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WILLIAMS HOLDING LEASE, STEAMFLOOD
DEMONSTRATION PROJECT, CAT CANYON
OIL FIELD

Topical Report I. Project Design and Development

By
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MASTER

June 1977

Work Performed Under Contract No. EY-76-C-03-1188

Getty Oil Company
Ventura, California

U. S. DEPARTMENT OF ENERGY

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GETTY OIL COMPANY
WESTERN EXPLORATION AND PRODUCTION DIVISION

COASTAL DISTRICT
VENTURA, CALIFORNIA

TOPICAL REPORT I
PROJECT DESIGN AND DEVELOPMENT

E. J. Hanzlik, Editor

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J. Q. Herrera
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Contract No. E(04-3)-1188

Prepared for
Energy Research and Development Administration

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STEAMFLOOD DEMONSTRATION PROJECT
CAT CANYON OIL FIELD

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FOREWORD

The Nation's continued heavy reliance on liquid fossil fuels is demonstrated by the dwindling production of domestic oil and gas and uncertain continuity of imported fuels.

The ERDA enhanced oil recovery program is aimed at bolstering domestic production and thereby reducing our reliance on foreign oil. One of the chief efforts of the program is to generate and foster cost-sharing projects with industry to develop and demonstrate recovery methods which will increase production rates and ultimate recoveries from oil and gas fields. Data generated from the projects are designed to aid in evaluating the economic and technical risks more quickly and confidently. Transfer of the technology which has been developed to the petroleum industry and the general public is facilitated.

The Cat Canyon Steam Flood Pilot Demonstration Project is one of the enhanced oil recovery cost-shared projects presently in progress. This topical report documents the project design and development. Subsequent reports will describe research efforts in connection with the project on specific technical areas of interest to industry and will complement the annual reports for the project.

Alan J. Leighton
Technical Project Officer

INTRODUCTION

The Cat Canyon Field is located approximately eight miles southeast of the town of Santa Maria in Santa Barbara County, California (Figure 1). It is contained within the Santa Maria Basin, which lies between the westward trending Santa Ynez mountains on the south and the northwestward trending San Rafael mountains on the northeast.

The Sl-B Sand of the Cat Canyon Field is a relatively deep, heavy crude reservoir. It is found at an average depth of 2500 feet and produces a 9°API crude oil which has an estimated average oil viscosity of 25,000 centipoises at reservoir conditions (fully gas saturated). Although the field was discovered in 1908, only sporadic, generally unsuccessful development of the Sl-B Sand occurred prior to the advent of steam stimulation techniques in the 1960's.

Getty Oil Company has been utilizing steam stimulation to successfully recover this crude since 1964. To date, approximately 120 steam stimulation wells have been completed in the Sl-B Sand. However, only an estimated 10-15% of the initial oil in place will be recovered by steam stimulation.

In an early attempt to improve the recovery efficiency of the Sl-B, Getty Oil Company initiated a pilot steamflood on its Williams Holding Lease in 1966. By 1968, the pilot included 6 inverted 10-acre 5-spot patterns (Figure 2). However, a high incidence of casing failures due to the thermal stresses created by the high temperature steam (up to 550°F) combined with the low price of crude oil (just over \$1/bbl.) caused the project to be uneconomic. This initial attempt at steamflooding the Sl-B was terminated in 1970.

Figure 1
LOCATION MAP

Figure 2
EXTENT OF SI-B OIL SAND
SHOWING ORIGINAL PILOT

A review of the performance of this pilot, however, shows some significant response to steam displacement. Williams Holding 62A-25, the only well surrounded by 4 injectors during the full life of the project, showed good response, averaging nearly 150 BOPD for 3 years. Figure 3 shows Williams Holding 62A-25 production response.

By 1974, the casing failure problems encountered early in the life of S1-B thermal operations had been overcome by use of stronger couplings and application of a tensile pre-stress. Also, significant improvement in oil prices had occurred. These two factors, along with an increased understanding of the steam-flooding process, justified design of a second pilot steamflood.

Figure 3
 WILLIAMS HOLDING 62A-25
 PRODUCTION RESPONSE TO 1966-70 PILOT PROJECT

PILOT DESIGN

Design Criteria

The pilot project design was based on two primary criteria:

1. The operational characteristics should be essentially the same as those to be used for full-scale development.
2. The design of the pilot should not deviate dramatically from that of successful steamfloods.

The goal of the first criterion is to provide operating experience and results which can be applied to forecasting the performance of a future full-scale project. The second criterion was applied because the known characteristics of the S1-B Sand do not indicate any reason why a conventional displacement technique should not be successful, even though the S1-B will provide a very severe test of the process.

Pattern and Location

The initial design decision was that the pilot should consist of a minimum of four inverted five-spot patterns. This configuration was selected because it is the smallest possible five-spot configuration that will maintain confinement around at least one producing well. The selection of a five-spot pattern rather than an inverted seven-spot or inverted nine-spot pattern was based on two reasons:

1. Post-steamflood core holes in the Kern River Field have shown very high sweep efficiencies for repeated five-spot patterns;
2. Studies at Getty Oil Company's research center have shown that any additional sweep efficiency obtained by using inverted seven or nine-spot patterns is not sufficient to justify the additional well costs incurred.

The location selected is on the southwest portion of the Williams Holding Lease, and is shown in Figure 4. It was selected because it was in a previously undeveloped region of the reservoir, but a region in which the initial wells showed good production response to steam stimulation. Also, the reservoir characteristics appeared to be uniform and typical of the major productive area of the reservoir. Data obtained during subsequent drilling confirmed this.

The selection of an essentially virgin portion of the reservoir as the pilot site offered several advantages:

1. All wells would be new, thus lessening the chances of mechanical problems;
2. The drilling of new wells would provide the opportunity to acquire maximum reservoir data; and
3. The project would not be in an area containing residual heat from the 1966-70 pilot.

Computer Simulator

Following selection of the pilot pattern and location, a computer simulation study was conducted to help optimize the two most important operational criteria for a conventional five-spot steamflood - pattern size and steam injection rate schedule. The pilot project could then be designed to approximate future full-scale development.

