PG-3	596.7	343	1748	.15	<.05	<.01	2.28
PG-1 (1980)	620	250		2.8	0.11	0.03	1.3
PG-3 (1980)	610	240		5.0	0.11	0.02	NA

	mg/l				
		as $CaCO_3$			
Sample	Hardness	Alkalinity	Surfactants	Color	Odor
PG-1 #4	1788	110	<.025	<20	5
#7	1062	280	<.025	<20	2
#8	870	346	<.025	<20	5
#10	758	376	<.025	<20	10
PG-3	518	489	<.025	1	5

Sample	NTU Turbidity	As	Ba	Cd	Cr	Pb	Hg
PG-1 #4	330	.001	.43	.007	<.05	<.005	<.0002
#7	180	.001	.26	.005	<.05	<.005	<.0002
#8	180	.001	.21	.005	<.05	<.005	<.0002
#10	110	.002	.17	.005	<.05	<.005	<.0002
PG-3	1.2	.07	.07	.005	<.05	<.005	<.0002
PG-1 (1980)		<.004	<.	<.005	<.05	<.005	<.0002
PG-3 (1980)		<.004	<.04	<.005	<.05	<.005	<.0002

	mg/l		mg/l		mg/l	
Sample	Se	Ag	H_2S	Sample	Se	Ag
PG-1 #4	<.001	<.05		Pg-3	.001	.05
#7	<.001	<.05				
#8	<.001	<.005	.13			
#10	<.001	<.005				
PG-1 (1980)	<.002	<.05	0.06			
PG-3 (1980)	<.002	<.05	0.14			

TABLE 5-4

H_2S IN NMSU GEOTHERMAL WELLS

(Values in mg/liter)

Date	PG-1	PG-2	PG-3
15 Mar 83	0.14 (sampling from Y strainer) 0.21 (sampling from Gas Sep.)	----	----
24 Mar 83	----	----	0.21 (sampling from Gas Separator)
14 Apr 83	----	----	0.07 (sampling from well head)
22 June 83	----	2.50 (before treating the well with NaOCl)	
10 Aug 83	----	After treating the well; 2.00 (two hrs. after starting pump) 0.50 (seven hours after)	----
26 Aug 83	<0.30 (sample was bailed from the well during the Acid-NaOCl treatment)	----	----
Sep 83	<0.10 (sample was taken turing flow-test, i.e. one week after treating the well)		
26 Sep 83	----	----	<0.10 (sampling from well head)
7 Oct 83	----	----	<0.10 (sampling from well head)
1 Nov 83	----	0.15 (one week after starting pump)	0.07 (sampling from well head)
15 Dec 83	0.13	----	----
12 Jan 84	----	0.24	0.16/0.15
5 May 84	----	0.09	0.14

NOTE: Previous H_2S measurements made by Carl Bernhardt in 1980 using a completely different sampling and analytical techniques are as follows:

PG-1; H_2S = 0.06 mg/liter
PG-2; H_2S = 0.15 mg/liter
PG-3; H_2S = 0.14 mg/liter

only samples #4, #7, #8, and #10 are necessary for the complete chemical analysis. The results of the chemical analysis of the samples are tabulated in Table 5-3. Also tabulated in Table 5-3 are; (a) chemical analysis of water sample from PG-3 obtained at the end of the flow test, (b) chemical analysis of water sample from PG-1 made in 1980, and (c) chemical analysis of water sample from PG-3 made in 1980.

In reviewing the data from these chemical analysis, it is seen that there is a slight elevation in the levels of Na, Ca, Mg, Cl, SO_4, and Fe. However, the trend of the levels of the elevated chemical species decreased toward the original (1980) measured levels as pumping progressed. This suggests that even after 300,000 gallons of pumping, there still were traces of the chemical residues left from the acid treatment of PG-1 in August, 1983. The chemical analysis of PG-1 (#10) is essentially similar to the original water (1980), and also is similar to the water sample obtained from PG-3 at the end of the flow. Within limits of analysis uncertainty, the end samples are representative of original water quality.

In light of the chemical analysis, treatment with NaOCl to abate the suspected anaerobic bacteria in PG-1 probably was not as effective as desired. This tentative conclusion results from comparing the new analysis to recorded levels of H_2S in PG-1. Using sampling and analytical methodology for the period 15 March through December 1983 tends to indicate the H_2S level was approximately reduced by 50% as a result of the chemical treatment. However, data acquired by Carl Bernhardt in 1980, using a very sophisticated sampling technique, and an elaborate and tightly controlled gas chromotograph process produced measured values only one-half the current values. Because of the widely different techniques used in 1980 and 1983, direct comparison of the results is not possible. History of H_2S content in the geothermal wells is given in Table 5-4. Initially at least, the chemical treatment of PG-2 decreased the H_2S level in the well to less than 20% of the level existing before the treatment Additional measurements of PG-2 verified an apparent permanent reduction in H_2S levels.

5.5.1.2 Conclusions

A large volume of sand was produced during the 24-hour test, and an inspection after the pump was removed indicated that sand had filled-in some 16 to 17 feet of the well, in only 24 hours of pumping.

If the 16 to 17 feet of fill in the well represents larger particles of sand, this is an unacceptable level of sand in-migration. If this rate continued (which is not likely for reasons explained as follows) the screen section would sand-in totally in 6-7 days of pumping operation. Assuming the sand was originating uniformly at every level from 700 to 795 feet (the current perforated screen section), the continued passage of sand would stop as the screen section filled with sand, because the reduced screen inlet area would act to reduce well production. However, the TV log acquired after the jetting operation in May, 1983, showed evidence of a zone of silty fine sand at roughly 750 feet of depth. Perhaps this zone (which was detected during the original drilling), is the major producer of sand, and possible the well would not produce as much sand if the well bore became filled above that depth. If this occurred, however, the screen would then be only 50 feet deep, and flow rates possibly would be significantly reduced.

The presence of the fill in the well, together with the large volume of sand which was intercepted by the Y-Strainer, and that quantity passed through to the holding pond is a worrisome sign. It is important to note the well was air-jetted extensively in May, 1983, to remove sand. Then, after the chemical treatment, the well was bailed for a lengthy period. These two procedures under normal circumstances should have acted to reduce or eliminate sand in the immediate vicinity of the well bore. However, the December 1983 test produced the largest amount of sand production ever noted.

In reviewing the sand particle sizes, it is useful to summarize as follows: The original well screen had 1/16-inch slots, which is 1.5875 mm. The sieve analysis showed that the Y-Strainer intercepted only 0.074 to 0.84 mm sand. Hence, particles larger than 0.84 mm, but smaller than 1.5875 mm could represent the material left in the well. However, if some of the slots are in fact enlarged as detected in the previous TV log, it is possible even larger sand particles exist in the well. Note also that the lithology log of the formation shows the following:

(1) For the 750-feet zone, 30 percent is sand smaller than 1.0 mm. Another 25 percent is sand in the size range 1.5 to 4 mm.

(2) For the 800-feet zone, 10 percent is sand smaller than 1.0 mm, and another 30 percent is in the size range 1.0 to 2.0 mm.

(3) Based on these lithology analysis, upwards of 30 percent of the formation consists of size ranges which would pass through the well screen, and are small enough to be intercepted by the Y-strainer. Another 25 to 30 percent is small enough to pass through the Y-strainer, but too large to be carried out of the well.

(4) If enlarged well screen slots exist, which is true to some extent, even larger particles could enter the well bore.

A major conclusion for the detailed analysis of the sand content of the well, Y-strainer, and holding pond is that the gravel pack probably has deteriorated to the point that sand production likely will increase.

5.5.1.3 Final Actions

Because of the large amount of sand now present, and the fact that this sand has returned after every attempt to clean out the well, a detailed engineering study was conducted to see if a down-hole sand eductor would work. After considerable research, a conclusion was reached that the 10-inch well diameter is too small to permit the eductor to operate.

As a follow-on decison, the repaired Johnston pump will be reset in the well sc as to have a back-up well ready for service.

5.5.2 Observation Well OW-1

The well was drilled and completed in November, 1981. It has remained open ar in service since that date.

5.5.3 Production Well PG-3

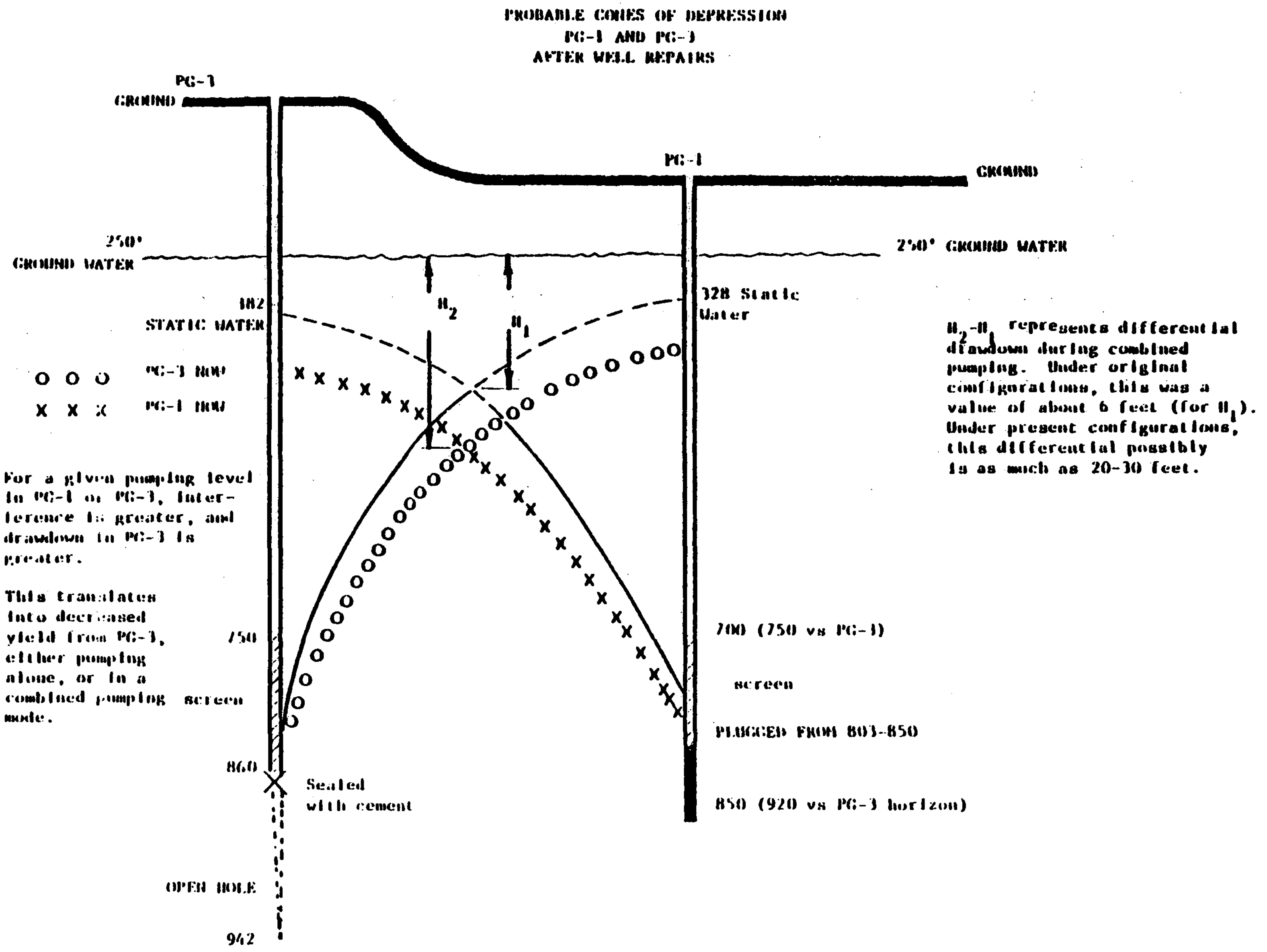
This well was drilled and completed in early 1982. An inspection of the completed well showed that the well had a gradual deviation which reached an off-set of one diameter at 280 feet of depth. Below that depth, unknown deviation existed. However, from the deviation log which was run on the pilot hole before the main hole was reamed out to final diameter, the pilot hole deviated almost continuously from general surface to total depth (T.D.) of 941 feet, and total deviation was 10.1 feet at T.D. It is likely that the completed well follows the same deviation, which is in a southwesterly azimuth.

After the initial well pump failed at 1,000 hours, the system operators attributed the failure to sand production. This well did not have a history of sand; and the factory tear-down of the failed pump found no evidence of sand erosion. Nevertheless, the operator decided to set a cement plug to seal the lowest section of open hole (830 to 940 feet). A down-hole video camera showed that the open-hole portion was open before the cementing action.

The new pump was installed, and a controlled pumping test was started on July 14, 1983. The test was suspended after two hours. From test data, the well was only capable of an estimated sustained yield of 150 gpm at 144°F, and only 186 gpm at maximum drawdown, at water temperature of 144°F. At maximum production of 195 gpm, the pump was at incipient cavitation. Flowing temperature was 2°F cooler than earlier production. Apparently, a significant portion of the original production was from the open hole. Formation logs on this well were examined, and this water production probably is from the 865-930 feet of depth.

It was recommended that the cement plug be drilled, and a gravel pack inserted. Instead, the operator tried to break the cement plug by inserting 870 feet of 4-inch column, and attempting to force the plug loose. After this operation, the well was air-jetted for five days. A second down-hole video camera revealed the plug was still intact. Figure 5-5 is a graphical representation of the effects of this cementing.

In spite of this loss of production, PG-3 has remained a usable well. In fact, because of the sand and hydrogen sulfide problem in PG-1, the former back-up well (PG-3) has been the primary well. The down-sized replacement pump in PG-3 had operated more than 7,000 hours, and has been submersed in the well for 20 months as of the end of April, 1984.



PROBABLE CONES OF DEPRESSION
PG-1 AND PG-3
AFTER WELL REPAIRS

H_2-H_1 represents differential drawdown during combined pumping. Under original configurations, this was a value of about 6 feet (for H_1). Under present configurations, this differential possibly is as much as 20-30 feet.

For a given pumping level in PG-1 or PG-3, interference is greater, and drawdown in PG-3 is greater.

This translates into decreased yield from PG-3, either pumping alone, or in a combined pumping mode.

Figure 5-5 Probable Cones of Depression of PG-1 and PG-3 after Well Repairs

6.0 ENVIRONMENTAL ISSUES

The environmental issues of the New Mexico State University Geothermal Energy Project consist of three areas, as follows: Air Pollution; Disposal; and the Archeological Survey.

Concerning Air Pollution, a direct benefit of geothermal is the reduction in air pollution based on the displacement of natural gas. Since the Las Cruces area suffers from below standard air quality during the winter season, a reduction in air pollution is a positive benefit.

Based on standard EPA emission factors for moderate size industrial boilers without emission control (Perkins, 1974) displacement of natural gas could result in reductions in air pollution as shown in the following table.

Table 6-1
AIR POLLUTION REDUCTIONS
(pounds/year)

	NO_2	SO_2	Particulates
11-building complexes (60,000 mcf)	12,950	24	1066
Full system (possible future expansion) (170,000 mcf)	36,500	68	3000

Disposal of the geothermal water has several environmental impacts. All surface discharges incident to well testing and repair require formal written approval from the State Oil Conservation Division. The same ruling was required for the reinjection of geothermal water. Surface disposal also requires the construction of ponds or revetments to contain the water within close proximity of the production facilities.

It was the responsibility of New Mexico State University as operator to prove that the injected geothermal water is of higher quality then the existing aquifer before any reinjection can take place. Pumping tests, detailed chemical analysis, the deep exploration drilling have produced a case to establish that the site and disposal operations are environmentally safe. Thus far, however, disposal operations have been limited solely to gravity reinjection.

Concerning Archeological Surveys, a complete field inspection and formal report were acquired for each of the wells, for the power line, new service roads, and the three miles of buried pipeline for those areas not covered by an existing archeological survey. No artifacts or other significant objects were found in any of these surveys.

7. INSTITUTIONAL ISSUES AND PERMITS

The Geothermal Pipeline required road crossing permits to cross under the Interstate I-25 and all roads on the main campus, which technically are New Mexico State Highways. These permits were obtained through the District Highway Engineer.

Since the entire project was constructed on New Mexico State University property, no other agencies were involved.

The permits for drilling, testing, and operating the production, operation, and disposal wells DT-1, DT-2, PG-1, PG-2, PG-3, OW-1, and GD-2 are listed in the Driller's Guide. For further details concerning the permit requirements of Geothermal well refer to the State of New Mexico Energy and Minerals Department, Geothermal Well Driller's Guide, which was written as a by-product of this project.

8. PRODUCTION DRILLING AND LOGGING

8.1 The location of PG-1 and PG-3 are 1,000 feet from the North Line, 500 feet from the East Line, Section 27, Towhship 235, Range 2E, and 4825 feet from the North Line, 80 feet from the East Line, Section 27, Township 235, Range 2E, Dona Ana County, New Mexico, respectively.

PG-1 was completed originally to a depth of 860 feet, with screen from 700 to 850 feet of depth. PG-3 was completed to 870 feet with perforations from 750 to 860 feet. The casing in PG-3 is copper-impregnated steel, and the screen is Roscoe-Moss shutter type. This particular screen was selected in order to attempt to evaluate a different type of screen. NMSU-PG-1 was completed using slotted steel screens, for a total screen interval of 150 feet. In turn, NMSU-PG-3 contained 110 feet of shutter-type screen. In NMSU-PG-3 the casing was cemented from the surface to 730 feet of depth, with gravel pack from 730 feet 860 feet of depth. An 18-inch conductor casing was cemented in a 26-inch hole for the top 60 feet of the well. PG-1 was a 17-inch hole drilled to 850 feet. The gravel pack originally extended 30 feet above the screened interval in the 3-inch annular space. The remaining 3-inch annular space from 670 feet to the surface was cemented.

Further details concerning the production wells PG-1 and PG-3 may be found in Technical Completion Reports for each well.

Figure 8-1

Geothermal Production Well PG-1

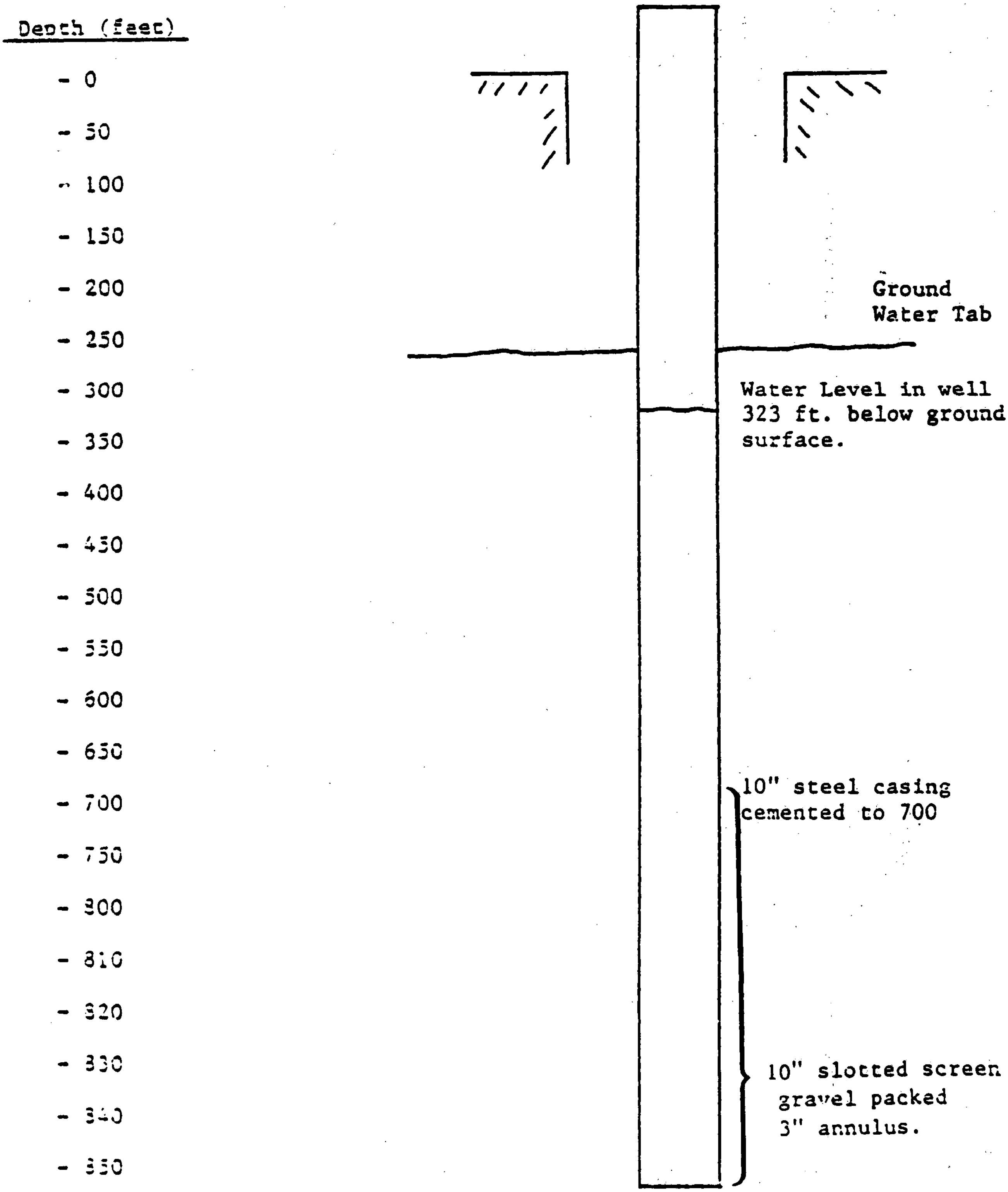
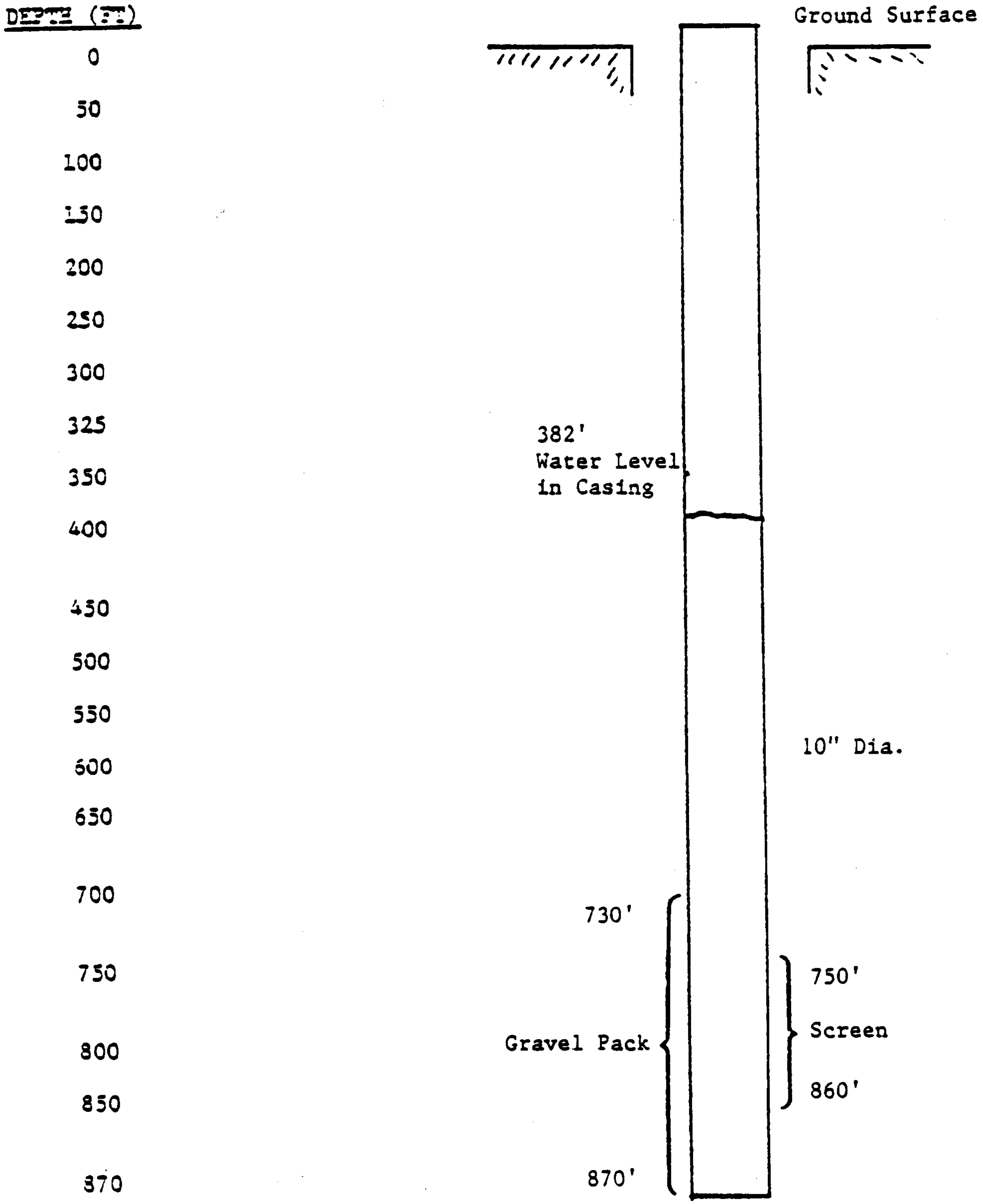


Figure 8-2

Geothermal Production Well NMSU-PG-3



9. RESOURCE TESTING

There are five current wells of significance in the Geothermal Demonstration System. Two of them, PG-1 and PG-3 are production wells, and OW-1 is an observation well which was completed to assess the hydrology of the geothermal aquifer. The remaining two wells are the old golf course well which was repaired for use as a disposal well, and the new disposal well GD-2, which was completed in October 1982 as a supplement to the Geothermal Demonstration System.

A study of geothermal well yield of the production wells PG-1 and PG-3 was established by a series of well testings conducted during the period of December 1981 - April 1982. On the basis of relevant data assessed from pumping tests of PG-1 and PG-3, the result of well yields of the production wells is detailed in the following sections.

9.1 PG-1

Controlled testing of this well using an installed 100-hp submersible pump produced some useful indicators of possible aquifer parameters.

The saturated thickness of the alluvial deposits is from the water table to at least 1,200 feet. Water table is roughly 250 feet below ground surface. Water temperature is 142°F at the well-head. Static water level is 328 feet. Using a 100 Hp pump, the well yield was measured to be 365 gpm at 526 feet of total drawdown depth. This is 365 gpm for 198 feet of net drawdown, or a specific yield of 1.8 gpm/foot of drawdown. This flow rate was 43% of probable aquifer maximum, based on drawdown. It should be noted, however, that the observed specific yield in sustained operations was only 1.3 gpm/foot of drawdown.

The maximum available drawdown for PG-1 is 522 feet, less 50 feet for dissolved gas control, or a net usable drawdown of 472 feet. The optimum drawdown is 67% of this maximum value, or 316 feet of drawdown, therefore:

a. Maximum aquifer yield is approximately 850 gpm, at total (or maximum) drawdown at a specific yield of 1.8 gpm per foot. At 1.3 gpm per foot, this maximum is 613 gpm.

b. At optimum drawdown, the yield is 92% of maximum, or 782 gpm for 1.8 gpm per foot, and is 564 gpm for 1.3 gpm per foot.

c. In order to attain optimum yield at optimum drawdown, the pump would have to set at a point 50 feet lower than the optimum drawdown level, which is calculated as follows:

Static Level + Optimum Drawdown + 50 feet = 328 feet + 316 feet + 50 feet = 694 feet

d. At this depth, the pump bowls would be in the top portion of the screen section, in the interval 695-710 feet of depth. This setting is consistent with normal rules of thumb for water wells, which suggest this location as optimal.

e. In order to produce the aquifer optimum yield, a 12-inch diameter, 250 Hp submersible pump would be required, which would necessitate an 8-inch pump column. The static lift would be 644 feet, plus the length of the pump and motor. (Note: This is for a theoretical well. The actual well is too small to accommodate such a large pump.)

f. From controlled tests previously run, the well yield is 365 gpm of water at 142°F. However, when both PG-1 and PG-3 were pumped simultaneously at 600 gpm, there is an indication of slight temperature decay. At this combined flow rate, PG-1 temperature declined to 139-140°F. Although not conclusive, this temperature decline suggests that an attempt to gain optimum yield of 782 gpm from the aquifer in the vicinity of PG-1 could result in a fluid temperature in the range of 135-138°F.

9.2 PG-3

The geothermal fluid temperature is 145-146°F. This slightly hotter fluid probably is the result of casing off the cooler zone from 700 to 750 feet of depth. This well contains a shutter-type screen, which has 34 percent more screen opening than does the slotted pipe screen in PG-1. Using an installed 100 Hp pump, the well yield was 194 gpm at 144 feet of net drawdown. Static water level is 382 feet. Specific yield was 1.34 gpm/foot of drawdown. During sustained usage, the well yield was roughly 1.05 gpm per foot.

The maximum available drawdown for the aquifer in the vicinity of PG-3 is 850-382 (static level) or 468 feet, less 50 feet for dissolved gas control, or 418 feet. The optimum drawdown is 67% of this maximum value or 280 feet of drawdown, therefore:

a. Maximum yield at maximum drawdown is roughly 560 gpm at 1.34 gpm per foot, and 439 gpm at 1.05 gpm per foot of drawdown.

b. Optimum yield at 92 percent of maximum is 515 gpm at 1.34 gpm per foot, and is 400 gpm at 1.05 gpm per foot of drawdown.

c. At optimum operating level of 280 feet the optimum yield is 375 gpm at 1.34 gpm per foot, and is 294 gpm at 1.05 gpm per foot.

d. To attain optimum yield, the pump should be set at least 50 feet deeper than the optimum operating level, or roughly 712 feet of depth. With a pump length of 18 feet, this geometry indicates a pump setting depth of 730 feet.

e. In actual test operations, a 100 Hp pump was set at 763 feet to top of bowls. The pump column is 5-inch ID. The measured yield was 330 gpm at full pump operation. This pump provided the capability of operating at 80 psig well head pressure, at a flow rate of 250 gpm. This is the well head pressure to assure the entrained and dissolved carbon dioxide (CO_2) remain in solution.

f. Concerning CO_2, this well contains 220-230 cc of CO_2 per liter of fluid. This value is roughly 5 percent higher than for PG-1.

g. Realistic production temperature for this well was 145°F at 300 gpm. During the combined pumping tests, this well continued to produce 145°F fluid at a two-well combined flow rate of 600 gpm. The conclusion reached was that the temperature in PG-3 is probably independent of PG-1 pumping rate. Probable reason for this phenomenon is that the sub-surface geothermal fluid migration (or flow) was believed to be South-to-South-West. Hence, PG-3 effectively is "uphill" from PG-1, and is intercepting the hotter strata. It is possible that PG-3 would show a decline in temperature if PG-1 was pumped at its optimum yield of 564 to 782 gpm.

The following table illustrates original well yields and temperatures. If the estimated yield, and estimated temperature at optimum yield are correct, the combined flowrate at optimum would be 1000 gpm, at an average temperature of 138°F.

Table 9-1

ACTUAL AND THEORETICAL YIELD,
NMSU GEOTHERMAL WELLS

	Tested GPM	Optimum GPM	Tested Temp °F	Temp @ Optimum °F
PG-3	330	294	146	146
PG-1	365	782	142	(135)
Combined	600	(1000 est)	145 (PG-3) 139 (PG-1)	144 (PG-3) 135 (PG-1)

See Tables 9-2 and 9-3 for the history of each well.

Table 9-2

PRODUCTION WELL PG-1 HISTORY

August 1979	Well was drilled as NMSU-DG-3, a test well, and later redesignated production well NMSU-PG-1 (LRG-521). Well was drilled to 870 feet, and was completed to 850 feet, with cement plug in bottom.
February 1980	24-hour pump test.
June 1981	50 hp Peerless pump set in well.
July 1981	Ten-day controlled pump test and aquifer evaluation.
18-19 Dec 1980	48-hour flow test.
18-19, 22 Dec 1980	Test for dissolved gas in water.
July 1981	Combined flow test of PG-1 and PG-3 at 500 gpm. PG-1 pumped mud and sand for 45 minutes after which the 50 hp Peerless pump failed.
August 1981	The 100 hp pump was moved to PG-1 from PG-3. 365 gpm was pumped with little or no sand.
February 1982	Set new 100 Hp pump in PG-3
April 1982	Combined flow test of PG-1 and PG-3. PG-1 produced 225 gpm and PG-3 produced 275 gpm.
17 May 1982	Installed 100-hp pump failed. Break in screen in PG-1 at 803 feet, detected by down-hole video camera.
June 1982	Well repairs, to seal off defective screen section.
7-10 July 1982	Pump test using 80 hp pump and 100 hp motor. (265 gpm and with much sand)
1-8 August 1982	Air jetting to remove sand.
24-25 August 1982	Pump test of new performance pump (60 Hp, 265 gpm).
30 September 1982	The 60 Hp TRW-REDA pump failed after 30 hours.
18 November 1982	Installed a new Johnston, vertical shaft turbine pump.
March 1983	PG-1 pump column was penetrated by corrosion, and the production rate declined to 100 gpm.

Table 9-3

PRODUCTION WELL PG-3 HISTORY

January 1981	Well was drilled as NMSU-PG-3 (LRG-520), a test well, and in February 1982 was designated LRG-521-S, a production well supplement to PG-1 (LRG-521). Well was drilled to 930 feet, and completed to 870 feet, with open-hole completion.
25-27 January 1981	48-hour flow test and analysis of water samples.
January 1981	Combined flow test of PG-1 and PG-3 at 400 gpm. Each well produced 200 gpm.
July 1981	Combined flow test of PG-1 and PG-3 at 500 gpm.
August 1981	The 100 hp pump was moved from PG-3 to PG-1.
February 1982	PG-3 redesignated - see above.
April 1982	New 100-Hp pump installed; flow tested at 320 gpm
April 1982	Combined flow test of PG-1 and PG-3 at 500 pgm. PG-1 produced 225 gpm and PG-3 produced 275 gpm
May 1982	Pump failure. Tear down inspection was inconclusive. Operator decided that the lower section (870 to 930) of open hole was likely source of sand, even though no evidence existed that this well produced sand.
June 1982	Well repairs, cement plug installed in bottom to seal open hole.
July 1982	Flow tested using 100 Hp pump; well could not produce more than 175 gpm.
August 1982	Air jetted for 5 days to re-develop well after attempt made to loosen cement plug.
25-26 August 1982	New permanent pump was installed (60 Hp). Production rate 185 gpm at 70 psig well head pressure. Well was placed in service as a backup well.
27 September 1983	After 2,400 hours of operation, well head pressure had declined to 35 psig. Operator decided to shut down the pump.
October 1983	Controlled testing indicated pump still retained at least 85% of capability. Decision made to continue operation.

Table 9-2 (Cont'd)

PRODUCTION WELL PG-1 HISTORY

23 March 1983	Switched the operation to PG-3. The Johnston pump was removed for repair. 80% of threaded portion of column pipe showed evidence of severe corrosion resulting from H_2S attack.
7-9 April 1983	Airjetted to remove sand for 20 hours
12 April 1983	TV logged for PG-1. Log showed significant evidence of screen plugging with carbonate build-up, and gravel pack probably gone at 740 feet of depth.
June-July 1983	Metallurgical testing and examination of failed pump column confirmed sulfide (hydrogen) embrittlement was the primary cause of failure.
August 1983	Well was treated with sodium hypochlorite to control suspected anerobic bacterial action, and hydrochloric acid to dissolve carbonate pump in the screen section. Well was bailed for 24 hours after chemical treatment.
September 1983	Repaired Johnston pump was reset, using flanged column pipe epoxy coated on interior and exterior surfaces. Special pump section sand screen also was installed. A planned 3-day test pumping was terminated early because excessive sand production plugged the pump and sand screen. Pump subsequently was removed and stored at NMSU.
December 1983	Using a contractor supplied pump, conducted a special 24-hour flow test designed to measure sand production and H_2S control measures. The chemical treatment resulted in a significant reduction in H_2S. Sand production at first appeared to be controllable at production rates of 200 gpm. After the pump was removed, however, inspection of the well indicated that at least 17 feet of sand had infiltrated the well. Equilibrium draw-down values showed evidence of a progressive pumping resistance as the test continued, which is consistent with the sand infiltration, and effective loss of useful screen.

Table 9-3 (Cont'd)
PRODUCTION WELL PG-3 HISTORY

26 April 1984	Pump performance still slowly declining, and is now only 60 gpm at 30 psig well head pressure. Pump has more than 7,000 hours of operation. Well was taken out of service temporarily, to preserve remaining pump life for use during a scheduled 10-day steam outage planned for mid-May, 1984.

10. DISPOSAL DRILLING AND LOGGING

10.1 Summary

This new disposal well was drilled as a New Mexico funded project, with funding provided through the Geothermal Demonstration Fund. The well, NMSU GD-2 LRG-3648, was designed to dispose of 100-250 gpm of geothermal water after the heat has been extracted. The well had to meet several tests.

a. It had to intersect the geothermal aquifer, and an underground aquifer at least as saline as the geothermal water to be reinjected.

b. The intersected formation had to be capable of accepting the planned reinjection rate.

c. If test drilling verified the first two unknowns, in order to develop the well by jetting and test pumping, additional safeguards had to be installed to comply with New Mexico statutory requirements and assure that other usable ground water was not contaminated by the surface discharge of the geothermal water during well drilling and test pumping operations.

d. If the well solved the first two unknowns, the well screen would be exposed to a potentially corrosive environment which dictated high quality, corrosive-resistant well screen material.

e. The research program had to contain measures to assure that the geothermal aquifer did not over-lie a potable water aquifer to avoid long-term degradation of potable water supplies.

The completed well was drilled, tested, and connected to the geothermal system in a 4-month period starting August 1, 1982. This well has been in service as a disposal well since December 1, 1982. As part of the drilling program, additional information has become available which helps document the nature and extent of the geothermal anomaly for follow-up commercialization.

The New Mexico State University disposal well (NMSU GD-2 LRG-3648) is located at 330 feet from the Westline, 1,000 feet from the Northline, Section 27, Township 23S, Range 2E, in Dona Ana County, New Mexico. The well is located at a ground level of 4,000 feet above the mean sea level, approximately ¼ mile east of highway I-15 in Las Cruces, New Mexico. New Mexico State University owns the land and the mineral resources under the land at the site of the well.

10.2 Organization

The drilling and development of NMSU GD-2 LRG-3648 was assisted by technical advice from Roger Bowers, Hunt Energy Corporation and Rick Chagnon of the Johnson Screen Division of U.O.P. Andrew Bristol of the NMSU Water and Soils Laboratory provided significant assistance in water chemistry analysis. George Scudella of the New Mexico Energy and Minerals Department provided funding assistance. The Physical Science Laboratory supervised the well construction.

10.3 Driller Bidding

The following is an extract of the Invitation for Bids that was issued to the construction of NMSU GD-2 LRG-3648.

The University requested bids on a reinjection well, a deeper pilot hole, and a well drawdown test of 24-hour duration. Contractors were allowed to bid on the total package, or to submit bids partially on only Option C as defined in this IFB. Consideration was given on the basis of cost, technical performance, and responsiveness to requested time-frames for performance. The total package included three options, defined as following:

Option A	Reinjection well, approximately 450 feet deep.
Option B	A deeper pilot hole, as an extension of the pilot hole for reinjection well, approximately to 1,000 feet of depth.
Option C	24-hour well drawdown and pumping test for the reinjection well.

Time-Frame for Performance

Task 1	Option A:	Drill reinjection well, within 30 days following bid award (Estimate 5 days for work).
Task 2	Option B:	Drill a deeper pilot hole, within 30 days following bid award. (Estimate 2 days for work).
Task 3	Option C:	Conduct 24-hour well drawdown and pumping test. This test is to be completed within 10 working days following well completion.

10.4 Completion Method

The pilot hole was spudded on 23 September 1982, and was drilled to 991 feet of total depth (TD). The drilled pilot hole was 7 7/8-inch diameter to 520 feet and 6½-inch diameter to 991 feet TD. Suite of geophysical logs was acquired, and the pilot hole was packed with gravel before jetting water samples at 240, 840 and 468 feet of depth. The hole was enlarged to 14 3/4-inch diameter to 486 feet of depth.

On 21-22 October 1982, casing of type A/20 Kaiser prime steel of 0.322-inch wall thickness and 8.625-inch diameter was set from a level one foot above the ground surface to 370 feet, 380 to 390 feet, and 470 to 477 feet. Screen section was set with proforated zones from 370 to 380 feet and 390 to 470 feet of depth. The screen used was 8.625-inch diameter Johnson Type 316L stainless steel with 0.60 slot and 1½ by 3-inch collars.

The bottom hole was sealed by a cement plug from 467 to 486 feet of depth using 20 sacks of cement. Colorado Silica gravel 0.079 to 0.132-inch was packed in the section from 347 to 486 feet. Cement from the surface to 347 feet of depth consisting of approximately by 200 sacks of cement was emplaced using a cement pump. Cement bonding was verified by good cement return.

A schematic diagram of the completed well is shown in Figure 10-1.

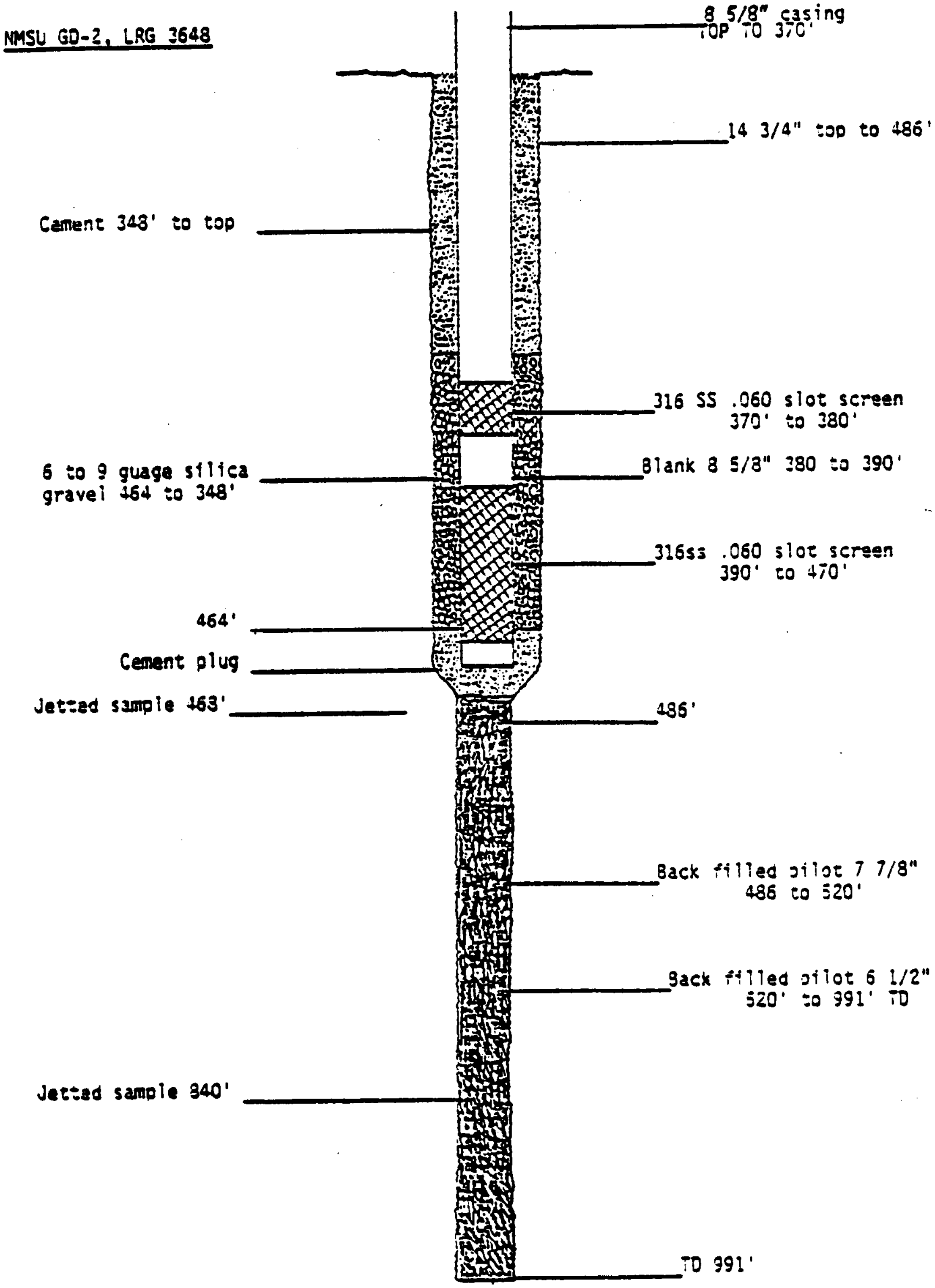


Figure 10-1. Schematic Diagram of the Completed Well

10.5 Stimulation Method

This new well, GD-2, is one of the first geothermal reinjection in New Mexico drilled specifically for the purpose of reinjection. As no prior history was available, a literature search was conducted to determine if any guidelines existed. Only one known controlled experiment has been conducted in which field and laboratory data were acquired and analyzed and compared. As reported in ASTM STP 735, American Society for Testing and Materials, Proceedings of the Second Symposium on Water for Subsurface Injection, Woodward Clyde, consultant reported on "Some Factors Contributing to Decreased Well Efficiency During Fluid Injection". This report served as a standard for the activities taken to develop NMSU GD-2.

Woodward and Clyde reported that compaction caused by vibration in the gravel-pack-aquifer model tended to decrease permeability by as much as 35 percent in the gravel pack, and 45 percent in the aquifer material. This decrease results from compaction of the gravel pack is a result of surging action from well-development procedures and the alternate injection and pumping tests. Based on this concern, the NMSU research team made a decision to proceed with a very careful well development.

Initially, the well was to be developed by a modest amount of air-jetting, followed by a 24-hour pumping test. Air jetting was initially very limited, and served mainly to produce samples for laboratory analysis. When the test pump was installed, the small pump could produce only 107-125 gpm, and well development was being hindered.

A new fixture was designed and installed for the air jetting, and consisted of a 4-inch diameter tube emplaced within 5 feet of well bottom. The 1.5-inch air line was set inside this larger tube, with a U-shaped end nozzle. This fixture kept the air from being directed into the well screen; instead, it was directed upwards so as to force water in a vertical flow path. The entire fixture was then raised by successive stages until the entire screen section had been jetted. This procedure was followed for almost two weeks of intermediate jetting, and jetted volume increase to approximately 250 gpm.

All the geothermal fluid produced by pumping and air jetting was routed through a 4-inch temporary pipeline to Tortugas Arroyo, and impounded within a small earthen dam, where it recharged the aquifer by natural percolation. An estimated volume of one acre foot of water was produced.

After the well had been developed by air jetting, it was then connected with a segment of 6-inch permanent disposal pipeline. The wellhead was installed, and temperature and pressure ports were installed. An air release valve also was installed so that air could be removed during initial filling of the pipeline and the well. The initial inflow test was set at a rate of 220-240 gpm, and the well accepted this flowrate by gravity reinjection. This initial test was for a 24-hour duration.

Based on the successful development program, a decision was made to forego further well development activities at that time. Now that a baseline has been established for natural-formation reinjection, future disposal operations can be monitored. If the well shows a decline in reinjection volume, or a build-up in wellhead pressure, the well can be acidized and cleaned out. Subsurface formation of the injection zone contains a large percentage of carbonates, and hydrochloric acid in suitable concentrations would be an effective acidizing agent.

Decline in reinjection volumes also could result from either air entrainment or gas binding caused by the release of dissolved gases. Concerning the dissolved gases, the NMSU geothermal system provides for separation of most of the free CO_2 prior to reinjection. Moreover, by reinjecting into an aquifer which is the same chemical composition as the geothermal water, and assuring that the reinjected fluid is slightly warmer than the natural ground water will tend to minimize the gas binding problem. The air entrainment problem is more difficult to solve. Although care was exercised in filling the pipeline to minimize air entrainment, it is possible that small air bubbles could become lodged in the well screen or aquifer. These air bubbles could be caused by the so-called Jamin effect, or could result from distortion of bubbles when they are forced through the capillary openings of the aquifer.

To minimize or eliminate air entrainment, the simplest (but most costly) solution is to install a reinjection pipe column, with a controllable butterfly valve near the bottom of the injection pipe. Modification of the well by this fixture would appear to be a useful future test if reinjection volume declines, or if wellhead pressure starts to rise. In the interim, care should be exercised by system operaters to assure a slow and careful filling of the pipeline, and to vent the well carefully during future start-up operations.

Further details concerning NMSU GD-2 LRG-3648 may be found in the New Mexico State University Geothermal Reinjection Well Completion and Testing Technical Completion Report.

The chemical analysis of the water samples at each horizon is given in Table 10-2. The analysis was performed by using standard procedures recommended by the U.S. Environmental Protection Agency (EPA).

Table 10-2
CHEMICAL ANALYSIS OF DISSOLVED MINERALS, GD-2
Concentration (mg/l)

Element	At 468'	At 840'	Method of Determination
Na	427.6	386.2	A
K	43.8	34.8	A
Ca	130.0	114.5	B
Mg	36.0	36.6	B
Cl	573.7	440.3	C
CO_3	0	0	D
HCO_3	422.2	494.2	D
SO_4	315.0	280.0	C
As	<0.001	0.001	B
Ba	0.08	0.09	B
Cd	<0.005	<0.005	B
Cr	<0.002	<0.002	B
Pb	0.005	0.005	B
Hg	<0.0002	<0.0002	B
Se	<0.001	0.001	B
Ag	0.05	0.05	B
NO_3-N	0.01	0.02	C
F	1.29	0.55	E
SiO_2	23.2	36.0	B
Fe	1.28	6.00	B
Mn	0.09	0.13	B
B	0.30	0.30	F
TDS	1,948	1,787	

A = Flame Emission; B = Atomic Absorption; C = Color Metric;
D = Acid Titration; E = Specific Electrode; F = Induced Conductive Plasma

11. DISPOSAL TESTING

There are two disposal wells, NMSU #4 (the old golf course well) and GD-2 LRG-3648 (the new disposal well). The golf course well originally was completed in 1962. It was in service for ten years, during which time trees and shrubs did not grow properly. The well was shut-in in 1972, and the pump was removed in 1977. The well was repaired and brought to operation as a disposal well in January 1982. The new disposal well GD-2 was drilled in September 1982 to provide an additional capacity to the existing golf course well. A history of each well, which briefly summarizes the results of test and performance during the construction and operation phases, is given in Table 11-1 and 11-2.

Golf Course Well

The golf course well was abandoned in 1971 as excessive mineralization was causing harm to the golf course vegetation. Based on previous research, a Disposal Order was issued by the New Mexico Oil Conservation Division which allowed testing of this well as a disposal well. Gravity reinjection only was initially allowable, and verification of disposal facilities was necessary before placing the well in service.

The well was pumped for six weeks using the 3.5 hp pump from the PG-2 well. Water temperature and conductivity values were logged, and at the end of the pumping period, water samples were taken for detailed analysis.

A reinjection test was conducted over a 5-day period for a total of 115 hours. This test indicated that the planned reinjection rate of 225-250 gpm would be feasible.

Table 11-1

GOLF COURSE WELL HISTORY

1961 - 1962	Well drilled and completed.
1971	Well taken out of production.
1977	Pump removed
February 1981	Trial injection of 100,000 gallons of domestic water. Controlled injection tests at 300 and 550 gpm.
13 July 1981	Well approved as disposal well for gravity flow only, by the Director, Oil Conservation Division of the Energy and Minerals Department, State of New Mexico.
1 Aug - 14 Sep 1981	Six weeks of low-flow rate pumping test conducted.
September 1981	Reinjection test conducted at 225 gpm.
December 1981	New well casing, and screen liner installed.
January 1982	Additional testing conducted to verify the new well casing and repairs. Reinjection tests conducted at rates up to 300 gpm.
February 1982	Well placed into geothermal service as a disposal well.

Table 11-2

GD-2 LRG-3648 HISTORY

Date	Action
23-24 Sep 1982	A pilot hole was drilled to 991 feet of depth. Jetted water samples were obtained at horizons of 468 and 860 feet. Water samples validated conclusion that the geothermal aquifer extended to the target zone, and was the same quality as production wells.
22-23 Oct 1982	Set casing, screen, and gravel pack.
27 October 1982	Well development. Jetted water samples were obtained 468 feet of depth.
November 1982	Field connection of the new disposal well to the geothermal system.
1-15 December 1982	Controlled reinjection tests. Gravity injection conducted at an average rate of 220-240 gpm.
1 December 1982	Well placed into service as primary disposal well, with the old golf course well (GD-1) as backup.

After the well repairs were completed, additional tests were conducted to verify conditions and to assure the integrity of the repairs.

An initial test at a flow rate of 300 gpm caused water to overflow from the well. The cause of this overflow was unknown, although it was suspected that a temporary bridge had formed during the repair operations. Because of this problem, the casing liner was sealed at the well head. This change also permitted the system to use the drop of 130 feet in elevation between the production and disposal wells (less an estimated 15 feet of friction losses) as the injection motive force to assure injection without the need for an injection pump. Moreover, this design completely isolated the geothermal flow so that a blockage of the disposal well would not result in a geothermal spill. Instead, if the well were blocked, system flow would cease, and automatic controls would shut down the production well pumps.

After design changes were incorporated, a 3-hour flow test was conducted. Changes in static water level were measured by differential pressure and flow rates were monitored by installed system flow meters at the Gas Separator tank and Heat Exchanger complex. The test was designed to assure that the well would accept up to 50 percent more flow than the system design flow rate of 200 gpm. Because automatic flow by-pass controls had not yet been installed, manual controls were used to set and control the flow at ± 10-15 gpm of the desired rate.

From this limited test, it appeared that the well would safely accept the planned 250 gpm disposal rate.

Subsequent testing at varying flow rates over a 30-day period validated the conclusion from these earlier tests. During all but two of the tests, the water level rise in the well bore at 300 gpm was not noticeable. However, on two tests, the water level rose to -142 feet, and then slowly dropped to -165 feet. This lack of stable behavior was unexplainable, and dictated continuous monitoring. Because the behavior of this well could mean early failure, a new disposal well (GD-2) was planned for a location adjacent to the Heat Exchanger Building, which is underlain by the geothermal aquifer, and which would facilitate disposal operations.

New Disposal Well

A controlled reinjection test was conducted during the period of 1-15 December 1982. The test established that the new disposal well GD-2 can dispose the spent geothermal fluid at the planned production rate of 220-240 gpm.

12. APPLICATIONS ANALYSIS

This section is not applicable to this project.

13. OBTAINING USER COMMITMENT

This section is not applicable to this project.

14. SYSTEM LOADS

14.1 Peak Loads

The total capacity of the New Mexico State University Geothermal Demonstration Project is 400 gpm @ 142°F or 15 million BTU per hour.

The present peak load is 105 gpm @ 142°F or 3.675 million BTU per hour.

14.2 The total annual heat load is displayed in the following table.

Table 14-1

GEOTHERMAL ANNUAL LOAD

DATE	BILLION BTU
April	5.82
17 May (end of normal academic year)	1.61
June (first summer session)	9.46
July (second summer session)	9.46
26 August (start of normal academic year)	7.49
September	5.13
October	5.31
November	7.23
December	7.23
January	3.10
February	6.71
March	6.14
TOTAL ANNUAL LOAD =	45.9 Billion BTU/YEAR

14.3 Fuel Replaced

By applying the information in Section 14.2 the Annual Fuel Replaced yields 57,375 MCF of natural gas at a boiler efficiency of 80 percent. For further details see Section 33. (System Economics).

15. PRODUCTION SYSTEM DESIGN

15.1 Selection Process

The design of PG-1 was developed from the data obtained from the exploratory holes DT-1 and DT-2. PG-1 was drilled only 15 feet away from DT-1.

The site of PG-3 was developed from data obtained from a several long-term aquifer tests utilizing PG-1, and thermal gradient data from all the shallow gradient wells in the Las Alturas area. Also available was information previously acquired in the site selection of PG-1.

15.2 Design

The explicit design policy followed in the design and completion of the production system was that a fully tested installed capacity of at least double the current requirement was needed. This policy was implemented with two production wells, each capable (theoretically) of a production rate twice the expected need.

Both PG-1 and PG-3 were designed to tap the aquifer between 700 and 850 feet. The design requirements for PG-1 were as follows:

1. 17-inch hole drilled to 850 feet.
2. 100 feet of screen with 750 feet of 10-inch casing.
3. A cement plug in the well bottom.
4. Gravel pack 150 feet and sand pack 30 feet of the 3-inch annular space.
5. Cement the remaining annular space to the surface.
6. Use a 50 Hp Peerless turbine pump at a production rate of 250 gpm.

The design requirements for PG-3 were as follows:

1. 16 3/4-inch hole drilled to 850 feet.
2. 750 feet of casing with 100 feet of screen.
3. Gravel pack in the bottom.

4. Lowest 150 feet of annular space packed with screen gravel. 30 feet of annular space packed with medium to coarse sand.
5. Cement the remaining annular space.
6. Use a 100 Hp TRW electric submersible pump at a production rate of 250 gpm.

For further details concerning PG-1 and PG-3 see the Technical Completion Reports for the two individual wells as noted in the Appendix.

16. DISPOSAL SYSTEM DESIGN

The Disposal System is made up of two disposal wells, NMSU GD-1 (formerly NMSU #4) and GD-2 (LRG-3648) and a Disposal Pipeline.

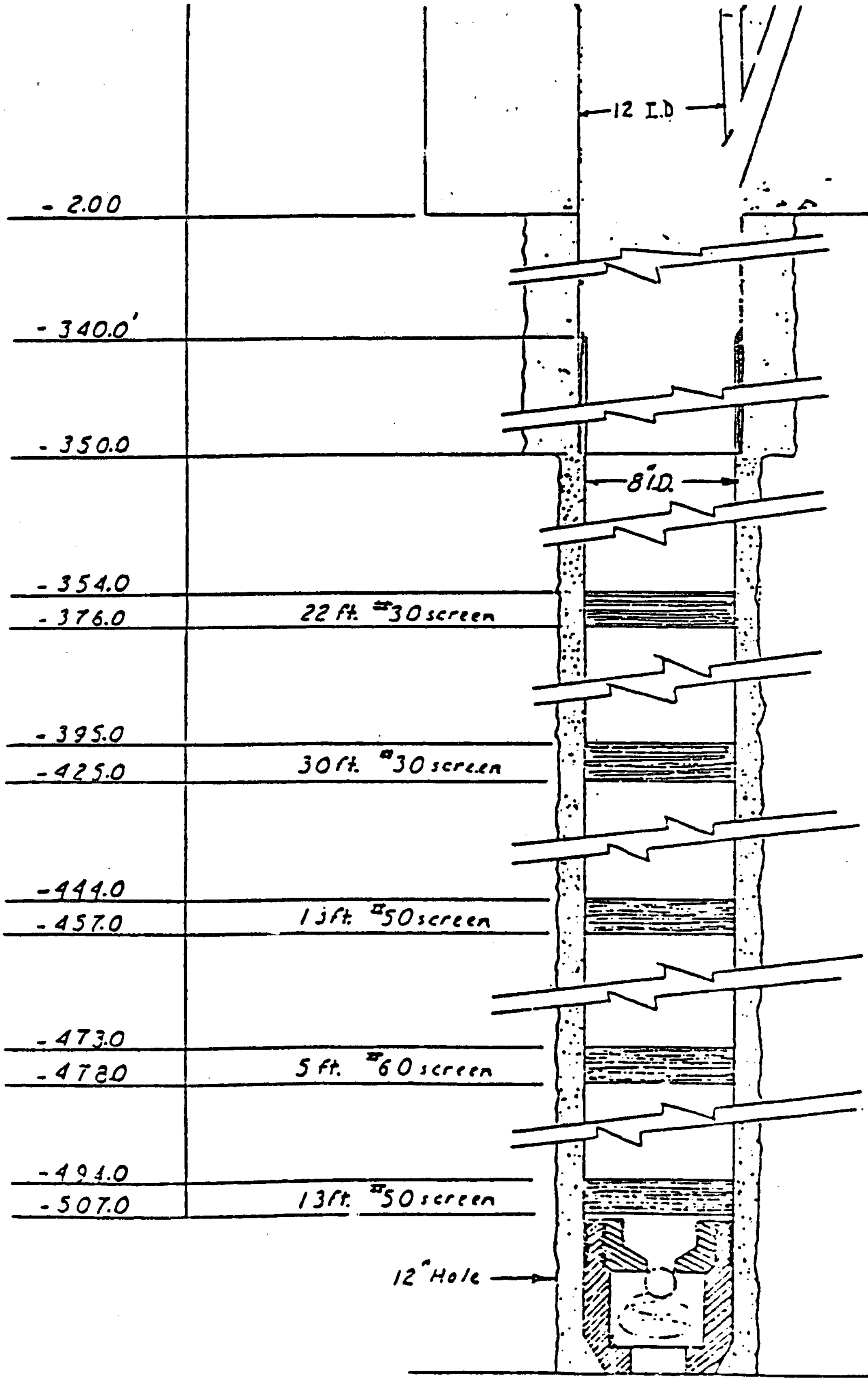
Disposal Well GD-1 (old Golf Course well) was drilled in 1961, and completed in early 1962. Due to poor water quality the well was placed in an active status in 1971, and the pump was removed.

Based on earlier research, a Disposal Order was issued by the New Mexico Oil Conservation Division, which allowed testing of this well as a disposal well. Implicit in this approval were the requirements that only gravity reinjection was initially allowable, and that verification of disposal facilities was necessary before placing the well in service.

If successful, this well could be used to dispose of 100 to 250 gpm of geothermal water after the heat has been extracted.

From available data, it appears this well (GD-1) is warmer now than when it was in production as an irrigation well. If this information was correct, it was expected that the higher temperature might be paralleled by an increase in salinity over earlier values. To assess geothermal parameters, the research was designed to gather key data on water temperature, dissolved gas content, dissolved minerals, and formation transmissibility for reinjection. In addition, if research substantiated that the well was in fact open to its original drilled depth of 606 feet, plans were made to install a submersible pump and conduct step-drawdown tests to determine geothermal parameters for temperature, flow rate and water quality, from depths down to 600 feet.

Available information on well parameters during its first ten years was very sparse and incomplete. In addition, an earlier trial reinjection test had used more than 100,000 gallons of domestic water, reinjected into the well. This domestic water contains only 400-500 ppm dissolved minerals. Accordingly, the research plan provided for a means to pump the well so as to restore base line parameters that might have existed prior to the trial reinjection.



Golf Course Well Schematic
Figure 16-1

Once this condition was attained, water samples were to be analyzed for dissolved minerals and dissolved gases. Then, a test fixture was to be installed designed to assess, if possible, mechanical integrity of the 20-year old casing. If conditions permitted, a small diameter pump column was to be inserted through the test fixture, to acquire additional samples by jetting samples. Then, after baseline data was acquired, a 120-hour controlled reinjection test was to be conducted to determine transmissibility of the aquifier in a reinjection mode. Concurrently, using one of the existing geothermal production wells, a controlled experiment was to be started to assess the long term effects of the geothermal water on golf course vegetation using sprinkler irrigation.

PUMPING TESTS

This well had not been pumped for ten years. It had been left uncovered, inside a maintenance building, under unknown conditions. Moreover, in February, 1981, a trial injection test had been performed, and more than 100,000 gallons of domestic water (400-500 ppm TDS) had been flowed into the well.

For these reasons, the water quality of the aquifier could not be accurately assessed. A need existed to pump the well for as long as possible, or until stable conditions could be met for water temperature and conductivity, with the latter value equivalent to probably salinity as total dissolved solids.

Because of the unknown length of time that the pumping would require, it was not practical or economic to consider a contractor - operated test pump. The only choice remaining was to use the small submersible pump serving the geothermal well at the University Center. This is a 3.5 Hp pump, which has capability for only 22 gpm. Because the pump could be made available, decision was made to relocate the pump temporarily in the Golf Course Well.

The pump was installed, using 1.5-inch PVC column, and set at 240 feet of depth to pump bowls. This setting provided at least 20 feet of water over the pump bowls. The pump discharge was then connected to 300 feet of temporary pipeline to a drainage area. A turbine flowmeter and electronic temperature monitoring points were installed, and the probes were connected to strip chart recorders.

Conductivity values continued to increase, but were not stable. A time constraint then occurred, and the Disposal Order for the Golf Course Well required a formal reinjection test, witnessed by OCD representatives. Accordingly, a decision was made to acquire water samples for detailed analysis for dissolved minerals and gases. Conductivity values at the time of sampling were equivalent to approximately 1,575 ppm of total dissolved solids. The pH of the samples was 6.8. From the slope of the conductivity-time curve it is likely that an increased pumping rate, or a longer time period of pumping would have produced higher conductivity values.

REINJECTION TEST

A. Test Fixture: After the small submersible pump was withdrawn, an attempt was made to acquire a temperature log. The hole was bridged at roughly 350 feet of depth, and a complete log could not be acquired. This same problem arose on an earlier test. Moreover, concern existed about the integrity of the closure valve originally installed at 507 feet of depth. In order to pierce the bridge, and to explore the condition of the well bottom, a special test fixture was designed. Details of this fixture are depicted in Figure 16-2. In turn, the fixture was designed to be threaded on the bottom of heavy wall, 5-inch inside diameter pipe, and lowered into the well.

B. Insertion of Test Fixture: The fixture and steep pipe were lowered into the well on a day when ambient air temperature was 65°F. The weight of the steel pipe, and the sharp-pointed fixture very easily cleared the small bridge at 350 feet of depth. A second more substantial bridge was encountered at 385 feet of depth, and also was cleared. Existence of these two bridges could mean the pumping test involved only water movement from the top screen section at 354 to 376 feet of depth, with possible minor seepage from lower sections.

At 488 feet of depth, the fixture encountered an unknown mass. With the weight of the column (approximately 8,500 pounds) resting on the mass, it was not possible to rotate the column. When the column was raised only an inch, it was possible to rotate the column. Inadvertently, due to a mix-up in crane signals, the entire 8,500-pound weight was suddenly dropped 8-10 feet on the mass. The test fixture did not penetrate the mass. The conclusion reached was that this

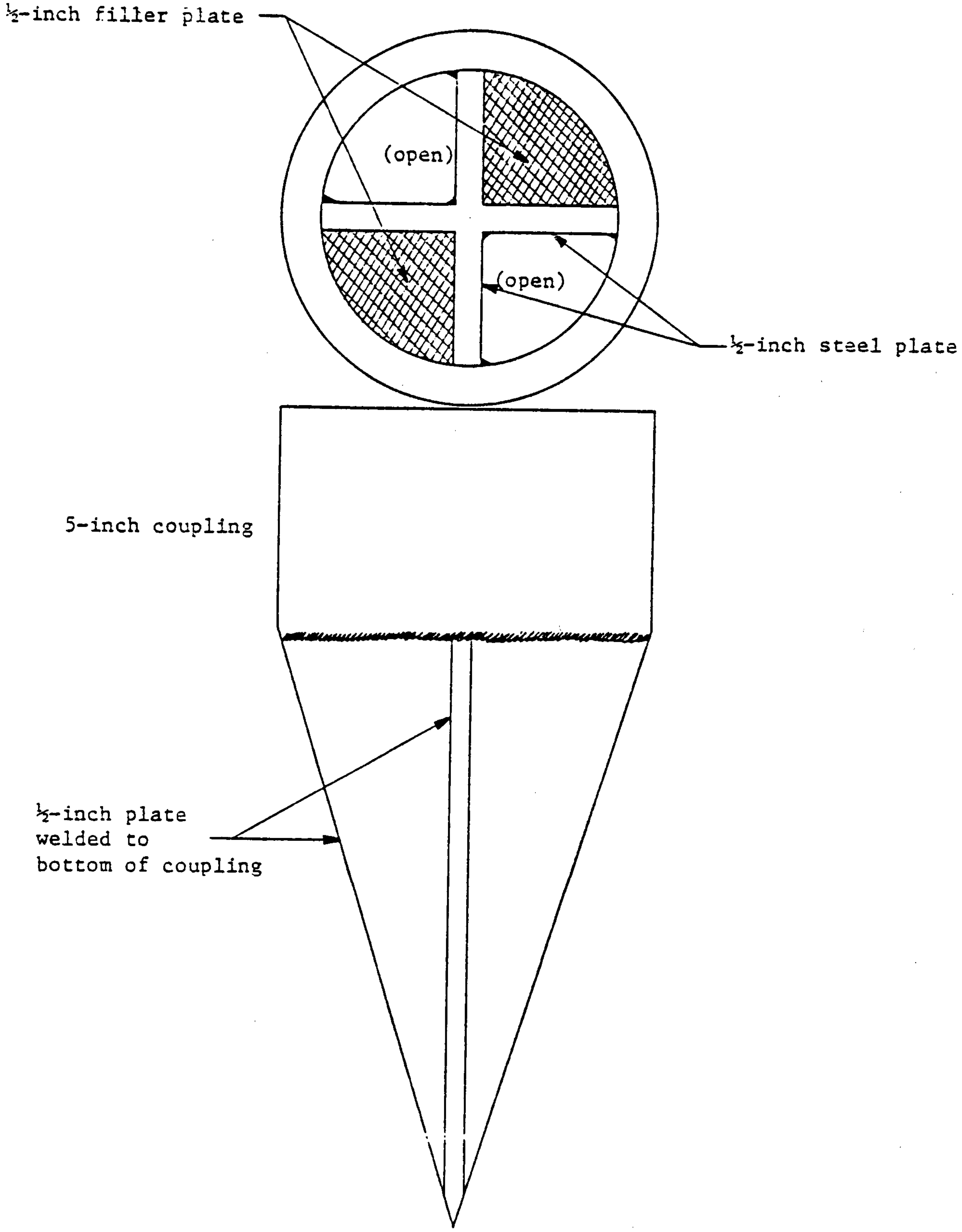


Figure 16-2
Test fixture, screwed onto bottom of
5-inch steel column, NMSU Golf Course Well

unknown mass probably was a fused mixture of debris, rust and scale which had collected over the past 20 years. This conclusion leads to two other observations. First, the screen section between 495 to 505 feet of depth probably is blocked, with a possibility that is might allow minor flow (leakage) of fluid. Secondly, the closure device probably still is intact. Subsequently, it was determined that the valve was fabricated of cypress wood, which is quite long-lived, and relatively resistant to rot. This fact also supports the belief the foot valve is intact.

Because it appeared to be impossible to pierce or remove the blockage at 488 feet of depth, a decision was made to position the test fixture just above the mass at 480 test of depth. The resulting test configuration is depicted in Figure 16-3.

C. Reinjection Test. A need existed to test the well capability to accept inflow of 250 gpm, which is the system design geothermal flow rate. In order to provide assurance of continuous intake of 250 gpm, a need existed to prove well capability at a rate above this value if it could be attained. The limiting factor was the availability of static head, or mechanical assisted pumping to provide the required flow rate. At the site was a stand-by water storage tank, which could provide 44 feet of head. This tank was connected to the well by a temporary pipeline, and a short duration test was conducted. This test indicated flow rate up to 270 gpm could be attained. Prior to this test, a very low flow rate test was conducted, consisting of 20-25 gpm for 20 hours to assure the test fixture was intact, and open to flow.

A review of the test data, water and dissolved gas analyses, and the corrosion problems in the well resulted in a perceived need to insert a liner in the well casing. Purpose of this liner is to prevent loose rust and scale from falling into, and bridging the well. With an inside diameter of 8-inches in the screen section, a liner of 6-inches inside diameter could be inserted, and would provide mechanical strength to the well, in addition to solving the bridging problem. Moreover, the planned liner also would include new Johnson steel well screen for the screen section of the well.

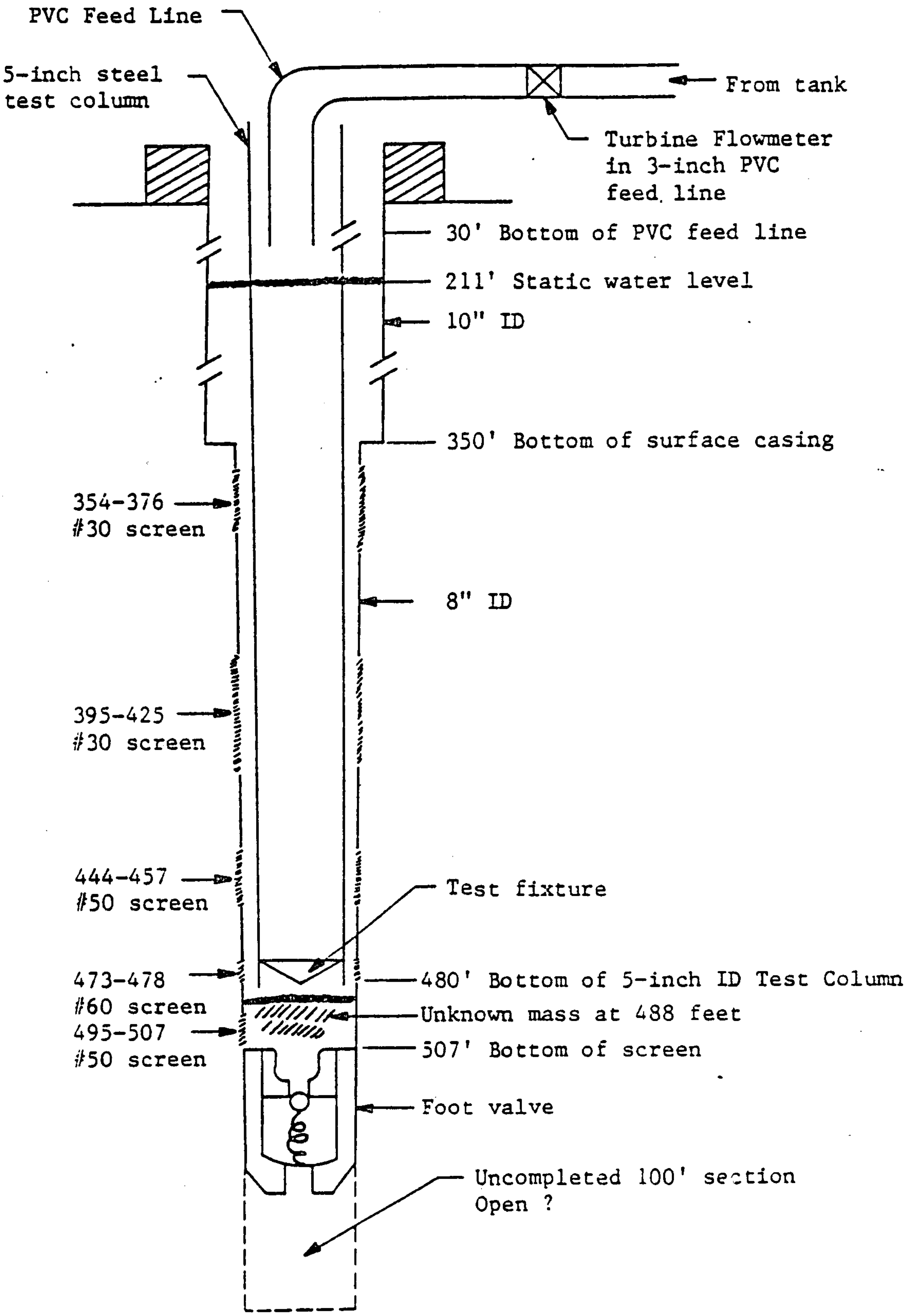


Figure 16-3
NMSU Golf Course Well

Trial Injection Test

24-29 September, 1981

After the 5-inch column was removed, the liner was installed. This liner had been pre-fabricated in 30- to 40-feet lengths, with the lowest 100-feet section consisting of alternating steel screen and sections of blank pipe. This portion of the liner was designed to match the original screen sections from 354 to 454 feet of depth. During the course of the repair operation, it was determined that the original schematic was not factual. As depicted on this schematic, the original well decreased from 10-inches to 8-inches inside diameter at 354 feet of depth. However, exact measurements made while inserting of sections of the new liner indicate this dimension change occurs at 340 feet of depth. Accordingly, the planned scheme was altered to provide a liner section from ground surface to 400 feet of depth. It was hoped that the screen sections and their location were accurately depicted on the original schematic, and the new liner will match the original screen intervals. The change in plan made during repairs was designed to optimize as much as possible in this uncertain situation.

The liner as finally installed is portrayed in the following table, and consists of welded sections.

Table 16-4
WELL CONFIGURATION

Setting Depth	Liner Material
2 feet above ground surface to 350 feet	6-inch inside diameter, schedule 40 steel pipe
350 to 380 feet	6-inch steel screen, #50
380 to 400	6-inch steel pipe
400 to 410 feet	6-inch screen section, #50

The top of the 6-inch liner was then secured by flanges to the top of the surface casing, and bolted down. The well was completed by inserting a 4-inch diameter steel pipe in the top of the 6-inch liner. This allowed one-inch open annular space around the insertion pipe, so as to assure only gravity reinjection. This insertion pipe was connected to the disposal pipeline.

For further details concerning the Golf Course Disposal Well see (Technical Completion Report) Testing and Repair, NMSU Geothermal Disposal Well Cold Golf Course Well).

Due to the low reliability of the repaired golf course well, another injection well, NMSU GD-2 LRG-3648, was required.

The primary consideration in site selection of LRG-3648 was the potential for degradation of domestic water samples.

The site for the new disposal well GD-2 was selected on the basis of water analysis, reinjection tests utilizing the Golf Course Well (NMSU #4), and proximity to the existing disposal pipeline. If the necessary and sufficient conditions exist for the selected site, then the long-term effects on potable water supplies are expected to the minimal. These conditions are that that the site selected for the new disposal well will be in the same aquifer as the geothermal productive wells, and that the reinjected fluid can be contained within that aquifer. Water analysis was conducted to compare the water quality of the geothermal production wells, PG-1 and PG-3, to that of the new disposal well. The analysis was performed by on-site conductivity measurements of water samples jetted from the drilled pilot hole of the new disposal well. The following Table 16-5 provides a summary data which supports the conclusion that within experimental limits of accuracy, the wells were produced form a single aquifer.

Table 16-5

CONDUCTIVITY AND TOTAL DISSOLVED SOLIDS (TDS) DATA, NMSU GEOTHERMAL WELLS

Well	Depth (Feet)	Conductivity (mmhos/cm)	TDS (mg/l)
PG-1	850	3.11	2,000
PG-2 (University Center Well)	500	3.17	1,980
PG-3	866	3.16	2,010
GD-2, LRG-3648	468	3.12	1,948
(New Disposal Well)	840	2.68	1,787

A need existed to ascertain the new disposal well capability to accept an inflow of 220-250 gpm, which is the system design geothermal flowrate. In order to enhance the assurance of continuous intake of 250 gpm with the limited available information of the well site, a need existed to utilize the data of reinjection test from the previous study of the Golf Course Well (NMSU #4) which is located at 1/3 mile North-East of the new disposal well site.

Reinjection test of the Golf Course Well indicated that it can accept an average intake of 270 gpm with the available head for gravity injection. The test also reviewed its transmissibility range of 8,570-9,260 gpd/ft which is very favorable for the reinjection mode. The new disposal well site, which is only 1/3 mile away from the Golf Course Well, was estimated to have a comparable range of transmissibility, and thus it will have a capability of accepting inflow of 220-250 gpm. This conclusion was reinforced by results of the controlled reinjection test, which established that the well will accept by gravity injection and planned production rate of 220-240 gpm.

The new disposal well site is located in the vicinity of the existing disposal pipeline which is connected to the primary heat exchanger complex. The new well was connected to the pipeline by installing approximately 300 feet of 6-inch diameter, new asbestos-cement pipeline. From an analysis of elevation head availability, sufficient back pressure will be available at the outlet of the heat exchanger to provide motive force for the reinjection. Furthermore, there will be less frictional pressure drop for this new disposal well when compared to the existing Golf Course Well since the Golf Course Well is 2,000 feet farther along the disposal pipeline from the Heat Exchanger building (see Figure 16-6).

An analysis of well cuttings, electrical logs, temperature log and water analysis has revealed a clear understanding of the geothermal aquifer at this location. Cuttings and electrical logs portray an alluvial fill, with distinct water bearing formations at 370 to 470 feet of depth, interspaced with clay lenses. In this interval, the temperature log showed a modest but steady increase in temperature to 500 feet of depth. From 500 to 700 feet of depth, the well was essentially isothermal. Below this horizon, a negative temperature gradient was noted. A massive clay lens was intersected from 725 to 790 feet of depth, and the negative temperature gradient was more pronounced below 760 feet of depth. From 790 feet to total depth of 991 feet, the pilot hole intersected a very tight formation of fractured rhyolite, with only minor fracture formations characteristic of the identical material located during drilling of the production geothermal wells.

Because of the distinct layering effect of the subsurface horizons, a concern existed that possibly the geothermal aquifer was underlain by a fresh water formation. The nature of the formation material tended to rule out this possibility, but confirmation was needed based on water chemistry analysis. It is noted that the lower horizon clearly is part of the geothermal aquifer but that it apparently contributes very little geothermal fluid production.

Based on the total evidence acquired, the most probable explanation for the temperature inversion noted is that most of the geothermal fluid is originating in a massive fracture formation several miles to the East in the vicinity of Tortugas Peak, and then is migrating through the substrata down hydrolic gradient to the Rio Grande River Basin. The major aquifer is a substratum above the 700 feet horizon at GD-2, and a distinct lateral flow probably is occurring.

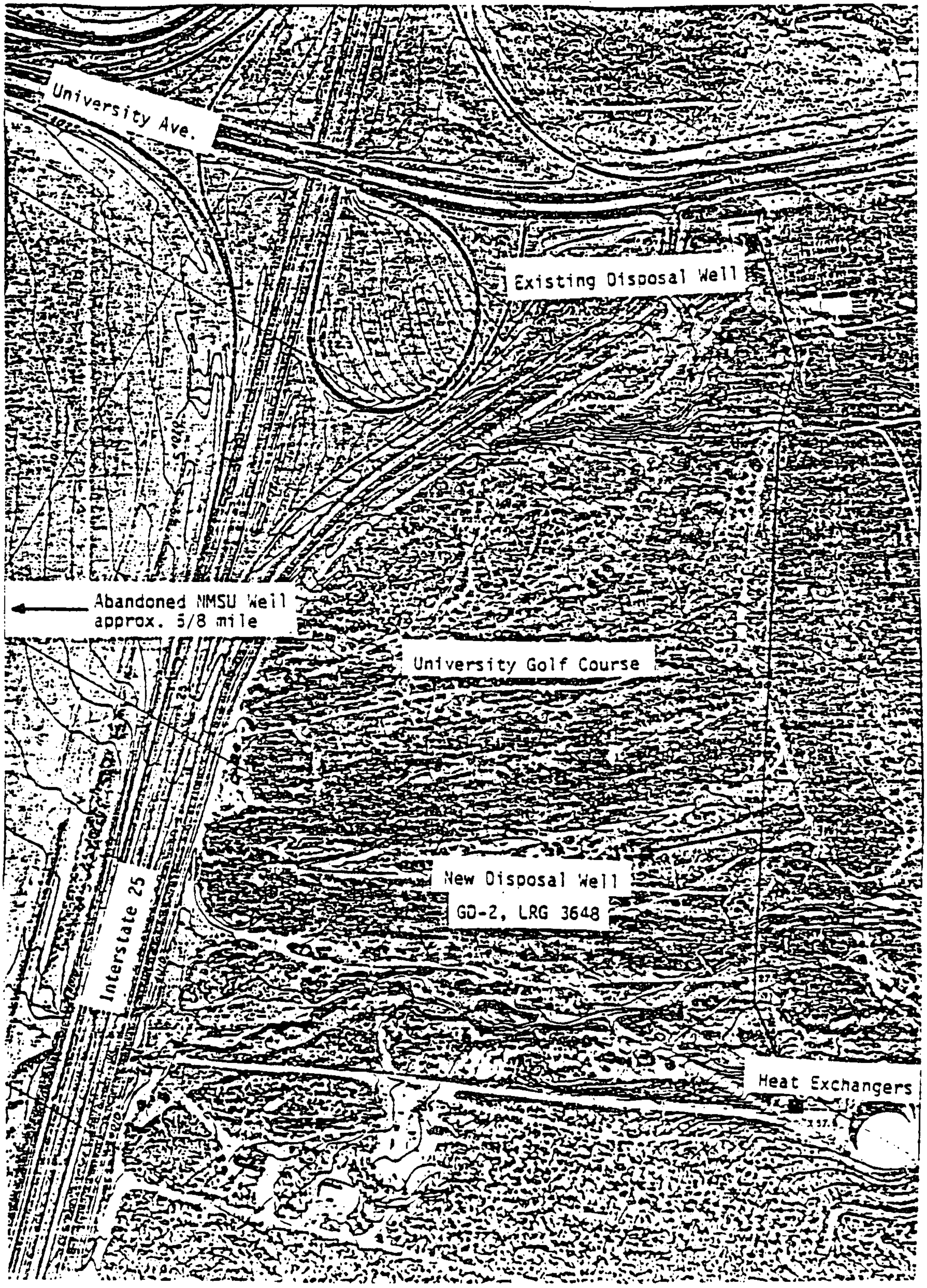


Figure 16-6 Aerial Photograph of the Disposal Well GD-2 LRG-3648

As the fluids migrate from the major fault system, they tend to cool as they travel away from the source, and the cooling trend is accelerated by contract with the cooler substrata in the Rio Grande River valley. This theory is consistent with the chemical analysis, which shows no apparent mixing with less saline waters, and a consistent chemical analysis in the various NMSU wells located along an E-W trending line. (PG-1 is further East and is 142°F; PG-2 is at a midpoint and is 122°F; and GD-2 is further West and displayed a pilot hole mud temperature of only 89°F.)

It should be noted however, that a well completed at GD-2 for a large volume discharge would very likely show a higher pumped water temperature than inferred from the mud log. All other NMSU geothermal wells showed the same characteristic; i.e., the final pumped water temperature was roughly 25 percent higher then the mud log temperature profile acquired at the same time as the electrical logs. Based on this common behavior, it would not be unrealistic to anticipate a pumped water temperature at GD-2 of 105 to 110°F.

This possible temperature is reaffirmed by careful analysis of the drilling mud temperature (as determined during geophysical logging) compared with the pumped water temperature of the several geothermal production wells. The correlation shown in Table 16-7 is based on the logging temperature compared with final well temperature. This correlation is very sensitive to the amount of time that has elapsed after drilling mud circulation is stopped prior to the geophysical logging. The comparison is also affected by the composition and weight of the drilling mud, the size of the pilot hole, circulation rate, and mud pit temperatures. In spite of these off-setting tendencies, the correlation has proved useful in estimating final hole production temperature.

Table 16-7

MUD TEMPERATURE VS. PUMPING WATER TEMPERATURE

NMSU GEOTHERMAL WELLS

Well	Mud Temperature (°F)	Water Temp. (°F)	Percent Change	Remarks
PG-1	115	142	23.4	Log acquired 30 minutes after circulation stopped
PG-2	95	118	24.2	Log acquired 30 minutes after circulation stopped
PG-3	121	145	16.5	Log acquired 3 hours after circulation stopped
GD-2	89	(108 EST)	(23.5 EST)	Log acquired 30 minutes after circulation stopped

As a result of the thorough study of the interpreted subsurface conditions and the conductivity measurements of water samples jetted from various depths of the drilled pilot hole, the disposal well GD-2 was designed to reinject the spent geothermal fluid to the aquifer through the screen sections at depths of 370-380 feet and 390-470 feet.

Controlled Testing of Direct Use Geothermal Water

The geothermal water was tested for irrigation uses. Permission was obtained from the old for surface discharge of geothermal water sufficient to irrigate test plots. This permission was necessary in order to conduct the long-term experiment to assess the effects of geothermal water on various types of grass which are or could be used for the golf course.

An early, limited experiment had been designed, which would have been conducted during the growing season of 1980. This experiment was cancelled because of the need to relocate the pump from the PG-2 well to the golf course well. Moreover, this early experiment lacked adequate controls, and was poorly designed.

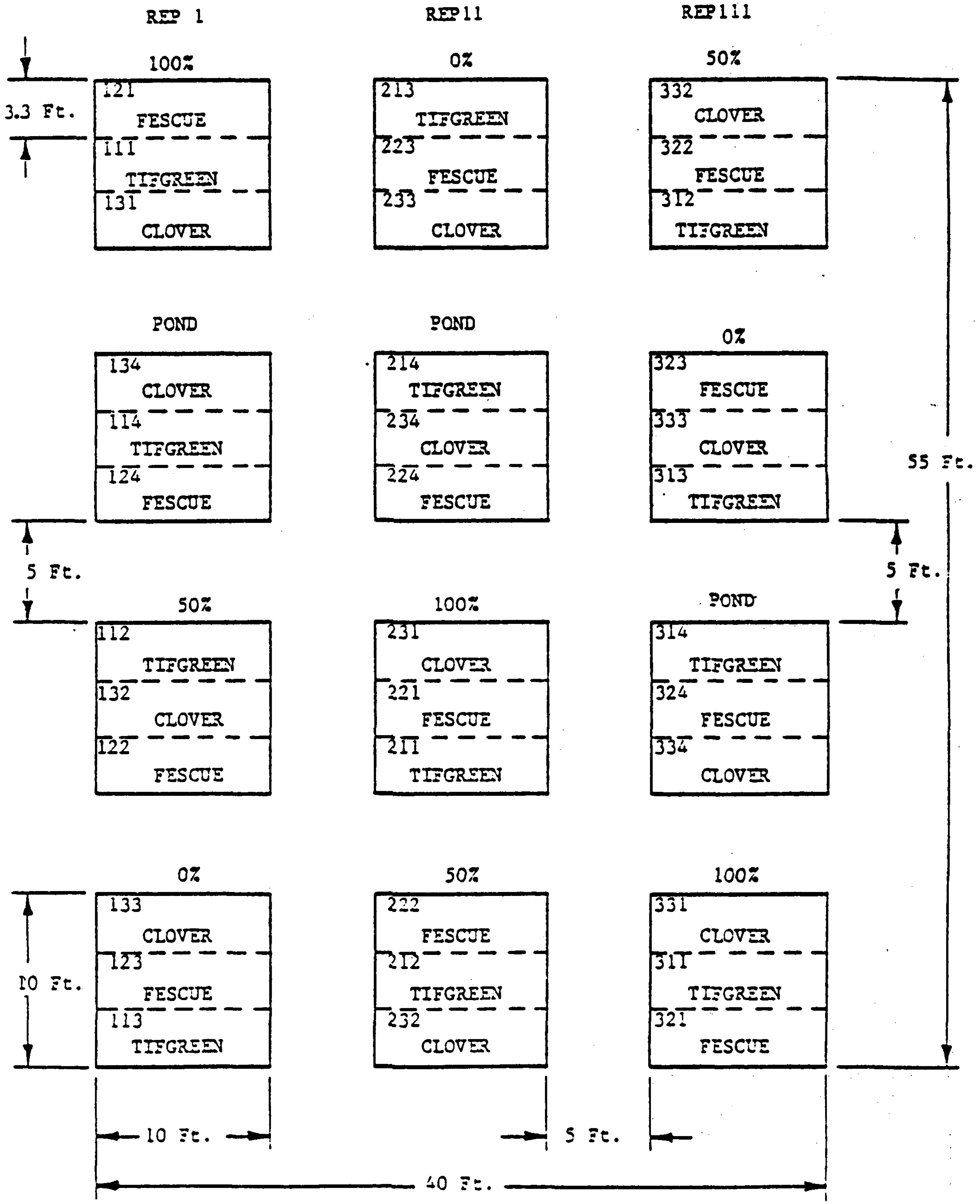
A new experiment was set-up, and consisted of a total of 12 test plots, each containing the same three varieties of grass. A piping and sprinkler system was installed which permitted watering these test plots in individual 3-grass plots by using varying ratios of geothermal and domestic water. This experiment was designed by Dr. Arden Baltensperger of the NMSU Agronomy Department. A schematic of the test plots is shown in Figure 16-8. The plots have been sodded, and were brought to maturity with domestic water. Controlled growth tests were conducted to assess the effects of geothermal water.

To interpret Figure 16-8, the percentage number above each plot indicated the mixture of geothermal water and domestic water to be used. The figure "0%" indicates all domestic water, whereas "100%" means all geothermal water. Three sets of plots have been reserved for possible future irrigation using a small test pond filled with geothermal water.

It was found that irrigation with geothermal water mixed with normal water is <u>not</u> recommended unless further research is done for a greater time period to insure that application of this water will not decrease the turf quality or raise soil salinity to unacceptable levels. For further information see the final report on evaluation of the effects of irrigation with geothermal water on turf quality of 'tif green' bermuda grass 'K-31' tall fescue and white clover and soil salinity. (Roch Gaussion, Steve Smith, Ken O'Donnell, Dan Turnham and A. A. Baltensperger.)

Figure 16-8

GEOTHERMAL TEST PLOT PLAN



17. TRANSMISSION SYSTEM DESIGN

17.1 Selection Process and Design

A number of different routes for piping the geothermal hot water to a heat exchanger reinjection well and hot water storage tank complex were considered. The primary factors influencing the various piping schemes were cost, damage to the environment, pipe length, and maintenance of the maximum feasible hydraulic head.

Two different pipeline routes were selected for closer analysis to bring the geothermal hot water to the heat exchanger. These two were selected from seven separate routes evaluated on the basis of length of pipeline and potential damage to the environment.