The computer simulation study was conducted using a sophisticated thermal simulation model jointly developed by Getty Oil Company and Intercomp Resource Development and Engineering Inc. The Thermal Model is a three-dimensional non-isothermal reservoir simulator that will calculate flow behavior of steam and hot water injection processes. This model is used much the same as any conventional computer model. That is, the reservoir is represented by dividing it into a

Figure 4
EXTENT OF SI-B OIL SAND
SHOWING CURRENT PILOT

set of connected cells or grid blocks. Flow from one cell to another is controlled by Darcy's law modified for three-phase flow. The resultant mass balance equations, one for each phase, are solved simultaneously with an energy balance equation. The solution process is stepped forward in time in a series of discrete time increments. At each time the "solution" is represented as the set of pressures, fluid saturations and temperatures calculated for each cell. Fluid injection and production volumes are also supplied. The model can be run in one dimension, two dimensions areally or vertically (cross-section), or in three dimensions.

The model equations account for viscous, gravity, and capillary forces affecting the three-phase flow of water, oil, and steam-hydrocarbon gas mixture in heterogeneous formations. The equations also represent the transport of heat by conduction to overlying and underlying strata. The model, in its most general usage, treats oil as a 3-component mixture consisting of solution gas (component 1), an intermediate distillable component (component 2), and a non-volatile component (component 3). Vaporization and condensation of the volatile components depends on local temperatures and pressures. The gas phase will thus contain three components - hydrocarbon components 1 and 2 as well as steam. Hydrocarbon mass transfer between the liquid and vapor phases is handled through the use of equilibrium K-values which are represented as functions of temperature and pressure. Saturated water and steam PVT behavior obey the thermodynamic constraints set forth in the steam tables. The oil and gas phase densities and gas viscosity are treated as functions of temperature, pressure and composition. Oil phase viscosity is a function of temperature and composition; and water viscosity is a function of tempera-

ture only. Relative permeabilities and capillary pressures are treated as functions of fluid saturations in accordance with Stone's⁽¹⁾ recent simplified method and also incorporates a rather flexible but simple representation of temperature dependence. The gas phase relative permeability curve incorporates a hysteresis effect reflecting the critical gas saturation during periods of rising gas saturation and residual gas saturation during periods of decreasing gas saturation.

The primary oil recovery mechanism reflected in the model calculations is viscous displacement enhanced by the reduced oil viscosity at elevated temperatures. A secondary mechanism simulated in cases where distillation occurs is the "solvent extraction" resulting from the stripping of lighter ends from the oil in the steam bank and their transport to the leading edge of the steam bank where they condense. This effect lightens the oil at the leading edge causing the oil viscosity to be reduced at that point.

In cases where solution gas and/or distillation effects are insignificant, the model simply treats flow of a single-component oil, steam, and water.

The model has been extensively compared with laboratory experimental results including data obtained by Willman, et al,⁽²⁾ Shutler,⁽³⁾ and Getty Oil Company Exploration and Production Research. These laboratory data range from one-dimensional to three-dimensional steamfloods and include temperature distribution, time of fluid breakthrough, oil production, and water-oil and steam-oil ratios. Agreement between experimentally observed and model calculated results has been generally good. Application of the model to an actual five-spot steamflood in the Kern River Field has also been accomplished with reasonably good agreement between observed and calculated behavior⁽⁴⁾.

More specific details of the model formulation and methods of solution can be found in references 5 and 6.

Analysis of Distillation Effects

Before proceeding with studies to select the pattern size and injection rates, a preliminary study was made to determine if crude oil distillation effects were significant enough to justify their inclusion in all model runs.

To test the effect of including crude oil distillation characteristics on the simulator-predicted oil production of this very heavy, viscous crude, two cases were run - one with and one without distillation effects. One-eighth of a five acre five-spot was modeled using a sand thickness of 75 feet and a constant injection rate of 500 barrels of water as steam per day. The data used for the reservoir simulations are listed in Appendix A.

The oil production comparison for the two runs is shown in Figure 5. Although the daily production rates vary somewhat for the two runs, the cumulative production after six years of steam displacement was only 3% greater for the run with distillation than for the run without distillation. The differences between the two runs were not significant enough to warrant the extra cost of using the distillation capabilities of the model for the remainder of the study. To have included these effects would have increased the computer cost by nearly 50%.

Injection Rate Optimization

The general plan for this phase of the study was to make a carefully selected series of computer runs using a variety of injection rate schedules for each of the two pattern sizes

Figure 5

COMPARISON OF OIL PRODUCTION-WITH AND WITHOUT DISTILLATION

(2-1/2 and 5 acres). The output from the runs would be used to select the "best" pattern size and injection rate schedule.

The pattern sizes were restricted to 2-1/2 and 5 acres for three reasons:

1. The previous S1-B pilot had been on 10-acre spacing. This spacing may have contributed to the problems encountered of premature steam breakthrough at some of the producers. 10-acre spacing may have been too large to overcome heterogenities causing preferential flow of steam in some directions. Consequently, a smaller spacing may give better operational control over the pilot.
2. Current spacing of S1-B stimulation wells is 5 and 10-acres. Infill wells would be on 2-1/2 and 5-acre spacing.
3. Optimum Kern River Field steamflood pattern size had been determined by field experience and computer thermal simulator studies to be 2-1/2 acres for sand thicknesses similar to S1-B thicknesses. However, since the S1-B sand is at a much greater depth than the Kern River formation, optimum Cat Canyon spacing was considered to be at least 2-1/2 acres for economic reasons.

To be perfectly complete, the study would entail running every possible injection rate schedule for each spacing. However, the number of runs and computer cost for this type of study would be prohibitive. For instance, if the study were limited to only 5 possible yearly rates for each of 5 years, the number of runs required would be 6,250.

If a number could be generated for each operating scheme that would be a measure of its "desirability", the number of

runs could be reduced significantly. Thus the first task was to select an appropriate objective function to maximize. This function should be based on the design of the particular operating scheme and its corresponding predicted production rates. This function should also closely reflect the major goals of the project.