Route 2 (see map Figure 17-1) was selected for analysis because it would be a more direct route to the heat exchanger complex, and pass close to the new University Center. This routing would have the advantage of making additional geothermal hot water available to the new residence at a minimum cost in piping.

Description: Route 2 would follow Geothermal Drive from the well to the intersection with the existing powerline service road. At this point the pipeline would follow the contours at the side of an arroyo in a northwesterly direction until it intersected an existing road that runs east-west on the crest of the hills. The cross-country distance from road to road is about 1,400 feet, and the pipeline could be placed in a manner such that the construction would not be apparent from the University Center. After reaching the crestline road, the pipeline would follow the road to the parking lot of the University Center and turn to intersect with the trench carrying the existing waterline from the four million gallon tank to the Rodeo Arena. The geothermal hot water pipeline would follow this existing waterline to the heat exchanger complex.

Route 4 (see map, Figure 17-1) was selected for analysis because of minimum environmental impact, while minimizing distance and cost. This route would make maximum use of terrain slopes, and provide optimal locations for a gas separator.

Description: From PG-1 west on Geothermal Drive to vicinity of plugged well; thence Northwest bypassing the University Center; then west along lowest portion of slope to the heat exchanger complex in the vicinity of the four million gallon water tank.

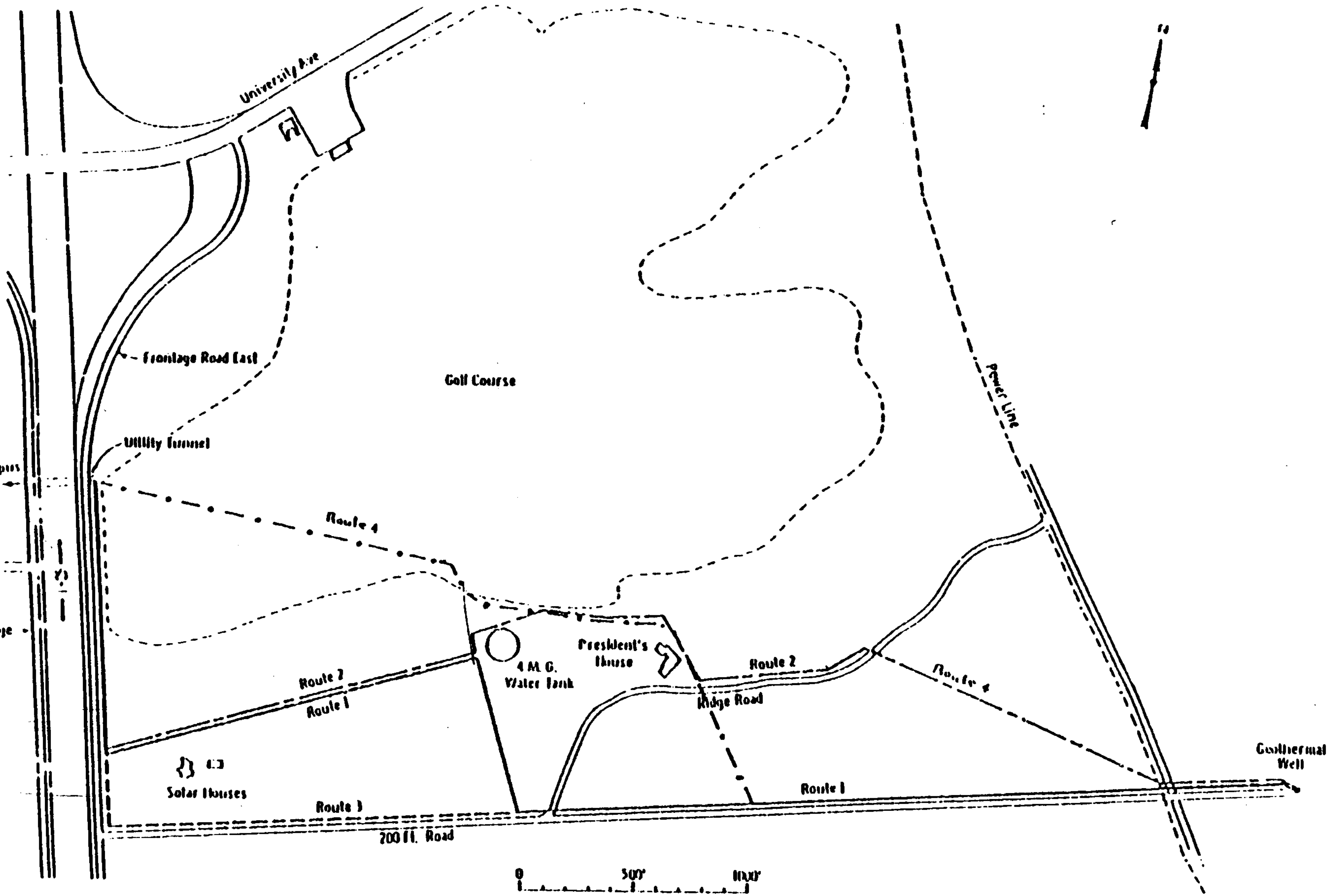
a. Geothermal usage loop for golf course would head Northwest into golf course, across number 14 fairway, entering ravine east of No. 2 tee. Branch off to interconnect with golf course pump house and disposal system.

b. Heated domestic water would be in same trench as geothermal water; at the ravine the domestic hot water pipeline would be oriented west-north-west, cutting across number 16 and number 17 fairway, and run west along road between number 17 green and number 18 tee, and then enter the utility tunnel under Interstate Highway-25.

After reviewing the distance, cost, construction impact on ecology, and esthetic consideration, Route 4 was selected as the primary route. This route was then surveyed for exact location and construction elevation profiles. Cost estimates were then made based solely on this route. Final route selection as coordinated with the Physical Plant Department, was a modification of Route 1, connecting to Route 4, and connecting with Route 2 at the heat exchanger. At this time approval was not granted by the Highway Department to allow the route to pass under Interstate 25 through the south arroyo underpass, rather than the north utility underpass as shown on Figure 17-1.

a. The pipeline route which runs from the well field past the University Center, connecting with the heat exchanger complex, is the most feasible and cost effective. This is Route 4 as depicted on attached Figure 17-1 and 17-2. This route also is least environmentally impacting, and offered significant advantages for ease of construction and maintaining hydraulic head. This route was used for all detailed route surveys and cost analysis, and for follow-on contractual specifications for eventual installation.

b. Use of a pre-insulated pipeline for direct burial offers significant cost savings compared with black steel or galvanized piping. The final procurement specifications will optimize on engineering, cost, installation, and maintenance factors.



CAMPUS GEOTHERMAL PROJECT EAST OF I-25

Figure 17-1

CAMPUS GEOTHERMAL PIPELINE SYSTEM

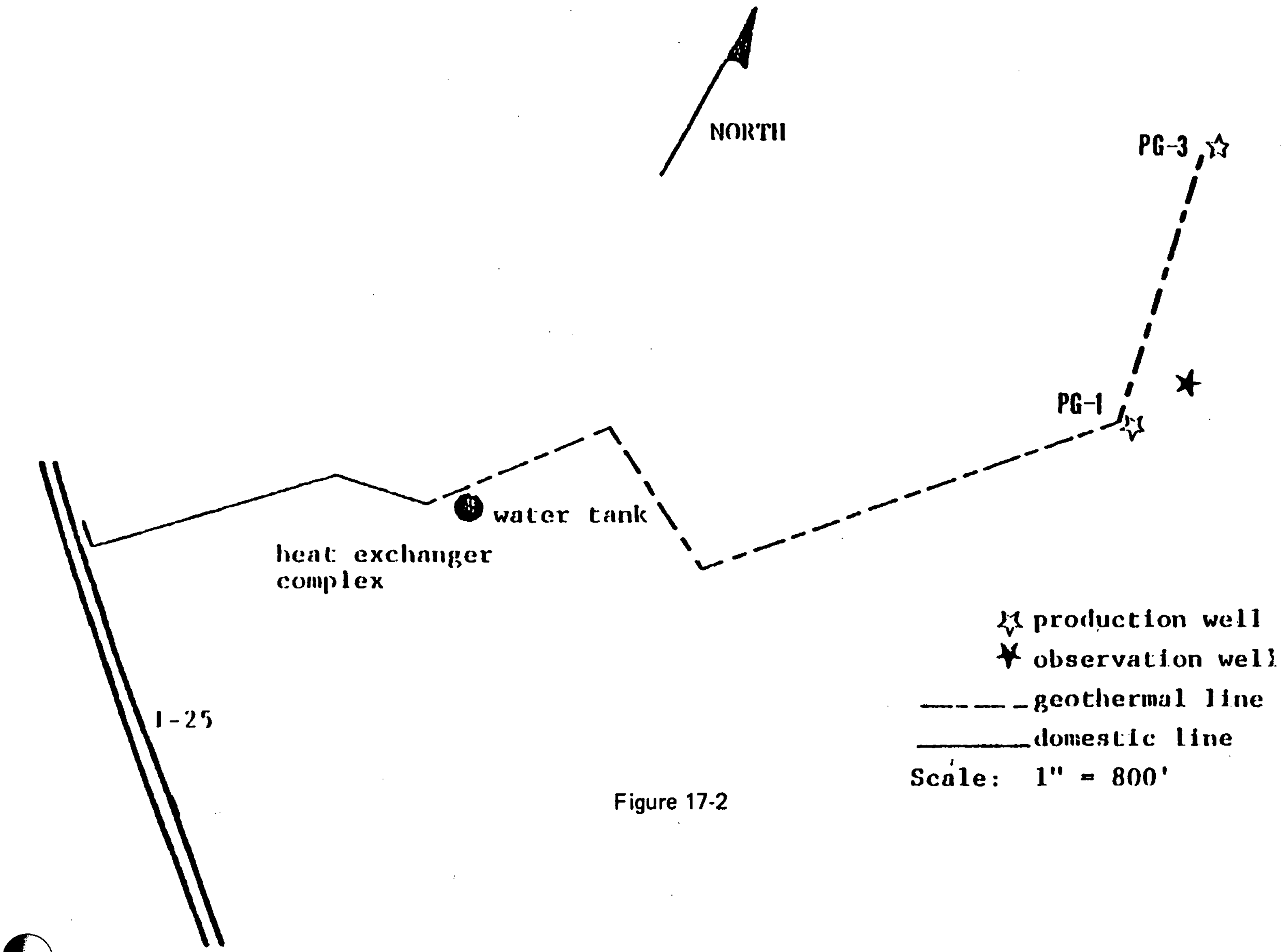


Figure 17-2

CROSS SECTION OF PIPELINE
ELEVATION, LOOKING NORTH

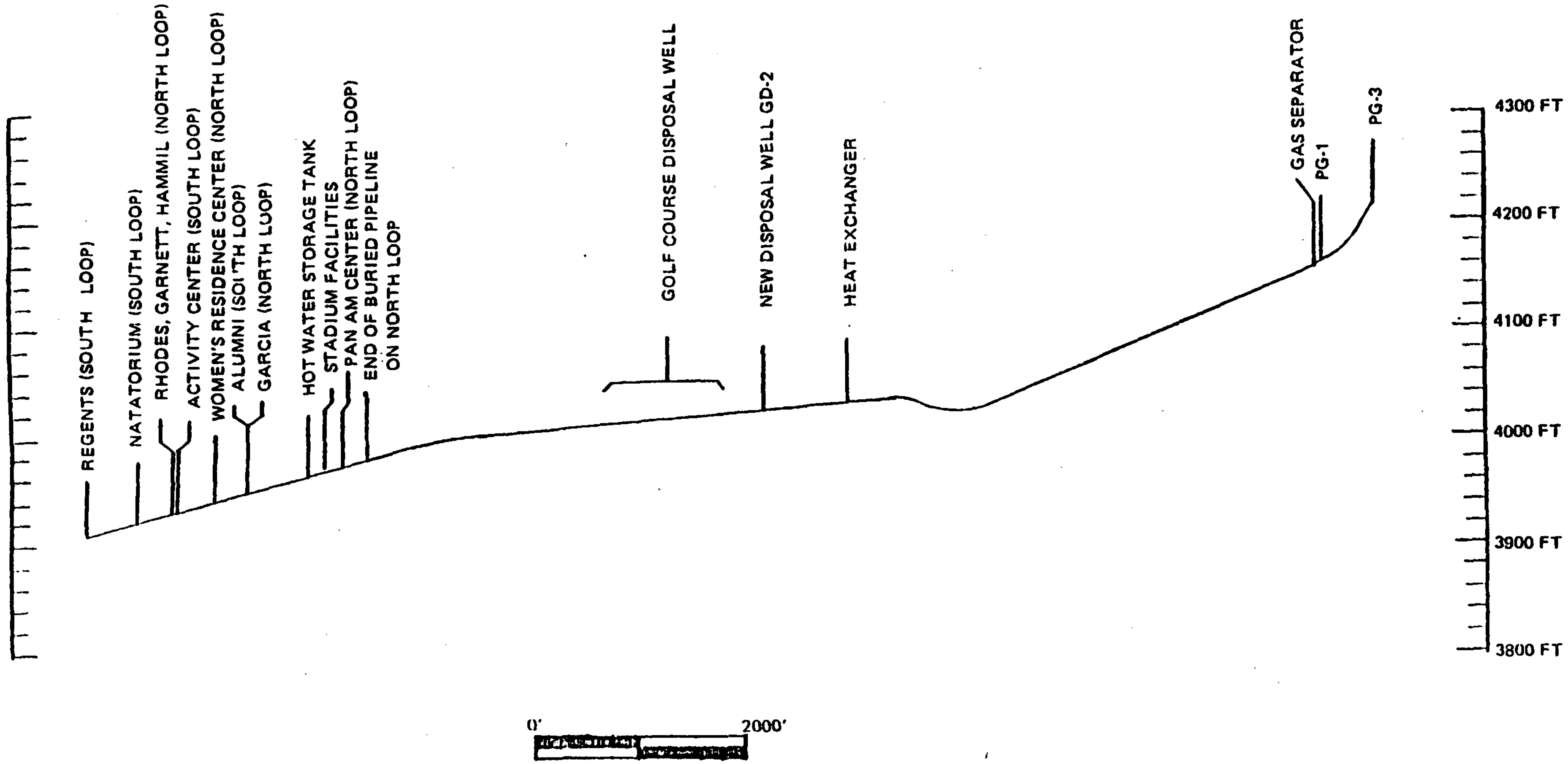


Figure 17-3

c. For the utility tunnel, use of Rovanco welded steel pipe, with pre-insulation except for the weld sections, appears to offer significant cost advantages in comparison with welded steel pipe which must have insulation applied in place. Steel, however, is much more costly than pre-insulated material such as cement-asbestos.

d. The use of TEMPTITE or ROVANCO pipe, either of which is epoxy lined, provides clean flow and minimal head loss due to fluid friction. Based on roughness factors as provided by the vendors, and assuming ROVANCO steel or regular steel pipe for the tunnel section, head loss data have been estimated. A review of this head loss data indicates that head gain due to decreasing elevation more than offsets the head loss due to fluid friction, except for a portion of the line between the gas separator and the University Center, which is a high point in the pipeline route. In-line pressure assist boost pumps will be required for the domestic water from the storage tank, for the pressurized hot water system, and in the future for the disposal system.

e. The possible presence of dissolved gas posed a major problem to efficient heat exchanger operation, because the gas could tend to separate in the heat exchanger because of pressure and temperature drops, thus resulting in two-phase flow. Even if the gas is vented continuously, a sharply reduced heat exchanger efficiency could result.

After the water was analyzed, it was found that a relatively large amount of CO_2 and N_2 are dissolved in the liquid. See Table 17-4.

Figure 17-5 is a plot of gas separation rate versus back pressure, using the small text fixture. A down-hole gas separator was recommended by the pump supplier as needed to improve pump efficiency, and to facilitate gas separation. From available data as depicted in Figure 17-5, the down-hole gas separator appears to offer negligible improvement in controlling gas separation, since the gas generation rate at the surface remained effectively unchanged by the use of the gas separator.

Table 17-4

GAS COMPOSITION, DISSOLVED IN LIQUID

(Preliminary Values)

	Composition, moles per liter				Composition mg/l	
Gas	PG-1(#1)*	PG-1(#2)	PG-2	PG-1(#1)*	PG-1(#2)	PG-2
CO_2	$8x10^{-4}$	$8.5x10^{-3}$	$7.3x10^{-3}$	352	374	321
N_2	$3.3x10^{-4}$	$5.2x10^{-4}$	$5.2x10^{-3}$	9.24	14.56	14.56
Argon	$6.4x10^{-6}$	$8.5x10^{-6}$	$9.3x10^{-6}$	0.256	0.34	0.372
Neon	$5.2x10^{-6}$	$4.7x10^{-6}$	$7.1x10^{-6}$	0.105	0.188	0.284
Helium	$1.3x10^{-6}$	$5.1x10^{-6}$	$5.2x10^{-6}$	0.005	0.0204	0.0208
O_2	$6.6x10^{-7}$	$1.3x10^{-6}$	$7.2x10^{-7}$	0.021	0.042	0.023
Krypton	$4.8x10^{-10}$	$5.1x10^{-10}$	$3.1x10^{-10}$	$4.0x10^{-5}$	$4.3x10^{-5}$	$2.6x10^{-5}$

Also depicted by a star on Figure 17-5 is the single datum obtained before the down-hole gas separator was installed. The energy required to pump the water through the down-hole separator resulted in a small but significant decrease in overall pump efficiency. For design purposes, the controlled experiments lead to the conclusion that an increase in back pressure, and a corresponding increase in the magnitude of the pressure drop across the orifice (construction valve) would result in maximizing the rate of gas separation. From the data, the rate of gas separation is more strongly affected by the size of the pressure drop, but the best rate of separation is obtained where the final pressure is slightly above atmospheric pressure. If these conclusions are correct, the desired state is to obtain a back pressure at the entrance to the gas separator of 80 to 100 psig (consistent with overall energy needs of the well pump needed to provide this back pressure) and to allow the fluid to rapidly expand to atmospheric pressure. (See also Figure 28-1 which provides data on actual performance of the installed gas separator complex.)

NMSU PG-1 GAS FLOW RATE vs DISCHARGE BACK PRESSURE

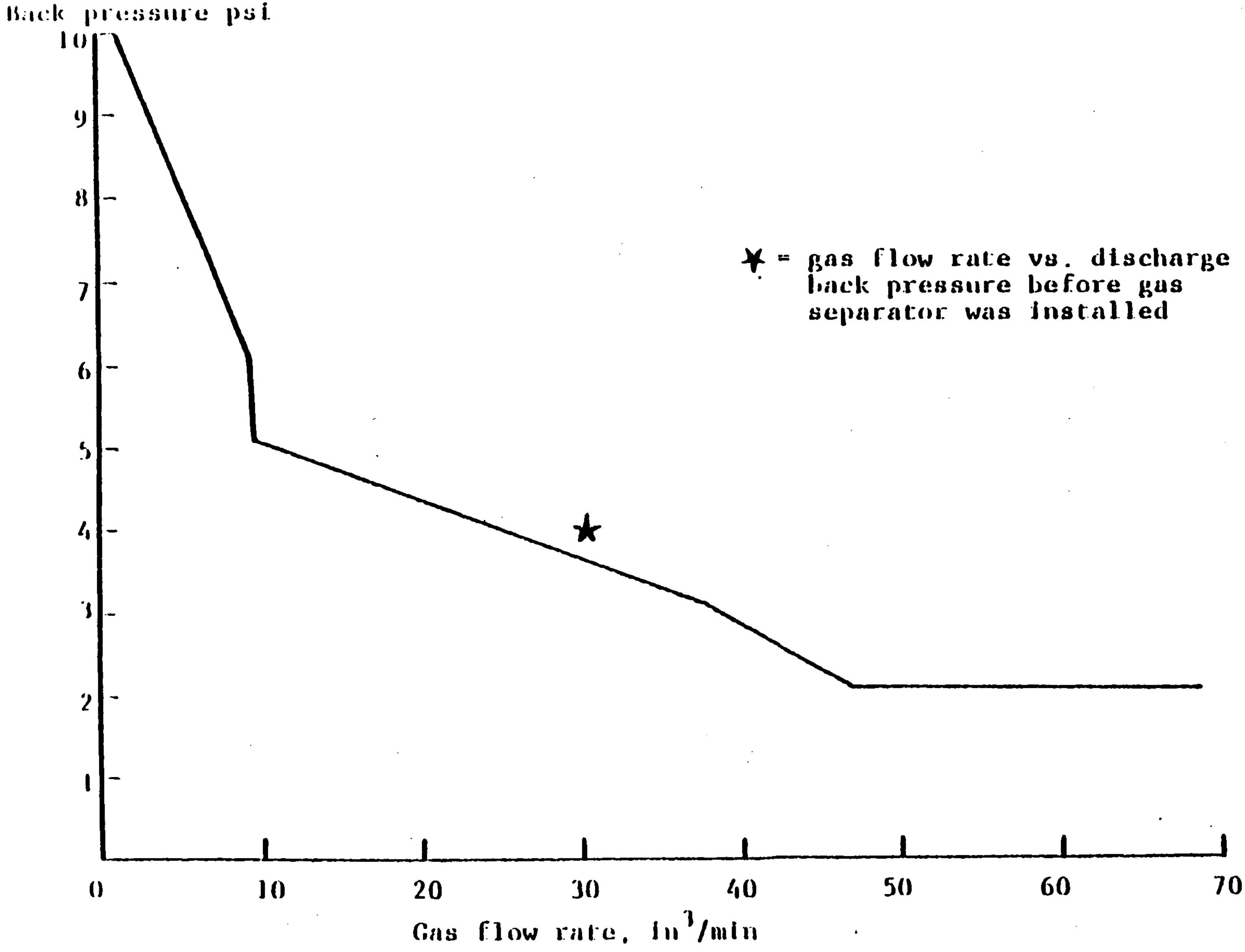


Figure 17-5

The design of the gas separator was based on the following parameters.

(1) The tank should be of significant volume to handle 200 gpm of fluid, and retain sufficient vapor volume to facilitate gas separation.

(2) Constant liquid volume should be available to provide a water level at a minimum of four feet of water over the pump suction on the discharge line.

(3) Since the tank should be maintained very slightly above atmospheric pressure, a gas vent valve system must be installed to allow gas to vent freely from the system.

(4) The tank will handle flow from either well, and provision must be made for well pump cut-off if the liquid level rises above a preset maximum.

(5) Elevation head will be available from the outlet of the gas separator to the heat exchanger, so that the pressure drop across the heat exchanger can be accommodated. However, minor fluctuations in well pump output, and the need to provide constant head above the gas separator discharge, might necessitate a small in-line pump.

(6) It is desirable that all, or as many as practicable, of the controls and mechanical items be co-located. The logical and desirable location is immediately adjacent to the gas separator.

(7) The gas separator and attendant valve and fittings must be insulated, and buried. This burial is both for insulation purposes, elevation head purposes, and esthetic reasons.

The final design parameters were as follows:

(1) An epoxy coated interior, steel tank, 12 feet in diameter and 6 feet long will satisfy the minimum requirements. This tank will be buried with the 12-foot axis vertical. Figure 17-6 is a simplified drawing of this installation. The tank will be insulated with 2-inches of polyurethane foam sprayed on before burial. Vapor barriers will be Diathon or equivalent.

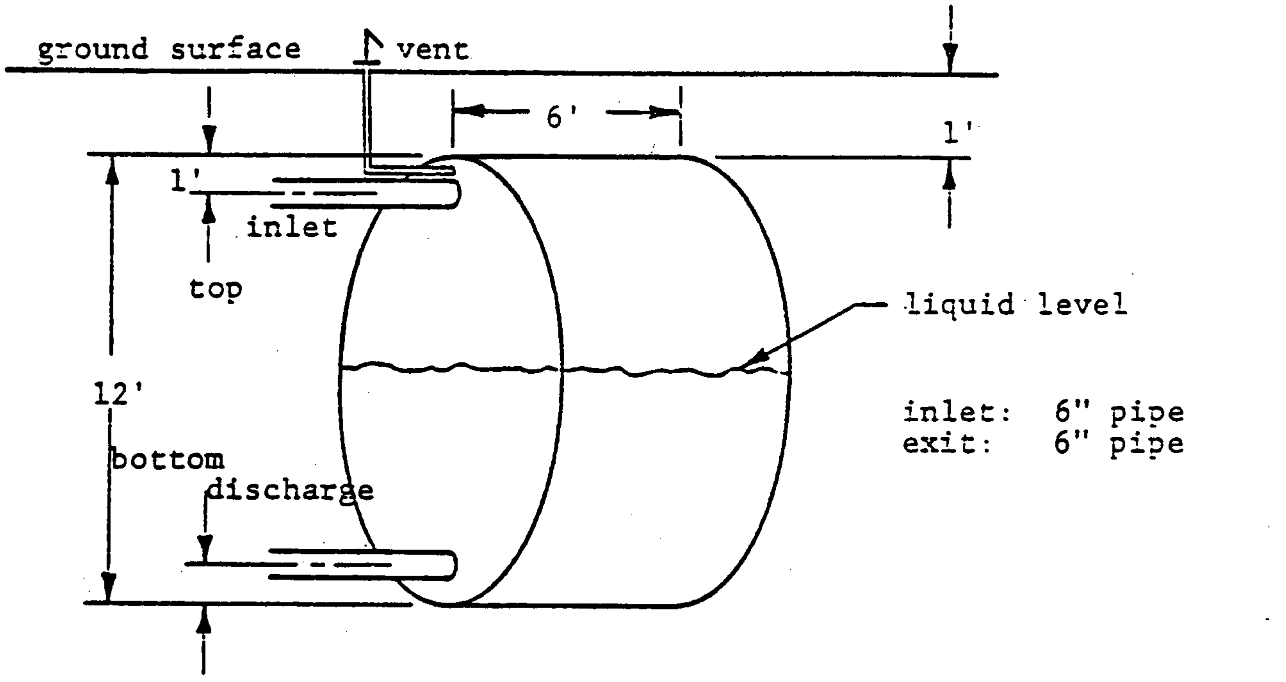
(2) The tank will be installed adjacent to the pump house for well PG-1, and located approximately 30 feet to the west, alongside Geothermal Road. Taking advantage of natural terrain features, the elevation will minimize burial depth requirements for the gas separator discharge lines which must exit approximately eleven feet below normal grade.

(3) To facilitate location of controls, for insulation purposes, and for physical security, the tank will be enclosed by an equipment well on one end. This well is 12 feet deep, and 12 feet long. Access will be through a roof hatch. The bottom and three side walls will be pre-cast (tilt-slab) concrete, coated with a vapor barrier before installation. The fourth wall, abutting the gas separator tank, will be concrete block. All pumps, pneumatic valves, connections to both wells, and gas separator inlet and outlet pipes will be located in the equipment well. In addition, an inspection port for the gas separator will be accessible from the equipment well.

(4) Concerning controls, Figures 17-6 and 17-7 are schematics of the system, depicting major controls. Not depicted are manual isolation valves, check valves, and other minor system controls. Those will be finalized as part of the procurement package.

For further details concerning the gas separator design see EMD 2-68-2207 Report.

GAS SEPARATOR



PLAN VIEW

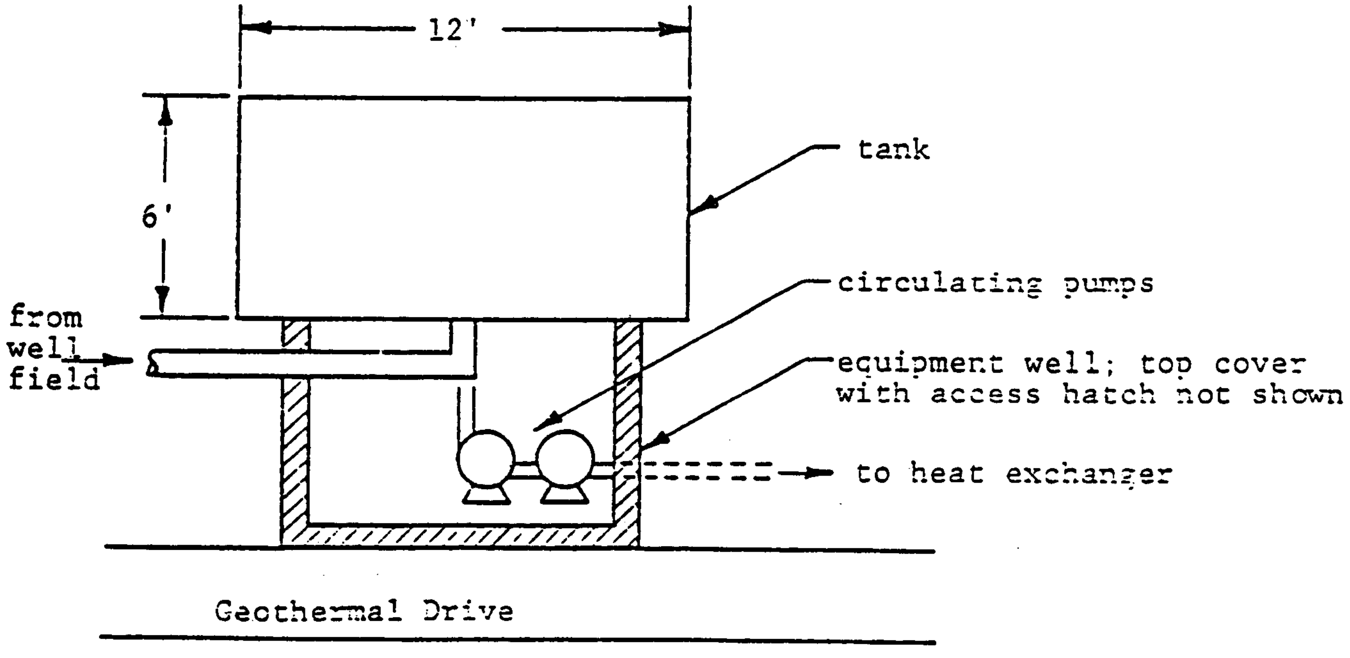


Figure 17-6

DETAILS OF CONTROLS OF GAS SEPARATOR SYSTEM

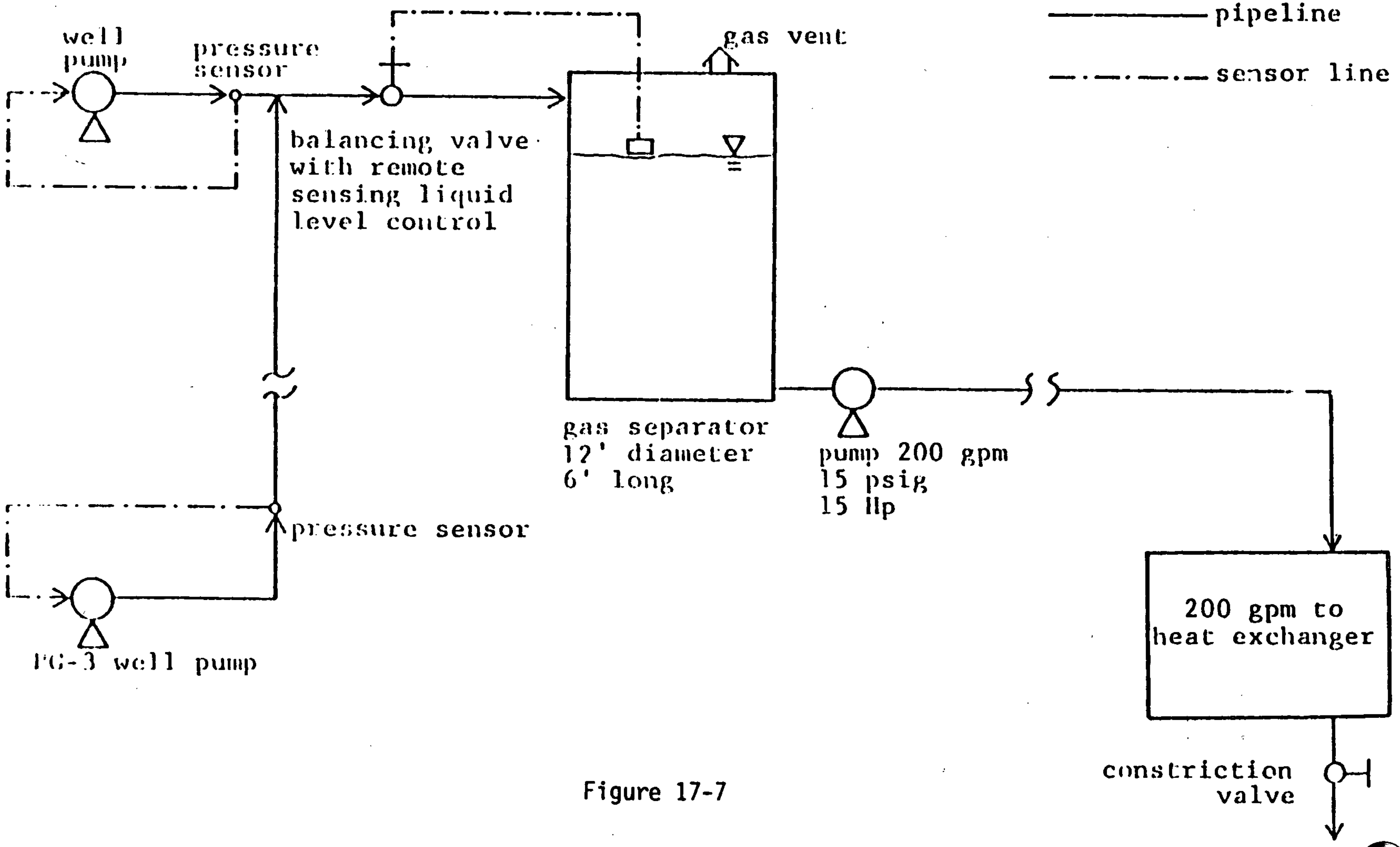


Figure 17-7

18. DISTRIBUTION SYSTEM DESIGN

18.1 Design Section

The Distribution System is made up of three major elements, the heat exchangers (primary and pool), the hot water storage tank, and the tunnel pipeline.

Heat Exchangers

Choosing the proper heat exchanger to yield the maximum heat exchange and also be capable of withstanding the corrosive geothermal water required careful study of model types and construction. Heat exchanger suppliers were contacted, and their cost and performance data resulted in a design decision to use plate-type exchangers. These are simple, reliable, and easily maintained units. It is true that a conventional shell-in-tube exchanger also is reliable and easy to maintain, particularly if the geothermal water is contained in the tube side. However, the plate-type exchanger is capable of a closer approach temperature for a given cost than is the shell and tube exchanger. Because obtaining the highest possible domestic water temperature for a given cost was the primary consideration, a decision was made to consider only plate-type exchangers.

Another project consideration was the use of a heat exchangers at the NMSU Indoor and Outdoor Pools. In order to maintain the pool water at a constant temperature, a heat exchange between the pool water and potable hot water must take place. The heat source for the pool is domestic hot water. In concept, the exchangers would use circulating pool water from the filter system, which will then be warmed by the domestic hot water.

The heat exchanger size and cost quotations were obtained from possible suppliers, and the least cost and best performance quoted was from the Trantor Corporation. The Trantor Corporation suggested that titanium heat exchangers be used since the geothermal water was considered to be quite corrosive. However, through further research it was found that 316 stainless steel has almost the same resistance to corrosion as titanium, but for only half of the cost. Summary description and technical specifications are attached. See Table 18-1.

Table 18-1
INDOOR POOL HEAT EXCHANGER

PERFORMANCE	HOT SIDE	COLD SIDE	
Fluid Circulated	Water	Water	
Total Flow Rate	15.00	35.00	gpm
Unit Flow Rate	15.00	35.00	gpm
Specific Heat	0.999	0.999	BTU/lb. °F
Specific Gravity	0.991	0.996	
Thermal Conductivity	0.364	0.353	BTU/hr. ft. °F
Viscosity	0.627	0.820	C.P. at avg.temp.
Inlet Temperature	125.00	77.00	°F
Outlet Temperature	92.00	91.09	°F
Pressure Drop	1.80	7.50	psig
Operating Pressure	0	0	psig
Heat Exchanged	245639.1		BTU/hr./unit
Heat Transfer Area	13.1 sq./ft. per unit		
Plates Per Unit: 16			

CONSTRUCTION		
Design Pressure	100	psig
Test Pressure	150	psig
Design Temperature	250	°F
Unit Net Weight	350.8	pounds

UNIT DIMENSIONS	
A (Max)	2.079
A (Min)	1.953
B	10.938
C	--
T	1.000

MATERIALS	
Plates	316SS
Gaskets	NBR
Nozzles	316L
Frame	CS Epoxy Painted
Bars	Stainless Steel Clad
Bolts	ZN Plated CS

Table 18-1 (Cont'd)
OUTDOOR POOL HEAT EXCHANGER

PERFORMANCE	HOT SIDE	COLD SIDE	
Fluid Circulated	Water	Water	
Total Flow Rate	50.00	110.00	gpm
Unit Flow Rate	50.00	110.00	gpm
Specific Heat	0.999	0.999	BTU/lb. °F
Specific Gravity	0.992	0.997	
Thermal Conductivity	0.363	0.351	BTU/hr. ft. °F
Viscosity	0.633	0.856	C.P. at avg.temp.
Inlet Temperature	125.00	72.60	°F
Outlet Temperature	90.00	88.45	°F
Pressure Drop	2.25	9.99	psig
Operating Pressure	0	0	psig
Heat Exchanged	868268.6		BTU/hr
Plates Per Unit: 44			

CONSTRUCTION	
Design Pressure	100 psig
Test Pressure	150 psig
Design Temperature	250 °F
Unit Net Weight	392.2 pounds
39.3 Sq./Ft. Per Unit	

UNIT DIMENSIONS	
A (Max)	5.716
A (Min)	5.370
B	18.438
C	--
T	1.000

MATERIALS	
Plates	316SS
Gaskets	NBR
Nozzles	316L
Frame	CS Epoxy Painted
Bars	Hard CR Plated CS
Bolts	ZN Plated CS

Table 18-1 (Cont'd)
PRIMARY HEAT EXCHANGERS

PERFORMANCE	HOT SIDE	COLD SIDE	
Fluid Circulated	Water	Water	
Total Flow Rate	200.00	200.00	gpm
Unit Flow Rate	200.00	200.00	gpm
Specific Heat	0.999	0.999	BTU/lb. °F
Specific Gravity	0.992	0.994	
Thermal Conductivity	0.363	0.360	BTU/hr. ft. °F
Viscosity	0.633	0.704	C.P. at avg.temp.
Inlet Temperature	140.00	65.00	°F
Outlet Temperature	75.00	129.88	°F
Pressure Drop	4.49	4.62	psig
Operating Pressure	0	0	psig
Heat Exchanged	6448521.0		BTU/hr
Plates Per Unit: 217			

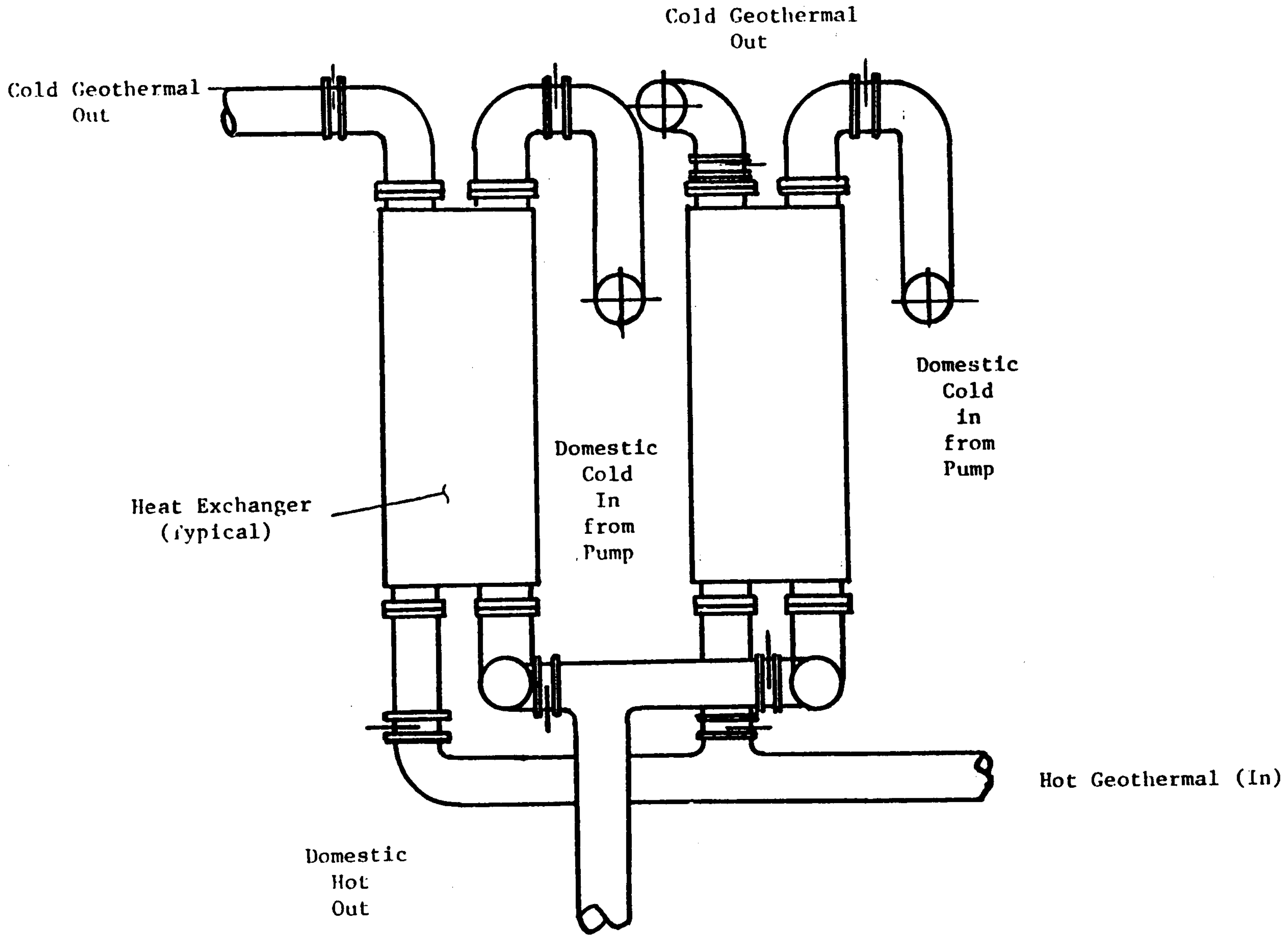
CONSTRUCTION		
Design Pressure	100	psig
Test Pressure	150	psig
Design Temperature	250	°F
Unit Net Weight	2636.9	pounds
867.8 Sq./Ft. Per Unit		

UNIT DIMENSIONS	
A (Max)	30.541
A (Min)	28.384
B	74.625
C	80.625
T	0.875

MATERIALS	
Plates	316SS
Gaskets	NBR
Nozzles	316L
Frame	CS Epoxy Painted
Bars	Hard CR Plated CS
Bolts	ZN Plated CS

FIGURE 18-3

SCHEMATIC OF HEAT EXCHANGER COMPLEX



Heat Exchanger Building

Although a single exchanger, capable of handling 200 gpm of hot water, was needed, the design team felt that flexibility should be created for space for a second exchanger for possible future system expansion. Moreover, in-line circulation pumps are required on the cold water inlet side, and other controls and instrumentation are necessary. To meet these spatial requirements, a 300 square feet building was necessary. Figure 18-3 is a schematic representation of the heat exchangers complex.

For further details concerning the heat exchanger design see the EMD 2-68-2207 Report.

Hot Water Storage Tank

From the analysis of peak and average flow rates in the 12 target buildings, a pattern has been established. With the exception of the outdoor pool, a cyclic consumption pattern exists. For a brief period, one to four hours in duration, the consumption is at a sharp peak. For the balance of the day, consumption is almost uniform except for two minor early and late evening peak demand periods. This instrumented data collection indicates the peak consumption rate is 320-400 gallons per minute, and the 24-hour average consumption is 145-225 gallons per minute. If the outdoor swimming pool is excluded, the peak is 320 gallons per minute, with an average rate of 145 gallons per minute (Ratio of peak to average flow rate of approximately 2.2). These data are summarized as follows:

Table 18-2

SUMMARY OF HOT WATER DEMAND

	Composite	Composite, Less Pool
Peak	400	320
Minimum	109	29
Average	225	145

Figure 18-4 shows this relationship over a 24-hour period.