The first function considered was present worth. Although industry normally uses present worth as one of the primary criteria for evaluating nearly all projects, it was felt that it had drawbacks for this study. First, there existed tremendous uncertainty in what oil prices and operating costs should be used in the present worth calculation. Second, the primary goal of the pilot is to determine the technical feasibility of steamflooding the S1-B Sand. For this reason it was decided to use a function related to saleable oil to determine the "desirability" of various injection rate schemes. This function is called the Cumulative Discounted Net Oil (CDNO), and is a function of three things:

1. Oil produced,
2. Oil burned for fuel, and
3. Time value (discounting) of the net oil produced.

The CDNO was calculated as follows:

$$CDNO = \sum_{t=1}^n \left[\frac{CNO_t - CNO_{t-1}}{(1+d)^{t-.5}} \right]$$

where,

CNO_t = cumulative net oil (produced minus burned)
at the end of t years

n = total number of years that $CNO_t > CNO_{t-1}$

d = discount rate (decimal)

This criterion closely represents the goals of the pilot. In effect, using CDNO optimizes saleable oil discounted to give weight to alternatives that produce oil quickly. Also, it is free of the uncertainties of costs and prices.

The next step was to select the variables necessary to describe the various injection rate schedules to be considered. Before proceeding, however, it was decided to place the following restrictions on the injection rates.

1. The maximum injection rate should be 1000 BSPD. This was felt to be an upper limit because of field operating experience as to pressure limitations. Experience with the pilot should indicate whether this is a true limitation.
2. Rates should change only in increments of 100 BSPD. Smaller increments were not felt to be reasonable from operating considerations.
3. Rates should not change more often than yearly. Since changing rates involves rearrangement of piping, etc. for maximum generator utilization, yearly changes seemed reasonable.
4. The initial injection rate should not change until after steam breakthrough. Since little recovery is usually seen prior to steam breakthrough when the wells are kept pumped off, there seemed little justification for allowing rates to change prior to breakthrough.

A number of different cases were run for both the 2-1/2 and 5-acre pattern sizes. The CDNO was calculated for each case. Based on the CDNO criterion and the above restrictions,

the following optimum injection rate schedules were found for each pattern:

<u>Year</u>	<u>BSPD Injection, 2-1/2 Acre Optimum</u>	<u>BSPD Injection 5 Acre Optimum</u>
1	500	1000
2	500	700
3	400	600
4	400	500
5	300	400

Both cases had a negative net oil stream during the sixth year. Thus, injection was terminated after five years. The model predictions show that little oil will be produced after injection ceases.

The predicted recovery for the optimum 2-1/2 acre run was 63% of original oil in place. The recovery for the 5-acre optimum was 51% of original oil in place.

The optimum production performance for each pattern size is shown in Figure 6.

Selection of Pattern Size

Although the Cumulative Discounted Net Oil criterion was used to rank injection rate alternatives, it was decided to use present worth to select the optimum pattern size. Since this was a simple selection between 2-1/2 acre and 5-acre pattern sizes, a variety of costs and prices could be considered without unduly complicating the present worth analysis.

The analysis was run on a per pattern basis; i.e., 1 injector, 1 producer, and the fraction of a 50MM Btu/hr steam generator needed for the initial injection rate. This method of comparison is equivalent to that of full scale steam displacement economics.

Figure 6
OPTIMUM RATE
STEAM DISPLACEMENT RESPONSE

Capital expenses included well costs, generator and flue gas scrubber costs, and upgrading of central facilities. Operating costs were estimated based on a combination of fixed well costs and allocated costs varying with oil and fluid production, and fuel usage. It was assumed that high tier oil would be produced and burned as fuel. Therefore the production stream was net oil production. The following was used for the analysis:

2-1/2 ACRE CASE

<u>Year</u>	<u>Inj. Rate (BSPD)</u>	<u>Net Oil Produced (M-Bbls)</u>	<u>Operating Costs (M\$)</u>
1	500	50.1	121
2	500	22.3	91
3	400	5.5	62
4	400	3.3	61

Capital Costs (M\$)

	<u>Tangible</u>	<u>Intangible</u>	<u>Total</u>
Producer	96.4	54.6	151
Injector	69.5	71.6	141.1
1/5 Generator	104.4	0	104.4
Central Facilities	<u>43.0</u>	<u>0</u>	<u>43.0</u>
TOTAL	313.3	126.2	439.5

5 ACRE CASE

<u>Year</u>	<u>Inj. Rate (BSPD)</u>	<u>Net Oil Produced (M-Bbls)</u>	<u>Operating Costs (M\$)</u>
1	1000	73.7	201
2	700	31.2	123
3	600	26.5	106
4	500	10.0	81

Capital Costs (M\$)

	<u>Tangible</u>	<u>Intangible</u>	<u>Total</u>
Producer	96.4	54.6	151.0
Injector	69.5	71.6	141.1
1/3 Generator	174.0	0	174.0
Central Facilities	<u>59.0</u>	<u>0</u>	<u>59.0</u>
TOTAL	398.9	126.2	525.1

Economic analyses using the above production and expense streams showed that both the 2-1/2 acre and 5 acre would show a net operating loss beginning in the fifth year. Consequently, injection was stopped after the fourth year. Present worth analyses of the after tax cash flows showed that the 2-1/2 acre pattern resulted in a net loss, while the 5 acre pattern was profitable. Thus it was decided to use four 5 acre patterns for the pilot steamflood.

Operational Considerations

The simulator runs made in the initial optimization phase of this study assumed ideal operating conditions. After determining the optimum injection rates for these idealized conditions, a more severe review of the simulator prediction was made.

One of the assumptions initially made was that production wells were continually pumped off (100 psia sandface pressure). This is the reason for the extremely high peak production rates shown for the optimum case. This ideal condition was used for two reasons. First, there was no way of knowing what portion of the water being produced by the model would actually flash to steam and be produced from the casing rather than through the pump. Second, it is not known what production rates can be achieved in the field - particularly if very high rates cause unforeseen production problems. This is one of the reasons for performing a pilot project.

Another of the initial assumptions was that a maximum injection rate of 1,000 barrels of water per day (as steam) could be injected into each injector. This maximum rate was set based upon experience which showed this rate to be achievable for most steam stimulation wells (which have essentially the entire zone open to injection/production). Since the steamflood injectors were to have only the bottom one-third of the zone open, this 1,000 barrel per day rate was arbitrarily chosen as the maximum rate to be studied. Close review of computer simulations using the 1,000 BSPD injection rate revealed a short period of abnormally high, localized reservoir pressures surrounding the injection well. Since evidence of these short term, undesirably high pressures was found under the averaged reservoir conditions used in the simulator, there was some concern about whether the 1,000 BSPD rate could be achieved in all injection wells due to the normal variation in reservoir properties.