COMPOSITE HOT WATER DEMAND
(gpm)

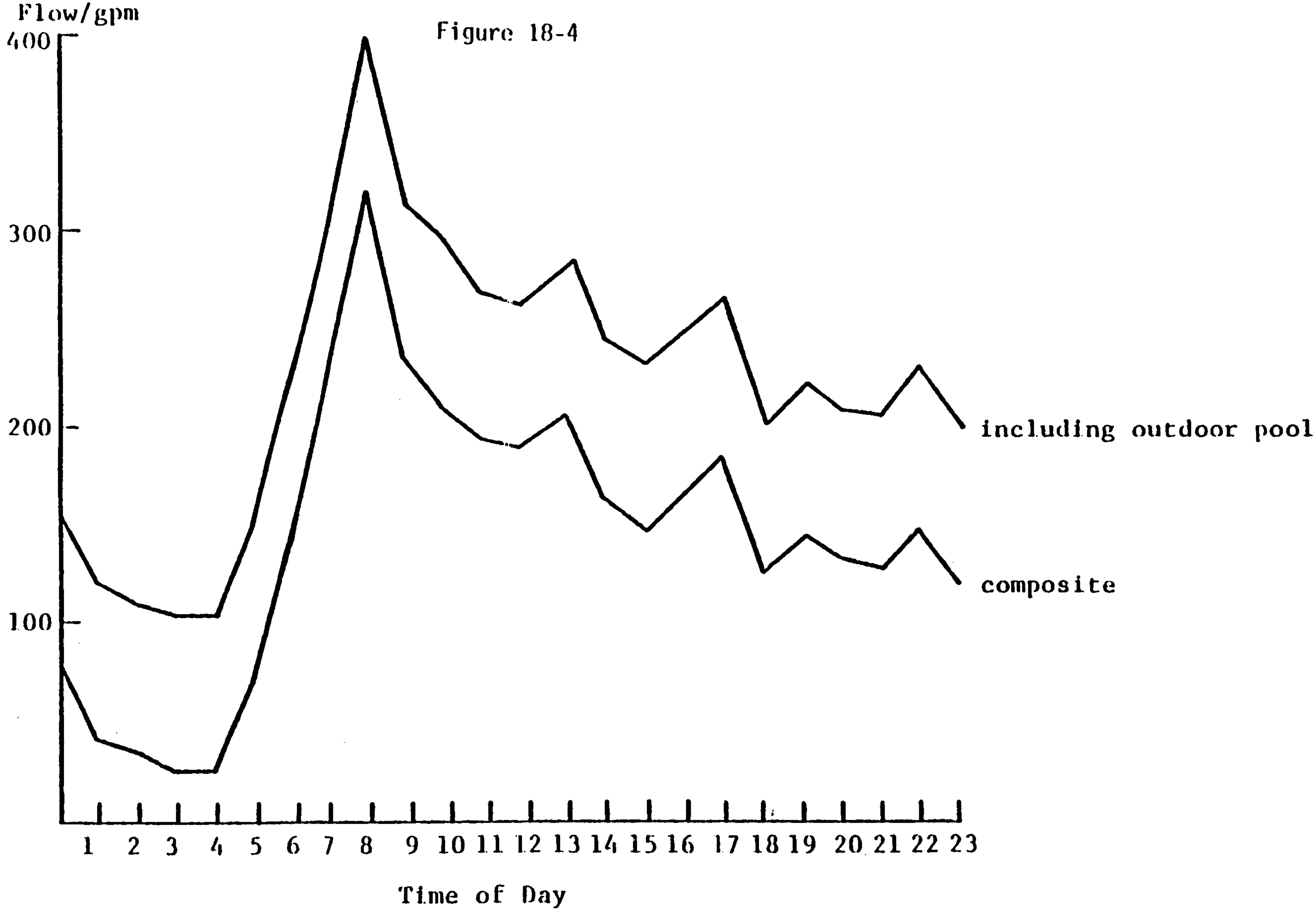


Figure 18-4

The tank had to be optimally-sized to meet economic construction conditions. Other design consideration besides size were as follows:

a. Insulation is essential to assure that the beneficial heat is retained.

b. Provision must be made for constant replenishment flow at some rate lower than the peak demand rate.

c. To balance hot and cold water service to the target buildings, the tank and distribution system must be capable of pressurization to 80 psig, or an alternative in-line pump used at the outlet of the storage tank to balance line pressures with the domestic cold water system.

d. To satisfy engineering requirements for sufficient head over the intake to the in-line pump, the pump suction line from the tank must have design provisions to assure continuous availability of at least four feet of static head above the pump inlet. In addition, the water in the tank will tend to stratify by temperature, with cooler water in the lowest portion. The design must make practical provision to guard against supply only from this cooler portion.

e. For back-up in periods of extended outages, provision must be made for emergency heat supply to heat cold water. Those outages are defined as a major failure in the wells or well pump, pipeline, or heat exchanger which require repair time more than a few hours in duration. Implicit in this design feature is a need to assure continuity of hot water supply for periods up to four days in duration. (Four days is assumed to be realistic period of time in which the central boiler could be brought up to temperature from a cold start.)

Given a constant inflow of hot water and a variable demand, the tank must be large enough to provide a reserve for limited duration emergencies, and to maintain a minimum static water level above the discharge pump. A tank capacity of 60,000 gallons will satisfy these conditions as defined in the following paragraphs.

The early conceptual designs of the hot water storage tank facility considered the use of a single constant speed pump, designed to deliver up to 500 gpm at 80 psig, connected to a balancing valve. However, this design would not allow for pump repair without shutting the geothermal system off. Moreover, it is a costly system for electricity usage.

The final design used a total of five small pumps. The distribution system is divided into two main loops, with two pumps per loop. This type of design allows pump maintenance, without a hot water outage, by operating only one pump on each loop.

Also, previous design showed a floating suction pump inlet in the tank. This pump suction device was designed to provide draw-down of the presumably hotter water strata in the upper part of the tank.

The final design incorporated a unique arrangement in which the tank inlet is connected to a perforated tube running the entire length of the tank. A similar perforated tube is used for the tank outlet. As a result, thermal layering is minimized and outlet flow rate is always within two degrees of inlet temperature. See Section 29.1 for further details. Figure 18-5 shows the final hot water storage tank design.

For further details concerning the hot water storage tank see the EMD 2-68-2207 Report.

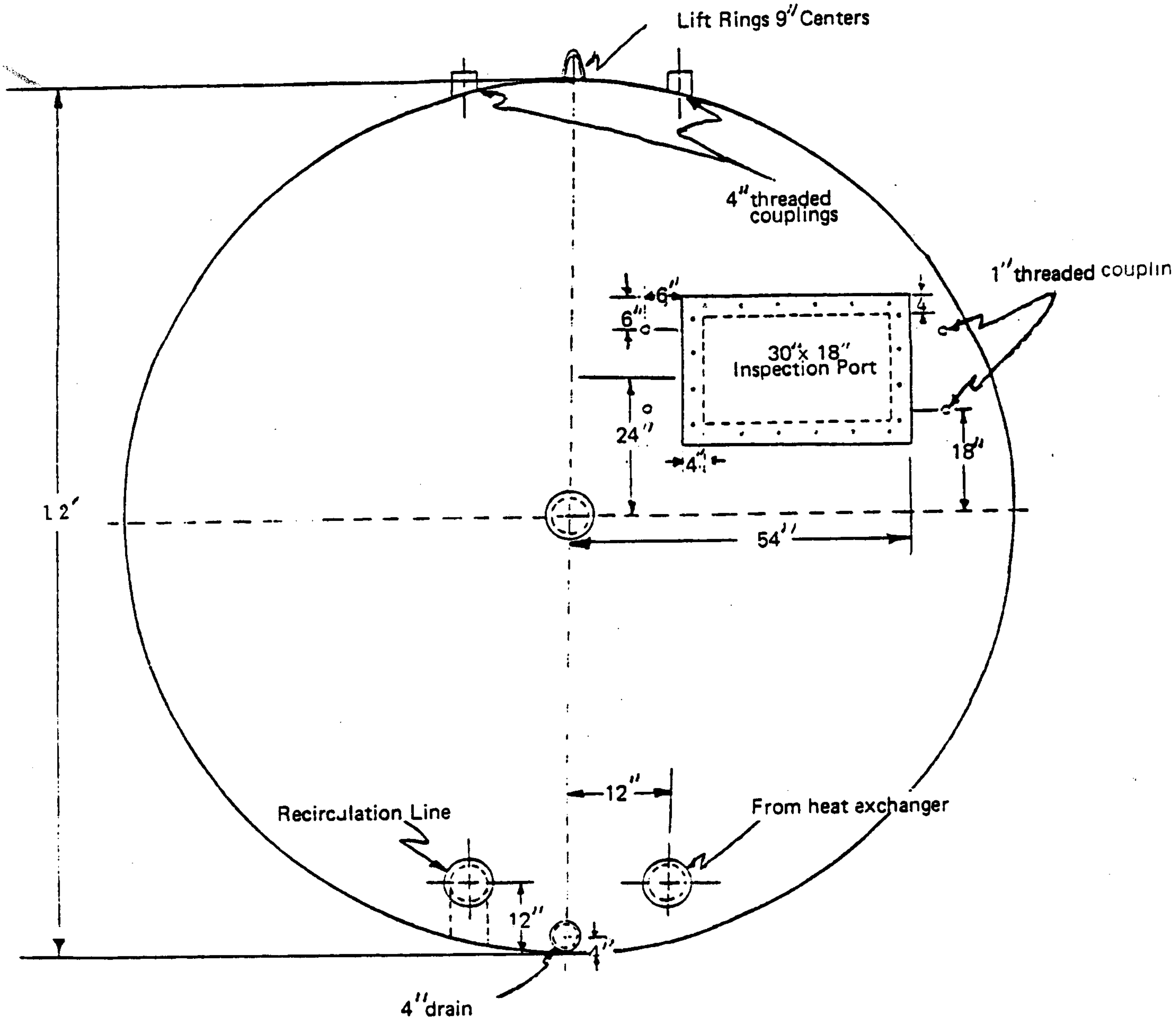
Tunnel/Buried Pipeline Distribution System (From The Hot Water Storage Tank)

The pipeline from the hot water storage tank to end users is divided into a north and south loop. See Table 18-6.

Table 18-6

North Loop
Pan American Center
Garcia Hall
Women's Residence Center
Rhodes, Garrett, Hammil

South Loop
Alumni Hall
Activity Center
Natatorium (Indoor Pool/Outdoor Pool)
Regents
Breland Hall (conversion in process)
O'Donnell Hall (conversion in process)



FRONT VIEW

Figure 18-5

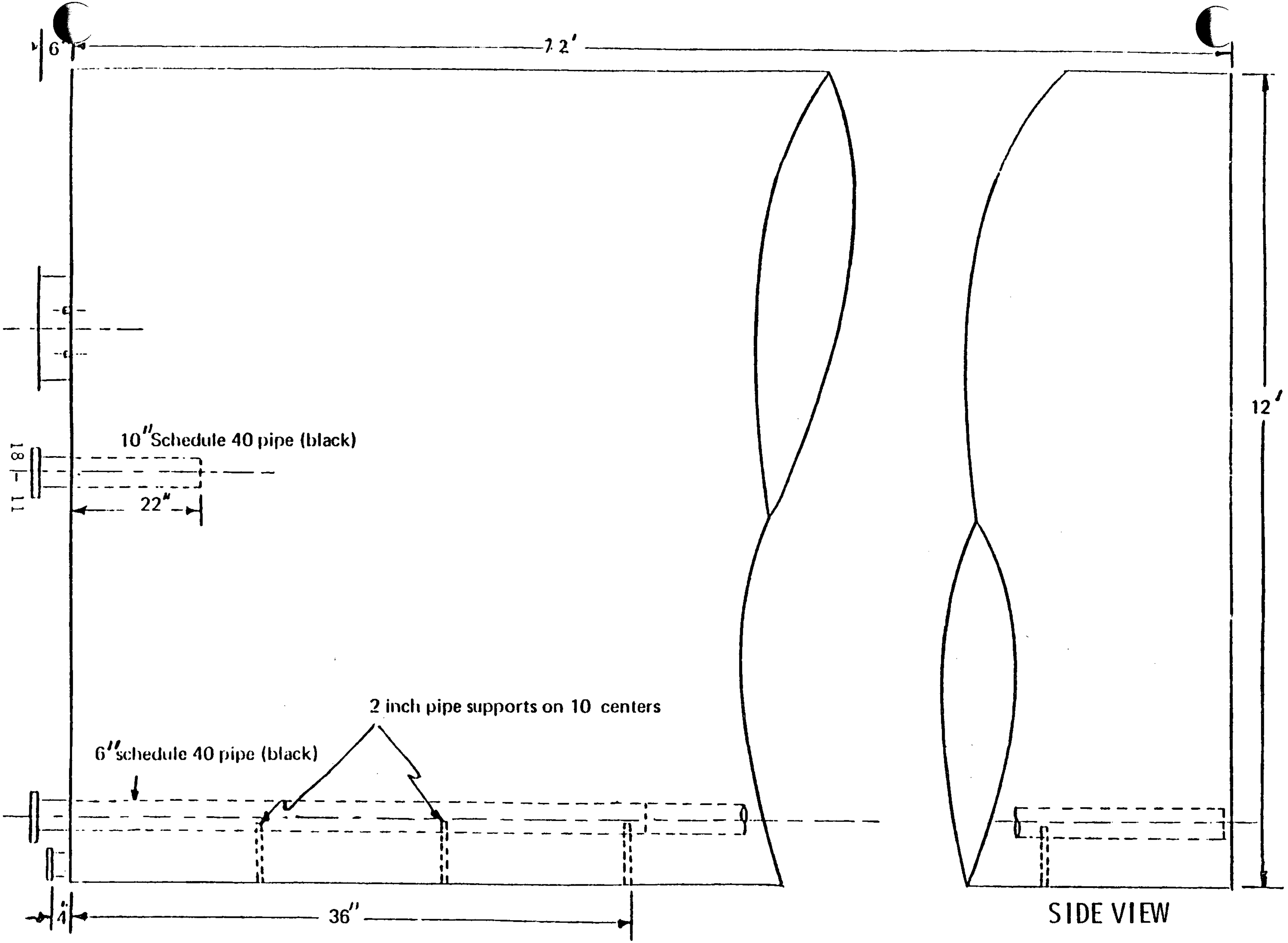

6"
72'
12'
10" Schedule 40 pipe (black)
18 - 11
22"
2 inch pipe supports on 10 centers
6" schedule 40 pipe (black)
4"
36"
SIDE VIEW

Figure 18-5

The south loop requires six-inch welded steel pipe with separately installed insulation. The north loop requires a combination of six-inch buried preinsulated pipe, and four-inch welded pipe with separately installed insulation in the utility tunnel. The south loop pipeline was over-sized to fill the high Natatorium load, including both swimming pools, as well as provide capacity for future expansion. O'Donnell and Breland Hall will be served by this south loop.

The circulating pumps for the north and south loops are located at the hot water storage tank. A small high capacity, low head three Hp pump is used to assure a positive section pressure for the primary circulating pumps. Dual five Hp pumps are installed for the south loop, and dual 7.5 hp pumps are installed for the north loop. Even though the south loop has a higher load requirement, the north loop has a greater amount of head to overcome. For further details concerning the utility tunnel and buried distribution pipeline, see the EMD 2-68-2207 Report.

19. APPLICATION SYSTEM DESIGN

19.1 Selection Process and Design

In all of the facilities as listed in Table 18-15 except for the Stadium Facilities and the Natatorium, the general retrofit design used was to connect the domestic water into each of the facilities' cold inlet to the steam driven heat exchangers. This basic system of retrofit allows a quick switch from hot water to steam and from steam to hot water.

The stadium facilities use the hot water for space heating and domestic hot water usage. In this building the hot water was connected to the steam side of the space heating heat exchangers, and to the cold inlet of the domestic hot water heat exchanger. This type of design allows for a rapid switch from steam to hot water.

The Natatorium retrofit design required the purchase of two plate-type heat exchangers. Each of these heat exchangers is discussed in Section 18. The geothermally heated hot water is piped through each of the exchangers. The pool water is circulated through each of the heat exchangers, using the pool filtration and circulating system. The heated pool water flows back into the pool, and the cooled hot water is injected by a booster pump into the domestic cold water.

The hot water is also connected with the Natatorium space heating system. A small TRANE heater, designed to operate with a 180°F source of hot water, is used for a fan-forced hot air system for the Natatorium administration space. A separate plumbing tie was made to the hot water system used for showers. For further details concerning the application systems design see the EMD 2-68-2207 Report.

20. PRODUCTION SYSTEM CONSTRUCTION

20.1 An example of the well bid requirements for the production wells is found in each of the technical completion reports for PG-1 and PG-3.

20.2 The as-built system is identical to the bid requirements found in the technical completion reports. However, the well head configuration of PG-3 has changed slightly from the original design. A flow turbine port was added. Figures 20-1 and 20-2 are the as-built drawings for the two production wells, PG-1 and PG-3.

Details concerning post construction modification are found in Section 26.

PG-1

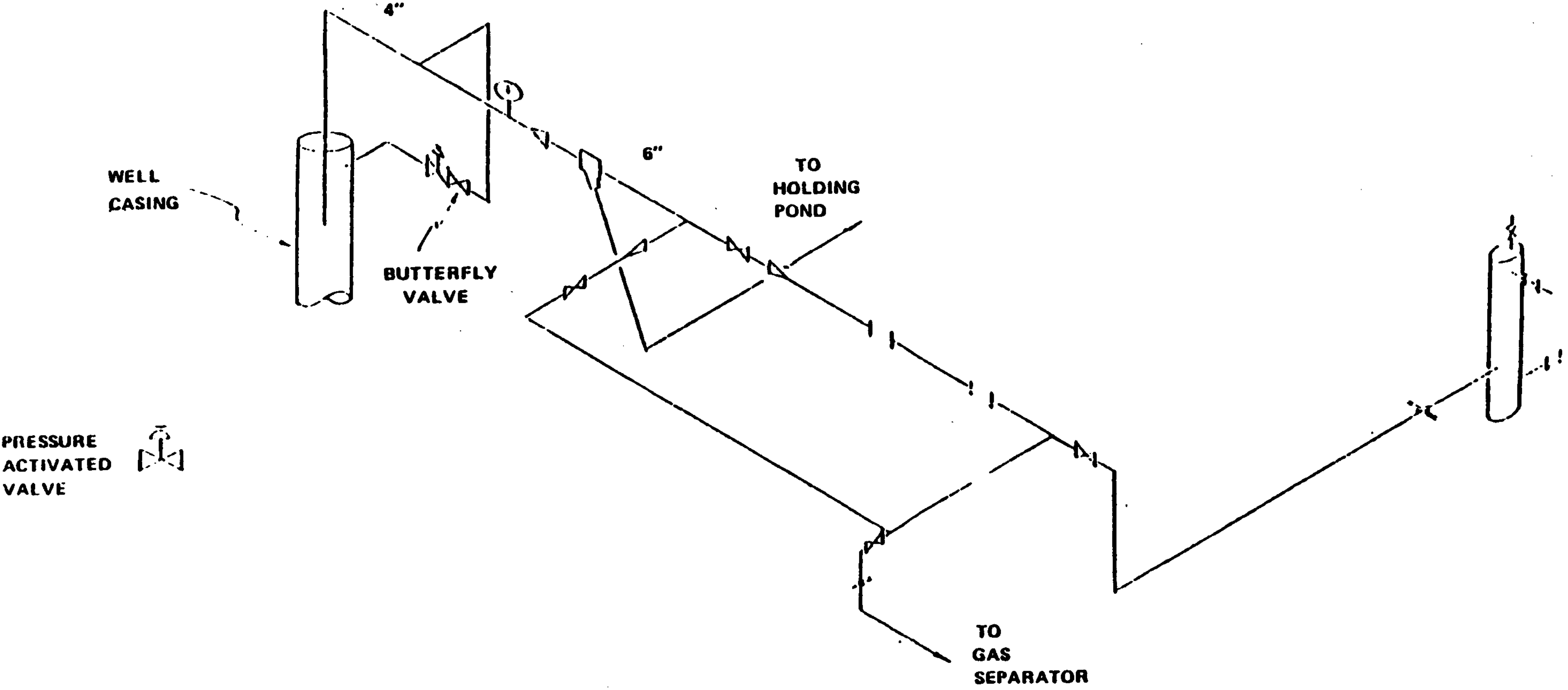


Figure 20-1

PG-3

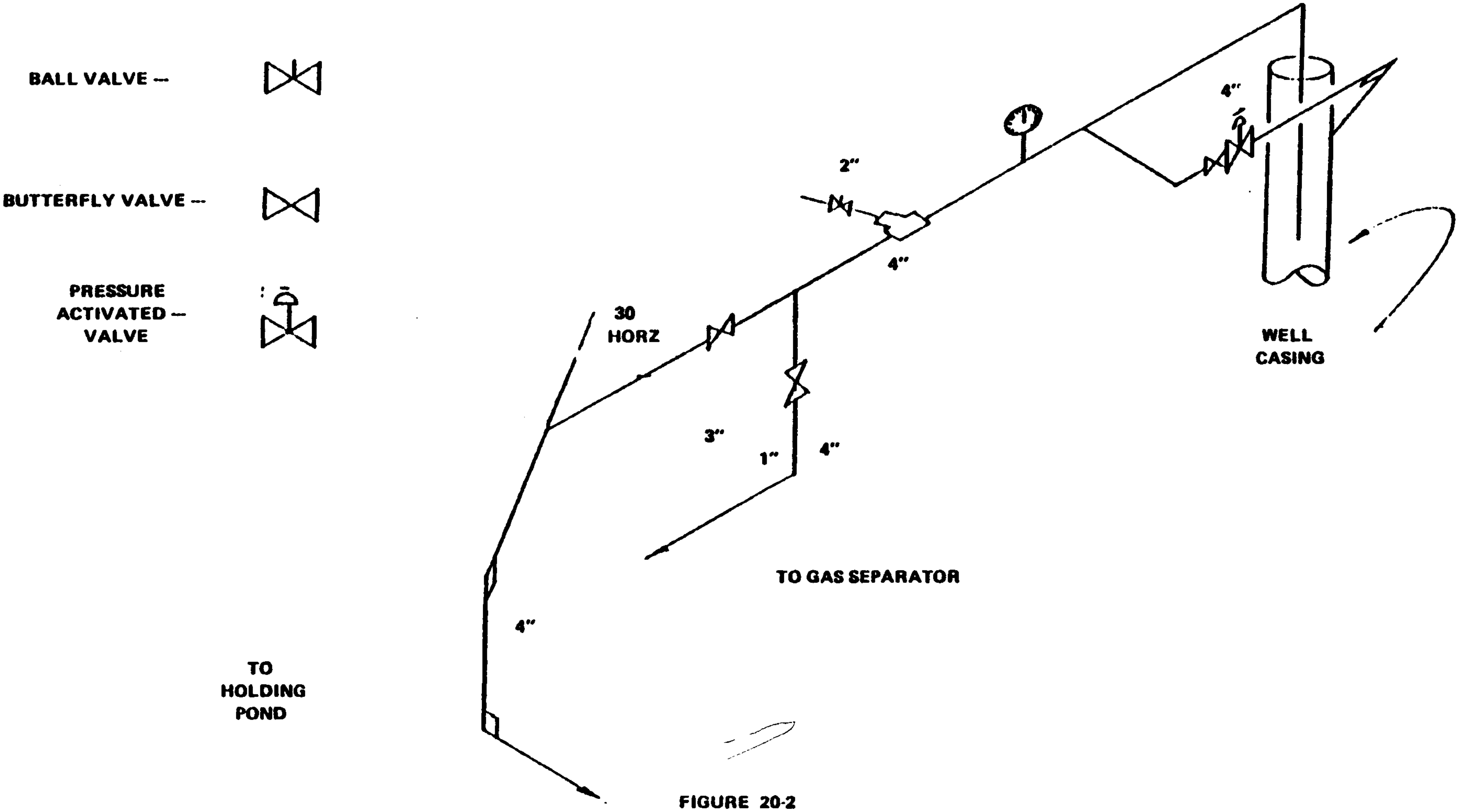


FIGURE 20-2

21. DISPOSAL SYSTEM CONSTRUCTION

See Section 16.

22. TRANSMISSION SYSTEM CONSTRUCTION

Gas Separator

The Gas separator was built to design as detailed in Report EMD 2-68-2207 with the exception that the circulating pumps were not required.

Included in the transmission system are the gas separator and the pipeline to the hot water storage tank.

The gas separator was modified by deleting the in-line pump, because adequate gravity head is available between the gas separator and the primary heat exchangers for the system to operate. The piping configuration was changed in detail, from Report EMD 2-68-2207, but not in principal. Figure 22-1 shows the as-built configuration of the gas separator.

Post construction modification to the gas separator building includes the addition of a side door instead of the port that is located on top of the building. This door leads to a new platform in the building. This new entrance provides an easier access.

The pipeline was constructed in approximately two months. The route of the buried pipeline was changed as shown in Figure 22-2. Permission was granted from the State Highway Engineer to pass through the south arroyo underpass, which is the shortest route to the campus. (As discussed in Section 17.0, the pipeline was to pass through the north utility tunnel.) Further details concerning the pipeline construction are found in the Geothermal Project Survey.

Several problems occured during construction of the pipeline. Most of the problems were due to poor weather conditions. In the Las Cruces climate it is common for flash floods to occur. Two weeks of delay were attributed to the flooding of the pipeline trench.

GAS SEPARATOR

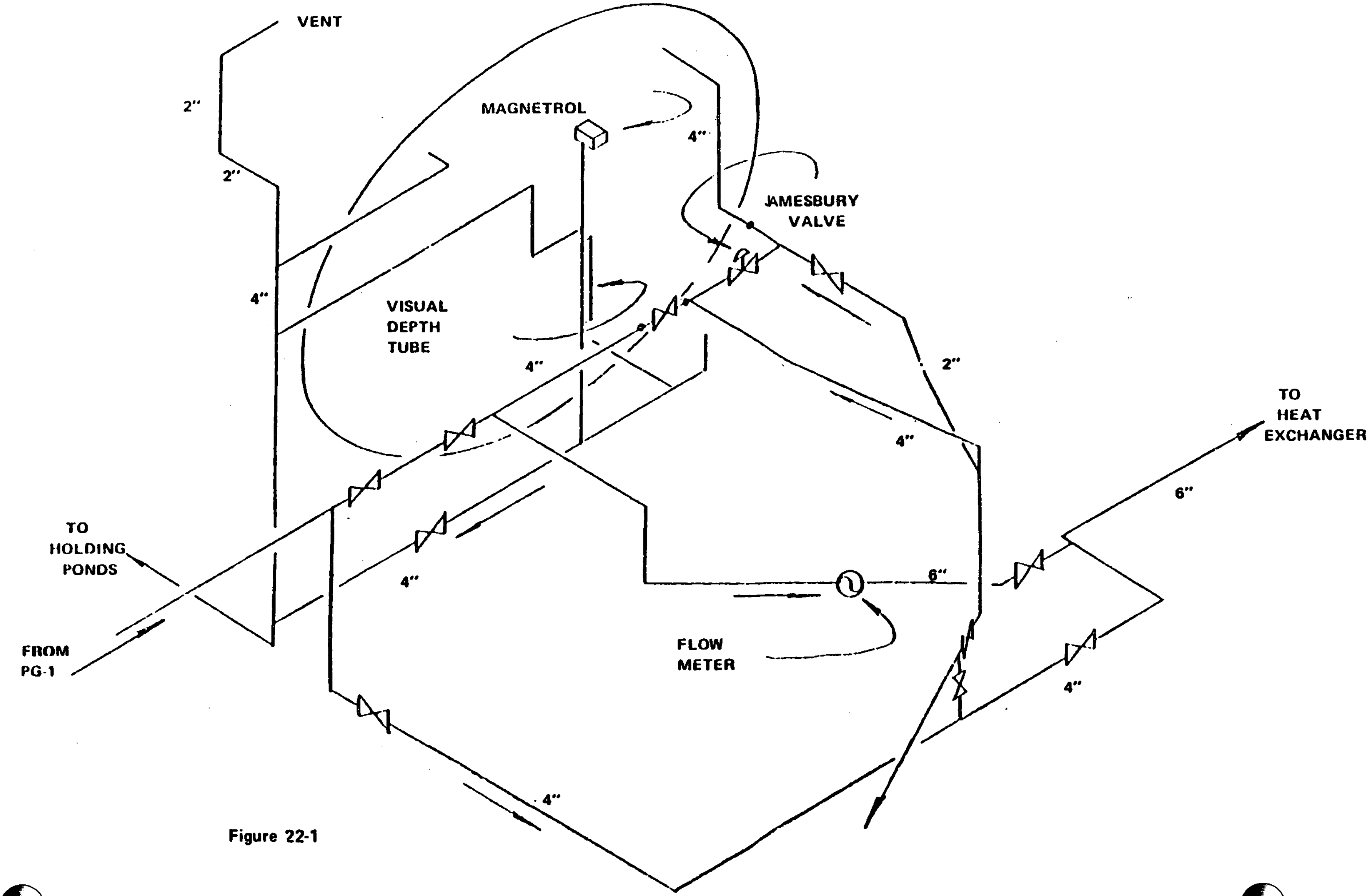


Figure 22-1

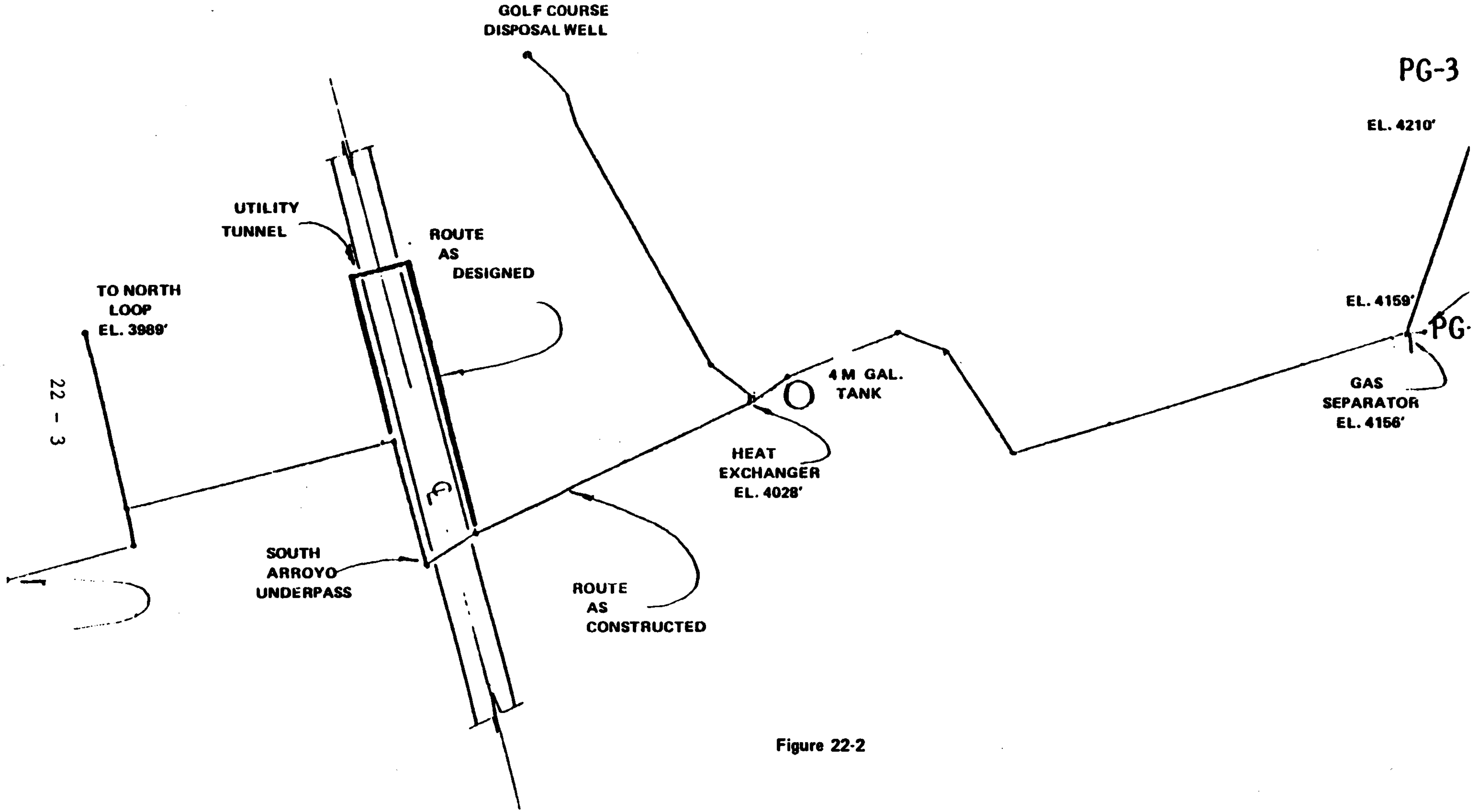

GOLF COURSE
DISPOSAL WELL
PG-3
EL. 4210'
UTILITY
TUNNEL
ROUTE
AS
DESIGNED
TO NORTH
LOOP
EL. 3989'
EL. 4159'
PG
4 M GAL.
TANK
GAS
SEPARATOR
EL. 4156'
HEAT
EXCHANGER
EL. 4028'
SOUTH
ARROYO
UNDERPASS
ROUTE
AS
CONSTRUCTED

Figure 22-2

23. DISTRIBUTION SYSTEM CONSTRUCTION

Primary Heat Exhangers

The primary heat exchangers were installed as detailed in Section 18. See Figure 23-1 for heat exchanger complex as built.

Hot Water Storage Tank

See Section 18. See Figure 23-2 for hot water storage tank as built.

PRIMARY HEAT EXCHANGERS

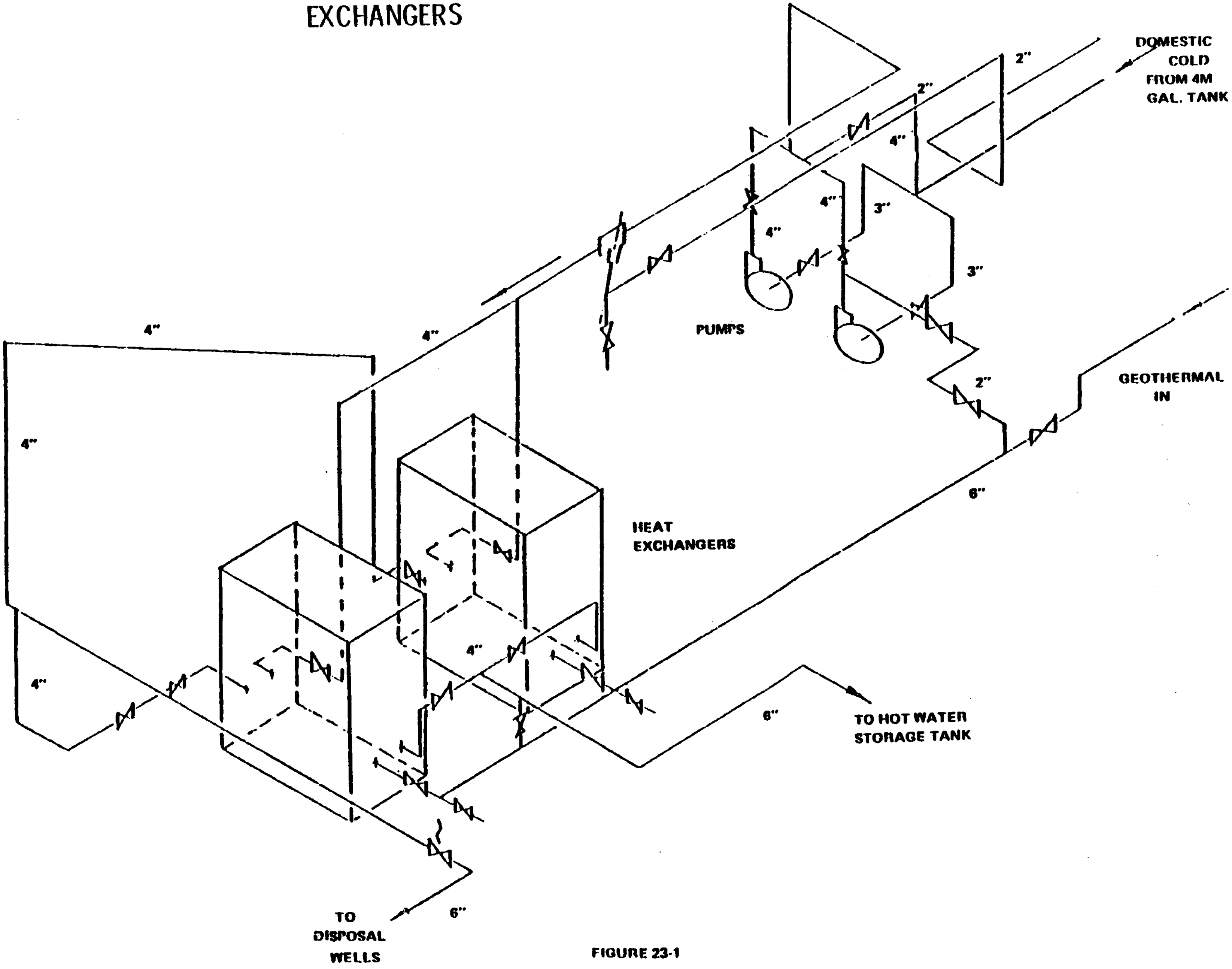


FIGURE 23-1

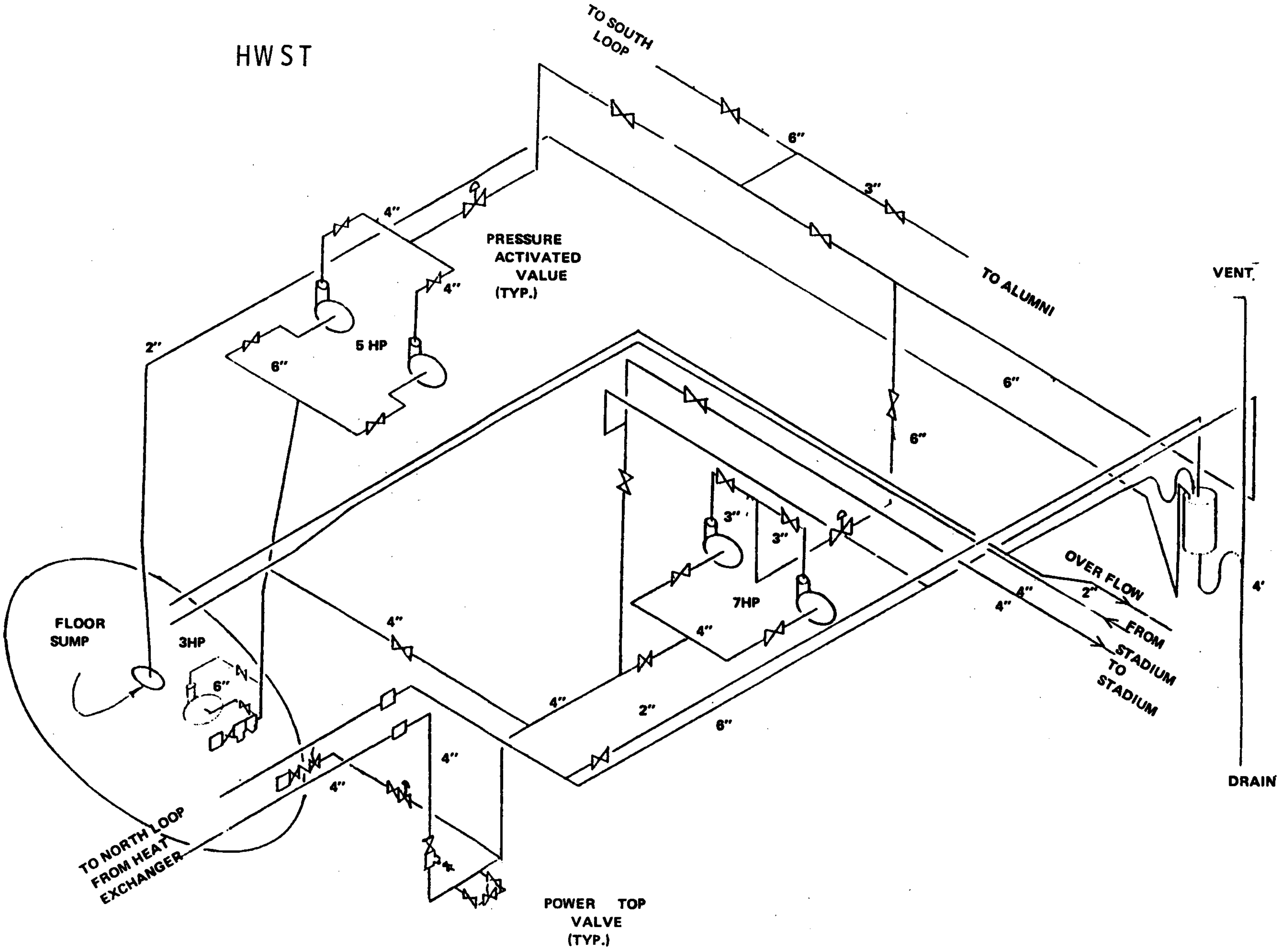
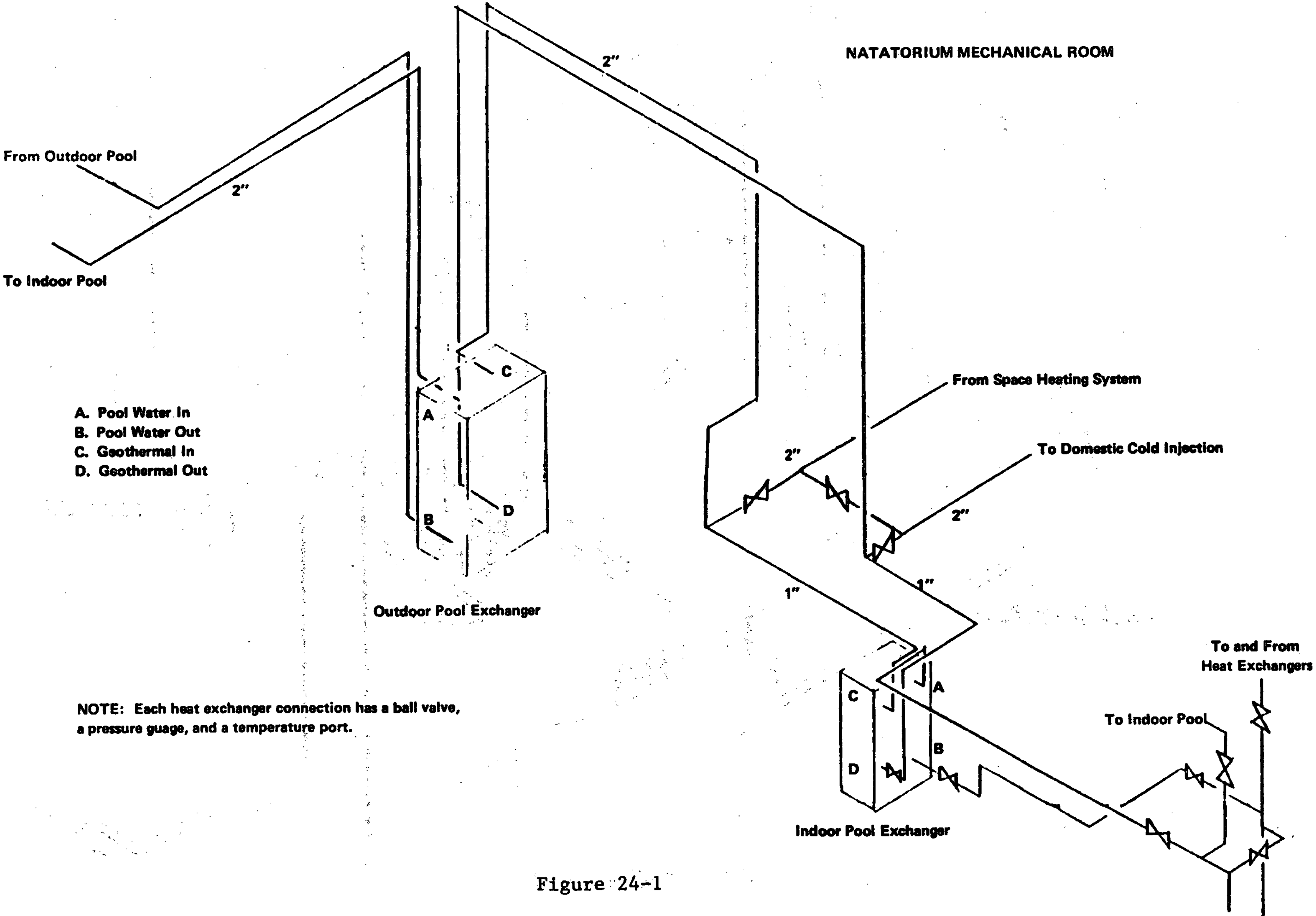

HWST
TO SOUTH LOOP
6"
3"
TO ALUMNI
4"
4"
PRESSURE ACTIVATED VALUE (TYP.)
2"
5 HP
6"
6"
6"
VENT
3"
3"
7HP
OVER FLOW
2"
4"
4"
FROM STADIUM
TO STADIUM
4'
FLOOR SUMP
3HP
6"
4"
4"
4"
2"
6"
4"
4"
TO NORTH LOOP
FROM HEAT EXCHANGER
POWER TOP VALVE (TYP.)
DRAIN

Figure 23-2

24. APPLICATION SYSTEM CONSTRUCTION

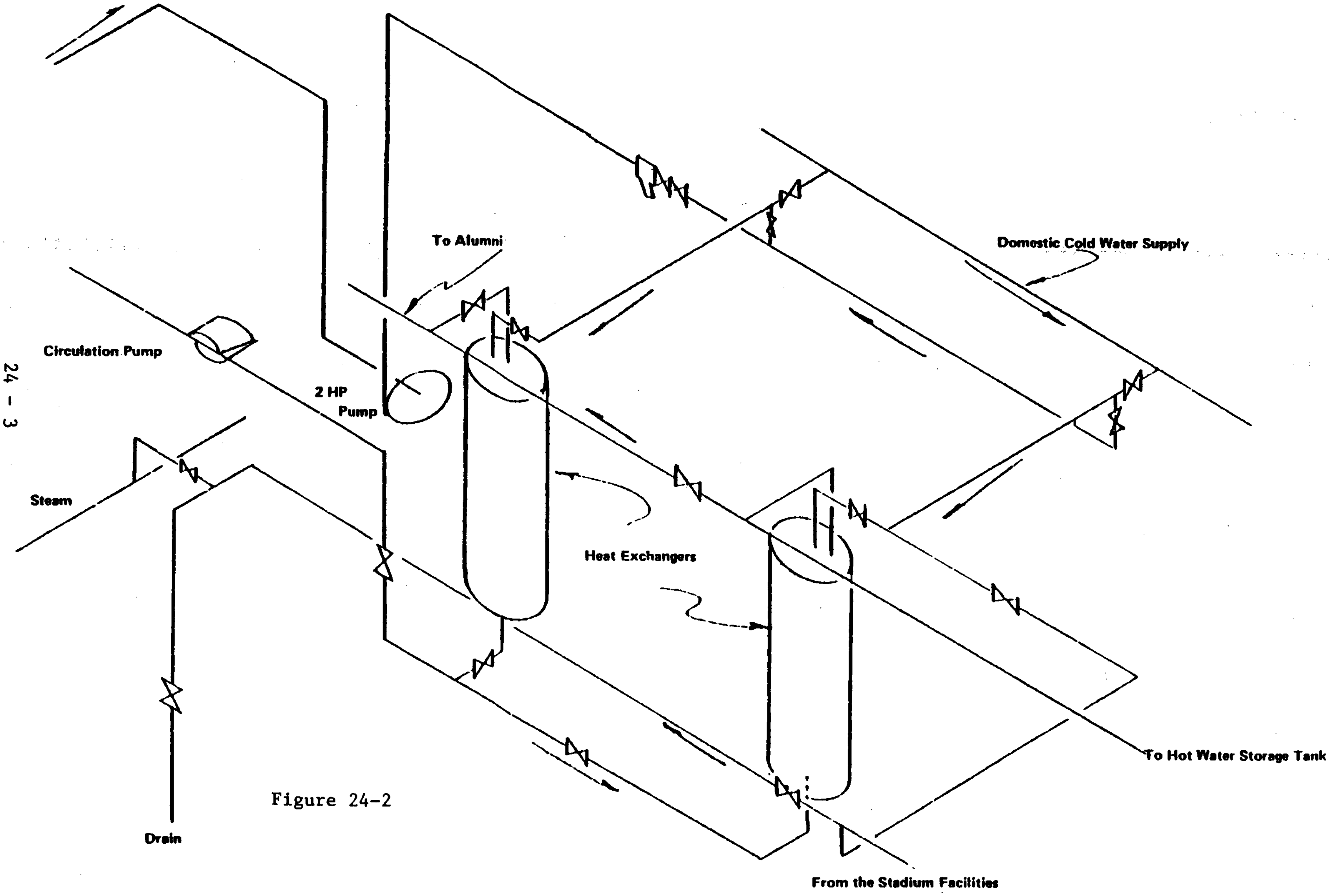
The application system was constructed as designed in Report EMD 2-68-2207.