A third concern which arose regarding the use of the theoretical optimum injection rate of 1,000 BSPD was that of equipment utilization. In any thermal project it is necessary to maximize the use of steam generation equipment due to the very large amount of capital invested in it. In a large-scale, expanding project it is relatively easy to provide a great deal of injection rate flexibility while still maintaining a high degree of equipment utilization. Such is not the case for a relatively small pilot steamflood. This consideration, along with the potential inability to achieve a 1,000 BSPD per well injection rate and maintain the producing wells in a pumped-off condition, led to a compromise design for the pilot.

The compromise decided upon was a constant injection rate of 600 BSPD for five years. This rate should be readily achievable and will permit maximum utilization of one 50 million BTU/hr steam generator. In addition, it is reasonably certain that the producing wells can be maintained in a pumped off condition at this injection rate. A simulator run was made for this operating scheme which showed that the predicted net oil recovery was within 0.5% of that predicted for the optimized injection rate. However, the proposed operating method did result in an 8.5% reduction in predicted Cumulative Discounted Net Oil. This decrease was considered acceptable, since sufficient data will be gathered from the pilot operation to determine if the higher rates recommended by the optimization procedure are achievable. Thus the 600 BSPD per well pilot operation will demonstrate the recovery potential of the steamflooding process in the S1-B Sand and provide the operating data required to optimize the economic performance of future steamflood expansion in the zone. The predicted performance for the 600 BSPD injection rate is shown in Figure 7.

Figure 7
STEAM DISPLACEMENT RESPONSE
5 ACRE PATTERN, 600 BSPD CONSTANT RATE

WELL DESIGN

Production Wells

The production wells are typically completed with approximately 2500' of 7", 23#, N-80 casing, the shoe of which is set just below the top of the Sl-B zone, and 5-1/2", 17# slotted liner gravel packed across the Sl-B producing interval.

The 7" casing is cemented using two cement slurries. The first slurry is API Class "G" cement with 1:2 expanded perlite, 40% silica flour, and treated for 12 hours setting time. This cement is followed by 100 cubic feet of luminite cement mixed with 20% silica flour and treated for 1500 psi compressive strength in four hours. This second slurry provides a quick setting anchor section approximately 375 feet long which holds the casing as it is stretched. Six hours after the second slurry is in place, the casing is stretched with casing jacks to 280,000 lbs over the hook load. The casing is then landed in a high strength spider and slips provided by Ventura Tool Company.* This tensile prestress is employed to reduce the compressive thermal stress which will occur when steam is injected into the well. Without the tensile prestress, compressive thermal stresses can cause buckling and failure of the casing (see sample stress calculations in Appendix B). Although both buttress and Hydril HCS casing joints have been used in Sl-B completions, the HCS joints are preferred (and have been more frequently employed) because they are specifically designed to withstand high compressive loads.

*Brand or trade names are used in this report for identification only, and do not imply endorsement by the Energy Research and Development Administration, Federal Government, or Getty Oil Company.

After the 7" casing has been cemented and the shoe has been drilled out, the gel-water mud system which was used for drilling the 9-7/8" hole is replaced by XC-polymer for hole opening. The hole is opened to 12" diameter from the shoe of the 7" casing to T.D. The 5-1/2", 17# liner is run on Baker gravel packing tools which include a Lok-Set packer with interval crossover pipe, a slotted retrievable tell-tale, and a shear joint. The liner has openhole centralizers on bottom and in the middle of the second joint from the bottom. The liner section inside the 7" casing has welded steel centralizing lugs. Flush joint connections are used on the liner section inside the 7" casing. The well is pressure gravel packed using fresh water (filtered through 2-micron cartridge filters) to carry the gravel. Gravel sizes vary from well to well because sieve analyses of cored samples show different sand sizes in various areas of the field. Gravel and slot sizes which have been used include 10-18 (Tyler) or 10-16 (U.S.) mesh gravel with 0.040" liner slots, and 10-20 (U.S.) or 16-20 (U.S.) gravel with 0.030" liner slots. After pack-off is completed, the gravel packing tools are sheared off the liner, and a drive-on lead seal adaptor is installed on the top of the liner.

The liner design typically includes approximately 100 feet of blank liner inside the 7" casing and 5 to 10 feet of blank liner below the 7" casing shoe. This design helps to eliminate liner failures due to sand production through the exposed upper liner slots when the gravel pack slumps following steaming. The bottom 5 feet of liner is not slotted. This prevents sand production if the liner is landed in fill and is therefore not gravel packed at the bottom.

Production is lifted by rod pump using 1-3/8" hollow sucker rods in 3-1/2", J-55 8RD, EUE tubing. The pump is typically set just above the liner adaptor. Two joints of 4-1/2" tubing are included in the tubing string just above the pump shoe. When the well is to be stimulated by steam injection down the tubing, the pump is raised into the 4-1/2" tubing section. After the steam injection is completed, the pump is reseated in the pump shoe. Oilwell RWA-KD-SSV diluent pumps have given the best results in lifting the heavy Sl-B crude. These pumps inject diluent (which has been pumped down the hollow rods) directly below the standing valve. API C-320D-256-120 pumping units are used currently; however, larger pumping units will be required to lift the fluid in some of the wells after they respond to steam injected at the injection wells.

The typical production wellhead has a 5000 psi S.O.W. tubing head which suspends the tubing from a 6" top flange (API ring joint) which is threaded up and down for 3-1/2", 8RD thread, EUE tubing. A 3-1/2", 8RD x 3" nipple connects a 3" cross to the tubing suspension flange. A Ratigan 3000 psi blowout preventor is installed above the cross and a Ratigan #176 (3000 psi) stuffing box is installed above the B.O.P. Both the B.O.P. and the stuffing box are removed when the producer is steam stimulated. Before steam is injected, the polished rod is removed and the rod string is suspended from a fabricated adaptor nipple which is screwed into the top of the 3" cross. Steam is confined by a bullplug screwed into the collar on the adaptor nipple.