The individual user systems were constructed as described in Section 19 of this report. Little or no difficulty was encountered during the construction phase of the project. For as-built example sketches of some users see Figures 24-1 through 24-6.



NOTE: Each heat exchanger connection has a ball valve, a pressure guage, and a temperature port.

Figure 24-1



ALUMNI MECHANICAL ROOM

Figure 24-2

STADIUM FACILITY MECHANICAL ROOM

NOTE: All valves are gate type unless noted otherwise.

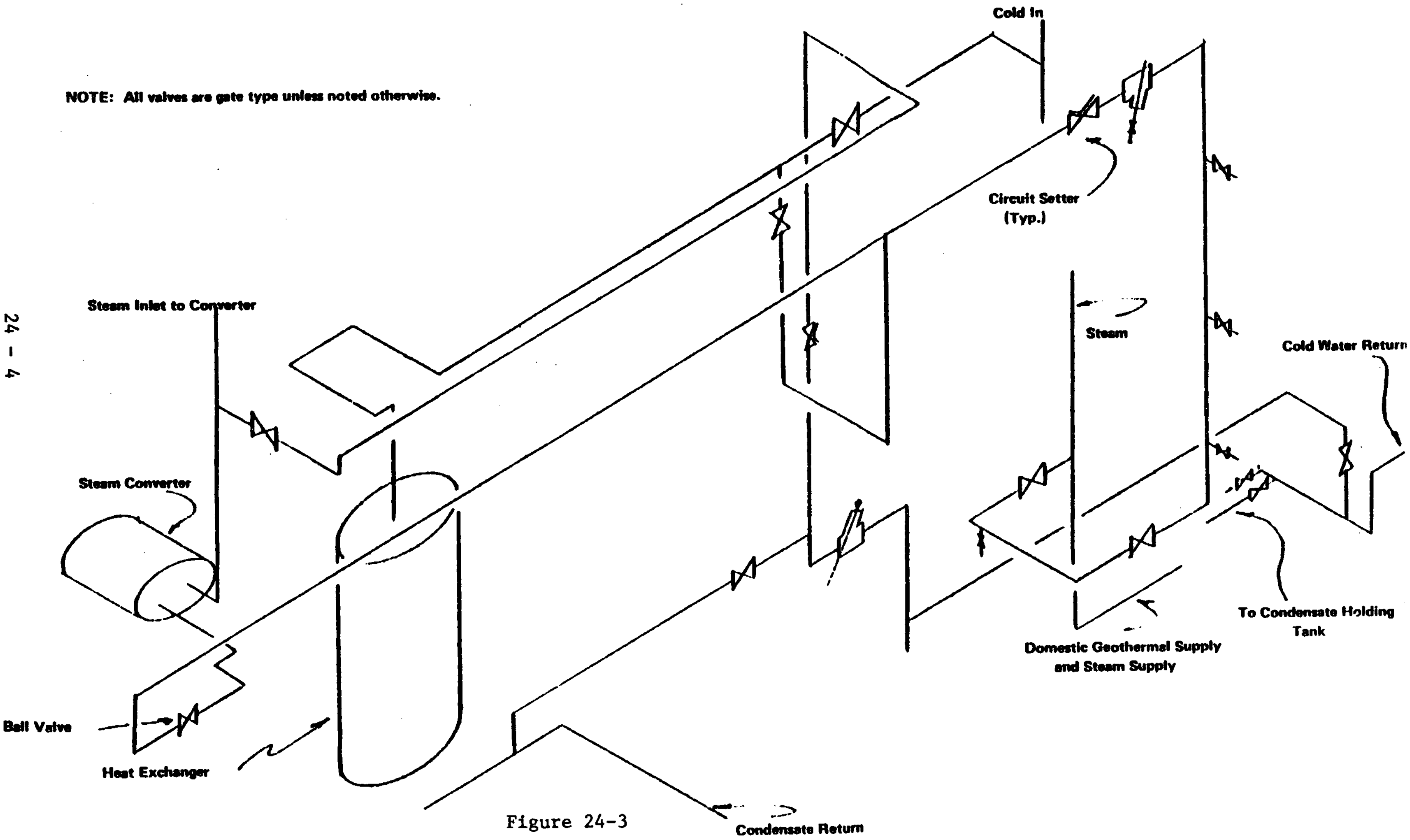


Figure 24-3

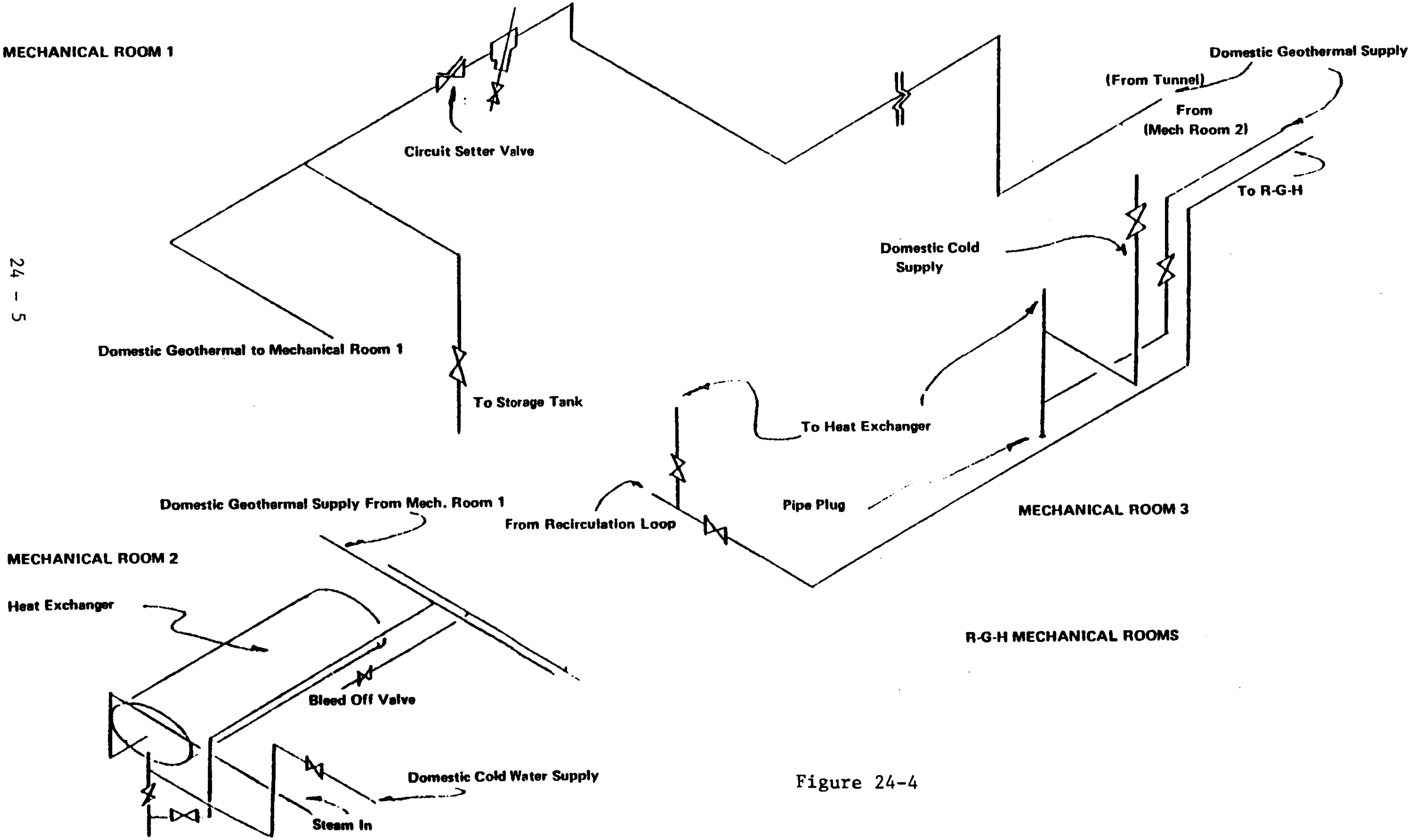
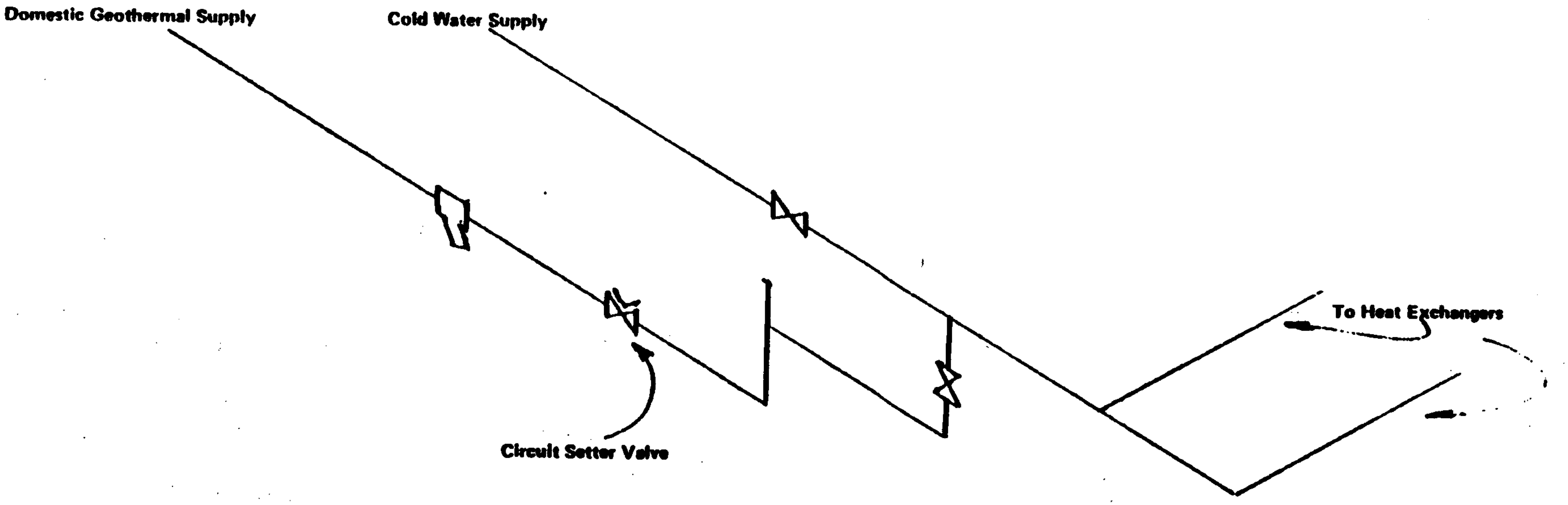

MECHANICAL ROOM 1
Circuit Setter Valve
Domestic Geothermal Supply
(From Tunnel)
From
(Mech Room 2)
To R-G-H
Domestic Cold
Supply
Domestic Geothermal to Mechanical Room 1
To Storage Tank
To Heat Exchanger
Domestic Geothermal Supply From Mech. Room 1
From Recirculation Loop
Pipe Plug
MECHANICAL ROOM 3
MECHANICAL ROOM 2
Heat Exchanger
Bleed Off Valve
Domestic Cold Water Supply
Steam In
R-G-H MECHANICAL ROOMS

Figure 24-4


ACTIVITY MECHANICAL ROOM

NOTE: All valves are gate type unless noted otherwise.

Figure 24-5

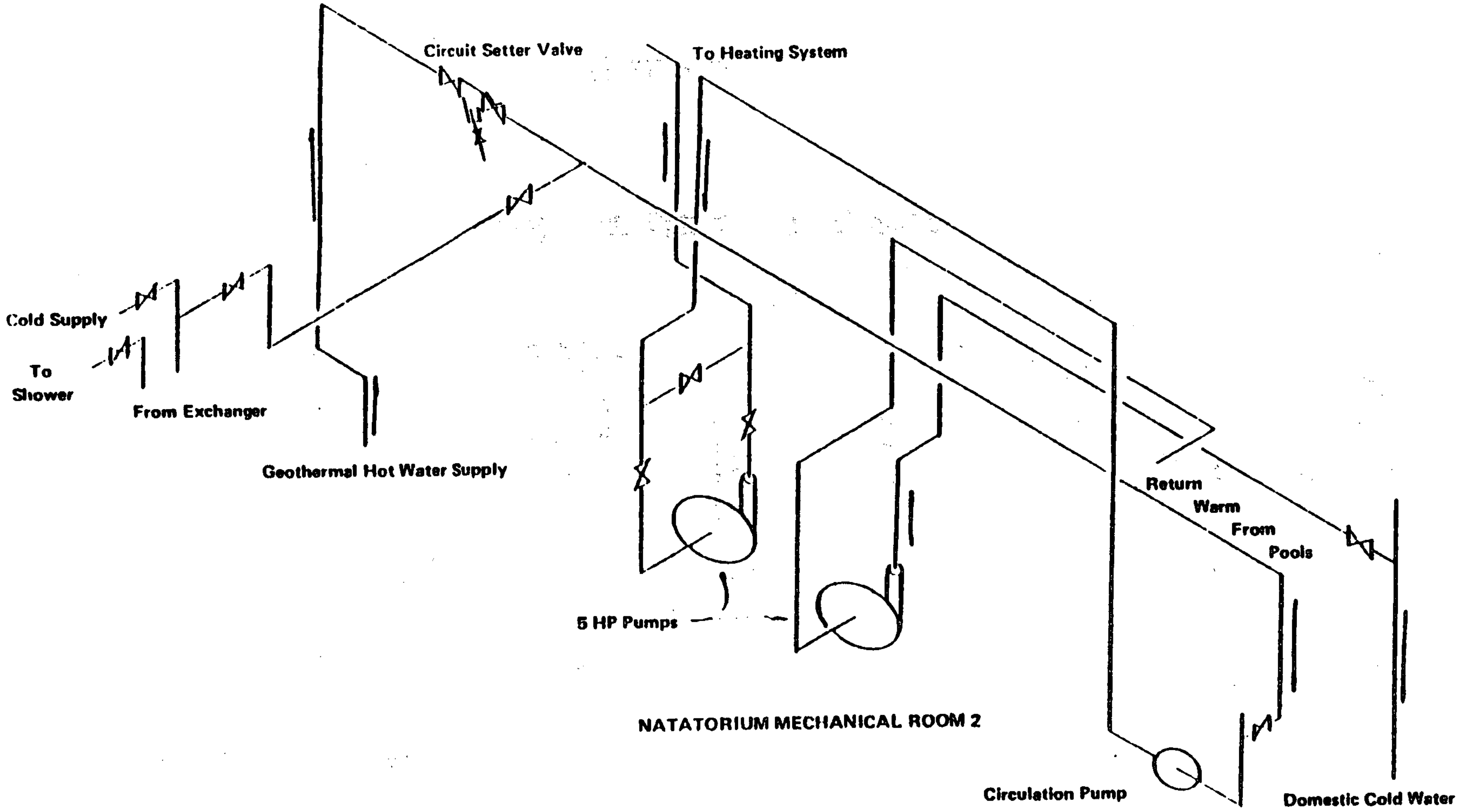
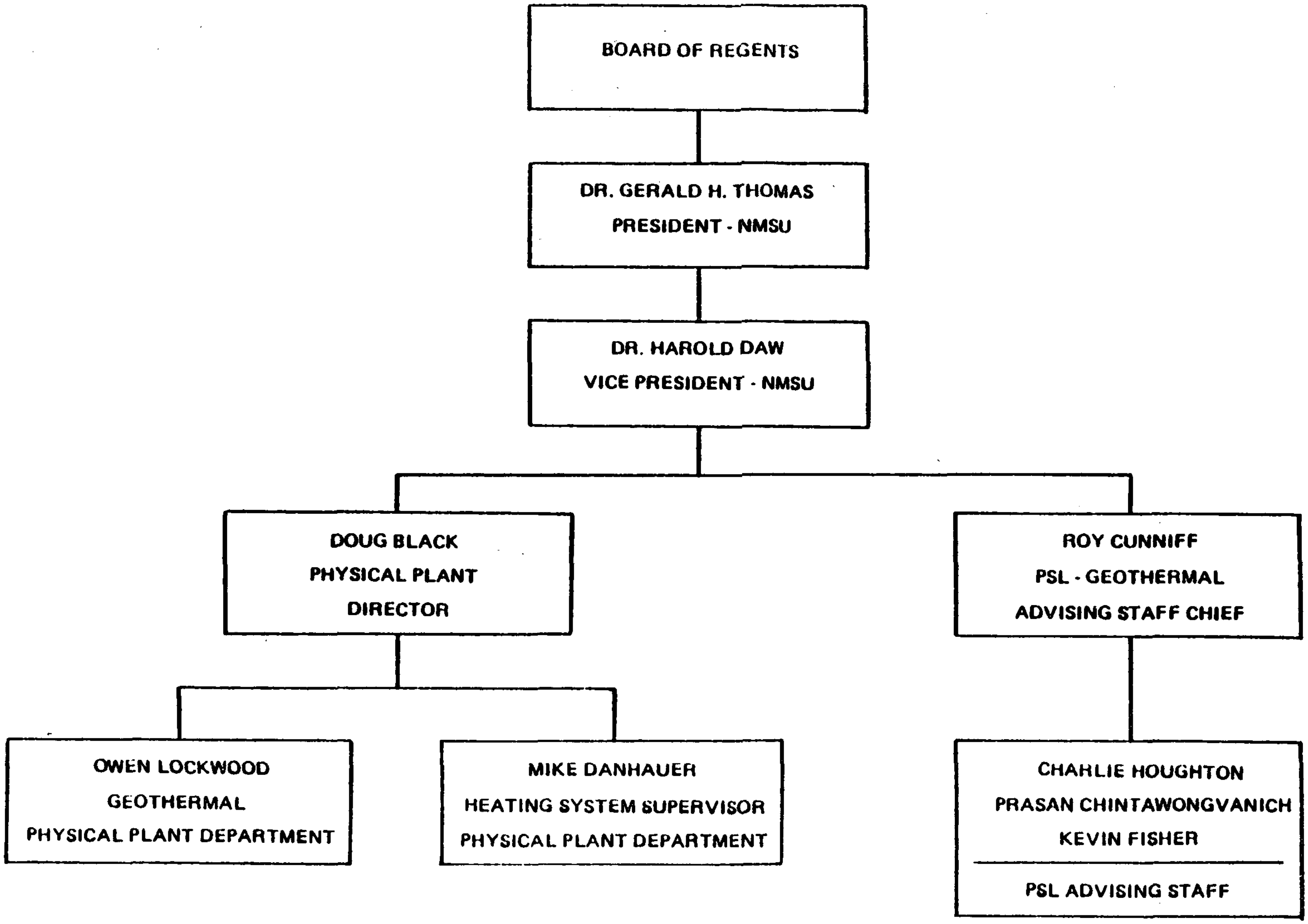

Circuit Setter Valve
To Heating System
Cold Supply
To Shower
From Exchanger
Geothermal Hot Water Supply
5 HP Pumps
Return Warm From Pools
NATATORIUM MECHANICAL ROOM 2
Circulation Pump
Domestic Cold Water

Figure 24-6

25. SYSTEM MANAGEMENT AND ORGANIZATION

This system is operated by the Physical Plant at New Mexico State University. The Physical Science Laboratory assists the Physical Plant Department in technical issues and future expansion. Figure 25-1 shows the organizational responsibilities.


BOARD OF REGENTS
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GEOTHERMAL
PHYSICAL PLANT DEPARTMENT
MIKE DANHAUER
HEATING SYSTEM SUPERVISOR
PHYSICAL PLANT DEPARTMENT
CHARLIE HOUGHTON
PRASAN CHINTAWONGVANICH
KEVIN FISHER
PSL ADVISING STAFF

Figure 25-1

26. PRODUCTION SYSTEM PERFORMANCE

26.1 Performance Summary

The New Mexico State University Geothermal Demonstration System has continued to perform well overall, although a well pump failure occured during aquifer testing. Following the early failure of the installed peerless 50 Hp vertical shaft turbine pump in PG-1 in June 1981, the 100 Hp submisible TRW-REDA pump was moved from PG-3 to PG-1 for a series of controlled tests. The results of testing showed that, with the installed TRW-REDA pump, PG-1 could produce a flow of clean water up to 365 gpm. Following the test results, a decision was made to purchase a new 100 Hp TRW-REDA pump which was installed in PG-3 in February 1982. During the two-year monitoring period, a total of four additional pump failures occurred, and major well problems with PG-1.

26.2 Data Acquisition

Starting on 15 February 1982, the Geothermal Demonstration System was placed in service gradually, providing heated domestic water to eleven building complexes on the NMSU campus. In March 1982 the system was put on a full scale operation, providing additional service to the Natatorium complex which included the indoor and outdoor swimming pools. The system continued to perform well until May 1982; both well pumps (in PG-1 and PG-3) failed (PG-1: 3,000 hours, and PG-3: 1,000 hours).

From the inspection of the pumps at PG-1 and PG-3 after they had been removed from the wells and had been dismantled at the factory, a conclusion was reached that the failure of PG-1 pump may have been caused contributed by excessive sand produced during the operation. It was noticed during the operation of the pumps that as much as several cubic yards of sand was produced. An inspection of TV logs performed by a down-hole camera in both wells revealed that in PG-1, the screen section was broken at 803 feet of depth. These are the primary reasons for the excessive sand produced during the operation which may have contributed to the failure of the well pumps. The tear down inspection of the PG-3 pump was ambiguous, and cause of failure could not be determined, although no evidence existed of pump exposure to a sandy environment.

Both production wells were repaired in June 1982. The screen section of PG-1 was cemented from 850 to 803 feet of depth, from the original screen of 695-850 feet. The open bottom hole of PG-3 was cement plugged with the screen section retained at its original configuration of 750-850 feet. Prior to repairing the wells, temperature logs were acquired for both wells. Figure 26-1 displays the temperature logs of PG-1 and PG-3 as a function of depth.

Pump tests were run on the production wells during 7-10 July 1982 to determine well parameters after the repairs. The results show that using 80 Hp pump with 100 Hp motor, PG-1 produced a flow of 262 gpm safety with very little sand detected. Controlled flow test on PG-3 with the 100 Hp pump also show that PG-3 could give a stable production rate of 175 gpm, which was a noticeable decline from the 275 to 300 gpm rate previously attained.

A decision was made to purchase two TRW-REDA pumps (60 Hp submissible) to be installed in PG-1 and PG-3 following the well repairs and testings. Consideration was made to accommodate the design factors, unit cost, operating cost (electricity consumption), and long term performance.

Testing of the wells with the new installed units was conducted during the period of August 24-25, 1982. The test result at PG-1 indicated that the well produced a steady state flow of 270 gpm with 69 psig back pressure, and very little sand was produced. The pump met or exceeded specifications. The well and pump were fully satisfactory. Details of PG-1 pump test is given in Tables 26-2 and 26-3.

The result of testing at PG-3 indicated that the well was capable of producing the desired rate of 185 gpm which is above pump minimum recommended value. This yield is adequate for system use since all current system needs are met with a 125 gpm flow. Drawdown stability was recorded during the last four (4) hours of the test. The reported drawdown provided a situation in which, if drawdown data were correct, the pump water level was within 30 feet of the pump intake. This is a point of incipient cavitation. Since no signs of cavitation were noted, and the measured TDH was 31 feet (or 3.5%) greater than specified, a tentative conclusion is that the actual drawdown is less than measured. Details of PG-3 pump test is given in Table 26-4.

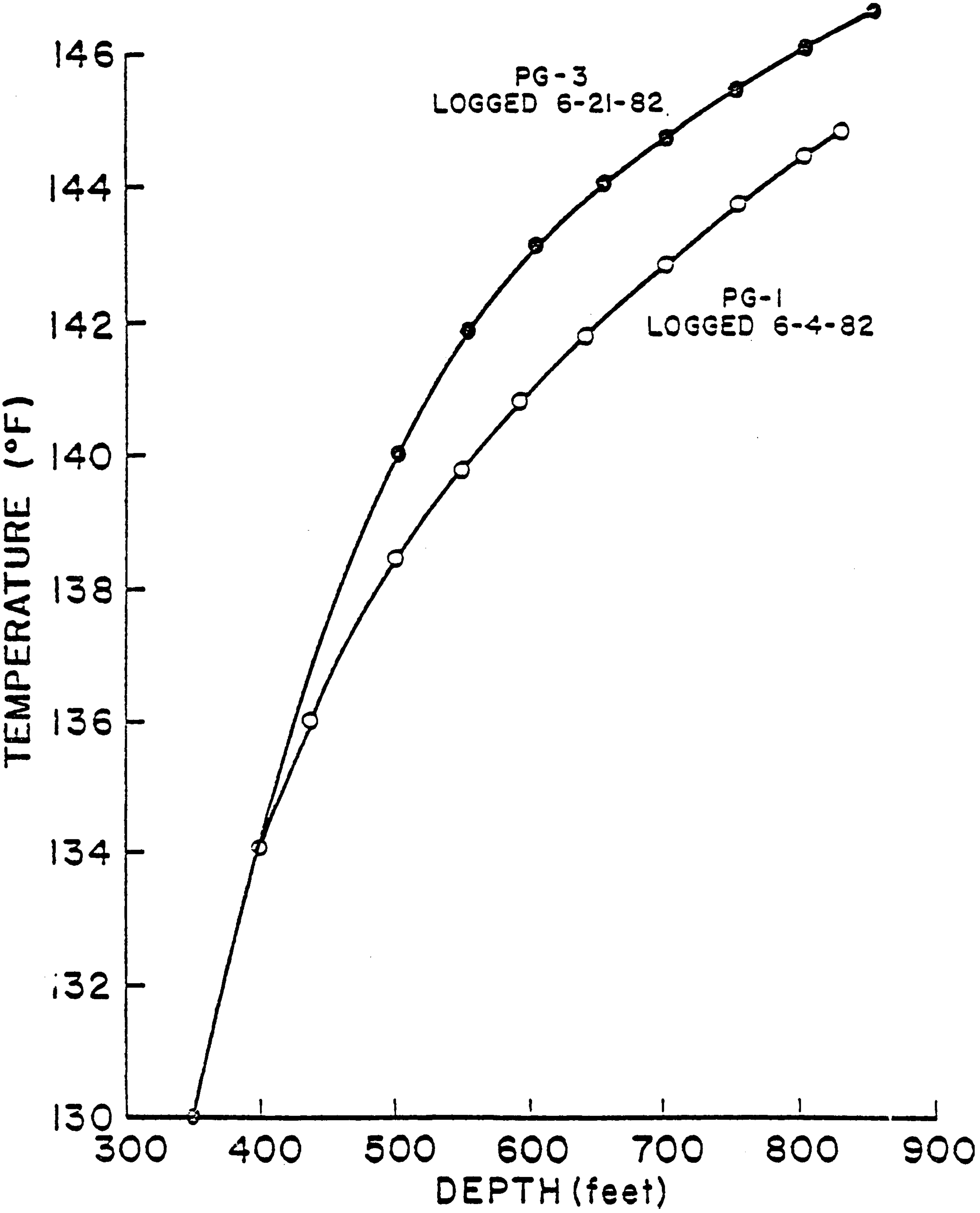


Figure 26-1 Temperature Logs of PG-1 and PG-3

Table 26-2

PG-1 PUMP TEST 7-10 JULY 1982

Start Conditions

Well Temp: 142°F

Static Level: 322 feet

Initial Flow (First 17 minutes)

Flow recorders not used until flow cleaned

Flow estimated 350 gpm for first few minutes

Flow semi-stablized after 17 minutes, and flow meter engaged: 300 gpm

Dynamic water level: 500 feet

Surface discharge pressure: 0 psig

Water temperatures: 140.5°F

Large amounts of sand and cement coloration for first two hours.

Controlled Flow

Flow rate: 262 gpm

Condition One (10 hours) Surface back pressure: 125 psig

Dynamic level: 505 feet

Water temperature: 140.5°F

Specific Yield: 1.44 gpm/ft

Condition Two (30 hours): Flow rate 250 gpm

Surface back pressure: 150 psig

Dynamic level: 492 feet

Water temperature: 140.5°F

Specific yield: 1.56 gpm/ft

NOTE: For the entire duration of test, sand was checked at Y-strainer hourly. Estimated sand fraction was 1/4 teaspoonful per 5 gallons, thru-out the test.

Table 26-3

PG-1 TESTS, 24-25 AUGUST 1982

Duration: 30 hours (8/24/82 - 8/25/82)

Pump specifications:

a. Description: motor is 60 HP, HU-6-62D, Pump is a 16-stage I-250.

b. Specified yield: at 262 gpm, the pump should produce 644 feet TDH.

	Feet	
Pumping Water Level:	512	
Well Head Back Pressure:	92	(40 psig)
Friction Loss:	40	
	644 feet TDH	

Demonstrated Yield: At 262 gpm, the pump produced the following TDH:

	Feet	
Pumping Water Level:	471	
Well Head Back Pressure:	159	(69 psig)
Friction Loss:	40	
	670 feet TDH	

Water temperature: 142°F

Table 26-4

PG-3 TEST 25-26 AUGUST 1982

Duration: 20 hours (8/25/82 - 8/26/82)

Pump Specifications:

a. Description: Motor is a 60 Hp, Hu-6-62D; Pump is a 16-stage I-250.

b. Specified yield: At 185 gpm, the pump should produce at least 880 feet of TDH, as follows:

	Feet	
Pumping Water Level:	773	
Well Head Pressure:	92	(40 psig)
Friction Loss:	15	
	880 feet TDH	

Minimum recommended flow: 175 gpm

Demonstrated Yield: At 185 gpm, the pump provided the following TDH:

	Feet	
Pumping Water Level:	734	
Well Head Back Pressure:	162	(70 psig)
Friction Loss:	15	
	911 feet TDH	

Water temperature 144°F

Because of uncertainties about the drawdown values, startup procedures for PG-3 were closely monitored to assure that cavitation is not occuring, particularly when PG-1 is also in production. One effect of the well repair was more interference between the wells than seen previously. This interference effect may be visualized by examining the attached sketch in Figure 5-5 when PG-3 was started on 8 August 1982 at the same time as PG-1, and both wells were operated simultaneously for 2 hours. PG-3 temperatures declined to 141°F, and drawdown rapidly increased to 730 feet. It took 8.5 hours after PG-1 was stopped for the temperature in PG-3 to recover to 144°F. This recovery time duration is twice as long as seen during previous combined flow tests, and the effect on PG-3 was more pronounced during this latter test in terms of the production temperature. Previously, PG-3 temperature remained at 145-146°F, regardless of pumping levels in PG-1.

The summary of key data in Table 26-5 shows that PG-3 bottom hole temperature loss is (-4°F); the loss of pumping temperature is (-2°F), the loss of production is (320 vs. 195 gpm), and increased drawdown of (+80 feet). All data point to the fact that a substantial portion of PG-3 production was from the open hole. In addition the marked increased in interference between the wells now, in a combined pumping mode, is additional evidence that a significant change has taken place.

Table 26-5

ANALYSIS OF PUMPING INTERFERENCE

	Bottom Hole Temp. °F	Flowing Yield GPM	Flowing Temp. °F	Drawdown at 262 GPM
I. PG-1 ALONE				
Original configuration (screen from 695-850 feet)	146	365	143	460'
Current configuration (screen from 695-803)	144	275	141.5	471-478'

	Bottom Hole Temp. °F	Flowing Yield GPM	Flowing Temp. °F	Drawdown at 200 GPM
II. PG-3 ALONE				
Original configuration (screen 750-850) open hole 860-942)	150.4	320	146	650'
Current configuration (screen 750-850 open hole plugged)	146.5	195	144	730'

	PG-1	PG-3	TOTAL	Combined Temperature
III. COMBINED YIELD (GPM)				
Original configuration	365	290	655	140-144
Current configuration (EST)	265	150	415	138-141

On 30 September 1982, after 30 hours of operation, the 60 Hp REDA pump installed in PG-1 failed. A comprehensive program of research was set up in attempting to define the probable reason for premature pump failure. Expert opinions were given by the following agencies or firms:

A. Magma Power, Emperial Valley (Ed Zajacs)

B. DOE, Idaho Falls (Raft River Facility) (Bob Van Treek, and Larry Walrathe)

C. Johnston Pump, Los Angles (Jack Frost)

D. Barber - Nichols Engineering Co. (Ken Nichols, and Senior Staff Chemist)

Table 26-6

DISSOLVED GAS CONTENTS IN PG-1 AND PG-3

PG-1

	Content			Partial Pressure at 142°F
	(mole/ℓ)	(cc/ℓ)		(psi)
CO_2	$8.9\text{x}10^{-3}$	200		8.5
H_2O	55.56	N/A		3.3
			TOTAL =	11.8

PG-3

	Content			Partial Pressure at 142°F
	(mole/ℓ)	(cc/ℓ)		(psi)
CO_2	$9.8\text{x}10^{-3}$	220		9.8
H_2O	55.56	N/A		3.7
			TOTAL =	13.5

26.3 Post Construction Modification

After reviewing all available data, the consensus of expert opinion was that only the Johnston Pump Company had the required pump expertise and successful performance record for geothermal well pumps. The price quoted was less than half the cost of a comparable TRW-REDA pump. The cost is extremely reasonable.

A series of controlled flow tests were conducted following the decision to purchase a new Johnston Pump, installed in PG-1 on 18 November 1982. Pump test of this unit revealed a very good result in which the pump performance matched a predicted value.

The installed Johnston pump in PG-1 continued to perform well overall. In early March 1983, the output from the pump in PG-1 started to decline (from the original flowrate of 215 gpm to 144 gpm at a back pressure of 60 psig), and the well head pressure had progressively reduced. After a series of controlled flow tests, a conclusion was reached that apparently the pump column had a break, which was allowing fluid to escape, thus reducing the production rate as well as well head pressure. On 28 March 1983, the system was switched to the back-up well, PG-3, and the pump was removed from PG-1. Water analysis revealed the H_2S concentration had increased, resulting in increased corrosion.

Inspection of the pump and pump column revealed several problems as follows:

a. The first three joints above the pump in the pump column were leaking badly at the couplings. This situation resulted in first a loss of well head pressure, and subsequently a loss in production. Just before the pump was pulled, production had declined to 150 gpm.

b. Sand had eroded the pump bearings at the top stage, which allowed the throttle bushing to be eroded. Hence, water was able to enter the oil tube, and cause severe corrosion of the pump shaft and bearings. No other damage had resulted to the pump.

c. Almost 80 percent of the pump column couplings showed evidence of erosion, in the threaded portion of the column pipe.

Based on the inspection, the pump was rebuilt using hard-faced bearings above and below the throttle bushing, and similar hard-faced bearings installed every five feet on the pump shaft. The threaded and coupled column was replaced by flanged fittings with O-rings for the lowest 160 feet of pump column. The column pipe was coated with epoxy on exterior and interior surfaces. When the pump was reinstalled, a special sand screen was installed on the pump suction, consisting of 6.5 feet of #10 Johnson stainless steel wire screen. This special sand screen would help eliminate all sand larger than 0.010 inches, which is now able to enter the regular well screen which has perforations 0.0625 inches. Moreover, the well pumping rate was to be controlled to a lower production rate of 150-165 gpm, which appeared to cause less sand to be pumped during controlled testing in March.

Subsequently, the repaired pump was reinstalled during Labor Day weekend, 1983. Repeated attempts were made to conduct a flow test, but excessive sand production caused each attempt to fail. The pump was shipped to the vendor facility in Salt Lake City, for inspection. Upon disassembly, a large amount of silt, fine sand, and scale was noted, completely plugging the pump. It was cleaned, and shipped back to NMSU. The pump will be reinstalled in late May, 1984.

27. DISPOSAL SYSTEM PERFORMANCE

A great deal of testing went into the design of the disposal system. These tests and performance evaluation are discussed in detail in Section 16.

28. TRANSMISSION SYSTEM PERFORMANCE

Gas Separator

Approximately 200 cubic centimeters (CC) of CO_2, plus nitrogen and traces of other gases are dissolved in each liter of the geothermal water. These dissolved gases, which may degrade the performance of the heat exchanger, and which represent a potential problem of hydraulic hammer in the pipe-lines, are removed by the gas separator.

Testing of the installed gas separator/surge tank was completed by September 1981. Under measured conditions, approximately 100 cubic centimeters of CO_2, nitrogen and traces of other gases were removed per liter of geothermal water.

A coordinated testing procedure was carried out to determine the performance of the gas separator. Under controlled conditions, the pressure drop was varied across the final valve leading to the gas separator tank. Five tests were conducted, with the system allowed to reach equilibrium between each test. Pressure drops of 40, 145, 270, 315, and 400 psig were set, and after equilibrium conditions were reached, water samples were taken at the exit side of the separator tank. These samples were analyzed for quantities of dissolved gases.

As can be seen from the testing results which were plotted in Figure 28-1, the gas separation rate increases with increasing pressure drop until a null point was reached at approximately 200 psig. Thereafter, increasing the pressure drop resulted in a gradually decreasing level of CO_2 separation. Explanation of this phenomenon is that the larger pressure drops caused proportionally larger fluid velocities, which then caused violent stirring action in the small tank. Under these conditions, CO_2 was entrained in the fluid in frothy bubbles, and did not separate totally from the fluid.

Under normal system operation, pressure drop is set at 80-100 psig which corresponds to a gas separation rate of 80 cubic centimeters/liter of fluid. Residual CO_2 remained in the geothermal fluid is thus approximately 120 cubic centimeters per liter. From controlled laboratory tests, this residual amount is subject to a slow release process, which can take up to two weeks in an open environment.

GAS SEPARATOR

MAINTENANCE

Purpose: To remove the inspection plate, and clean the gas separator tank. Also, to disassemble and inspect the Jamesbury valve.

Inspection Results: The bottom of the tank contained a 6-inch deep accumulation of fine sand. This sand most likely came from PG-1. In this sand were small flecks of metal which came from erosion of the nipple and Jamesbury valve. The epoxy coating on the tank interior was intact, and showed no visible evidence of peeling of flaking. The portion of the tank below normal water level had minor rust stains, evidence of the high iron content of the geothermal water. The Jamesbury valve (stainless steel) showed no evidence of corrosion. However, there was a visible mark on the exit nipple, which is the point which experiences the highest fluid velocity. Entrained sand in this water would cause such scouring.

Recommendations:

1) The Gas Separator tank should be drained and cleaned at least once every six months.

2) Because of the possible scouring actions, the Jamesbury valve should be examined every three months. If subsequent checks indicate erosion problems, considerations should be given to buying a stand-by replacement spare.

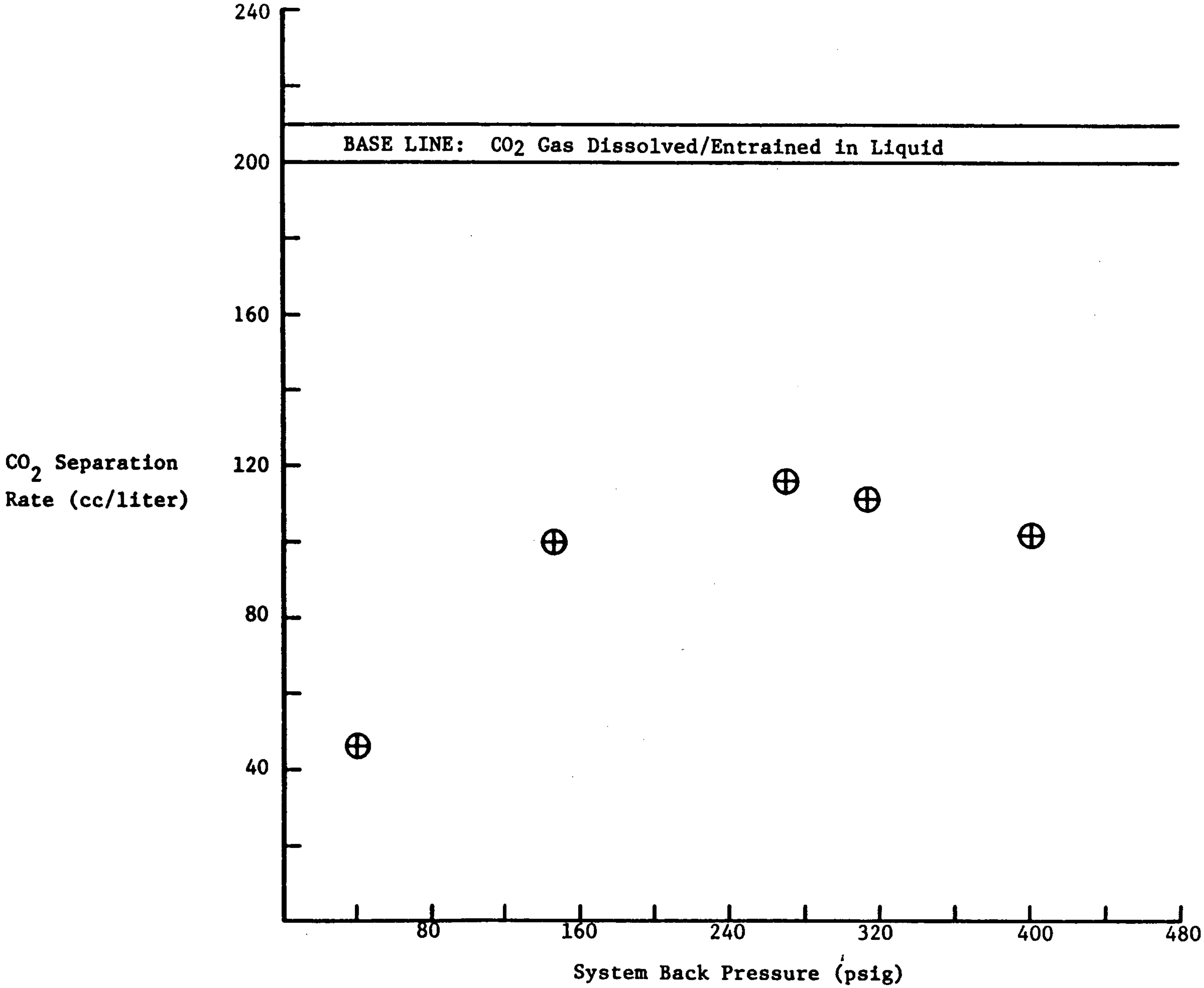


Figure 28-1 CO_2 Release Rate vs System Back Pressure

29. DISTRIBUTION SYSTEM PERFORMANCE

29.1 Performance Summary

Primary Heat Exchangers

Tests were conducted 31 March 1982 to determine the temperature of domestic hot water at various flow rates for a constant geothermal flow rate of 275 gpm. At 75 gpm the delivered temperature was 140°F and was 137°F at 235 gpm. The temperature drops sharply above this rate, 130°F for 300 gpm, and 120°F for 340 gpm. These heat exchangers have been tested extensively at various flow rates, and have given an excellent performance. Figure 29-1 depicts the results of a controlled flow test to assess both the heat exchanger performance as well as the heat loss in the 6,200 feet of insulated pipeline from the heat exchanger building to the hot water storage tank. As can be noted, a constant rate of geothermal of 245 gpm produced only a 4°F temperature loss in the sweet water arriving at the storage tank. At very high (300 gpm) flow rates, the exchanger was able to provide 133°F water at the storage tank. Even at low flow rates (25 gpm) the system was able to deliver 130°F water to the storage tank.

Summarizing the data in another way, at the constant flow rate of 240 gpm and 141.5°F, the heat exchangers provided 0.5 to 1.0°F approach temperature at cold side flow rates of 200 gpm. Even with a cold side flow rate of 300 gpm, the exchangers delivered an approach temperature of 9°F.

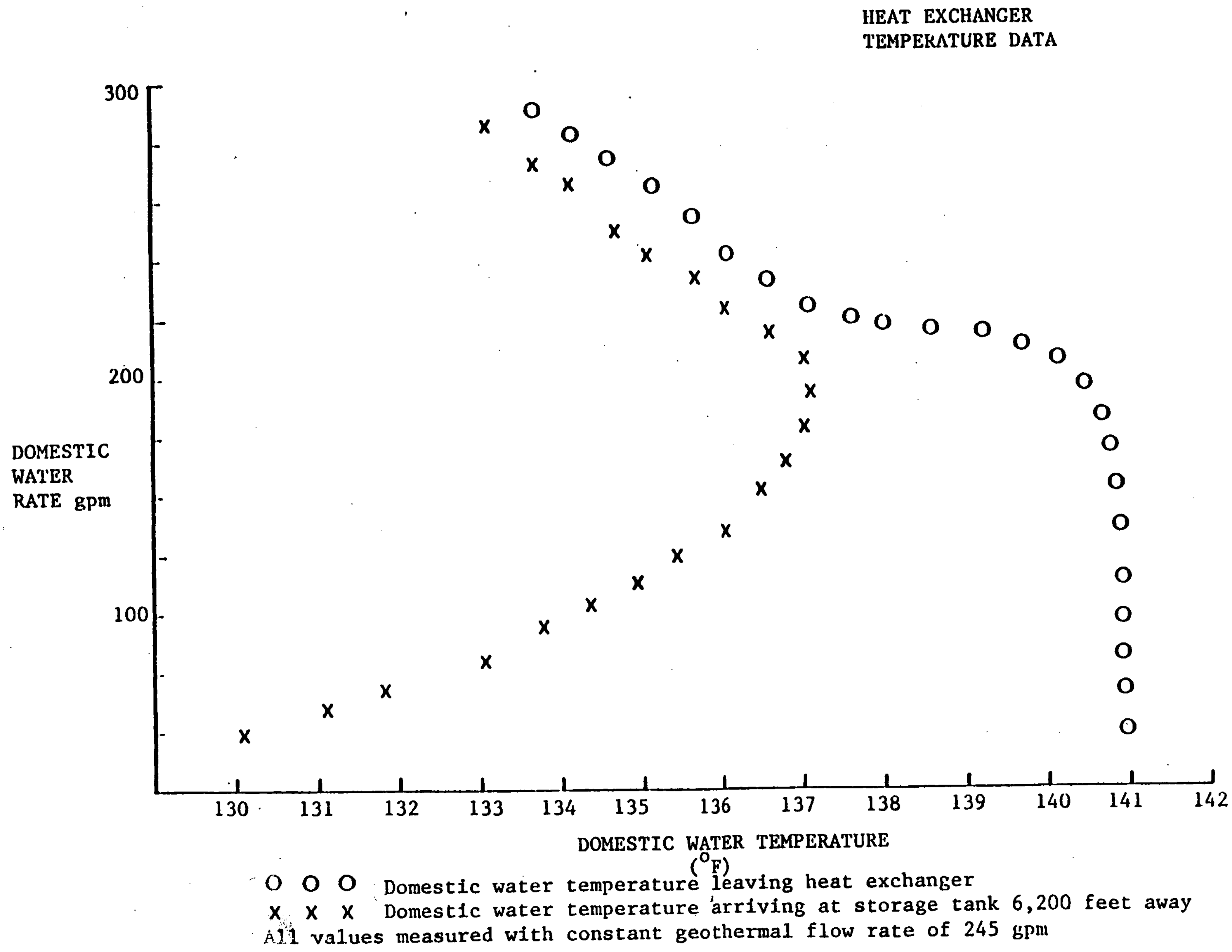


Figure 29-1 Heat Exchanger Temperature Data

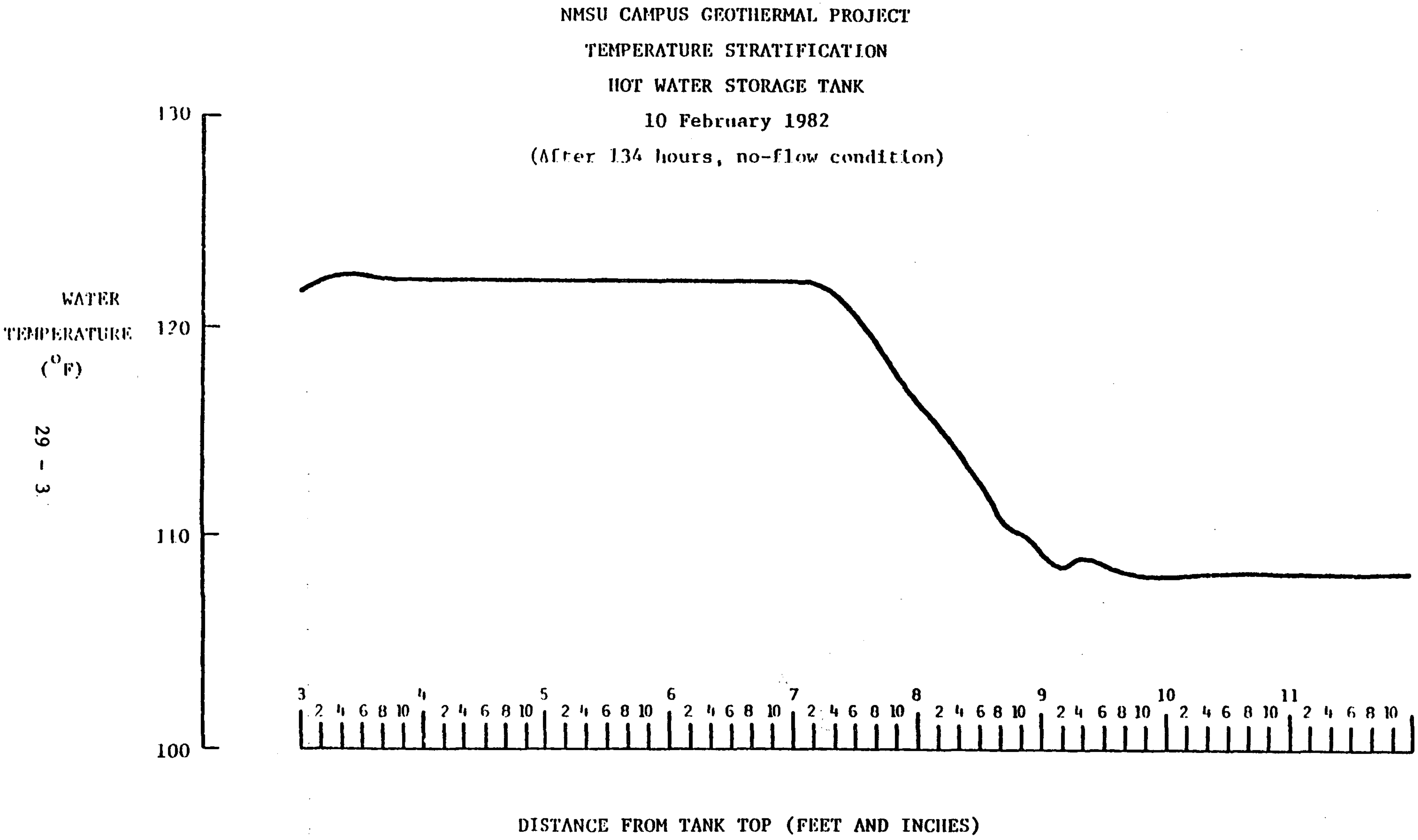


Figure 29-2 Temperature Stratification of Hot Water Storage Tank

NMSU GEOTHERMAL PROJECT

Temperature Stratification
Hot Water Storage Tank

22 February 1982

(64 Hours Lock-up Condition)

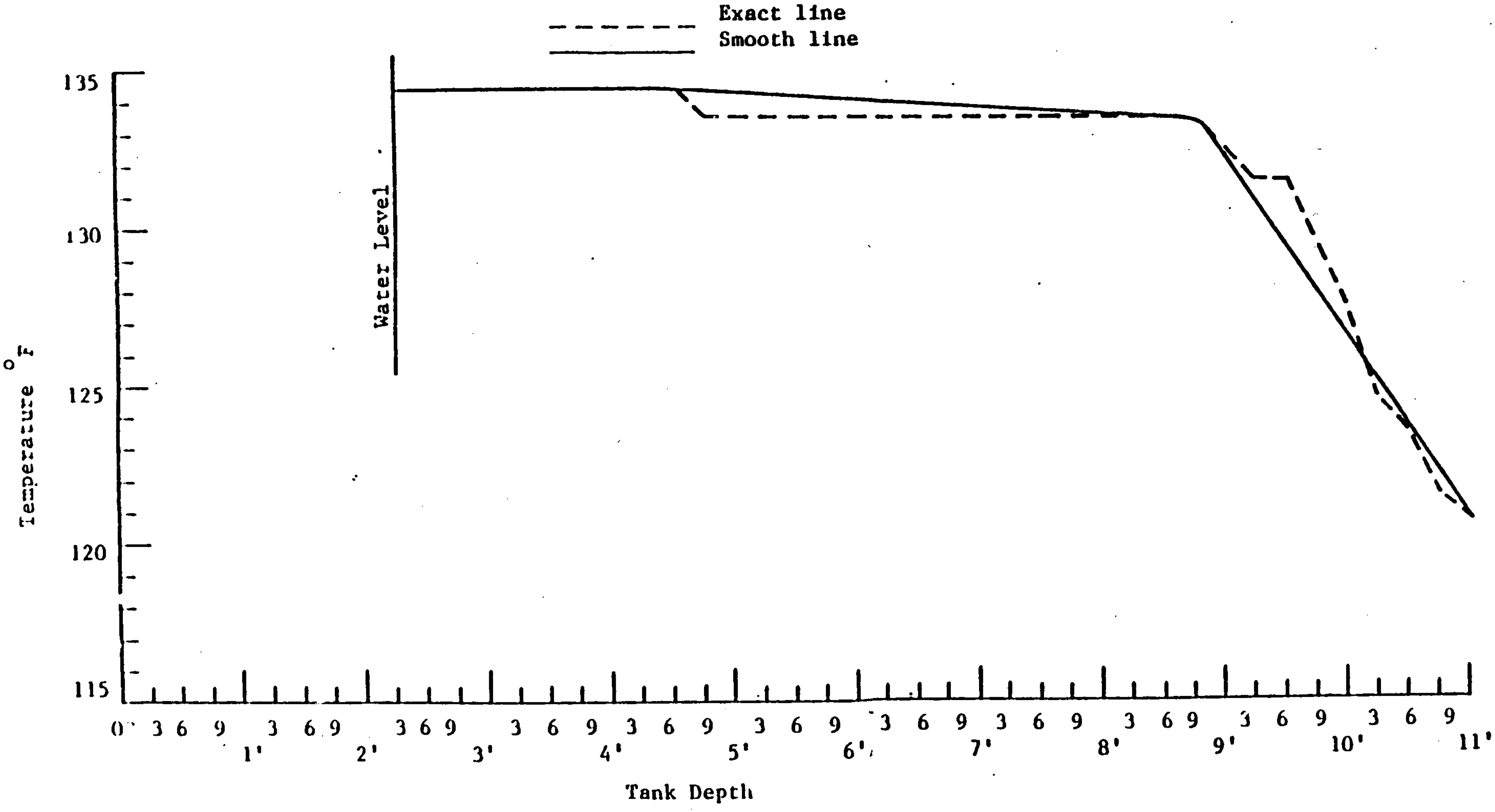


Figure 29-3

Hot Water Storage Tank

Several tests were performed during the period of February - March, 1982 to determine the performance of the hot water storage tank. The heat retention tests of the storage tank which were conducted in February 1982 show that the storage tank performed better than originally estimated. Testing of the emergency back-up supply of the storage tank which was carried out by a simulated heat exchanger or well pump outage on March 19, 1982 indicates that the system could provide the reserved hot water for limited duration emergencies. Figures 29-2 and 29-3 depict the tank water temperature stratification after shut-down tests of 64 and 134 hours.

Instrumentation and Controls

Instrumentation and controls for the geothermal system were installed at a cost of $45,000. These items are an integral part of the NMSU Energy Management System (EMS). Critical temperatures and flow rate data are routed to Remote Access Units (RAU); these are linked to the Central Steam Plant to provide 24-hour monitoring.

Fail-safe controls are installed at four critical points to stop the system to prevent damage or loss. The RAUs could provide instant alarms to maintenance personnel to take corrective action. These critical areas and protection provided are:

> At each well, automatic controls divert well flow back into the well if malfunction occurs. These controls protect against over-pressurization (300-400 psi) of the well head equipment and pipelines.
>
> At the gas separator, a liquid level indicator and control stops flow if the surge tank starts to overfill.
>
> At the heat exchangers, the geothermal loop is prevented from draining completely which could cause negative pressure and cause severe damage to the exchangers. A pressure-response motorized valve closes if feed line pressure drops due to a malfunction at the gas separator. Also installed are flow meters and temperature sensors which are linked to the EMS System.

At the storage tank, flow is stopped if wells or heat exchangers malfunction, to prevent thousands of gallons of cold water from filling the tank, distribution lines, and domestic lines. Moreover, if an electrical power outage occurs, a pressure regulating valve will automatically open on a low pressure sensing when the circulating pumps stop. This action permits a water flow rate to the distribution system so that these steel lines do not empty. This flow is driven by gravity head from the storage tank.

As an additional control, a temperature-sensing motorized valve will close on the storage tank supply line if a well field malfunction causes the geothermal flow to stop, thus preventing cold domestic water from passing through the heat exchangers and into the tank. The large tank is protected from over-filling by four independent systems. Two different systems, each with a control valve, sense liquid level. If both systems fail and the tank overflows, a sump pump is activated automatically to pump the excess water to the above-ground system and curb drain. In addition, a "high water" sensor has been installed which signals an alarm if as little as two inches of water are in the equipment well.

System Maintenance

Based on experience gained installing and operating the system, preventive maintenance procedures and schedules have been developed. The results of inspections and the resulting recommendations are given for the primary heat exchangers, the swimming pool heat exchangers, and the gas separator.

PRIMARY HEAT EXCHANGERS

MAINTENANCE

Purpose: To disassemble and clean the two primary exchangers. Both exchangers have had at least 2,000 hours of operation. The North exchanger previously was disassembled and cleaned at 500 hours, the South exchanger was left uncleaned for a comparison.

Inspection Results: Both exchangers are in excellent condition. No corrosion was detected. Both exchangers had a deposition, consisting of a soft silica/ carbonate material, and the thin coating wiped off easily with a damp cloth. The stainless steel plates had a minor stain of iron, which did not appear to penetrate the stainless steel surface. Both exchangers had a rather substantial build-up of sand on the domestic (cold) water side. This sand problem results from the fact that the inlet is from the bottom of the large water tank.

Recommendations:

1) If technically feasible, replace the Y-strainer screen with a finer mesh screen. This could keep most of the sand out of the exchanger.

2) The large four-million gallon tank possibly is overdue for cleaning.

3) Based on conditions found, it would be appropriate to clean each exchanger annually. The exchangers possibly could be used for a longer time period; however, the deposition of the silica/ carbonate material may degrade the performance of the heat exchangers since this deposited coating increases the resistance to heat transfer (i.e. it decreases the overall heat transfer coefficient). Also, the sand build-up can result in excessive pressure drop. In addition, the sharp-edged sand grains will scratch the stainless plates, which could lead to accelerated corrosion.

30. APPLICATION SYSTEM PERFORMANCE

30.1 Performance Summary

The indoor pool is heated by the 250,000 Btu/hr exchanger. The outdoor pool is heated by an installed one-million Btu/hr exchanger. During tests in the week of 29 March 1982 the indoor pool temperature was held within 1°F of the optimum 80°F temperature. The outdoor pool can be used for several months more in spring and fall using the geothermal heat. The heat exchanger has the capacity to handle double the current heat load.

30.2 Data Acquisition

Upon disassembly after 1,500 hours of operation, the outdoor pool exchanger contained a large amount of debris on the swimming pool side. Foreign matter included feathers, hair, leaves, grass, and one large-sized pebble roughly 1-inch long by ¼-inch wide and thick. No visible corrosion existed, but the debris buildup undoubtedly was causing excessive pressure drop. It is noted that this exchanger interrupts pool water just before the water reaches the pool. In this mode, the heat exchanger is acting as a final filter. The indoor pool exchanger contained no foreign matter, and was free of visible corrosion.

30.3 Post Construction Modification

1) The outdoor pool exchanger should be disassembled and cleaned prior to each scheduled service, or at the end of service as was done this time. If a future decision is made to operate the pool over an entire winter season, the exchanger should be cleaned at the end of each 60-day cycle.

2) Based on inspection results, the indoor pool exchanger should be cleaned twice a season; at the end of Spring, and during the Christmas break.

3) Install a Y-strainer between the pool circulatory system and the heat exchanger.

4) Increase the heat transfer area of the outdoor pool exchanger by adding 8 plates, at $60 per plate. Results were an increased efficiency, and ability to extract up to 825,000 Btu per hour, plus facilitating reinjection of the cooled hot side water into the domestic water system at 95°F rather than the unacceptability high 105°F previously used. Additional plates also provide capability to provide up to 1.5 million BTU per hour for cold start-up.

31. CONSTRUCTION COSTS

31.1 General

The installed system has a total cost of $1,360,000. By component, this cost is displayed in the following Table, 31-1. (This table takes the place of Section 31.1 through 31.5 in the PON Report format).

Table 31-1

GEOTHERMAL DEMONSTRATION SYSTEM COSTS
AND COMPLETION DATES OF SUBSYSTEM

Subsystem	Completion Date	Budgeted Cost	Actual Cost
Pipeline			
Buried	Aug 81	255,000	230,000
Tunnel	Dec 81	95,000	175,000
Gas Separator	Sep 81	11,000	25,000
Hot Water Storage Tank (Includes Equipment Room)	Jan 82	76,700	109,300
Well Pump and Installation	May 81	50,000	85,000[2]
Pump House	May 81		2,500
Power Line	May 81	13,560	15,780
Primary Heat Exchangers	Oct 81	48,000	32,000
Outdoor Pool Heat Exchanger	Jan 82	6,000	6,000
Indoor Pool Heat Exchanger	Jan 82	2,200	2,200
Heat Exchanger Equipment Building	Oct 81	22,500	10,200
Instrumentation	July 82[1]	13,000	45,000
Building Retrofit	Feb 82	30,000	17,500
Golf Course Disposal Well	Dec 81	23,000	15,000
New Disposal Well GD-2	Dec 82	70,000	70,000
Local Transportation and Equipment Rental		15,315	35,000
Contingency (New well pumps and Natatorium and football staduim heating)		60,765	60,765

NOTE 1. Instrumentation completed by contractor not part of geothermal team.

2. Replacement for Peerless well pump, which failed in Aug 82.

31.2 Major Cost Variances During Construction

Various project management decisions made before and during the construction phase resulted in savings sufficient to offset cost increases in some areas and ensure project completion within budget.

The project was completed early; within 7.5 months after the start of construction the system provided benficial use. Further, two space-heating users were added to the system within the original budget.

Savings from accelerated procurement were realized as follows:

Insulated Pipeline		$44,000
Well Pump		8,000
Heat Exchangers		$10,000
	TOTAL	$62,000

A contingency reserve of $60,000 was budgeted as part of the $829,000 appropriation.

There were cost increases for some budgeted items and additional expenses not included in the original budget. The major cost increases for budgeted items include:

Component	Budgeted	Actual	Cost Increase
Pipeline	$350,000	$405,000	$ 55,000
Hot Water Tank	76,700	109,300	32,000
Instrumentation	13,000	45,000	32,000
Well Pumps	50,000	85,000	35,000
Gas Separator	11,000	25,000	14,000
			$168,600

The largest cost increase was in the pipeline. These costs were driven by change orders, which are summarized as follows. (In each case, the change represents a deviation from the original pipeline configuration which formed the basis for the budgeting estimate.)

a. Change in route of the line from the Gas Separator to the President's House. Added 450 feet, or $8,500 to cost.

b. Change in route from the Heat Exchanger to the hot water storage tank, to a route through Tortugas Arroyo. Added 500 feet, and two weeks surveying for total cost of $10,500.

c. Change in route to Football Stadium and North Loop. Added 850 feet and $12,500 to cost. This change, however was a better long term design. Also enabled the system to provide space heating to the stadium.

d. Change in location of utility tunnel portion. (The approved location was used by the EMS contractor to route his conduit. Change to a much more labor intensive location was required.) This resulted in fittings and labor added costs of almost $16,000.

e. Insulation of the TEMPTITE joints. This change resulted in an additional cost of $7,500.

For the large hot water tank, the extra cost resulted from higher than expected equipment room costs and the combination of design changes, as well as subcontractor delays. The tank originally was to be delivered by 15 September, and emplaced by 25 September. After changing dirt contractors, the tank was emplaced and back-filled in early January, 1982.

The instrumentation cost increase was caused by the requirement that the geothermal instrumentation be compatible (identical) to the EMS. As eventually negotiated, the direct PSL plus EMS cost was $45,000, which was some $32,000 higher than the budget. Even at that, the final negotiated cost was almost $15,000 less than the original price quotation by the EMS contractor.

The Peerless pump in production well PG-1 failed July 1981. The 100 hp pump in production well PG-3 was moved to PG-1 and a new 100 hp pump was installed in PG-3.

The cost increases on the Gas Separator resulted from an extraordinarily high cost for the contract welder, and for NMSU foaming crews. The tank itself was within budgetary estimates.

Expenses not in the original budget include:

Leave and Fringe Benefits

Leave and fringe benefits accruals for temporary workers, who do not qualify for these benefits, were not included in the original budget. A change in accounting procedures, made after the contract work was started required that charges for these items be made. This charge for the 25 temporary employees was more than $31,000. This was not a stand-alone cost, however,as this unexpected cost was spread among all portions of the construction contract.

Instrumentation for President's Home

At Physical Plant Department (PPD) request, instrumentation was installed to monitor the President's pump house. This cost, including the cost to reduce and analyze the data, was more than $1,200.

Pull and Replace President's Well Pump

Two separate times, the President's well pump was pulled and replaced. The cost for this was comparable to the price charged by Aqua Drilling of $280.00 for each installation or removal. The cost for this was $1,100.

Water Cost for Trial Disposal Test

The project was charged $3,800 for 1.5 million gallons of water used in a trial disposal test of the Golf Course Well in September 1981.

Operation of System

Nearly half of the February 1982 expense and all the March and April 1982 labor expenses represented work required to operate the system; this included many temporary changes put in for the "Start-Stop" mode used. Labor and materials charges attributable to system operation for this period were more than $30,000.

PSL Overhead Charges

Under the PSL accounting system, some 16% of direct labor charges are assessed as an overhead charge termed "Allocated Direct Labor." In May 1981, these charges were ruled not applicable to the project. Subsequently, in May 1982, the decision was reversed. Thus, the indirect charges represented a major, unforecasted budget cost of $33,000.

These expenses are summarized in Table 31-2.

Table 31-2

ADDITIONAL EXPENSE

ITEM	COST
Leave and Fringe Benefits	$ 31,000
Instrumentation for President's Pump House	1,200
Pull and Replace President's Well Pump (two times)	1,100
Water Cost for Trial Disposal (1.5 million gallons)	3,800
Operation of System (15 February - 27 April)	30,000
PSL Overhead Charges (ADL)	33,000
	$100,100

32. OPERATING AND MAINTENANCE COSTS

32.1 Summary

In general, capital investments are considered on the basis of expected returns. These returns are essentially cash flows generated by the investment. Yearly system operating costs affect the net cash flow. In the Geothermal Demonstration System the investment cost for each major capital item is given with a brief description of performance or capability obtained for that cost. The net return generated by this system is the net saving or offset of natural gas consumed by the Central Heating and Cooling Plant.

Significant system operating costs include electricity, technician labor, and maintenance expense. Although depreciation is not a cash outlay as are the other expenses listed, consideration is made for replacement of items having a useful life of twenty years or less. The investment cost and associated performance are given for each capital item in the Geothermal System. This is done to indicate the cost for a given level of performance or capability and to provide a reference for future expansion. As the wells, the gas separator tank, and the water transmission line should have lives greater than twenty years, these items are not included in depreciation expense. For other system components the investment cost is divided by the useful life to determine a yearly depreciation cost. No salvage value is assumed. A depreciation cost is developed as part of the effort to determine a realistic yearly operating cost. Electricity costs are documented in detail to illustrate the cost for various items in the system and for future system expansion. As part of the process of bringing the system on line and operating for an extended period, maintenance schedules have been developed for system components. From this, maintenance expense and technician labor required for system operation have been determined.

Well and pump repairs with the associated costs are treated separately, as many of these should not be recurring costs if the system is to continue to be operated.

32.2 Operating Cost

Electricity Cost

The geothermal system electric costs are due primarily to cost of operating pumps, both the well pumps and the various system pumps. The yearly operating costs have been determined based on current rates. The calculations are given in detail such that for change in either demand or consumption rate new costs can be easily determined. A significant saving of $14,000/year could be effected by NMSU ownership of the power transmission line from Locust Street to the production wells.

The original electricity cost estimate was based on the following quotation provided by El Paso Electricity Company on 7 April 1980:

Demand Charge:	$6.54 per kw per month for one 50 Hp well pump.
Consumption Charge:	$0.026 per kwh.

The current estimate made use of January 1983 rates as follows:

	Well Field	Locust Sub-Station
Demand Charge:	$ 9.15/kw/month	$ 6.06/kw/month
Consumption Charge:	$ 0.0553/kwh	$ 0.0306/kwh

Monthly electricity costs are listed in the following Table 32-1. Because the metered service for the two well pumps also serves the Rodeo Arena, these latter costs are separately identified.

Table 32-1
Well Pumping Electricity Costs

DATE	MONTHLY BILLING	ADJUSTMENT FOR OVERCHARGE	MONTHLY USAGE RODEO ARENA	MONTHLY USAGE GEOTHERMAL WELLS
FEB 82	$ 3,801.13	-------	$ 516.11	$ 3,285.02
MAR	2,453.16	-------	607.06	1,846.10
APR	4,834.76	-------	516.11	4,318.65
MAY	2,581.72	-------	516.11	2,065.61
JUN	1,419.29	539.93	607.06	272.30
TOTAL	$15,090.06	$ 539.93	$2,762.45	$11,787.68

Actual billing from Feb 82 to Jun 82 = $14,550.13

NEW FISCAL YEAR

DATE	MONTHLY BILLING	ADJUSTMENT FOR OVERCHARGE	MONTHLY USAGE RODEO ARENA	MONTHLY USAGE GEOTHERMAL WELLS
JUL 82	$ 1,586.25	$ 539.93	$ 516.11	$ 530.21
AUG	2,906.48	539.93	516.11	1,850.44
SEP	3,834.91	539.93	516.11	2,778.87
OCT	3,779.51	539.93	516.11	2,723.47
NOV	3,457.35	539.93	516.11	2,401.31
DEC	3,573.81	539.93	516.11	2,517.77
JAN 83	3,289.75	------	516.11	2,773.64
FEB	2,947.26	------	516.11	2,431.15
MAR	3,495.61	------	607.06	2,888.55
APR	3,152.23	------	516.11	2,636.12
MAY	2,363.76	------	516.11	1,847.65
JUN	1,376.21	------	516.11	860.10
TOTAL	$35,763.13	$3,239.58	$6,284.27	$26,239.28

Actual billing from Jul 82 to Jun 83 = $32,523.55

Summary from FEB 82 - JUNE 83:

Actual billing = $14,550.13 + $32,523.55 = $47,073.68
Rodeo Arena usage = $2,762.45 + $6,284.27 = $9,046.72
Geothermal Wells = $11,787.68 + $26,239.28 = $38,026.96

TABLE 32-2

GEOTHERMAL SYSTEM OPERATING COSTS

(Thru 30 June 1983)

Well repairs and pumps (Since April, 1982)

	Total	Labor only
PPD	66,356.46	($14,451.25)
PSL	76,815.89	(26,112.13)
	$143,172.35	($40,563.38)

Other System Costs (Since February, 1982)

	Labor	Materials	Well Pump Electricity	Totals
PPD	$ 6,843.32	$2,166.19	$38,026.96	$47,036.47
PSL	6,528.04	--------	---------	6,528.04
Total	$13,371.36	$2,166.19	$38,026.96	$53,564.51

Total Support Costs

- Total cost: $196,736.86
- Monthly average: $13,115.79
- Well treatment and repairs monthly average: $9,544.82
- Other system costs monthly average: $3,222.83
- Electricity: $2,237.00

Normal Maintenance and Electricity: $5,500/month = $ 66,000
Well pump and well maintenance: $9,500/month = $114,000
$180,000

TABLE 32-3

PSL EXPENDITURE

DATE	LABOR, $	MATERIAL, SUPPLY AND OTHER $	MONTHLY TOTAL, $
FEB 82	--------	--------	--------
MAR 82	--------	--------	--------
APR 82	--------	--------	--------
MAY 82	4,738.78	683.79	5,422.57
JUN 82	2,423.06	462.12	2,885.18
TOTAL	$7,161.84	$1,145.91	$ 8,307.75
<u>New fiscal year</u>:			
JUL 82	2,517.22	232.27	2,749.49
AUG 82	4,837.32	1,874.97	6,712.29
SEP 82*	1,156.77	31,470.91	32,627.68
OCT 82*	4,509.74	8,915.42	13,425.16
NOV 82*	4,571.78	1,918.49	6,490.27
DEC 82	1,141.80	72.84	1,214.64
JAN 83	602.22	148.64	750.86
FEB 83	--------	2,617.75	2,617.75
MAR 83	1,693.81	47.26	1,741.07
APR 83	1,846.98	642.44	2,489.42
MAY 83	243.85	1,367.05	1,610.90
JUN 83	2,020.86	585.79	2,606.65
TOTAL	$25,142.35	$49,893.83	$75,036.18

Total PSL expenditures from Feb 82 to June 83 are;

Labor = 7,161.84 + 25,142.35 = $32,304.19
Supply = 1,145.91 + 49,893.83 = $51,039.74
$83,343.93

Remarks: *The major expense in Sep and Oct 82 is for the TRW pumps = $40,386.33

TABLE 32-4

PHYSICAL PLANT DEPARTMENT

8333 Geothermal Wells Maintenance

DATE	LABOR, $	MATERIAL, $	OTHER, $	MONTHLY TOTAL, $
APR 82	137.47	-------	--------	137.47
MAY 82	2,010.59	9.05	995.23	3,014.87
JUN 82	536.17	34.05	--------	570.22
TOTAL	$2,684.23	$ 43.55	$ 995.23	$ 3,723.07

DATE	LABOR, $	MATERIAL, $	OTHER, $	MONTHLY TOTAL, $
JUL 82	974.92	--------	--------	974.92
AUG	678.39	68.87	313.77	1,061.03
SEP	568.55	13.49	1,479.30	2,061.34
OCT	1,192.32	129.71	178.02	1,520.05
NOV	1,161.62	147.48	--------	1,309.10
DEC	766.46	0.48	466.42	1,233.36
JAN 83	305.79	25.35	--------	331.14
FEB	1,172.22	20.84	14.19	1,207.25
MAR	1,383.92	144.85	200.01	1,727.78
APR	208.19	1.10	42.24	251.53
MAY	187.74	-------	--------	187.74
JUN	222.40	-------	--------	222.40
TOTAL	$8,822.52	$522.17	$2,713.95	$12,088.64

Total on #8333 from Apr 82 to June 83;
Labor = 2,684.23 + 8,822.52 = 11,506.75
Material = 43.55 + 522.17 = 595.72
Other = 995.23 + 2,713.95 = 3,709.65
$15,811.65

TABLE 32-4 (Continued)

7136 Required Wells

DATE	LABOR, $	MATERIAL, $	OTHER, $	MONTHLY TOTAL, $
APR 82	--------	-------	--------	--------
MAY 82	165.78	-------	2,262.02	2,427.90
JUN 82	66.15	8.32	--------	74.37
TOTAL	$ 231.93	$ 8.32	$ 2,262.02	$ 2,502.27

DATE	LABOR, $	MATERIAL, $	OTHER, $	MONTHLY TOTAL, $
JUL 82	53.93	533.76	--------	587.69
AUG	704.10	163.06	1,553.15	867.16
SEP	53.78	--------	--------	53.78
OCT	23.41	--------	12.58	35.99
NOV	--------	--------	25,776.16*	25,776.16
DEC	--------	--------	13,717.11**	13,717.11
JAN 83	--------	--------	--------	--------
FEB	--------	--------	--------	--------
MAR	626.11	33.53	--------	659.64
APR	1,194.96	20.86	571.76	1,787.58
MAY	56.28	-------	--------	56.28
JUN	--------	-------	2,948.00	2,948.00
TOTAL	$2,712.57	$751.21	$44,578.76	$48,042.54

Total on #7136 from Apr 82 to June 83 are;
Labor = 231.93 + 2,712.57 = 2,944.50
Material = 8.32 + 751.21 = 759.53
Other = 2,262.02 + 44,578.76 = 46,840.78
$50,544.81

Remarks: *Major items in Nov 82 are; (a) Johnston pump = $19,332.58
(b) Rio Grande = $ 5,445.00
**Major item in Dec 82 is; Umphress Pump Company = $12,820.00
$37,597.58

TABLE 32-4 (Continued)

8313 PPD-Non-Reimbursable Work Distribution lines on Geothermal

DATE	LABOR, $	MATERIAL, $	OTHER, $	MONTHLY TOTAL, $
APR 82	--------	-------	-------	--------
MAY 82	413.66	137.74	-------	551.40
JUN 82	15.62	-------	-------	15.62
TOTAL	$ 429.28	$137.74	-------	$ 567.02

DATE	LABOR, $	MATERIAL, $	OTHER, $	MONTHLY TOTAL, $
JUL 82	17.07	-------	-------	17.07
AUG	1,131.86	76.81	2.66	1,211.33
SEP	1,573.87	407.24	46.70	1,981.11
OCT	539.11	201.03	-------	704.14
NOV	369.15	-------	-------	369.15
DEC	794.17	-------	-------	794.17
JAN 83	151.89	-------	-------	151.89
FEB	34.13	-------	-------	34.13
MAR	67.12	-------	-------	67.12
APR	249.69	263.04	-------	512.73
MAY	739.39	-------	83.44	822.83
JUN	--------	-------	-------	--------
TOTAL	$5,667.45	$948.12	$132.80	$6,748.37

Total on #8313 from April 82 to June 83 are;
Labor = 429.28 + 5,667.45 = 6,096.73
Material = 137.74 + 948.12 = 1,085.86
Other = 132.80 = 132.80
Total = $7,315.39

TABLE 32-4 (Continued)

8327 PPD-Non-Reimbursable Work on Geothermal Heat Exchangers

DATE	LABOR, $	MATERIAL, $	OTHER, $	MONTHLY TOTAL, $
APR 82	--------	--------	--------	--------
MAY 82	22.60	6.63	--------	29.23
JUN 82	19.29	--------	--------	17.29
TOTAL	$ 41.89	$ 6.63	--------	$ 48.52

DATE	LABOR, $	MATERIAL, $	OTHER, $	MONTHLY TOTAL, $
JUL 82	--------	--------	--------	--------
AUG	104.55	73.91	41.11	219.57
SEP	224.16	17.64	--------	241.80
OCT	106.00	--------	--------	106.00
NOV	46.55	--------	--------	46.55
DEC	156.98	--------	793.66	950.64
JAN 83	--------	--------	--------	--------
FEB	40.48	9.90	--------	50.38
MAR	--------	3.45	--------	3.45
APR	--------	--------	--------	--------
MAY	25.98	1.23	--------	27.21
JUN	--------	--------	--------	--------
TOTAL	$704.70	$106.13	$834.77	$1,645.60

Total on #8327 from April 82 to June 83 are;
Labor = 41.89 + 704.70 = 746.59
Material = 6.63 + 106.13 = 112.76
Other = 834.77 = 834.77
Total = $1,694.12

32.2 Annual Operating Cost

The annual operating cost, which includes electricity and maintenance cost, is summarized in Table 32-5. The yearly depreciation, which was determined from the significant items of the geothermal system elements, is itemized in Table 32-6.

Table 32-5

ESTIMATED ANNUAL OPERATING EXPENSE

Category		Annual Expense
Electricity		$38,000
Maintenance		28,000
	TOTAL =	$66,000

32.3 Maintenance Cost

32.3.1 Routine

The cost of normal maintenance for the geothermal system elements includes the technician labor cost to support the start-up procedure and to maintain the preventive maintenance schedules for the well pumps, the primary heat exchangers, the swimming pool heat exchangers, and the gas separator. Costs are based on the actual cost during the first 12-month period of February 1982 - January 1983. The cost is itemized as follows:

Physical Plant Department	Labor and Supported Material	$26,098
Physical Science Laboratory	Labor and Supported Material	$ 4,796
	TOTAL	$30,894

Table 32-6

DEPRECIATION COST FOR SIGNIFICANT CAPITAL ITEMS

COMPONENT	COST	LIFE	YEARLY DEPRECIATION
Primary Heat Exchangers	$ 48,000	10	$ 4,800
Hot Water Storage Tank	109,300	20	5,465
Instrumentation and Controls and Circulating Pumps	89,000	10	8,900
Transmission Line Components	50,000	10	5,000
Well Pumps	52,260	5*	10,452
(60 Hp TRW-REDA & Johnston pumps)	43,209		8,642
		TOTAL =	$32,807

*Overhaul at 30% of cost at end of 5 years for second 5 year life.

32.3.2 Major Component Repair or Replacement

(See Section 26 on Production Well History)

TABLE 32-7

GEOTHERMAL SYSTEM SUPPORT COSTS, DETAILED LISTING

	PSL EXPENDITURE			PPD EXPENDITURE			COMBINED PSL AND PPD EXPENDITURE		
DATE	LABOR, $	MATERIAL, SUPPLY AND OTHER, $	MONTHLY TOTAL, $	LABOR $	MATERIAL, SUPPLY AND OTHER, $	MONTHLY TOTAL, $	LABOR, $	MATERIAL, SUPPLY AND OTHER, $	MONTHLY TOTAL, $
FEB 82	--------	--------	--------	--------	--------	--------	--------	--------	--------
MAR	--------	--------	--------	--------	--------	--------	--------	--------	--------
APR	--------	--------	--------	137.47	--------	137.47	137.47	--------	137.47
MAY	4,738.78	683.79	5,422.57	2,612.63	3,410.67	6,023.30	7,351.41	4,094.46	11,445.87
JUN	2,423.06	462.12	2,885.18	637.23	42.37	679.60	3,060.29	504.49	3,564.78
TOTAL	$ 7,161.84	$ 1,145.91	$ 8,307.75	$ 3,387.33	$ 3,453.04	$ 6,840.37	$10,549.17	$ 4,598.95	$ 15,148.12
				NEW FISCAL YEAR					
JUL 82	2,517.22	232.27	2,749.49	1,045.92	533.76	1,579.68	3,563.14	766.03	4,329.17
AUG	4,837.32	1,874.97	6,712.29	2,618.90	2,293.34	4,912.24	7,456.22	4,168.31	11,624.53
SEP	1,156.77	31,470.91*	32,627.68	2,420.36	1,964.37	4,384.73	3,577.13	33,435.28	37,012.41
OCT	4,509.74	8,915.42*	13,425.16	1,860.84	481.34	2,342.18	6,370.58	9,396.76	15,767.34
NOV	4,571.78	1,918.49	6,490.27	1,577.32	25,923.64*	27,500.96	6,149.10	27,842.13	33,991.23
DEC	1,141.81	72.84	1,214.64	1,717.61	14,977.67**	16,695.28	2,859.42	15,050.51	17,909.93
JAN 83	602.22	148.64	750.86	457.68	25.35	483.03	1,059.90	173.99	1,233.89
FEB	--------	2,167.75	2,167.75	1,246.83	44.93	1,291.76	1,246.83	2,662.68	3,909.51
MAR	1,693.81	47.26	1,741.07	2,077.15	381.84	2,458.99	3,770.96	429.10	4,200.06
APR	1,846.98	642.44	2,489.42	1,652.84	899.00	2,511.84	3,499.82	1,541.44	5,041.26
MAY	243.85	1,367.05	1,610.90	1,009.39	84.67	1,094.06	1,253.24	1,451.72	2,704.96
JUN	2,020.86	585.79	2,606.65	222.40	2,978.45	3,200.85	2,243.26	3,564.24	5,807.50
TOTAL	$25,142.35	$49,893.83	$75,036.18	$17,907.24	$50,618.36	$68,525.60	$43,049.59	$100,512.19	$143,561.78

Total PSL expenditures from Feb 82 → Jun 83
= $83,343.93

Remark: *The major expense in Sep and Oct 82 is for the TRW pumps = $40,386.33

Total PPD expenditure from Feb 82 → Jun 83
= $75,365.97

Remark: *The major expense in Nov 82 is for;
(a) Johnston pump = $19,322.58
(b) Rio Grande = $5,445.00
**The major expense in Dec 82 is for Umpress Pump Company = $12,820.00

Total PSL and PPD expenditures from Feb 82 → Jun 83 =	$158,709.90
Well Pumping Electricity	38,026.96
Total Support Costs (Feb 1982 thru June 83)	$196,736.86

33. SYSTEM ECONOMICS

33.1 Capital Costs

The installed system, considered in this report, has an installed cost of $1,360,000, which is further defined as follows:

Table 33-1

INSTALLED COSTS, NMSU GEOTHERMAL SYSTEM

Component	Cost	Source
Aquifer Evaluation and Conceptual Design	$ 125,000	New Mexico Demo Fund
Well Field Construction Project Management and 2-year Monitoring	$ 336,000	DOE PON Program
System Construction	$ 829,000	New Mexico Legislative Appropriation
New Disposal Well	$ 70,000	New Mexico Geothermal Demonstration Program
	$1,360,000	

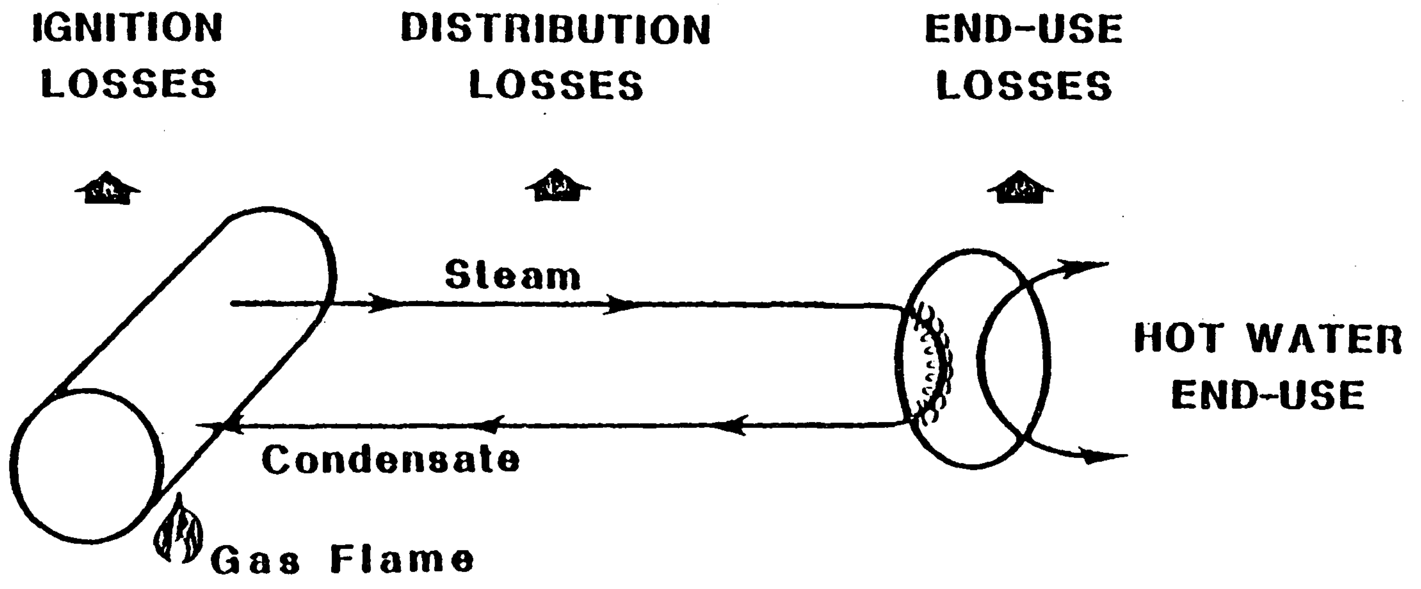
33.2 Operating and Maintenance Costs

From Section 32, the "normal" yearly operating costs are $66,000. In the first 15-months of operation, an "abnormal" operating cost (presumably one-time) was $143,172. This abnormal cost was for replacement well pumps and well repairs.

33.3 Fuel Savings

Savings provided by geothermal system displacement of natural gas have been determined by analysis of Central Heating and Cooling Plant natural gas usage and campus energy consumption. Various factors affecting natural gas usage have been analyzed to normalize the data to isolate changes due solely to the geothermal system. For background purposes, the Central Plant serves as an energy (steam) service for some 44 buildings complexes, and several hundred individual steam-fired heat exchangers or individual equipment. None of this end-use is instrumented, so estimates only can be made. Figure 33-2 is a schematic representation of the NMSU steam system.

NMSU CENTRAL PLANT STEAM SYSTEM



CENTRAL STEAM PLANT

1 Small Boiler
2 Large Boilers
Ignition Efficiency
75-85%

UTILITY TUNNEL AND BURIED LINES

Steam: 20,000 feet
Condensate: 20,000 feet
Distribution
Efficiency: 75%

44 BUILDING COMPLEXES

Includes supply and
return lines.
Steam/water heat exchange.
End-use efficiency: 65-75%

Figure 33-2

33.3.1 General

The analysis of natural gas consumption by the Central Heating and Cooling Plant is based upon data available from NMSU fiscal years 1980, 1981, and 1982. These data, displayed in Figure 33-3 show the variation in natural gas consumption annually.

33.3.2 Natural Gas Consumption

Natural gas consumption by the Central Heating and Cooling Plant is governed by a number of variables that affect the usage of natural gas. These variables include weather, building size (square footage served), specialized equipment in service, and operational factors. The following sub-paragraphs discuss these variables in detail.

a. New construction and remodeling of existing buildings have resulted in an increased area requiring space heating; which, in turn, has increased consumption of natural gas. The space-heated area is plotted as a function of time in Figure 33-3.