The tubing head has two 2" outlets below the tubing landing flange. Both outlets have 2" Rockwell Edward forged steel stop valves (2770 psi pressure rating at 600°F) installed. One of these valves has a 2" nipple and a 2" x 1" swedge connected. The swedge is connected to a 1" casing gas gathering line.

The horizontal outlets on the tubing head cross are both swedged down from 3" to 2" diameter. One outlet is used to connect the tubing to the flowline for production. The other outlet is used to connect the tubing to the flowline for steam injection. The flowline terminus near the wellhead consists of a 2" Graylock coupling on a 2" Rockwell Edward stop valve.

For steam injection, the line connecting the wellhead to the flowline consists of: a 2" Graylock coupling, a 2" Rockwell Edward stop valve, a swing-check valve, an expansion section which includes two 6' Schedule 80 pipe nipples and three 2500 psi Barco ball joints, and a 2" Graylock coupling. This connecting line is removed when the well is placed on production.

For production, the line connecting the wellhead to the flowline consists of : a 2" Rockwell Edward stop valve, a 2" Best choke valve, an expansion section which includes two 6' Schedule 80 pipe nipples and three 1500 psi Barco ball joints, and a 2" Graylock coupling. This line is disconnected at the flowline Graylock coupling during steam injection.

Steam Injection Wells

The injection wells are completed with 7", 23# N-80 buttress or Hydril HCS casing cemented from T.D. to surface. The 7" casing is jet perforated with four 3/4" holes per foot over 30 feet of Sl-B interval. A 3-1/2" liner (75 to 95 feet long) is landed with 30' of 30 gauge all-welded wire-wrapped screen set opposite the perforated interval. The perforations and casing-liner annulus are pressure gravel-packed with 10-18 (Tyler mesh) gravel. A lead seal adaptor is driven over the top of the liner. This completion will allow the steam injection interval to be modified later in the project, if desired, by removing the liner and cementing or perforating where necessary.

The 7" casing is cemented, stretched with 280,000 lbs. over the hook load, and landed in tension in the same manner as the producing wells.

The tubing string will include 2-7/8" 6.5#, 8RD, EUE tubing with a Baker Model C-2 Lok-Set Thermoseal Packer (2500 psi pressure rating at 675°F) and a Baker Model "D" high temperature expansion joint. Tubing string detail will be subject to change pending final determination of the type of tubing insulation to be used.

Three attempts to insulate injection tubing with foam by boiling sodium silicate in the annulus above the packer have failed. Failures have been caused by poor foam quality and by inability to circulate the remaining sodium silicate solution out of the annulus after steaming. To circumvent these problems, concentric tubing with 2-7/8" tubing inside 4" line pipe (with insulation between strings) will be evaluated for possible use in the injectors. Concurrently Getty Oil Company Exploration and Production Research is working with the sodium silicate supplier to attempt to overcome the difficulties encountered in applying this material.

The injection wellhead includes a 5000 psi S.O.W. tubing head with tubing suspended from a 6" top flange (API ring joint) which is threaded up and down for 3-1/2", 8RD, EUE tubing. A 2-1/2" full opening valve is installed above the landing flange.

FACILITIES DESIGN

Getty Oil Company's experience with steam displacement projects has been primarily in the Kern River Field near Bakersfield, California. Experience from this project has been used as a guide in the selection of equipment for the ERDA Project in the Cat Canyon Field.

Equipment requirements vary somewhat from those at Kern River, since the producing zone, the Sl-B, is much deeper and its injectivity is lower than the producing zone in Kern River. Much higher injection pressures are required in Cat Canyon to attain acceptable steam injection and reservoir fluid displacement rates. Kern River steam generators are rated at 1500 psi and operated at 500 to 1000 psi, while the Cat Canyon generators are rated at 2500 psi and will probably operate near this pressure.

Due to the greater depth of the wells, steam quality and heat losses to the wellbore are of critical interest to maximize the heat input to the reservoir. Accordingly, special equipment has been installed to monitor quality and minimize heat losses.

Special attention has also been given to piping, valves and wellhead pressure ratings, considering the high pressure rating of the steam generators. Some equipment in common use at Kern River has required major re-design to withstand the high injection pressures and temperatures expected at Cat Canyon.

Water Supply and Water Softeners

Getty Oil Company's operations in the Cat Canyon Field are supplied with fresh water from several wells completed in

the Careaga Formation. These wells typically produce 10,000 to 20,000 BWPD each from an aquifer between 300' and 500' sub-surface. Two wells, Recruit Fee #5-25 and #6-25, produce water exclusively for the Recruit Fee Soft Water Plant, which supplies all permanent generator installations in the field. The source well water is of good quality, as shown by the water analysis included as Table C-1 in Appendix C. Total hardness is 12.3 grains per gallon (Calcium Carbonate equivalent) and total dissolved solids concentration is 416 ppm.

Ion-exchange water softeners have been found to work well at Cat Canyon. In this process, the resin is charged with sodium ions by washing with concentrated sodium chloride brine. As hard water passes through the resin bed, calcium and magnesium ions displace sodium ions and become attached to the resin. When the sodium ion concentration declines to such a low level that calcium and magnesium ions start to pass through the resin bed, the softener is taken off-line and regenerated with brine. Each softener train has a larger primary softening vessel and a smaller polishing vessel to capture the few hardness ions which may occasionally break through the primary resin bed. We currently have two units, with 2 trains each, installed. With a capacity of 200 gpm (6700 BWPD) per train, the plant now has a total capacity of 20,000 BWPD, assuming 25% downtime for regeneration. A schematic drawing of the soft water system is included in Appendix C as Figure C-1.

Steam Generators

Two steam generators will be used in the pilot project, one 50MM BTU/Hr and one 22MM BTU/Hr unit. The larger unit will provide steam for the four injectors, while the smaller unit will be used to stimulate producing wells in the Project area and to supplement the steam supply to the injectors, if required.

The steam generators are both skid-mounted CE-Natco units with a 2500 psi pressure rating. Specifications for the generators are included in Appendix D.

Both generators can be fired on either natural gas or oil. They will be fired on oil, however, due to the limited supply of fuel gas available. Air quality standards require fuel oil to contain 0.5% or less sulfur. The 50MM BTU/Hr generator will be fired on low sulfur fuel oil of this type. An analysis of suitable oil from one supplier is shown in Table E-1. As Figure E-1 shows, this fuel oil is rather viscous. Facilities have been installed to lower the viscosity by heating and to deliver the properly conditioned oil to the generator. The fuel oil tank is 1000-barrel capacity, of welded construction and is insulated with 2" of urethane foam to reduce heat losses. The tank is painted on the outside to protect the insulation from sunlight and it is coated on the bottom and 18" up the walls inside with Koppers polyamide epoxy to prevent corrosion from bottom water. It is heated by a 1.2MM BTU/Hr gas-fired heater. The heater will circulate hot water through 3" heating coils in the tank to maintain a temperature which corresponds to a fuel oil viscosity of approximately 100 SSU. The heater is thermostatically controlled.

Hot fuel oil will be delivered to the generator by a gear pump through a 2" insulated and heat-traced line. The heat-tracing medium will be hot water from the tank heater. The fuel pumping rate is slightly in excess of the generator requirements. A control valve at the generator will meter the proper amount of fuel to the burner and the excess will be returned to the tank through a bypass line.

The fuel tank will be filled by a tanker truck as required. An open-impeller centrifugal pump has been installed for off-loading the fuel oil.

The 22MM BTU/Hr generator will have a similar fuel system. However, it will be fired with crude oil produced from the Cat Canyon Field. This oil is very viscous and has a high sulfur content, as detailed in the analysis included as Table E-2.

Since the sulfur content of this crude oil is well above the 0.5% limit, measures must be taken to reduce SO₂ emissions. An FMC flue gas scrubber has been purchased for this purpose. Air pollution regulations and selection of the scrubber are discussed in the section on environmental considerations.

The use of both low and high sulfur fuel oil will allow a cost comparison to aid in selection of the more economical approach for future projects.

Steam Quality and Steam Mass Flow Rate Measurement

Maintenance of high steam quality is necessary to deliver as much heat as possible to the reservoir. Also, steam quality must be known to allow measurement of the steam mass flow rate to each of the injectors. Therefore, close monitoring of steam quality is important. Both steam quality and mass flow rate are necessary for future computer simulation studies.

Steam quality will be measured by a method presented in a 1967 technical paper by J. W. Palm et al ("Determination of Steam Quality Using An Orifice Meter", SPE Preprint 1941). This method employs an orifice meter to measure pressure drop across a properly sized orifice at a known mass flow rate. The mass flow rate is easily determined by measuring the generator feed water rate.

Formulas are presented for sizing the flow line and orifice plate and for calculating a special orifice coefficient for wet steam service. This method has demonstrated accuracy

within approximately 1% over a quality range from 10% to 100% and for pressures up to 2000 psi. Accuracy will be somewhat less in our case, if pressures remain above 2000 psi. However, this is the most accurate and practical system for field application which has been found.

The individual mass flow rate to each of the four injectors will be measured by the use of critical flow conditions. When discharge pressure downstream from an orifice is 57% or less of the upstream pressure, a critical flow condition exists such that a terminal steam velocity is reached. The flow rate will not increase further as downstream pressure is decreased beyond this point. Therefore, mass flow rate is dependent upon only upstream pressure, orifice size and steam quality in the region of critical flow.

By installing the proper orifice sizes in each injector's flow line, critical flow conditions can be established into each well and mass flow rate can be calculated. However, the high injection pressure anticipated during the early life of this project may preclude the use of critical flow conditions. A satisfactory method of measuring mass flow rates to individual wells under these conditions is not presently available.

Piping in the area of the 50MM BTU/Hr generator (i.e., the steam quality meter and the four injector wellheads) has been designed according to ANSI B31.1, Power Piping. This standard applies to installations which normally have workers close to the piping system, and therefore it is very conservative. This standard has been used due to the close spacing of the injectors and their proximity to the generator. ANSI B31.1 specifies Schedule 160 pipe for 2500 psi steam service. Series 1500 flanges and valves are required. The layout of the steam distribution system is shown in Figure F-1.

Steam injection manifold detail is shown in Figure F-2. Each flowline will have a Thornhill Craver Figure 67 positive orifice choke, 5000# CWP. This type of choke has been used very successfully at Kern River since inception of that steam displacement project. Although considerable labor is required to disassemble the choke and change the orifice size, this choke has proved more dependable than adjustable orifice valves, which tend to bind after a short period of continuous steam service. Also, packing maintenance on the stem of an adjustable valve is a major problem.

Figure F-3 shows the wellhead configuration on the injectors. Major components are as follows:

Master Gate Valve:	Vogt cast steel gate, 1500# ANSI
Block Valves:	Conval "Clampseal" inclined stem globe valves, 1500# ANSI
Check Valve:	Conval "Clampseal" inclined body check, 1500# ANSI
Choke:	Thornhill Craver Figure 67, positive orifice, 5000# CWP
Swivel Joints:	Aeroquip "Barco" Series OW 1500 flexible ball joints, 2500# rating at 668°F.

ENVIRONMENTAL CONSIDERATIONS

General

The project is located in a rural, well established oil producing area of northern Santa Barbara County. No environmental impact reports have been required by either Santa Barbara County or the State of California Division of Oil and Gas for recent expansion of existing cyclic steam thermal operations on the property. The project area is remote from all residential areas and places of habitation. It is located in rolling to hilly terrain containing native oak trees, grass, and shrubs. Mature trees were removed only when absolutely necessary to the conduct of the project. There are no known endangered species within the project area. The land not occupied by project facilities is used for agricultural grazing. The project land use is compatible with this existing usage. There will be no noise or visual impact on any resident.

There are no waste water discharges from Getty Oil Company's Cat Canyon Field operations. All produced water is reclaimed and injected into other oil zones for secondary recovery purposes. Planning is in progress to recycle a portion of the S1-B Zone produced water to the thermal operation. This will involve oil removal, filtration, and softening through use of ion exchange resins to condition the water for use as steam generator feed water.

Air Quality

In the past, Getty Oil Company's operations in the Cat Canyon Field supplied sufficient natural gas to fuel the limited number of steam generators in use. Natural gas, either commercial or from field production, is not available to serve as a source of fuel for an expanded thermal recovery effort. Thus it became necessary to select a suitable liquid fuel.