   Increased square-footages also affect natural gas requirements for space cooling, as well as for space heating. A number of heating and cooling systems employed on NMSU campus are of double-duct type which necessitates steam usage for summer cooling. The new English - Speech building, completed April 1981, employs a double-duct type heating and cooling system. The natural gas consumption for summer cooling of this new building was estimated to be approximately 336 mcf per month during April - September time frame. (This estimate was determined by comparing known steam consumption of Anderson Hall and the relative square-footage of Anderson Hall to the new English - Speech building).

b. Laboratory experiments requiring increased use of special equipment such as sterilizer and distilling equipment caused an increase in natural gas consumption from 1981 to 1982. During the fall of 1981, the Biology Department added a second steam operated water still to one that was currently operated at an average load of 500 mcf per month. Assuming the

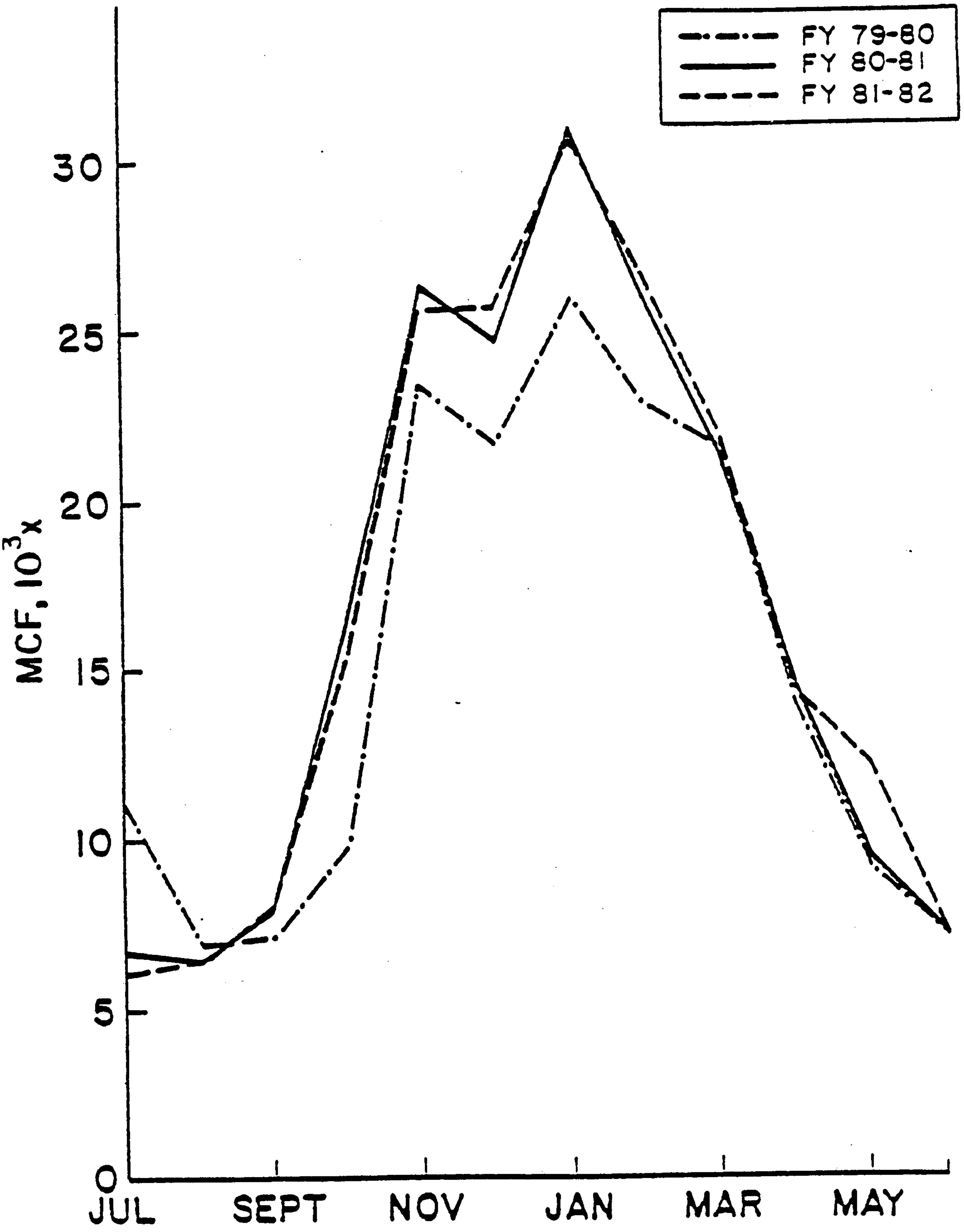


Figure 33-3. NMSU Natural gas Consumption

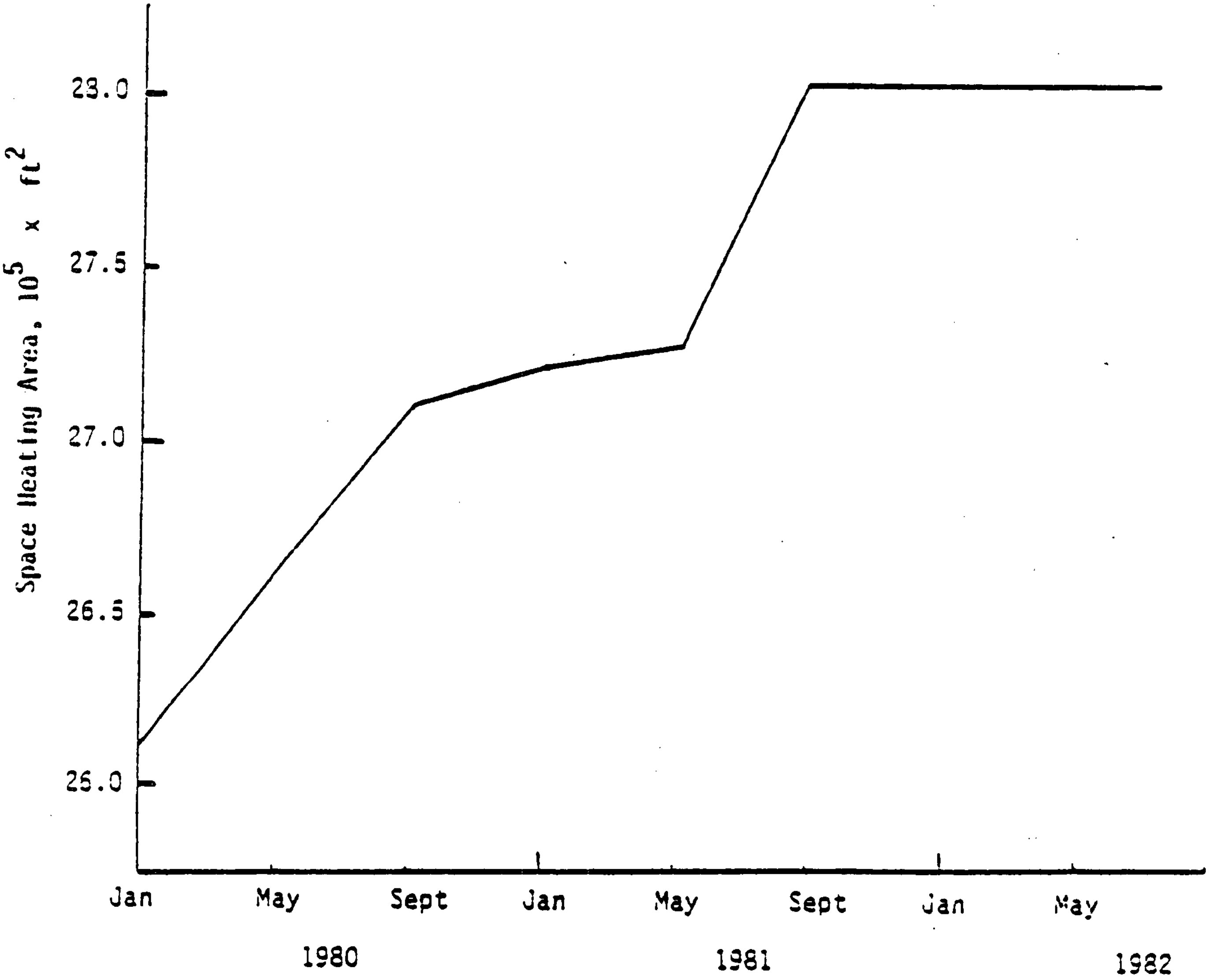


Figure 33-4. Space Heating Area Connected to Central Plant.

old still, which uses approximately 1,000 mcf per month at peak capacity, based on measured test data, uses an average of 500 mcf per month and that the new unit also uses 500 mcf per month, the increase in natural gas consumption for 1982 from 1981 would be 500 mcf. This estimated usage is based on a 45-day test in 1981 in which actual distilled water use was measured, which averaged 16.5 gallons per hour for the period. The average during normal daily usage was 34.9 gallons per hour. These values are for one still. Also, a new sterilizer added to the Chemistry Department in the spring of 1982 has added an average load of 200 mcf per month. For only these two items of equipment, an average of 700 mcf per month increase is noted.

c. As part of the NMSU energy conservation program the steam pressure is set to 50 psig (from the normal 100 psig) during periods of lower demand (Christmas break, spring, and fall). The net effect of this change is a decrease in consumption of approximately 300 mcf per day when operating at 50 psig. The summer steam load is met exclusively by the 50 psig mode. (Mid-April through mid-October). See Table 33-5.

d. Weather was determined to be the most important variable governing natural gas consumption. Weather data were reviewed to determine which factors weigh most heavily. After considerable iteration, it was determined that the heating degree days are not the only measure of natural gas consumption. Winter weather, particularly February - April, is also characterized by cold winds, which are not measured by heating degree days. The variation in natural gas consumption due to weather conditions may be expressed in terms of heating degrees days (which is a measure of ambient air temperature) and average wind speed. Monthly heating degree days for NMSU for 1980-1982 are tabulated in Table 33-6. Monthly average temperatures for the period 1980-1983 are listed in Table 33-7. This data is consistent with the monthly natural gas consumption; consumption increases directly as the number of heating degree days increases and increasing average wind speed. Average wind speed and variation from year-to-year for 1980-1983 are listed in Table 33-8. It must be noted that the heating degree day data probably has a 5 percent error, whereas the wind data is likely to be even more inexact. These are the best available data.

Table 33-5

PRESSURE ADJUSTMENT SCHEDULE

Date	Pressure Adjustment, psig
2 Jan 1980	50 to 100
12 Apr 1980	100 to 50
17 Oct 1980	50 to 100
26 Dec 1980	100 to 50
4 Jan 1981	50 to 100
13 Apr 1981	100 to 50
19 Oct 1981	50 to 100
21 Dec 1981	100 to 50
4 Jan 1982	50 to 100
14 Apr 1982	100 to 50
13 Oct 1982	50 to 100
21 Dec 1982	100 to 50
1 Jan 1983	50 to 100

Table 33-2[a]

NMSU HEATING DEGREE DAYS (°F-DAYS)

Date	1980	1981;	Variation from 1980, %	1982;	Variation from 1981, %	1983;	Variation from 1982, %
Jan	596	667	8.7	671	2.6	719	8.1
Feb	484	477	0.2	496	-1.2	480	-1.8
Mar	467	421	-9.4	348	-22.5	388	18.7
Apr	228	112	-56.1	112	45.7	329*	112.3
Oct	246	139	-43.9	177	29.1		
Nov	511	412	-23.2	477	24.1		
Dec	576	586	-1.4	723	27.3		

*Highest record of the past 30 years.

[a] These data were obtained from Dr. Norman Malm, NMSU Weather Station

Table 33-7

NMSU MONTHLY AVERAGE TEMPERATURE (°F)

Date	1980	1981;	Variation from 1980, %	1982;	Variation from 1981, %	1983;	Variation from 1982, %
Jan	45.9	44.1	10.6	43.4	-1.6	41.6	-4.1
Feb	48.2	47.8	-1.0	47.5	-0.6	47.7	0.4
Mar	50.0	51.4	2.8	54.3	5.6	52.5	-3.3
Apr	57.6	61.3	6.4	60.0	-2.1	54.0	-9.8
May	64.6	69.0	6.8	66.2	-4.1	65.7	-0.8
Jun	79.8	79.1	-0.9	76.3	-3.5		
Jul	83.8	81.4	-2.9	81.1	-0.4		
Aug	78.5	76.6	-2.4	79.9	4.3		
Sep	71.9	71.3	-0.8	73.4	2.9		
Oct	57.8	61.6	6.6	59.6	-3.2		
Nov	48.3	52.1	7.9	49.3	-5.4		
Dec	46.3	46.6	0.6	41.6	-10.7		

Table 33-8

NMSU MONTHLY AVERAGE WIND SPEED MPH

Date	1980	1981;	Variation from 1980, %	1982;	Variation from 1981, %	1983;	Variation from 1982, %
Jan	4.3	3.6	-16.3	5.0	-38.9	3.2	-36.0
Feb	4.6	4.6	0.0	3.7	-19.6	3.7	0.0
Mar	6.0	6.6	4.8	5.5	-16.7	6.7	21.8
Apr	6.2	5.7	-8.1	5.5	-3.5	5.8	5.5
May	5.2	6.6	26.9	4.7	-28.8	6.2	31.9
Jun	5.3	4.6	-13.2	3.6	-21.7		
Jul	5.4	4.4	-18.5	4.3	-2.3		
Aug	5.1	4.6	-9.8	3.9	-15.2		
Sep	6.2	3.9	-37.1	3.9	0		
Oct	7.3	4.4	-39.7	3.3	-25.0		
Nov	3.2	2.8	-31.3	3.0	7.1		
Dec	5.3	3.3	-37.7	3.1	-20.5		

[a] These data were obtained from Dr. Norman Malm, NMSU Weather Station

e. The operational factors include two major and one minor modification to the Central Steam Plant. A stack economizer was installed in April 1981. This economizer uses stack waste heat to preheat the condenser make-up water. The result of this change was a decrease in natural gas consumption of an estimated theoretical-maximum of 7,200 MCF per year. This does not act to reduce geothermal savings, because the stack economizer was installed before the geothermal system was constructed, and the effects are considered in the methodology for estimating geothermal natural gas offset. A second major modification to the plant consisted of an oxygen control system which was installed in January, 1982. These controls save an estimated theoretical maximum of 4,920 MCF of natural gas each year. Because the stack economizers and the oxygen controls are serving the same boiler, the combined effects of the two is less than the stand-alone theoretical efficiences of each system. Hence, it is estimated the oxygen control actually produced a net decrease of not more than 4,500 MCF per year. In the category of minor modifications is a program of re-insulating steam and condensate return lines, which was carried out over an 18-month period in calendar year 1981 and 1982. Appendices C and D contain the detailed calculations which form the basis for the overall performance factor adjustment for the stack economizer and the oxygen controls.

f. One general category of variance also exists. During the one-year period (calendar year 1980-1981) that instrumentation was used to acquire end-use consumption of hot water, the university was in a stringent conservation mode. Thermostats were set back, and many "non-essential" hot water faucets were turned off. Spot checks made subsequently in 1983 indicate that a less austere program now is in effect. One consequence is that the year-by-year comparison of consumption to analyse and detect variations and trends in natural gas consumption is skewed by an unknown amount. Hence, the methodology presented herein for a method of calculating natural gas offsets probably is conservative, since if the category other than geothermal consumption shows an increase, then so would have those areas supported by geothermal if there were no geothermal system.

g. There is yet one other factor to consider; namely, operational procedures for the geothermal system. In large measure, calculations for natural gas offsets are based on tests and measurements acquired during the three-month system testing period prior to formal dedication in late April, 1981. A detailed check was made in October, 1983, to ascertain current operational parameters. It should be noted that the unsatisfactory geothermal well performance has resulted in operator concern about the reliability of the system, and this concern translates into a need to have back-up steam supply immediately available to the users, because user support is the appropriate primary concern. The results of the operational checks indicate that the driving imperative to have responsive back-up steam, plus some poorly adjusted steam controls, resulted in a decrease of an estimated 7,000 MCF per year in the geothermal theoretically available offset. Results are tabulated in Table 33-9.

33.3.3 Other Adjustment To Natural Gas Consumption

A need exists to ascertain monthly natural gas consumption to assess the effects on a monthly basis of new equipment, weather conditions, and the geothermal system. In the present analysis, data for monthly natural gas consumption during the period 1980 - 1982 were obtained from the Central Heating and Cooling Plant. These data are based on the actual monthly consumption of natural gas. However, during the course of the year, contaminated fuel oil is consumed by the Central Heating and Cooling Plant as well. Since this fuel oil was burned in addition to the natural gas, the total energy consumption in terms of natural gas can be determined by converting the quantity of fuel oil to the natural gas equivalence and adding this to the monthly natural gas consumption. Monthly fuel oil consumption is tabulated in Table 33-10.

Table 33-9

REMARKS CONCERNING USE OF STEAM HEAT EXCHANGERS TO BACK-UP THE GEOTHERMAL

Building	Geo-(°F) Supply	Average Flowrate GPM	Temperature H/E Outlet	(Pre-Geo °F	Wasted ΔT
Alumni	135	9.5	138	135	3
Football Stadium	120	30	142	---	22
Return to Alumni					
Activity Bldg.	130	1	126		(No Steam)
Natatorium	(No Steam)				
O.P. Supply	134	30			
DHW	134	---	122		
Regents	134	8.5	157-160	130	24
Garcia	133	11.5	143	140	10
WRC	130	12.5	133	130	3
R-G-H	130	4.5	133	130	3
Pan Am	133	0.5	135	138	2

Table 33-10

FUEL OIL CONSUMPTION

Date	Fuel Oil, Gal	MCF Equivalence
December 1980	28,857	3,996
February 1982	7,171	993
March 1982	220	30

33.3.4 Energy Saving From The Geothermal Project

The geothermal system was placed on line during the periods from February 15 through May 17, 1982, and from the 26th of August, 1982 to May, 1983. The net saving from the operation of the geothermal system was previously estimated from the total heat furnished by the geothermal system. The analysis was carried out by comparing the monthly natural gas consumption from the period of February 1982 - May 1983 when the geothermal system was in operation to the same period of February 1980 - May 1981 when the geothermal system was not in operation.

Prior to making the comparison, the monthly figure of natural gas consumption during the 1981 period was adjusted to account for the variation in weather conditions, increase of space heating and cooling area, and addition of new equipment. The adjustment was necessary since the comparision must be made on a non-biased basis.

The procedure adopted for making the adjustment to natural gas consumption is given in Appendix B. The validity of this procedure was verified by utilizing the data for monthly natural gas consumption from the periods of 1980 and 1981. During these periods, the geothermal system had not yet been placed in operation. Therefore, for a valid procedure of adjustment to natural gas consumption, the variances from comparing the adjusted monthly natural gas consumption of 1980 to the monthly natural gas consumption of 1981 should approach zero.

The result of comparing the adjusted monthly gas consumption of 1980 to the monthly natural gas consumption of 1981 is given in Table 33-11. The variance distribution of monthly natural gas consumption shown in this table ranges from a negative -0.047 to a positive 0.033 with an average absolute value of 0.029. Samples of calculations for this analysis are given in Appendix B. This variance can be interpreted to indicate that the methodology will produce an estimate which on the average is within 2.9% of true values.

Table 33-11

COMPARISON OF NATURAL GAS CONSUMPTION

Date	Natural Gas Consumption, mcf 1981 Forecast (1980 Base)	 1981 Actual	Variance
Jan	30,192	30,972	-0.025
Feb	26,433	25,877	+0.021
Mar	25,291	25,871	-0.022
Apr	14,030	14,726	-0.047
Oct	14,537	15,045	-0.034
Nov	26,504	25,665	+0.048
Dec	26,174	25,570	+0.024
		Average Variance	0.029

Using the methodology established for comparing the natural gas consumption data of 1981 with the adjusted data of 1980, a similar procedure was used to analyze the net savings from the geothermal service in 1982. This comparison takes actual 1981 consumption, and derives a value for expected 1982 consumption if the geothermal system was not operational. The resulting forecast consumption was compared with actual comparison to estimate the geothermal offset.

The average weekly saving from the summary in Table 33-12 was determined to be approximately \$8,000. The computed saving thus compares favorable with earlier estimates that the system should save between \$8,000 and \$10,000 per week during the peak demand, depending on natural gas prices. Moreover, expansion of the system to Breland and O'Donnell will generate additional natural gas offset.

33.3.5 Alternative Study of Geothermal Saving

Evaluating geothermal benefits or any other steam system change is clearly a complex task since the process of energy distribution is large and complex. The study of geothermal benefits in Section 33.3 is an effort to assess what was occurring in the overall system which would act to detect gross changes in natural gas consumption. As devised, the methodology also can generate projected future year natural gas consumption data which might prove useable to prepare budget estimates on projected utility cost so as to provide flexibility for changes in hardware or procedure which would enable energy and cost conservation goals to be met.

In order to avoid misjudgement in geothermal benefits derived from the methodology used, as well as to further enhance the study of geothermal savings, an additional effort was made to assess the benefits from the geothermal system. This alternative study was made independently by determining the actual BTU's delivered to the campus. Calculations were based on the measurements of geoheated water (domestic hot water) flowrates which were accomplished by the use of a portable Controlotron flow meter, and the domestic water was heated from 65°F to 135°F. (NMSU is acquiring a permanent BTU meter, which will be used to acquire this data on a continuous basis. This BTU meter will be installed in mid 1984).

On the basis of a measured end-use efficiency of 65.5%, reported monthly efficiency of steam generation at the Central Heating and Cooling Plant, and a distribution efficiency of 89%, the following Table 33-13 summarize the saving analysis by the direct flow measurements. Appendix F provides the detailed methodology for this alternative assessment.

Table 33-12

GEOTHERMAL SAVINGS - A COMPARISON OF METHODOLOGIES

Date	Saving (original methodology) MCF	Savings (modified methodology)* MCF	Saving (modified methodology & Oxygen Controls + Insulation)**, MCF
15 Feb 82	3040	2704	2494
Mar	5677	5321	4741
Apr	6186	6306	5824
17 May	1612	1612	1612
Jun	(946)***	(946)***	(946)**
Jul			
26 Aug	749	749	749
Sep	5126	5126	5126
Oct	5703	5663	5307
Nov	8186	8030	7226
Dec	3857	3088	2229
Jan 83	3401	3968	3093
Feb	7675	7467	6707
Mar	7160	6880	6137
Apr	4188	4424	3925
17 May	2021	2021	2021
	Total = 65527	Total = 64305	Total = 58137

NOTE: * (1) The modified methodology was based on the presence of stack economizers installed in April 1981

** (2) Saving calculations were based on the modified methodology, plus the installation of oxygen controller in January 1982, and piping insulation which completed in August 1982.

*** Geothermal system equipment used for the football stadium to avoid excessive steam losses.

Table 33-13

NATURAL GAS SAVING BY DIRECT MEASUREMENTS

Da	Average Central Plan Efficiency, %	Flowrate gp	MCF Saved
15 Feb 82	80.0	50.0	1,613
Mar	77.1	62.5	3,301
Apr	76.0	102.5	5,801
17 May[a]	69.9	97.5	3,650
(19 May - 25 Aug 82)[b]			946
26 Aug	56.5	50.0	968
Sep	64.5	80.0	5,506
Oct	77.4	107.5	6,353
Nov	84.6	117.5	9,908
Dec	86.3	72.5	3,345
Jan 83	80.7	72.5	3,415
Feb	86.0	117.5	5,956
Mar	87.0	107.5	5,241
Apr	79.3	102.5	6,017
17 May[a]	75.4	97.5	3,384
		TOTAL =	61,409

NOTE: [a] Average usage period of 17 days.

[b] Geothermal system equipment used for football stadium to avoid excessive steam losses.

The study of geothermal saving from the direct measurements of actual BTU's delivered to the campus shows that the total natural gas saving from 15 February 1982 until 17 May 1983 is equal to 61,409 MCF. On the other hand, the methodology for assessing geothermal benefits developed earlier in Section 33.3 (Table 33-12) suggests that the total natural gas saving for the same period is equal to 58,137 MCF. The variance between the two estimating techniques is 5.3%. This variation is for the entire period; a by-month comparison reveals that the variance between the two methodologies is relatively large for months in which the outdoor pool is geothermally heated, and the second methodology provided much lower values for the initial start-up period for the geothermal system. The second methodology is quite sensitive to the assumed distribution system efficiencies, and the chosen value (a constant value of 89%) is probably not accurate through-out the year. Nevertheless, the two different methodologies provide a close enough correlation that the geothermal system order-of-magnitude natural gas offsets are approximately 60,000 MCF per year when the outdoor swimming pool is heated with geothermal energy.

33.3.6 Actual Natural Gas Offsets

The methodology previously discussed can be used to "predict" a consumption pattern for any given year. In fact, the methodology was used to establish a baseline for academic year 1982-1983 (1 July 1982 through 30 June 1983.) Concurrently, the Physical Plant Department maintained gross records for actual natural consumption for that year, and graphed a comparison with the previous year. This gross comparison suggested that there was no apparent noticeable decrease in natural gas consumption, which lead them to a conclusion that the geothermal system was not performing to expectations.

In analysing why this pattern existed, the primary cause was a colder than normal year. This unusually cold year resulted in an increase in natural gas sales to the Las Cruces-wide natural gas distribution system. Coordination with the city of Las Cruces produced data relative to the number of users by category (residential and commercial) and natural gas sales by category. Data was provided for 1981, 1982, and 1983. After adjustment were made to the 1982-1983 data to remove the bias caused by a change in the number of customers, residential consumption still showed a 22.9 percent increase for the heating season 1982-83 compared with the previous winter. This increase is an accurate reflection of the colder weather for the 1982-1983 winter. Notably, December 1982 was up 33.45%; January 1983 increased by 23.28% and April and May 1983 increased by 52.43% and 12.94% respectively compared to the previous winter. This correlation is based on a comparison of heating degree days, which is a relatively accurate broad measure for gaging the effects of weather.

Other operational uses of the geothermal system imposed a penalty of an estimated 7,000 MCF. (See Section 33.3.2 (f)).

A concerted effort also was made to assess whether any trend could be shown for natural gas consumption increases resulting from additional students, changed operational procedures, new equipment, or other "hidden" factors. Because the geothermal system was temporarily inoperative in September 1983, an opportunity was presented to analyze daily records for the Central Steam Plant for a 30-day period, use this data to ascertain trend lines, and then compare the trend prediction with actual daily consumption for the following 30-day period, after the geothermal system was re-started. To accomplish this methodology, all data were acquired from the central steam plant books for each of the three daily shifts, for the entire 60-day period. In turn, the same 60-day period was analysed for each of the past three years. Analysis of the data show that the steam consumption increases almost linearly each year from the start of the fall semester. This pattern was reversed in September 1982, (when the geothermal system was started) and consumption showed a decrease, and then an increasing trend.

For 1983, the start-up period for the school fall semester showed daily gas usage was almost 24 percent higher than the previous three years. This was not an unusual situation, because consumption increased at roughly the same rate as previous year. At this point in the analysis, a conclusion was reached that the non-heating season steam load is considerably higher for 1983-84 than was the case for the preceeding three years. In fact the slope of the consumption curve is almost an exponential curve, gradually increasing until the official heating season occurs. We have fitted a polynomial function to this curve, which in turn is fitted to 1983 data.

From that curve, one can estimate with a high degree of accuracy what the consumption would have been had the geothermal system not been used. This extrapolation more clearly depicts the significant reduction caused by the geothermal system performance.

Attached is Figure 33-14, which depicts the curve-fitting of the data sets for the 4-year period. This technique clearly shows that the geothermal system acts to sharply decrease natural gas consumption.

NMSU CENTRAL PLANT DAILY NATURAL GAS TRENDS

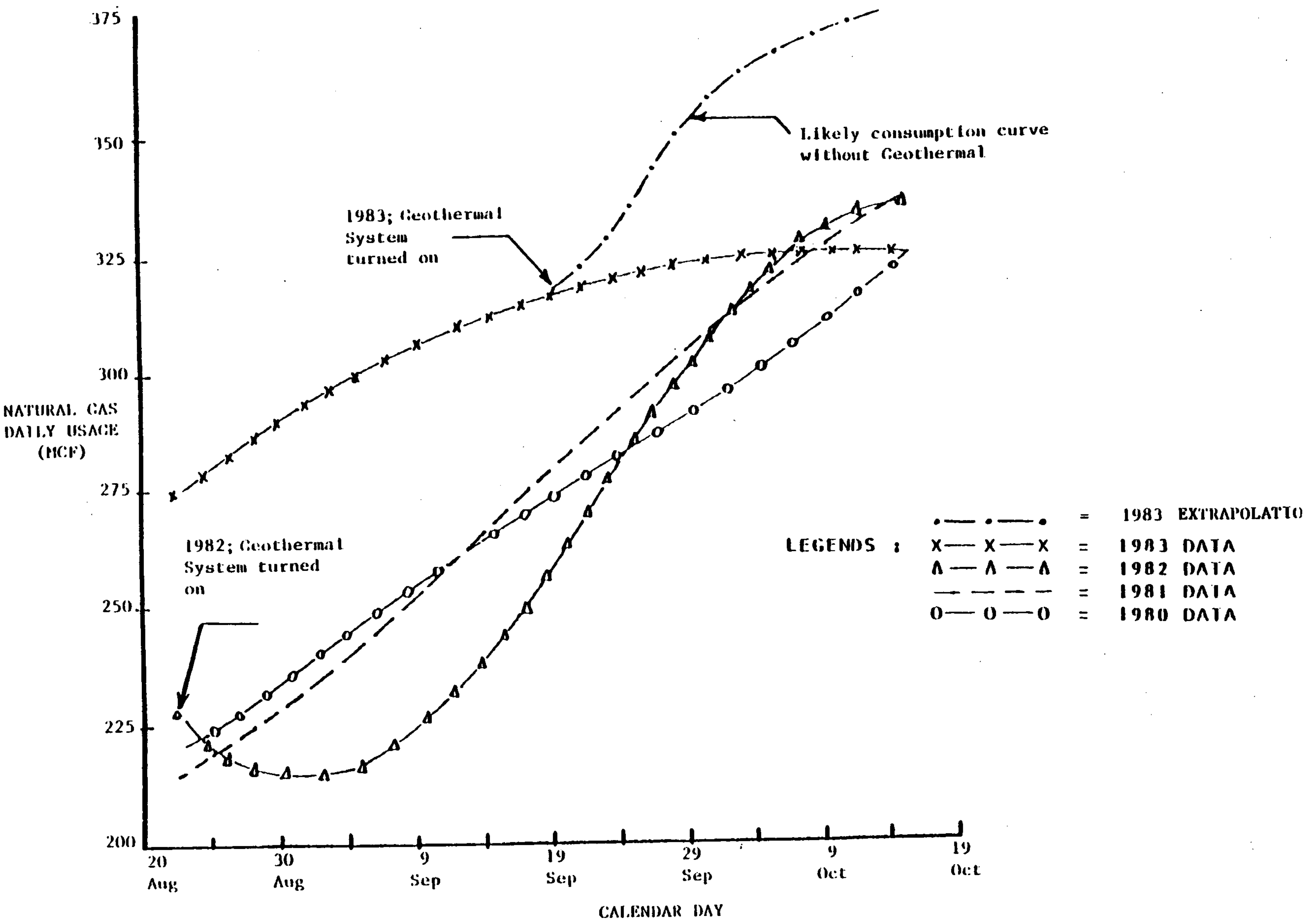


Figure 33-14

33.4 Customer Billing

(not applicable)

33.5 Analysis

From the discussion in Section 33.3, it can be seen that the geothermal system gross savings can only be estimated. The analysis for NMSU is summarized in the following table:

Table 33-15

NATURAL GAS OFFSETS RESULTING FROM GEOTHERMAL
(MCF)

February 1982 - April 1983:	72,015	
July 1982 - June 1983:	53,000	System start-up
"Normal" Academic Year:	50,000 MCF	
Academic Year with Outdoor Pool in use	60,000 MCF	

33.5.1 Simple Payback

Using a capital cost of $1,360,000 (Section 33.1) and "normal" operating and maintenance cost of $66,000 per year, (Section 33.2), a simple payback can be calculated using the current natural gas price of $4.79 per MCF. Calculations are as follows, holding all operating costs (natural gas, electricity, labor) constant.

- o Yearly gross savings: 60,000 MCF at $4.79 per MCF equals $287,400.
- o Yearly net savings: Gross savings less operating costs, or ($287,400-$66,000), which is $221,400.
- o Simple payback: Capital costs divided by net savings, or 6.1 years.

33.5.2 Pon Analysis

(not applicable)

The above analysis is overly simplified, and a more thorough and accurate assessment is contained in Section 33.6.

33.5.3 Other Analyses

Using the experience for total support costs from initial use of the system for a 15-month period ending in April 1983, a net favorable cost avoidance can be calculated:

Table 33-16

GEOTHERMAL SYSTEM COST AVOIDANCE

<u>Gross Savings</u>

Feb - Sep 1982	26,823 mcf @ $4.47	$119,899
Oct 1982 - Jan 1983	26,436 mcf @ $4.95	130,858
Feb - Apr 1983	18,756 mcf @ $4.79	89,841
TOTAL		$340,598

<u>Operating Costs</u>

Electricity (Feb. 1982 - April 1983)	$ 38,587
Normal maintenance labor and materials	35,394
Abnormal costs for well and pump repairs	148,247
TOTAL	$ 222,228
Net Favorable Cost Avoidance (First 15 months of operation)	$ 118,370

If the cost avoidance methodology is used, and one assumes that the system will continue to experience serious well and pump problems, the simple payback is 11.5 years.

A long-term payback (11.5 years) is not realistic for several reasons. First, the cost of the new pump, which was purchased in April 1983, is included in the above abnormal costs. There was extra expense incurred in trying to install this pump, and to perform follow-on repair and testing of the well. However, the back-up well (PG-3) has continued to perform satisfactorily, and by 1 March 1983 an additional $200,000 in benefits have accrued, while support costs have been considerably less than the previous year. Secondly, if the wells and well pumps displayed the same level of poor performance, it is totally unrealistic to assume NMSU would continue to operate the system. Thirdly, expanded use of the system is occuring, and the follow-on expansion will generate additional benefits at a much greater rate than the costs to operate the system. (Marginal cost to add users is building retrofit cost plus some small increase in pumping electricity. This will be true until the connected load is 15.0 million BTU per hour, or roughly four times the current usage. Thus, marginal benefits will greatly outweigh marginal costs.) As a final factor, natural gas costs have been increasing at a much faster rate than have electricity costs, although there has been a 12-month hiatus in natural gas cost increases. (In fact, natural gas costs dropped slightly from $4.95 per MCF to $4.79 per MCF in February 1983, and have remained at that level.) Moreover, natural gas still remains an depletible resource. New Mexico production has declined 2.4 per cent or more every year since 1973. Thus, increasing scarcity is likely to cause higher prices, which in turn will enhance the benefits of geothermal use.

Given the wide range of variables affecting this project, the most reasonable conclusion is that the geothermal system has a payback ranging from five to six years under the best circumstances, and ten years or less under the worst circumstances.

33.6 Possible Future Costs and Cost Savings

It is possible to calculate possible future fuel costs and operating costs. The reader is cautioned that these are not predictions. Instead, these are possible prices if the assumptions are reasonably valid. As such, they present a logical framework to evaluate the question as to the overall cost-effectiveness of the geothermal system. See Table 33-18.

Table 33-17

POSSIBLE FUTURE COSTS AND COST SAVINGS
(Based on 50,000 MCF Natural Gas Savings)

Possible Natural Gas Prices	1980 $	1985 $	1991 $
Case #1	$4.27	$7.25	$9.75
Case #2	4.27	5.56	7.50
Possible Annual Cost Savings At 50,000 MCF/Year	1980	1985	1991
Case #1	$213,500	$362,500	$487,500
Case #2	213,500	278,000	375,000
Possible Annual Operating Costs*	1980	1985	1991
Case #1	$80,800	$131,700	$176,000
Total Net Surplus Potential	$132,700	$146,300-$230,300	$199,000-$311,500

*For 1985, the operating costs are assumed to be double the projected annual operating expense previously defined. These costs then are assumed to increase at 5 percent per year. This approach was used to attain a very conservative measure of the estimated potential surplus.

The preceeding discussion provides an optimistic view of the potential net savings that the geothermal system could provide. It is emphasized however, that these savings are conjectural, and must be demonstrated. Moreover, these savings are based on the implicit assumption that the investment costs are from appropriated dollars which will not be repaid directly, or at most would be repaid through future year decreases in monies appropriated for utility bills. At any event, there is no monthly or annual interest cost on the investment. Accordingly, the NMSU system, although very cost-beneficial, is in a different category than would be a system which required loan amortization and interest payments.

33.7 Pay-Off Period

General: Conventionally, the payoff or cost break-even period is one of the more significant measures of the overall worth of a project. This demonstration project as funded is financed within a system not available to the private sector. Hence, the payoff period as calculated is not done with the normally accepted discounted cash-flow system. Instead, calculations are based on total taxpayer investments compared with the possible net annual surplus as defined previously. One possibly can argue that research costs should be excluded, because the return on that cost is an increase in the information pool. Because there are several different ways to look at such costs, the payoff period also is calculated using the expended investment cost basis, including research, previously defined. For each investment cost, however, the payoff period is calculated by dividing the summation of investment costs by the summation of net potential surplus.

Payoff Period, Varying Investment Categories

The following table reflects the possible payoff period, for the two cases, and in comparison of the possible future cost of natural gas. In this regard, the expiration of the 1978 Natural Gas Policy Act could cause an increase in 1985 of 20 to 25 percent. If that increase occurred, the natural gas cost would be $5.99 per MCF. A lower price ($5.56 per MCF) was used for Case #2, and a pessimistic price of $7.25 was used for Case #1. The possible year 1991 prices are then based on an assumed annual price growth of 5 percent. From this methodology, it can be seen that in the near term Case #1 is unduly pessimistic, but possibly not so over the 7-year period. On the converse, Case #2 is unduly optimistic for 1985, and unrealistically low for 1991.

Table 33-18

POSSIBLE PAYOFF PERIOD
(Years of Operation)

	Cost Basis				
Category of Investment	1980 Base	*Case #1 1985 Gas Costs	*Case #1 1991 Gas Costs	*Case #2 1985 Gas Costs	*Case #2 1991 Gas Costs
DOE Funds ($532,000)	2.5	3.6	1.7	2.4	2.7
New Mexico Funds (1,108,000)	5.2	7.5	3.5	4.8	5.5
Total Investment ($1,640,000)	12.3	11.2	5.0	7.1	8.2

*Costs Starting in 1982

From the preceeding tabulation and analysis, the overall conclusion is that the system is cost effective, and has a pay-off period on the total investment ranging from 5 to 12 years, depending on the future natural gas costs. Most likely pay-off period, keyed to 1985 natural gas costs, is 7.1 years. Concerning the New Mexico investment, which is the largest share, if all the savings are applied, the payoff period is in the range of 5 to 7.5 years, keyed again to the possible 1985 gas costs.

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APPENDIX A

WATER QUALITY REPORT

CHEMICAL ANALYSIS

		µmhos/cm	mg/l					
Sample	pH	EC	Na	K	Ca	Mg	Cl	CO_3
PG-1 #4	6.17	6.59	627.2	80.5	538.4	108.0	1714.8	0
#7	6.60	4.51	536.3	61.1	325.9	60.4	1123.2	0
#8	6.64	4.05	504.6	55.2	267.6	49.4	963.0	0
#10	6.45	3.72	500.7	54.1	232.7	43.2	847.1	0
PG-3								
PG-1 (1980)	6.30	3.11	488	54	143	18.6	584	0
PG-3 (1980)	6.25	3.13	488	52	141	18.8	546	0

	mg/l						
Sample	HCO_3	SO_4	TDS	Fe	Mn	NO_3-N	F
PG-1 #4	134.2	645	4220	81.6	5.37	.04	3.51
#7	341.7	402.5	2868	13.03	2.11	<.01	2.70
#8	422.2	292.5	2416	9.31	1.43	.02	2.41
#10	458.8	308	2044	7.71	1.11	<.01	2.54
PG-3	596.7	343	1748	.15	<.05	<.01	2.28
PG-1 (1980)	620	250		2.8	0.11	0.03	1.3
PG-3 (1980)	610	240		5.0	0.11	0.02	NA

	mg/l				
		as $CaCO_3$			
Sample	Hardness	Alkalinity	Surfactants	Color	Odor
PG-1 #4	1788	110	<.025	<20	5
#7	1062	280	<.025	<20	2
#8	870	346	<.025	<20	5
#10	758	376	<.025	<20	10
PG-3	518	489	<.025	1	5

	NTU						
Sample	Turbidity	As	Ba	Cd	Cr	Pb	Hg
PG-1 #4	330	.001	.43	.007	<.05	<.005	<.0002
#7	180	.001	.26	.005	<.05	<.005	<.0002
#8	180	.001	.21	.005	<.05	<.005	<.0002
#10	110	.002	.17	.005	<.05	<.005	<.0002
PG-3	1.2	.07	.07	.005	<.05	<.005	<.0002
PG-1 (1980)		<.004	<.	<.005	<.05	<.005	<.0002
PG-3 (1980)		<.004	<.04	<.005	<.05	<.005	<.0002

	mg/l		mg/l
Sample	Se	Ag	H_2S
PG-1 #4	<.001	<.05	
#7	<.001	<.05	
#8	<.001	<.005	.13
#10	<.001	<.005	
PG-1 (1980)	<.002	<.05	0.06
PG-3 (1980)	<.002	<.05	0.14

	mg/l	
Sample	Se	Ag
Pg-3	.001	.05

APPENDIX B

METHODOLOGY FOR ADJUSTING THE NATURAL GAS CONSUMPTION TO A GIVEN YEAR

APPENDIX B

Methodology for adjusting the natural gas consumption to a given base year.

1. Adjusting for the use of fuel oil.

$$mcf_{i+1} = mcf_i + \text{MCF equivalence}$$

Where mcf_{i+1} is the adjusted monthly natural gas consumption, mcf_i is the monthly natural gas consumption, and MCF equivalence is the natural gas equivalence to the quantity of fuel oil.

2. Adjusting for change in steam pressure.

$$mcf_{i+1} = mcf_i \pm (300 \text{ mcf per day x no. of days})$$

where mcf_i is the adjusted monthly natural gas consumption from step 1.

3. Adjusting for increase in space heating and cooling.

$$mcf_{i+1} = mcf_i \times \frac{(\text{square-footage})_{i+1}}{(\text{square-footage})_i}$$

Where $(\text{square-footage})_{i+1}$ is the area in the base year, and $(\text{square-footage})_i$ is the area in the preceding year.

4. Adjusting for correction factor.

$$mcf_{i+1} = \left[1 + \left(\frac{0.15\ D}{M}\right)\right] \times mcf_i$$

where D is the No. of days when steam was used for heating and M is the No. of days of the month.

5. Adjusting for the variation in weather condition. This adjustment is applied only to those months when steam was used for heating.

$$\Delta mcf_i = mcf_i - \overline{mcf_i}$$

where Δmcf_i is the net natural gas consumption for heating, mcf_i is the adjusted monthly natural gas consumption from step 4, and $\overline{mcf_i}$ is the average monthly natural gas consumption during the May - September period.

5.1 Adjusting for the variation in heating degree days (HDD).

$$\Delta mcf_{i+1} = \Delta mcf_i \times \left(\frac{HDD_{i+1}}{HDD_i}\right)^{\frac{1}{2}}$$

5.2 Adjusting for the variation in average wind speed.

$$\Delta mcf_{i+1} = \Delta mcf_i \times \left(\frac{WS_{i+1}}{WS_i}\right)^{a}$$

where WS is the monthly average wind speed, and a has an expression of

$$\frac{HDD_i}{65°F \times 30.4 \text{ days}}$$

where 30.4 is the average number of days per month

6. The monthly natural gas consumption adjusted to a given base year is therefore:

$$mcf = \overline{mcf} + \Delta mcf + mcf_e - mcfs$$

where mcf is the adjusted monthly natural gas consumption, $\overline{mcf}$ is the average monthly natural gas consumption during May - September, Δmcf is the adjusted natural gas consumption for heating from step 5.2, mcf_e is the natural gas consumption of additional services, mcf is additional natural gas saving from conservation measures.

Attachment One to Appendix B

Sample of Calculations

Following is an example of calculations applied to adjust the natural gas consumption of January 1980 to that of January 1981.

<u>Step 1</u> Omit (Since MCF equivalence = 0)

<u>Step 2</u> $\mathrm{mcf}_{i+1} = 25{,}942 \text{ mcf} + 300 \frac{\text{mcf}}{\text{day}} \times 2 \text{ days}$

$= 26{,}542 \text{ mcf}$

<u>Step 3</u> $\mathrm{mcf}_{i+1} = 26{,}542 \text{ mcf} \times \frac{2{,}723{,}016 \text{ ft}^2}{2{,}612{,}049 \text{ ft}^2}$

$= 27{,}657 \text{ mcf}$

<u>Step 4</u> $\mathrm{mcf}_{i+1} = 1 + 0.15 \times \frac{20 \text{ days}}{31 \text{ days}} \times 27657 \text{ mcf}$

$= 30{,}423 \text{ mcf}$

<u>Step 5</u> $\Delta\mathrm{mcf}_{i} = (30{,}423 - 7{,}713) \text{ mcf}$

$= 22{,}710 \text{ mcf}$

5.1 $\Delta\mathrm{mcf}_{i+1} = 22{,}710 \text{ mcf} \times \left(\frac{637°\text{F}\cdot\text{day}}{586°\text{F}\cdot\text{day}}\right)^{\frac{1}{2}}$

$= 23{,}687 \text{ mcf}$

$$\frac{586}{(65 \times 30.4)}$$

5.2 $\Delta\mathrm{mcf}_{i+1} = 23{,}101 \text{ mcf} \times \left(\frac{3.6 \text{ mph}}{4.3 \text{ mph}}\right)$

$= 22{,}479 \text{ mcf}$

<u>Step 6</u> $\mathrm{mcf}_{i+1} = (22{,}479 + 7{,}713 + 0 - 0) \text{ mcf}$

$= 30{,}192$ mcf, the adjusted natural gas consumption

Attachment Two to Appendix B

Analysis of Geothermal Savings for September and October, 1982

The service of the geothermal system produced net savings of natural gas of 5,126 and 5,703 mcf for September and October, respectively. These savings were determined from two factors;

1) Decrease in natural gas consumption at the Central Heating and Cooling Plant due to geothermal offset -- offset (A)
2) Additional heating load provided to the football station, indoor and outdoor pools, and the Natatorium -- offset (B).

Following is the detail analysis of geothermal saving of September and October, 1982:

September Saving

1) Offset (A) - decrease in natural gas consumption due to geothermal offset.

$$\text{Offset (A)} = \frac{\text{Natural gas consumption}}{1 - \frac{\text{Percentage Offset}}{100}} - \text{Natural gas consumption}$$

$$= \frac{7{,}367 \text{ mcf}}{1 - \frac{27.7}{100}} - 7{,}367 \text{ mcf}$$

$$= 2{,}822 \text{ mcf}$$

2) Offset (B) - additional heating load provided to the football stadium, indoor and outdoor pools, and the Natatorium

$$\text{Offset (B)} = \frac{\text{Heating Load}}{\text{Overall Efficiency}} \times \frac{1}{10^6 \text{ Btu/mcf}}$$

$$= \frac{9.03 \times 10^8 \text{ Btu}}{0.7 \times 0.8 \times 0.7} \times \frac{1}{10^6 \text{ Btu/}_{\text{mcf}}}$$

$$= 2{,}304 \text{ mcf}$$

Thus, total natural gas offset for September = Offset (A) + Offset (B)
= 5,126 mcf

October Saving

1) Offset (A) - decrease in natural gas consumption due to geothermal offset.

Offset (A) = 3,655 mcf*

*(The term 3,655 mcf in the above equation is the offset accounted for variation in weather conditions as the steam pressure was increased to 100 psig for space heating on October 13, 1982).

2) Offset (B) - additional heating load provided to the football stadium, indoor and outdoor pools, and the Natatorium.

$$\text{Offset (B)} = \frac{\text{Heating load}}{\text{Overall efficiency}} \times \frac{1}{10^6 \text{ Btu/mcf}}$$

$$= \frac{9.03 \times 10^8 \text{ Btu}}{0.441} \times \frac{1}{10^6 \text{ Btu/mcf}}$$

$$= 2{,}048 \text{ mcf}$$

Thus, the total natural gas offset for October = Offset (A) + Offset (B)
= 5,703 mcf

APPENDIX C

OXYGEN CONTROLLERS

APPENDIX B: Calculation of Saving from the Oxygen Controller.

Basis ; (1) Natural gas is 90% CH_4 , 5% C_2H_6 and 5% N_2

(2) A complete combustion occurred

$$90\ CH_4 + 180\ O_2 \rightarrow 90\ CO_2 + 180\ H_2O \qquad (1)$$

$$50\ C_2H_6 + 17\tfrac{1}{2}\ O_2 \rightarrow 10\ CO_2 + 15\ H_2O \qquad (2)$$

$$5\ N_2 \rightarrow 5\ N_2 \qquad (3)$$

$$(1)+(2)+(3)\ ;\ \underline{\overline{90\ CH_4 + 5\ C_2H_6 + 5\ N_2 + 197\tfrac{1}{2}O_2 \rightarrow 100_2CO + 195\ H_2O + 5N_2}} \quad (4)$$

Eq. (4) dictates that for 100 MCF of natural gas, 197½ MCF of O_2 is needed for the basic combustion.

Now, calculations will be made for two cases ;

Case I ; with the oxygen controller, 15% excess air (or 2-4%O_2)

Case II ; without the oxygen controller, 80% excess air (or 10% O_2)

Case I ; Excess air of 15%

For the basic combustion of Eq. (4), 197½ MCF of O_2 is required for 100 MCF of natural gas.

Since atmospheric air composition is 21% O_2 , and 79% N_2

Therefore, The amount of air required for basic combustion is

$$\text{amount of air} = \frac{197.5\ \text{MCF}}{0.21}$$

$$= 940.5\ \text{MCF}$$

If we are looking for 15% excess air,

Then, the amount of air required = 1.15 x 940.5 MCF

= 1,081.5 MCF of air for the natural gas of 100 MCF

Case II ; Excess air of 80%

From Case I, we learned that the total amount of air required for the basic combustion with 100 MCF of natural gas is equal to 940.5 MCF.

If we are looking for 80% excess air.

Then, the amount of air required = 1.80 x 940.5 MCF

= 1.692.9 MCF of air for the natural gas of 100 MCF

Now, <u>combining the results of Case I and Case II</u> ;

The excess - excess - air rate that will go up the stack as waste heat is equal to

$$(\text{Air})_{xs} = \text{Amount air Case II} - \text{Amount air Case I}$$

$$= 1692.9 \text{ MCF} - 1081.6 \text{ MCF}$$

= 611.3 MCF for every 100 MCF of natural gas consumed

or in terms of lbs. = 49,240 lbs of excess - excess - air

Now, in terms of heat equivalence

$$Q = (\text{Flowrate})\ (\text{Heat capacity})\ (\Delta T)$$

$$= (49{,}240 \text{ lb.})\ \left(0.25 \frac{\text{BTU}}{\text{lb}^\circ\text{F}}\right)\ (280\ \text{F}^\circ - 80\ ^\circ\text{F})$$

$= (2.46 \text{ X } 10^6$ Btu for 100 MCF of burned natural gas

Annually, natural gas consumption = 200,000 MCF,

Therefore the amount heat saved is

$$Q = 2.46 \text{ X } 10^6 \text{ X } \frac{200{,}000 \text{ MCF}}{100 \text{ MCF}} = 4.92 \text{ X } 10^9 \text{ Btu/year}$$

Or, in terms of natural gas,

$$\text{Fuel saved} = 4.92 \text{ X } 10^9 \ \frac{\text{Btu}}{\text{year}} \ \frac{1 \text{ MCF}}{10^6 \text{Btu}} = 4{,}920 \ \frac{\text{MCF}}{\text{year}}$$

Since the annual natural gas consumption is 200,000 MCF,

Therefore, the percent fuel save $= \dfrac{4920}{200{,}000} \times 100 = 2.46\%$

<u>Key Points</u>:

1. Our calculations are based on an assummed complete combustion process which is not theoretically possible for the study flow process. In actual fact, incomplete combustion product CO is at least a few percent in the fuel gas. Therefore, the saving of 2.46% is the theoretically maximum (if a complete combustion occur).

2. An excess air flow rate will tend to reduce the heat film resistance on the boiler walls contact surfaces. This in term will act to increase the overall heat transfer coefficient of the boiler, with the result being improved boiler efficiency. Thus, the oxygen control works in the opposite direction, and this factor would tend to limit the overall efficiency gases of the oxygen control.

3. One test of the claimed efficiency of the oxygen controls is to test the results of calculations against physical reactions such as the capacity of the air blowers. I think we have to careful on this matter, especially when using the charts and figures provided by the manufacturer of oxygen controllers. Those charts and figures are not specific to any particular boiler system. Both size and operating conditions of the boiler affect the saving from the oxygen controller greatly.

Here is our reason why we cannot believe that the saving from the oxygen controller on our boilers is 5% of the total natural gas consumption:

If the saving is 5% as suggested, the annual saving would be

= 0.05 X 200,000 mcf/year
= 10,000 Btu/year

or, an equivalent heat of $Q = 10{,}000 \text{ MCF} \quad \times \quad 10 \ \underline{\text{Btu}}$

$= 10^{10}$ Btu/year

or, $Q = 19{,}290$ Btu/min (360 days/year)

Now, look closely when this is translated into terms of additional air rate ;

$$Q = (\text{Flowrate}) (\text{Air heat capacity}) (\Delta T) \text{ ---------- } (1)$$

Data ; Air heat capacity = 0.25 Btu/lb°F (for temp. 0-500°F)

$$\Delta T = T_2 - T_1$$

where T_2 = the stack gas temp. (after the economizers) ≅ (400-120)°F
T_1 = ambient temp. = 80°F

Thus from Eq.(1),

$$19{,}290 \text{ Btu/min} = (\text{Flowrate}) (0.25 \text{ Btu/lb.°F}) (280\text{°F}-80\text{°F})$$

or Flowrate = 385.8 lbs/min of additional air

or in terms of volume flowrate,

Flowrate = 4,790 cfm @ STD

That is the excess-excess-airrate = 4,790 cubic feet per minute @ STD
Total air flowrate would be 8,622 cubic feet per minute @ STD

This means in the past the boilers were consuming 4,790 cfm more excess air than the present. In fact, we can not be certain that the air blowers used at the Central Plant would have such excess capacity. Noting, the 4,790 cfm is only the claimed excess-excess-airrate for the 5% saving, you still need additional air to run the basic combustion. (Note; the wind box pressures for boilers #1 and 2 range from 3-inches to 5-inches of water.) When you check the rating of our blowers (25 HP @), you may find that our air-blowers do not have such capacity to deliver 8,622 CFM @ 5 inches of water.

The calculations above suggest two things;

(a) We did not have 10% oxygen (or 80% excess air) in the flow gas before installing the oxygen controller.
(b) Those charts and figures from the PPD handout do not directly apply to our boilers operating conditions.

We personally believe that the main benefit of the oxygen controller is to ensure that there is adequate air for the so-called complete combustion, and save energy in terms of electricity for the air blowers. The natural gas saving from our oxygen controller is less than 2.46%

There is yet another alternative calculation for oxygen controller efficiency. This calculation is based on the actual Central Plant data.

ALTERNATIVE CALCULATIONS

Study of Savings from the Oxygen Controller

Basis ; (1) Natural gas is 90% Ch_4, 5% C_2H_6 and 5% N_2
(2) A complete combustion occurred.

$$90\ CH_4 + 180\ O_2 \quad 90\ CO_2 + 180\ H_2O \qquad (1)$$

$$5\ C_2H_6 + 17\tfrac{1}{2}\ O_2 \quad 10\ CO_2 + 15\ H_2O \qquad (2)$$

$$5\ N_2 \quad 5\ N_2 \qquad (3)$$

$$(1)+(2)+(3)\ ; \quad 90CH_4 + 5C_2H_6 + 5N_2 + 197\tfrac{1}{2}O_2 \rightarrow 100CO_2 + 195H_2O + 5N_2 \qquad (4)$$

100 MCF of natural gas from air

Eq.(4) dictates that for 100 MCF of natural gas used, 197½ MCF of O_2 is needed for the basic combustion.

Since the atmospheric air composition is 21% O_2 and 79% N ; therefore, the amount of air required for the basic combustion is equal to:

$$\text{Amount of air} = \frac{197.5}{0.21}\ \text{MCF}$$

$$= 940.5\ \text{MCF of air per 100 MCF of natural gas}$$

For 15% excess air ; the amount of air = 1.15 X 940.5 MCF
= 1081.6 MCF

The amount of exhaust gas @ 15% excess air is equal to

Exhaust gas = 300 MCF + (1081.6 - 197.5) MCF
= 1184.1 MCF of exhaust gas per 100 MCF of natural gas consumed.
or = 95,380 lbs. per 100 MCF natural gas

For 80% excess air ; The amount of air = 1.80 X 940.5 MCF
= 1692.9 MCF

The amount of exhaust gas @ 80% excess air is equal to

Exhaust gas = 300 MCF + (1692.9-197.5) MCF
= 1795.4 MCF of exhaust gas per 100 MCF of natural gas consumed

or = 144,621 lbs. per 100 MCF natural gas

Savings from the Oxygen Controller :

According to Rich MacRorie, the oxygen controller limited the amount of air flow from 80% excess (before the installation) to 15% excess (after the installation). Based on this change, an energy savings can occur from limiting the amount of excess air which carries heat up the stack as waste heat. The saving can be calculated from

Rate of energy saved = (Exhaust gas rate) (Heat capacity) (ΔT)

where $\Delta T = T_2 - T_1$

T_2 = Temperature of exhaust gas (after the economizer)

T_1 = Temperature of the feed air (80%°F)

Heat capacity = 0.25 Btu/lb°F (for range of 0 to 500°F)

Determination of T_2, the temperature of exhaust gas ;

There are records of the temperature of exhaust gas (before the economizer), therefore if the exhaust gas temperature drop across the stack gas is known, then the temperature of the exhaust gas (after the stack economizer) can be determined.

Since the rate of heat extraction from the stack economizer is known, and the flowrate of the exhaust gas is also known, then from the energy balance around the stack economizer, the exhaust gas temperature drop across the stack can be calculated by

Heat extracted by the stack economizer = Heat loss of the exhaust gas

= (Flowrate) (Heat capacity) (ΔT_s)

Where ΔT_s = Exhaust gas temperature drop across the stack economizer.

The calculation of ΔT will be made for two cases ;

Case I 50-psig mode (saving from the stack economizer = 2.22%)

Case II 100-psig mode (saving from the stack economizer = 4.11%)

Note: These stack economizer saving are based on our detailed review of records for a 15-month period.

Case I ; 50-psig mode.

The saving from the stack economizer in this operation mode is 2.22% , or the saving of 2.22 MCF per 100 MCF of natural gas.

@ 15% excess air, the exhaust gas = 95,380 lb. per 100 MCF natural gas.

Thus,

$$2.22 \text{ X } 10 \text{ Btu} = (95380 \text{ lb.})(0.25 \text{ Btu/lb°F})(\Delta T_s)$$

$$\text{or} \quad \Delta T_s = 93.1°\text{F}$$

In the 50-psig mode, the average exhaust gas temperature (before the economizer) is 375°F. Thus the exhaust gas temperature (after the economizer) $T_2 = (375-93.1)$
$= 281.90°\text{F}$

Case II ; 100 psig mode

The saving from the stack economizer in the 100 psig mode is 4.11% , or the saving of 4.11 MCF per 100 MCF natural gas.

Thus,

$$4.11 \text{ X } 10 \text{ Btu} = (95380 \text{ lb.})(0.25 \text{ Btu/lb°F})(\Delta T_s)$$

$$\text{or} \quad \Delta T_s = 172.4°\text{F}$$

In the 100 psig mode, the average exhaust gas temperature (before the economizer) is 430°F. Thus the exhaust gas temperature (after the economizer) $T_2 = (430-172.4)°\text{F} = 257.6°\text{F}$.

Calculation of saving from the oxygen controller ;

The saving from the oxygen controller by limiting the amount of stack gas waste heat can be calculated from

Savings = (Exhaust gas heat @ 80% XS) - (Exhaust gas heat @ 15% XS)

= (ΔFlow) (heat capacity) (ΔT)

Where ΔFlow = (Exhaust gas flow @ 80% XS) - (Exhaust gas flow @ 15% XS)

$$\Delta T = T_2 - T_1$$

The calculations will be made for 2 cases ;

Case I ; 50 psig mode

Basis : 100 MCF of natural gas

saving = (ΔFlow) (Heat capacity) (ΔT)

= (49241 lb) (0.25 Btu/lb.°F) (281.9°F - 80°F)

= 2.49×10^6 Btu per 100 MCF natural gas

or, saving = 2.49 MCF per 100 MCF natural gas

Thus, the savings from the oxygen controller in the 50 psig mode is equal to 2.49%.

Case II ; 100 psig mode

Basis : 100 MCF of natural gas

saving = (Δflow) (heat capacity) (ΔT)

= (49241 lb.) (0.25 Btu/lb°F) (257.6°F-80°F)

or, saving = 2.19 MCF per 100 MCF natural gas

Thus, the savings from the oxygen controller in the 100 psig mode is equal to 2.19%.

Overall saving of the oxygen controller ;

Annual natural gas consumption is 200,000 MCF (70,000 MCF during the 50-psig mode, and 130,000 MCF during the 100 psig mode).

The overall saving is therefore equal to

overall saving = (0.0249) (70,000 MCF) + (0.0219) (130,000 MCF)

= 4590 MCF per 200,000 MCF natural gas

or the overall saving is = 2.30%

or 4590 MCF of natural gas annually.

NOTE: The temperature drop of stack gas across the economizer was measured by Dean on 6 October, 1983. In the 50 psig mode, the temperature drop was 90°F. Thus, our assumed temperature drop of 93.1°F is a little high. This suggests that instead of 15% excess air, we really have somewhat higher excess rate, perhaps as high as 20%.

APPENDIX D

ANALYSIS OF THE CENTRAL STEAM PLANT

STACK ECONOMIZERS

APPENDIX D

STACK ECONOMIZERS PERFORMANCE

1. In reviewing the performance of the stack economizers with personnel from the Central Plant, the maintenance personnel indicate that the difference between the supply and return temperatures on the boiler feed side of the economizer range from 15° F to 50° F, with the latter figure only noted when one of the large boilers was running full open. To a certain extent, the temperature gain is a function of whether the small or large boiler is used, and what load is placed on the boilers.

2. Using these temperature differences, it is a straight-forward calculation to show theoretical maximum gain from the stack economizers. Calculations are attached. A summary is as follows:

Steam Pressure	Useable T,°F	% Reduction in Natural Gas	Yearly MCF* Savings
50 psig	15	1.50	1,050
50 psig	25	2.51	1,757
100 psig	36	3.57	4,641
100 psig	50	4.97	6,461

*Based on annual consumption of 70,000 MCF in the 50 psig mode, and annual consumption of 130,000 MCF in the 100 psig mode.

3. These calculations tend to suggest that the maximum savings from the stack economizer are in the range of 5,691 to 8,218 MCF per year.

4. In order to acquire a more precise estimate, we extracted from Central Plant records the data on a per shift basis, and have calculated an average value of 3.04% for the fifteen-month period. Extracted data included average values by shift for steam pressure, inlet and outlet temperatures and natural gas consumption. Using that percentage and the total natural gas consumption, produces a value of 7,294 MCF savings since the stack economizers were installed. This estimate could be off by as much as 5% (Range from 6,293 to 7,659 MCF) because of measurement uncertainties in the thermometer and steam pressure gages, or in the natural gas meter. At any rate, the estimate is the most precise that can be made with available data and does suggest that the economizers are saving roughly $29.000 per year at current natural gas prices.

Two Enclosures:
1. Sample Calculations
2. Computer Output

SAMPLE CALCULATIONS

Calculations:

Normally, the Central Plant is operated in two modes;

(A) 50 psig (steam temperature = 290°F)
(b) 100 psig (steam temperature = 338°F)

If two assumpstions are made about the temperature gain (ΔT) as follows:

(1) During the 50 psig mode, the temperature ΔT gained from the stack economizers ranges from 15 to 25°F
(2) During the 100 psig mode, the temperature ΔT gained from the stack economizers ranges from 36 to 50°F,

then, the probable benefit of the stack economizers can be estimated.

Basis: 1 lb of feed H_2O at 215°F

(A) 50 psig-mode;

(A-1) without the stack economizer, the total heat supply to bring 1 lb of H_2O @ 215°F to 1 lb of steam @ 50 psig, 290°F is equal to

$$\begin{aligned} Q &= \text{sensible heat} + \text{heat of vaporization} \\ &= [(1\text{ lb}) \times (1\text{ Btu/lb }^\circ F) \times (290-215)\ ^\circ F] + 922\text{ Btu} \\ &= 997\text{ Btu} \end{aligned}$$

(A-2) with the Stack economizers, the total heat supply required would be

$$\begin{aligned} Q &= [(1\text{ lb}) \times (1\text{ Btu/lb }^\circ F) \times (290-215)\ ^\circ F] + 922\text{ Btu} \\ &= 982\text{ Btu @ } \Delta T\text{ of } 25^\circ F \end{aligned}$$

Similarly,

$$Q = 972\text{ Btu @ } \Delta T\text{ of } 25^\circ F$$

Therefore, the maximum theoretical MCF reduction benefit from the stack economizers is

$$\Delta MCF = \frac{(997 - 982)}{997} \times 100\%$$

$$= 1.50\ \%\text{ @ } \Delta T\text{ of } 15^\circ F$$

Similarly,

$$\Delta MCF = \frac{(997 - 972)}{997} \times 100$$

$$= 2.51\ \%\text{ @ } \Delta T\text{ of } 25^\circ F$$

(B) 100 psig-mode;

(B-1) without the stack economizers, the total heat supply required to bring 1 lb of H_2O @ 215°F to 1 lb of steam @ 100 psig, 338°F is equal to

$$Q = [(1\ \text{lb}) \times (1\text{Btu/lb °F}) \times (338 - 215)\ \text{°F}] + 884\ \text{Btu}$$
$$= 1007\ \text{Btu}$$

(B-2) with the stack economizers, the total heat supply required would be

$$Q = [(1\ \text{lb}) \times (1\ \text{Btu/lb °F}) \times (338 - (215 + 36))\ \text{°F}] + 884\ \text{Btu}$$
$$= 971\ \text{Btu @ } \Delta T \text{ of } 36\text{°F}$$

Similarly,

$$Q = 957\ \text{Btu @ of } 50\text{°F}$$

Therefore, the maximum theoretical MCF reduction benefit from the stack economizer is

$$\Delta MCF = \frac{(1007 - 971)}{1007} \times 100\ \%$$

$$= 3.57\ \%\ \text{@ } \Delta T \text{ of } 36\text{°F}$$

Similarly,

$$\Delta MCF = \frac{(1007 - 957)}{1007} \times 100\ \%$$

$$= 4.97\ \%\ \text{@ } \Delta T \text{ of } 50\text{°F}$$

Summary Data

Extracted from Computer Analysis of Stack Economizers Performance

Data Based on Complete Records*

Month	% Complete Records	Fuel Used	Fuel Saved	Average % Savings
4/82	68.89	9,926	266.2	2.54
5/82	90.32	10,961	201.0	1.81
6/82	96.67	6,925	161.7	2.28
7/82	98.92	6,331	159.7	2.46
8/82	90.32	6,043	150.3	2.43
9/82	98.89	7,262	183.4	2.46
10/82	98.92	15,467	495.5	2.99
11/82	96.67	24,361	1,076.5	4.24
12/82	97.85	27,097	1,412.8	4.93
1/83	98.92	27,972	1,303.1	4.44
2/83	96.43	22,599	978.9	4.15
3/83	73.12	16,305	800.5	4.66
4/83	53.33	10,955	393.6	3.06
5/83	80.65	11,347	166.8	1.43
6/83	78.89	6,974	119.4	1.7
TOTALS	87.94	210,525	7,869.4	3.04
4/82 thru 3/83	92.15	181,249	7,189.5	3.28

*If you assume the "incomplete" records would show a similiar pattern, then total gas consumption would be 210,525 - 0.8794, or 239, 396 MCF, and 3.04% savings would produce 7,294 MCF savings.

APPENDIX E

TOTAL FUND EXPENDITURES DURING CONSTRUCTION

APPENDIX

TOTAL FUND EXPENDITURES DURING CONSTRUCTION

Construction Funds			BUDGET ESTIMATE	NM FUNDS FUND 715	DOE FUNDS	OTHER NM FUNDS
71501	Pipeline	TOTAL	$349,000.	375,472.		
00287	Buried Pipeline Material		$140,000.	$177,809.		
00288	Tunnel Pipeline Material		97,000.	62,384.	$ 6,928.00	
00289	Bleed Line Material		8,000.	354.		
00290	Water Line Material		4,000.	3,492.		
00291	Pipeline Labor		100,000.	131,432.		
71502	Gas Separator	TOTAL	11,000.	18,760		
00292	Steel Tank		$ 4,000.	$ 7,193.		
00293	Insulation		1,000.	1,074.		
00294	Excavation & Buriel		2,400.			
00295	Materials		1,200.	3,402.		
00296	Labor		2,400.	6,531.		
71503	Hot Water Storage Tank	TOTAL	76,700.	702,878.		
00297	Steel Tank		$ 39,000.	$ 50,041.		
00298	Insulation		5,000.			
00299	Excavation		1,500.	19,739.		
00300	Water Heaters		7,500.	----------		
00301	N. G. Pipeline		3,000.	----------		
00302	Materials		6,700.	12,265.		
00303	Labor		14,000.	20,742.		
71504	Well Pumps Testing	TOTAL	30,720.	66,180.		
00304	Pumps		$ 30,720.	$ 66,180.	$147,006.00	
00305	Resevoir Hydrology & Well		$147,006.			
71505	Power Line	TOTAL	$15,765.	$9,750.		
00306	Material		8,000.	----------		
00307	Labor		7,765.	9,750.		
71506	Primary Heat Exchangers	TOTAL	$ 48,000.	$ 37,348.		
00308	Heat Exchangers		42,000.	30,472.		
00309	Installation Labor		3,000.	4,862.		
00310	Materials		3,000.	2,014.		

71507	Pool Exchangers TOTAL	$ 6,000.	$ 8,165.		
00311	Heat Exchangers	4,500.	2,823.		
00312	Installation Labor	1,000.	5,000.		
00313	Materials	500.	342.		
71508	Heat Exchanger Equipment Building TOTAL	$ 22,500.	$ 23,519.		
00314	Materials	14,000.	8,215.		
00315	Labor	8,500.	15,402.		
71509	Instrumentation and Controls TOTAL	$ 89,000.	$ 101,286.		
00316	Control Valves	34,000.	33,159.		
00317	In-Line Pumps	15,000.	7,819.		
00318	Instrumentation	15,000.	30,108.		
00319	Labor	25,000.	30,200.		
71510	Building Retrofit TOTAL	$ 60,000.	$ 50,770.		
00320	Material	15,000.	$ 5,089.		
00321	Labor	15,000.	17,089.		
00322	PSL Material	20,000.	11.		
00323	Labor	10,000.	12,581.		
71511	Disposal System TOTAL	$ 65,000.	$ 50,770		
00324	Disposal Pipeline Material	5,000.	6,370.		
00325	Labor	15,000.	15,632.		
00326	Disposal Well	$ 40,000.	56.		$70,000
00327	Material	5,000.	116.		(EMD Fund 726)
71512	Local Transportation and Equipment Rental TOTAL	$ 15,315.	$ 8,398.		
00328	NMSU/PSL Vehicle Use	7,315.	$ 3,477.		
00329	Equipment Rental (construction equipment)	8,000.	4,921.		
71513	Contingency				
00330	A	$ 40,000.			
Project Management and Monitoring				$188,994.	
TOTALS:		$829,000.00	$829,000.	$336,000.	EMD DESIGN FUNDING; $125,000 $195,000.

APPENDIX F

ALTERNATIVE METHOD FOR ESTIMATING NATURAL GAS SAVINGS

APPENDIX F

Alternative Method for Estimating Natural Gas Savings

1. General

There is an alternative method of computing geothermal costs avoidance, which is based on actual useable BTU's delivered to the campus. These are measureable values, and one can use the imputed end-use system conversion and central plant efficiency to estimate natural gas offsets. In this regard, the Director of the NMSU Physical Plant Department suggested these two efficiencies have a combined value of 68-70 percent. Considering Central Plant average burner efficiency of 73.25%, the distribution and end-use efficiencies would have to be 93-96% for this number to be correct. In fact, we measured end-use efficiency at 65%. Moreover, since the football stadium and natatorium facilities are significantly different from the domestic hot water systems in the other buildings, an adjustment has been made to accomodate different values previously measured.

2. Based on the alternative method described above which ignores distribution losses, we estimate that the minimum geothermal cost avoidance for February was 5,227 mcf, which is $ 25,037 at $4.79/mcf. Please note that this reduction is larger than the actual February decrease (compared with the previous year) and relatively close to the data derived from the previous estimate. Calculations are attached.

Attachments:

1 Summary of February 1983 Geothermal Cost Avoidance

Geothermal Cost Avoidance Summary
February 1983
(Alternative Estimate)

(Data based on actual system measurements on 11, 18, and 21-25 March which are assumed to be representative of February data.)

1. Flow rate for Geothermal Heated Water.

Natatorium Complex:	52.5 gpm	(Outdoor Pool 45 gpm, indoor pool 5 gpm, space heat 2.5 gpm)
Other uses:	55 gpm	(Dormatory hot water)
TOTAL	107.5 gpm	(This is 24-hour average flow, delivered to the campus at 135-136°F.

2. Cost Avoidance

	mcf saved	$ saved
Domestic Hot Water:	2,917	$13,972
Football Stadium Heating:	424	2,031
Natatorium Complex		
Indoor Pool	248	1,188
Nat Space Heat	114	546
Nat Hot Water	160	766
	3,863	$18,503
Outdoor Pool (cost avoidance)	1,364	$ 6,534
	5,227	$25,037

NOTE: Above calculations exclude distribution steam system losses; thus, the savings and cost avoidance might be understated.

Incl 1

APPENDIX G

LAS CRUCES NATURAL GAS SALES

Las Cruces Natural Gas Consumption

1. Las Cruces natural gas system is a wholesale activity, with a city-owned distribution system, and a locally-owned subsidiary (Rio Grande Natural Gas Company). Records are maintained separately, but are all administered by the Controller's office for the City.

2. Records and reports were made available by the city, which depict for both wholesale companies the number and type of users, and the consumption of gas by user type and category. Records are available for each month for the period 1980-1983.

3. The number of users varies by season, but does show a distinct increase consistent with growth pattern. In summary form, the records show a typical winter/summer variance as follows (1982 data):

Total Yearly Consumption

User Category	MCF (@14.73 psi)	Winter High User Count	Summer Low User Count
Residential	923,338	19,068	17,147
Commercial	942,897	1,527	1,402
TOTAL	1,866,235	20,595	18,549

4. Commercial users include such large consumers as NMSU and Sandy Land Nurseries, plus a large number of smaller operations. Because the commercial sector includes some process heat (L'EGGS and other semi-industrial users) the residential sector consumption is considered to be a better statistical base from which to attempt to assess the effects of weather on natural gas consumption.

5. After adjustments were made to the 1982-1983 data to remove the effects of increases in users, residential consumption still showed an 16.11% increase over the previous year. This increase is an accurate reflection of the colder weather for the 1982-1983 year. Notably, December 1982 was up 33.45%, January 1983 increased by 23.28%, and April and May 1983 increased by 52.43% and 12.94% respectively compared with the previous year. See attached tabulation enclosed. For just the normal heating heating season of November through April, the cooler weather (22 percent by heating degree day measure) resulted in a 22.9 percent increase in natural gas consumption. (Encl. 1)

6. A similar analysis was made for the commercial only sector, and for the combined residential/commercial usage. As expected, because the commercial usage is relatively independent of weather effects, the weather correlation is not as distinct. Also attached are the comparative evaluations for winter 1980-1981 compared with winter 1981-1982. As expected, the winter 1981-1982 was warmer than the previous year, and consumption was reduced.

7. In reviewing the comparative data for Enclosure 1, several apparent inconsistencies can be resolved. Some of the residential usage in summer months is natural-gas operated refrigerated air conditioning equipment. Whether or not some of the new users employ this type of equipment cannot be determined without an exhaustive review of individual records. Lacking this, it would appear a warmer than normal summer would act to increase natural gas consumption. However, since the non-space heating months account for only 3,800 of the total 147,000 MCF variance, the effects are negligible. A more significant factor is the decreased level of consumption in March 1983. Although March of 1983 was a little warmer than the previous year, another explanation is likely. From the large volume of user complaints and inquiries, the city representatives deduce that likely there was a sharp drop caused by voluntary conservation. The cold weather in December and January occurred simultaneously with a sizeable rate increase. User protests were reflected in March consumption, and by April the users had accommodated to the higher prices and used their heaters again.

8. To correlate changes in consumption resulting from colder weather, the only available data are from the NMSU Weather Station. By many observers, the large variations in the city the size of Las Cruces caused by topography make the use of NMSU data extrapolated city-wide prone to error. In fact, a temperature variance can exist of as much as 7° F between the valley and the East Mesa. Wind efforts have a large effect on the heating load, and the wind effects are even more variable through-out Las Cruces. Accordingly, only a general trend can be safely deduced from available data.

7 Enclosures:

1. Residential only (1982-1983 vs 1981-1982)
2. Residential only (1981-1982 vs 1980-1981)
3. Commercial only (1982-1983 vs 1981-1982)
4. Commercial only (1981-1982 vs 1980-1981)
5. Residential and commercial (1982-1983 vs 1981-1982)
6. Residential and commercial (1981-1982 vs 1980-1981)
7. Comparitive weather data, NMSU Weather Station, Dr. Norm Malm

Las Cruces Residential Natural Gas Consumption (1982-1983 compared with 1981-1982)

Month	1982-83 Actual	1981-82 Actual	Variance 81-82 to 82-83	User Factor	Adjusted Variance	% "Weather" Induced Change 81-82 to 82-83
Jul	26,407	23,709	2,698	1.029	1,954	8.24
Aug	25,178	23,828	1,350	1.018	905	3.80
Sep	24,476	23,124	1,352	1.018	919	3.97
Oct	30,507	28,848	1,659	1.013	1,267	4.39
Nov	73,185	68,625	4,560	1.011	3,764	5.48
Dec (82)	184,193	(81) 134,925	49,268	1.023	45,127	33.45
Jan (83)	248,049	(82) 195,347	52,702	1.030	45,477	23.28
Feb	173,653	157,939	15,714	1.030	10,656	6.75
Mar	126,148	133,369	-7,221	1.020	-9,695	-7.27
Apr	122,725	78,016	44,709	1.032	40,904	52.43
May	53,815	46,306	7,509	1.029	5,992	12.94
Jun	NA	30,794	--	NA	--	--
TOTAL (11 Months)	1,088,336	914,036	188,742		147,270	16.11%

Based on approximately 19,000 residential customers connected to the Las Cruces/Rio Grande Natural Gas Co.

Residential Only (1981-1982 compared with 1980-1981)

Month	1981-82 Actual	1980-81 Actual	Variance 80-81 to 81-82	User Factor	Adjusted Variance	% "Weather" Induced Change 80-81 to 81-82
Jul	23,709	24,294	-585	1.035	-1,387	-5.71
Aug	23,828	22,414	1,414	1.045	388	1.73
Sep	23,124	23,660	-536	1.041	-1,447	-6.12
Oct	28,848	30,588	-1,740	1.049	-3,088	-10.10
Nov	68,625	93,016	-24,391	1.026	-26,130	-28.09
Dec (81)	134,925	(80) 167,474	-32,549	1.022	-35,453	-21.17
Jan (82)	195,347	(81) 196,756	-1,409	1.030	-7,099	-3.61
Feb	157,939	174,722	-16,783	1.030	-21,383	-12.24
Mar	133,369	131,439	1,930	1.031	-2,080	-1.58
Apr	78,016	93,268	-15,252	1.028	-17,377	-18.63
May	46,306	35,631	10,675	1.035	9,109	25.56
Jun	30,794	27,698	4,837	1.030	3,096	11.18
TOTAL (12 Months)	944,830	1,020,960	-76,130		-102,851	-10.07%

Commercial Only (1982-1983 compared with 1981-1982)

Month	1982-83 Actual	1981-82 Actual	Variance 81-82 to 82-83	User Factor	Adjusted Variance	% "Weather" Induced Change 81-82 to 82-83
Jul	39,511	41,262	-1,751	1.025	-2,715	-6.58
Aug	38,062	44,048	-5,986	1.015	-6,548	-14.87
Sep	60,309	42,734	17,575	1.035	15,536	36.35
Oct	64,604	64,416	188	1.017	-892	-1.38
Nov	116,280	121,595	-5,315	1.024	-8,040	-6.61
Dec (82)	173,469	(81) 141,557	31,912	1.054	23,025	16.27
Jan (83)	167,552	(82) 139,878	27,734	1.047	20,213	14.46
Feb	129,246	138,410	-9,164	1.030	-12,928	-9.34
Mar	114,892	118,346	-3,454	1.034	-7,233	-6.11
Apr	101,084	77,998	23,086	1.041	19,105	24.49
May	58,645	53,663	4,982	1.046	2,403	4.48
Jun	NA	43,996	--	NA	--	--
TOTAL (11 Months)	1,063,654	983,847	79,807		41,926	4.26%

Commercial Only (1981-1982 compared with 1980-1981)

Month	1981-82 Actual	1980-81 Actual	Variance 80-81 to 81-82	User Factor	Adjusted Variance	% "Weather" Induced Change 80-81 to 81-82
Jul	41,262	41,576	-314	1.004	-478	-1.15
Aug	44,048	38,676	5,372	1.022	4,424	11.44
Sep	42,734	41,866	868	1.004	698	1.67
Oct	64,416	54,328	10,088	1.028	8,333	15.34
Nov	121,595	136,911	-15,316	1.010	-16,520	-12.07
Dec (81)	141,557	(80) 151,859	-10,302	1.004	-10,866	-7.16
Jan (82)	139,818	(81) 159,099	-19,281	1.021	-22,157	-13.93
Feb	138,410	131,498	6,912	1.030	2,881	2.19
Mar	118,346	97,928	20,418	1.033	16,637	16.99
Apr	77,998	80,296	-2,298	1.020	-3,827	-4.77
May	53,663	51,110	2,553	1.029	1,041	2.04
Jun	43,996	45,605	-1,609	1.037	-3,179	-6.97
TOTAL (12 Months)	1,027,843	1,030,752	-2,909		-20,313	-2.23%

Residential and Commercial (1982-1983 compared with 1981-1982)

Month	1982-83 Actual	1981-82 Actual	Variance 81-82 to 82-83	User Factor	Adjusted Variance	% "Weather" Induced Change 81-82 to 82-83
Jul	65,918	64,971	947	1.029	-911	-1.40
Aug	63,240	67,876	-4,636	1.018	-5,754	-8.48
Sep	84,785	65,858	18,927	1.020	17,265	26.22
Oct	95,111	93,264	1,847	1.013	626	0.67
Nov	189,465	190,220	-755	1.012	-3,022	-1.59
Dec (82)	357,662	(81) 276,482	81,180	1.025	72,457	26.21
Jan (83)	415,601	(82) 335,165	80,436	1.032	67,549	20.15
Feb	302,899	296,349	6,550	1.030	-2,272	-0.77
Mar	241,040	251,715	-10,675	1.021	-15,633	-6.21
Apr	223,809	156,014	67,795	1.033	60,645	38.87
May	112,460	99,969	12,491	1.030	9,215	9.22
Jun	NA	74,790	--	NA	--	--
TOTAL (11 Months)	2,151,990	1,897,883	254,107		200,165	10.55%

Residential and Commercial (1981-1982 compared with 1980-1981)

Month	1981-82 Actual	1980-81 Actual	Variance 80-81 to 81-82	User Factor	Adjusted Variance	% "Weather" Induced Change 80-81 to 81-82
Jul	64,971	65,870	-899	1.032	-2,914	-4.42
Aug	67,876	61,090	6,786	1.043	3,988	6.53
Sep	65,858	65,526	332	1.038	-2,079	-3.17
Oct	93,264	84,916	8,348	1.048	4,076	4.80
Nov	190,220	229,927	-39,707	1.025	-44,347	-19.29
Dec (81)	276,482	(80) 319,333	-42,851	1.020	-48,272	-15.12
Jan (82)	335,165	(81) 355,855	-20,690	1.030	-30,452	-8.56
Feb	296,349	306,270	-9,921	1.030	-18,553	-6.06
Mar	251,715	229,367	22,348	1.031	14,779	6.44
Apr	156,014	173,564	-17,550	1.027	-21,652	-12.47
May	99,969	86,741	13,328	1.035	9,847	11.35
Jun	74,790	73,303	1,487	1.031	-762	-1.04
TOTAL (12 Months)	1,972,673	2,051,762	-79,089		-136,341	-6.65%

APPENDIX H

CALCULATION OF NET ENERGY ANALYSIS

APPENDIX H

CALCULATION OF NET ENERGY ANALYSIS

The following are detail calculations of net energy analysis, by category, for total energy expended on the project in 15 years. The geothermal resource is considered free and renewable.

Well Drilling

There is a total of six drilled wells. The energy requirement for well drilling in our type of formation is as follows;

(a) Two 100 HP machineries which consumed 5-10 gal/hr each.
(b) Drilling rate of 25-50 feet per hour.

(1) PG-1 and PG-3; each 850 feet, 10-inch well.

(a) Fuel; each 10 gal/hr
(b) Drilling rate; each 25 ft/hr

$$\text{Total fuel consumed} = 24{,}850 \text{ ft } \frac{(10 \text{ gal/hr})}{(25 \text{ ft/hr})}$$

$$= 680 \text{ gallons}$$

(2) Observation well OW-1; 850 feet, 4-inch well.

(a) Fuel; 6 gal/hr
(b) Drilling rate; 40 ft/hr

$$\text{Total fuel consumed} = 850 \text{ ft } \frac{(\ 6 \text{ gal/hr})}{(40 \text{ ft/hr}}$$

$$= 128 \text{ gallons}$$

(3) DT-1 (1000') and DT-2 (1200'); 2 3/8-inch wells.

(a) Fuel; 5 gal/hr

(b) Drilling rate; 50 ft/hr

$$\text{Total fuel consumed} = 2200 \text{ ft } \frac{(5 \text{ gal/hr})}{(50 \text{ ft/hr})} = 220 \text{ gallons}$$

(4) GD-2; 1,000 feet of drilling.

(a) Fuel; 7 gal/hr

(b) Drilling rate; 30 ft/hr

$$\text{Total fuel consumed} = 1{,}000 \text{ ft } \frac{(7 \text{ gal/hr})}{(30 \text{ ft/hr})} = 233 \text{ gallons}$$

(5) Transportation energy for well drilling. Assume 500 miles of transportations of rig and other related materials for each well drilling, also assume a vehicle mileage of 10 mpg. The total fuel consumption is therefore equal to;

$$\text{Transportation fuel} = 6 \times \frac{500 \text{ miles}}{10 \text{ mile/gal}} = 300 \text{ gallons}$$

Combining all items, the total energy of well drilling is equal to 1,560 gallons of fuel which is equivalent to;

$$\text{BTU equivalent} = (1{,}560 \text{ gal})(135{,}000 \text{ BTU/gal}) = 211 \times 10^6 \text{ BTU}$$

33.5.4.2 Well Completion

The energy expended for well completion may be categorized into;

(a) Energy consumption for iron and steel making, plus design weight of metal used to fabricate well casings, well pumps, pump columns, etc.

(b) Fuel consumption for well completion such as fuel for machineries used in setting well casings, and well pumps.

(1) PG-1 and PG-3;

2 x 850 feet of 10-inch casing = (2 x 850 ft)(40.5 lbs/ft)
2 x 650 feet of 5-inch pump column = (2 x 650 ft)(14.6 lbs/ft)
2 x 650 feet of 2-inch oil tube = (2 x 650 ft)(3.7 lbs/ft)
2 x 650 feet of 1 3/16-inch shaft = (2 x 650 ft)(5 lbs/ft)
Sub Total = 104,980 lbs
Plus pump bowl and motor = 241,500 lbs

(2) OW-1;

850 feet of 4-inch casing = (850 ft)(10.8 lbs/ft)
= 9,180 lbs

(3) DT-1 (1000') and DT-2 (1200');

Each well is of 2 5/8-inch heavy well casing

Total weight = (2,200 ft)(7.7 lbs/ft)
= 16,940 lbs

(4) GD-1 and GD-2;

Each well is of 8-inch casing, and completed to 500 feet.

Total weight = (2 x 500 ft)(24.7 lbs/ft)
= 24,700 lbs

Combining (1), (2), (3) and (4), the total weight of steel required for well completion = 155,800 lbs. Energy required to fabricate 155,800 pounds of steel materials is;

Energy consumed = (155,800 lbs)(3,500 lb/lb)
= 556 x 10^6 BTU

Fuel consumption in setting and completing wells is also considered as expended energy. It was estimated from the size of machineries used to be 700 gallons of fuel used for system well completion. This is equivalent to;

Energy consumed = (700 gal)(135,000 BTU/gal)
= 45 x 10^6 BTU

The total energy for well completion is therefore (556 + 95) x 10^6 BTU

or, = 651 x 10^6 BTU

33.5.4.3 Pipe Fabrication

The system pipeline consists of both steel and asbestos-cement pipes. Energy consumption for pipe fabricating was based on the published figures of energy for steel and asbestos-cement making.

(1) Insulated pipes (Temptite);

1,100 feet of 4-inch pipe (PG-3 to gas separator),
Section weight = (1,100 ft)(19 lb/ft) = 20,900 lbs
4,650 feet of 6-inch pipe (gas separator to H/E),
Section weight = (4,650 ft)(8,400 ft)(23 lb/ft) = 193,200 lbs

Total temptite pipe weight = 321,050 lbs. Since the energy for fabricating asbestos-cement ≃ 1,200 BTU/lbs, the total equivalent BTU for fabricating pipes is;

Energy consumption = (321,050 lbs)(1,200 BTU/lb)
= 385 x 10^6 BTU

(2) Uninsulated asbestos-cement pipe;

2500 feet of 6-inch asbestos-cement pipe from H/E main H/E to disposal well,

Section height = (2,500 ft)(12.3 lb/ft)
= 30,750 lbs

The equivalent energy for fabricating this pipe section is;

Equivalent BTU = (30,750 lbs)(1,200 BTU/lb)
= 37 x 10^6 BTU

(3) Steep pipes for distribution of DHW to all end users;

2,500 feet of 6-inch pipe; weight = (2,500 ft)(19.0 lb/ft)
3,500 feet of 4-inch pipe; weight = (3,500 ft)(10.8 lb/ft)
3,000 feet of 3-inch pipe; weight = (3,000 ft)(7.6 lb/ft)
3,000 feet of 2-inch pipe; weight = (3,000 ft)(3.7 lb/ft)
Total Steel = 121,900 lbs

Equivalent BTU for steel making = (121,900 lbs)(3,500 BTU/lb)
= 427 x 10^6 BTU

(4) Miscellaneous;

Total weight of miscellaneous items such as values, fittings, and system components for 6-inch, 4-inch, 3-inch, and 2-inch piping is approximately 60,000 pounds, and the equivalent BTU = (60,000 lbs)(3,500 BTU/lb).
= 210 x 10^6 BTU

Combining (1), (2), (3) and (4), the total energy consumed for pipe fabrication is equal to 1,059 x 10^6 BTU.

33.5.4.4 Heat Exchangers, gas separators, and hot water storage tank

(1) Heat Exchangers;

There are two large units as primary heat exchangers, and two smaller units for the indoor and outdoor swimming pools. The total weight of the heat exchanger system which includes associated piping, valves, and pumps is 24,000 lbs. In terms of expended energy for fabrication;

Equivalent BTU = (24,000 lbs)(3,500 BTU/lb)
= 84 x 10^6 BTU

(2) Gas Separator;

The total weight of the gas separator, plus piping and valves is 20,000 lbs;

Equivalent BTU = (20,000 lbs)(3,500 BTU/lb)
= 70×10^6 BTU

(3) Hot Water Storage Tank;

The weight of the hot water storage tank is 48,000 lbs, plus 24,000 lbs for piping, valves, and pumps. Thus, the total hot water storage system weight is 72,000 lbs equivalent of steel.

Equivalent BTU = (72,000 lbs)(3,500 BTU/lb)
= 252×10^6 BTU

33.5.4.4 Insulation

Energy expended for fabrication of insulating materials for the system pipeline, and hot water storage tank is determined from heat of formation for design amount of insulating materials. Approximately 600 BTU is required for processing one pound of insulation. It is estimated that 20,000 lbs of insulation was used for the system pipeline, and 5,000 lbs of insulation was used for the hot water storage tank and the gas separator. Energy consumption is equivalent to;

Energy consumed = (25,000 lbs)(600 BTU/lb)
= 15×10^6 BTU

33.5.4.5 Installation

Approximate figures on hourly fuel consumption of trenching and welding machinery, plus the total hours of operation in completing the system.

(1) Trenching;

Approximately 300 hours of trench work with two 200-HP machinery (each consumed approximately 10 gallons of fuel per hour);

Total fuel used = (2 x 10 gal/hr)(300 hrs)
= 6,000 gallons

In terms of BTU equivalent, this is equal to;

Energy = (6,000 gal)(135,000 BTU/gal)
= 810 x 10^6 BTU

(2) Welding;

Approximately 750 hours of welding work which consumed 0.1 x 10^6 BTU per hour. The total energy associated with system welding is, therefore, equal to 75 x 10^6 BTU.

The total installation energy is thus = (1) + (2)
= 885 x 10^6 BTU

33.5.4.6 Maintenance and Operations

(1) Maintenance;

Due to abnormally frequent well pump failures, the energy of well pumps and system maintenance can only be crudely estimated for the operation over the 15-year period. The following is the basis of energy cost estimation;

(a) Sixteen pump removals which includes six new pumps, four new shafts, and four new pump columns replacement. This amounts to 56,960 lbs of steel fabricating the equivalent energy for the fabrication process is equal to (56,960 lbs)(3,500 BTU/lb), or 199 x 10^6 BTU.

(b) Estimate eight hours of operation was required for each pump removal, and a rig of 150 HP which consumed five gallons of fuel per hour was needed.

Total fuel used = 16 x 8 hours x 5 gal/hr
= 640 gallons

or, equivalent BTU = (640 gals)(135,000 BTU/gal)
= 86×10^6 BTU

(c) Estimate 1,000 miles of vehicle used per operation at fuel consumption rate of 10 miles per gallon.

Total fuel consumed = 16 x 1,000 miles x 1 gal/10 miles
= 1,600 gallons

or, equivalent BTU = 1,600 gals)(135,000 BTU/gal)
= 86×10^6 BTU

(2) Operations;

Estimated 30 mile per day of vehicle used at 15 mpg is required on a steady basis for maintaining the operation. The total fuel consumption over the 15-year period (240 days per year) is equal to;

$$\text{Fuel consumption} = \frac{30\ \text{mile}}{\text{day}}\ \frac{240\ \text{day}}{\text{year}}\ (15\ \text{years})\ \frac{1\ \text{gal}}{15\ \text{miles}}$$

$$= 7{,}200\ \text{gallons}$$

$$\text{and, equivalent BTU} = (7{,}200\ \text{gallons})(135{,}000\ \frac{\text{BTU}}{\text{gal}})$$

$$= 972 \times 10^6\ \text{BTU}$$

The total maintenance and operations = (1) + (2)
= $1{,}473 \times 10^6$ BTU

33.5.4.7 Energy for Well Pumping

The system operation energy was based on the actual data of annual electricity consumption for well pumping. Expended energy for producing electricity was computed at 30% overall efficiency. The total energy consumed for well pumping over a 15-year period at 0.5×10^6 KW-hr per year is equal to;

$$\text{Energy consumption} = 0.5 \times 10^6 \ \frac{\text{KW-hr}}{\text{year}} \ \frac{3413 \text{ BTU}}{\text{KW-hr}} \ (15 \text{ years}) \ \frac{1}{0.30}$$

$$= 85{,}325 \times 10^6 \text{ BTU}$$

33.5.4.8 Natural Gas Use Replaced

The energy extracted from geothermal fluid is used for domestic hot water heating which otherwise would be heated by burning natural gas. The amount of natural gas use replaced by geothermal energy is determined from:

(a) The flowrate of domestic hot water; 100 gpm.
(b) Temperature add (ΔT) to the domestic water; 75°F.
(c) The overall system efficiency; this overall system efficiency includes; the efficiency of central heating plant (80%), and end use efficiency (65%).

Energy credit over the 15-year project life operation at 240 days per year is equal to;

Energy credit =

$$\text{Energy credit} = (100 \text{ gpm}) \ \frac{500 \text{ lb/hr}}{\text{gpm}} \ (75^\circ\text{F}) \ \frac{1 \text{ BTU}}{\text{lb}^\circ\text{F}} \ \frac{5{,}760 \text{ hrs}}{\text{year}} \ \frac{1}{0.80 \times 0.65}$$

$$= 623{,}080 \times 10^6 \text{ BTU}$$