Two regulatory agencies had to be considered in selecting a fuel source. The EPA has established ambient air standards for sulfur dioxide, which must be met. Also, the Santa Barbara County Air Pollution Control District Regulation 32.1 prohibits the burning of liquid fuel having a sulfur content greater than 0.5 percent by weight, unless sulfur compounds are removed from the combustion gases to the extent that the emissions are no greater than those of a liquid fuel containing 0.5% sulfur.

Diffusion modeling studies conducted by Getty Oil Company indicate that a fuel meeting the Santa Barbara County A.P.C.D. regulations will not cause the EPA ambient air standards to be exceeded for this project. The primary fuel specification for sulfur then becomes 0.5% sulfur by weight maximum, unless a flue gas scrubber is employed.

A survey of available fuel sources was made, as follows:

1. Lease Crude. Crude produced from the Cat Canyon Field has a sulfur content of approximately 4.5% by weight.
2. Other Crude Oil. No sources of California crude oil containing less than 0.5% sulfur are available to Getty Oil Company for use as fuel in the Cat Canyon Field.
3. Low Sulfur Fuel Oil. A survey revealed that low sulfur oil, with less than 0.5% sulfur, is available, although at a substantially higher cost than the lease crude.

A survey of existing oil field flue gas scrubbing installations was made. A number of flue gas scrubbers are operating in the San Ardo Field on oil fired steam generators. Getty Oil Company has also conducted testing on a pilot unit in the Kern River Field.

The San Ardo units are of two basic types, a cross flow packed bed unit, and counter flow columns with trays. These units primarily use naturally alkaline oil field produced water as the absorption medium. The Getty Oil Company Unit in the Kern River Field tested spray nozzles, trays, and packing, using water, caustic, and ammonia as the absorption media. The sulfur content of the fuels used in these field-tested units has generally been under 2%.

A literature review of available flue gas scrubbing processes was also made. The basic requirement for a flue gas scrubber for oil field steam generators is that they must be relatively small units, operate continuously, and not require constant surveillance and operator attention. Many relatively complex processes, which might be suitable for large installations, were discarded on this basis. The calcium-based processes, which result in a solid sludge for disposal, were also rejected for the initial test for operational reasons. The acceptable processes all involve absorption and neutralization of the sulfur oxide flue gas components with sodium or ammonium compounds (caustic soda, soda ash, or ammonia) which result in soluble sulfate compounds for disposal. The literature indicated ammonia may result in a particulate plume and may not be suitable. Economics favor soda ash over caustic soda, so an absorption process using soda ash was selected.

Sulfur dioxide reacts in water with soluble alkalis such as soda ash (sodium carbonate, Na_2CO_3) or caustic (sodium hydroxide, NaOH) to form sodium sulfite and/or sodium bisulfite.

Quotations were requested from several manufacturers for scrubbing equipment to be fitted on one 22 million BTU per hour generator. The scrubber was to be capable of achieving 90% removal of sulfur from the flue gas when firing with crude oil containing 5% sulfur. The FMC disc contactor was selected on the basis of equipment design, pressure drop, cost, and anticipated reliability.

The FMC scrubber is designed to operate at a pH of 6.5 to 7.0, in the sulfite-bisulfite range, to minimize scale formation and maximize soda ash utilization. Automatic pH control is incorporated in the process to maintain inlet pH of the circulating system at pH 7.0. The circulating rate is sized so that the scrubber effluent should have a pH of 6.5. Soda ash will be automatically added, and a bleed stream will be continuously removed to control buildup of dissolved solids.

A review of operating scrubbers indicate that 316L stainless steel may be a suitable material for construction of flue gas scrubbers. The 316L does not appear to be suitable for acidic water with a high chloride content, however. We are considering the testing or use of raw trona (soda ash) as a neutralization chemical. This raw trona product contains up to 10% salt. To provide flexibility, Incoloy 825 alloy was selected as a construction material for this scrubber, due to its greater tolerance of chlorides.

A choice of dry chemical feed or wet chemical storage of soda ash was available. A wet storage system, operating at 130°F, was selected. This system minimizes the dry storage volume, eliminates continuous dry storage feed, and results in a concentrated (30%) solution feed to the scrubber. The wet storage tank must be heated, however, to prevent solidification of the soda ash solution.

The following items will be evaluated with the FMC scrubber.

1. Sulfur removal efficiency.
2. Reliability.
3. Operational cost (power, chemical, labor).
4. Chemical storage and feed problems.

It is anticipated that operating costs for power, chemicals, and labor for this scrubber will be in the range of \$2.00 to \$3.00 per barrel of fuel burned.

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APPENDIX A

RESERVOIR DATA USED FOR COMPUTER SIMULATION

TABLE A-1
RESERVOIR DATA

	<u>Source</u>	<u>Symbol</u>	<u>Value</u>
Water compressibility (psi^{-1})	1	CW	3×10^{-6}
Oil compressibility, (psi^{-1})	2	CO	5×10^{-6}
Rock compressibility, (psi^{-1})	3	CR	3×10^{-4}
Oil thermal expansion factor, ($^{\circ}\text{F}^{-1}$)	4	CTO	3.5×10^{-4}
Oil specific heat, ($\text{Btu/lb/}^{\circ}\text{F}$)	5	CP	.5
Rock heat capacity, ($\text{Btu/ft}^3/^{\circ}\text{F}$)	5	CPR	19
Water density at T_i , P_i (lbs/ft^3)	6	DWB	61.8
Initial reservoir temperature, ($^{\circ}\text{F}$)	7	TO	125
Stock tank oil density, (lbs/ft^3)	8	DOB	61.6
Oil formation volume factor at T_i , P_i , (RB/STB)	2	BORES	1.06
Solution gas/oil ratio at T_i , P_i , (SCF/STB)	9	RS	75
Molecular weight of solution gas	10	MW1	16
Reservoir thermal conductivity, ($\text{Btu/ft/day/}^{\circ}\text{F}$)	5	KTX, KTY, KTZ	38
Thermal conductivity of over and underburden, ($\text{Btu/ft/day/}^{\circ}\text{F}$)	5	KOB, KUB	23
Heat capacity of over and under burden, ($\text{Btu/ft}^3/^{\circ}\text{F}$)	5	CPOB, CPVB	32
Permeability, (md.)	11, 12	KX, KY, KZ	1500
Initial water saturation, (fraction)	11	SWI	.35
Porosity, (fraction)	11	PHI	.30
Initial reservoir pressure, (psia)	13	PINIT	1000
Sand thickness, (ft.)	14	TH	60

TABLE A-2
VISCOSITY - TEMPERATURE^{8, 9}

<u>TEMPERATURE (°F)</u>	<u>OIL VISCOSITY (cp.)</u>
100	26,000
150	2,500
200	700
250	200
300	80
350	42
400	25
450	16
500	11
550	8.5
600	7.0
650	6.3
700	6.0

TABLE A-3
RELATIVE PERMEABILITY 12,15

<u>SW</u>	<u>KRW</u>	<u>KRO</u>	<u>SL</u>	<u>KRG</u>	<u>KRO</u>
.350	0	.780	.850	.800	0
.360	.0007	.589	.865	.240	.023
.370	.0015	.451	.880	.148	.055
.380	.0024	.352	.895	.104	.090
.390	.0036	.270	.910	.080	.133
.400	.0052	.202	.925	.056	.183
.410	.0072	.146	.940	.040	.261
.420	.0110	.100	.955	.024	.425
.430	.0179	.059	.970	.014	.577
.440	.0330	.026	.985	.004	.694
.450	.1300	0	1.000	0	.780
1.000	1.0000	0			

<u>TEMP (°F)</u>	<u>SWC</u>	<u>SGC</u>	<u>SORW</u>	<u>SORG</u>	<u>SGR</u>	<u>KRWRO</u>	<u>KROCW</u>	<u>KRGRO</u>
150	.35	0	.55	.50	.20	.130	.78	.80
250	.20	0	.40	.10	.20	.065	1.00	.20
350	.20	0	.40	.10	.20	.220	.93	.20
450	.15	0	.40	.10	.20	.380	.83	.45

Production Well Data

Open interval: Full zone

Minimum bottom hole pressure: 100 psia

Productivity/injectivity indices: Calculated based on cell size, configuration, and permeability.

Rates:

0-30	days	Produce at 400 BFPD maximum rate
30-40	days	Inject 1000 BSPD at 1000 psia, 40% quality
40-42	days	Soak
42-212.5	days	Produce at 400 BFPD maximum rate
212.5-222.5	days	Inject 1000 BSPD at 1000 psia, 40% quality
222.5-224.5	days	Soak
224.5-	days	Produce - no rate restriction

Injection Well Data

Open interval: Bottom one-third of zone

Well injectivity index: Calculated based on cell size, configuration, and permeability.

Rates:

0-212.5	days	Off
212.5-577.5	days	Inject at initial rate, 1000 psia, 65% quality
577.5 +	days	Inject at various rates - pressure and quality as below.

Pressures were determined assuming a linear relationship between pressure and rate. Sandface steam qualities were calculated using a proprietary computer program for calculating well bore heat losses, based on the following data:

Well head steam quality	70%
Depth	2500'
Tubing O.D.	3-1/2"
Casing O.D.	7"
Hole Diameter	9-7/8"
Thermal conductivity of tubing insulation (silicate foam)	.017 BTU/hr-ft-°F
Thickness of tubing insulation	3/8"
Annular fluid	Air
Injection time	3 yrs.

TABLE A-4
STEAM INJECTION CONDITIONS

<u>RATE (BSPD)</u>	<u>PRESSURE (psia)</u>	<u>SANDFACE QUALITY (%)</u>
100	100	55.0
200	200	57.5
300	300	60.0
400	400	62.5
500	500	65.0
600	600	65.0
700	700	65.0
800	800	65.0
900	900	65.0
1000	1000	65.0

SOURCES

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10. Value for methane assumed.
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12. EPR-TL-74-91, Relative Permeability Measurements for Cat Canyon Field, unpublished laboratory report.
13. Assumed: hydrostatic pressure gradient (.43 psi/ft), 2300' depth.
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APPENDIX B

EXAMPLE CASING STRESS CALCULATION

EXAMPLE CASING STRESS CALCULATION

7" 23# N-80 CASING - 2500' total casing length -
anchored by cement to 2125'

$$\begin{aligned}\text{Cross sectional metal area} &= (7^2 - 6.366^2) \pi / 4 \\ &= 6.655 \text{ in}^2\end{aligned}$$

$$\text{Thermal Stress} = \alpha E \Delta T$$

$$\begin{aligned}\text{At } 600^\circ\text{F: Thermal Stress} &= (7.0 \times 10^{-6} \text{ } ^\circ\text{F}^{-1}) (19.5 \times 10^6 \text{ psi}) \\ &\quad (600 - 100^\circ\text{F}) \\ &= 68,300 \text{ psi (Compression)}\end{aligned}$$

Casing is pre-stressed to 280,000 lb_f over hook load

$$\begin{aligned}\text{at } 2125', \text{ pre-stress} &= \frac{280,000 \text{ lb}_f}{6.655 \text{ in}^2} \\ &= 42,100 \text{ psi (Tension)}\end{aligned}$$

$$\begin{aligned}\text{At } 600^\circ\text{F, resultant stress} &= 68,300 \text{ psi (compression)} - \\ &\quad 42,100 \text{ psi (tension)} \\ &= 26,200 \text{ psi (Compression)}\end{aligned}$$

$$\begin{aligned}\text{Minimum yield strength of 7", 23#, N-80 casing} \\ &= 80,000 \text{ psi} \times 6.655 \text{ in}^2 \\ &= 532,000 \text{ lb}_f\end{aligned}$$

$$\begin{aligned}\text{Tensile load on top joint during pre-stress} \\ &= 280,000 \text{ lb}_f + 42,000 \text{ lb}_f \text{ (wt. of csg.)} \\ &= 322,000 \text{ lb}_f\end{aligned}$$

$$\begin{aligned}\text{Tensile safety factor during pre-stress} \\ &= \frac{532,000 \text{ lb}_f}{322,000 \text{ lb}_f} \\ &= 1.65\end{aligned}$$

APPENDIX C

FRESH WATER SUPPLY

TABLE C-1
FRESH WATER ANALYSIS
RECRUIT FEE #5

	<u>Milligram per Liter</u>
Calcium	74
Magnesium	6
Sodium	32
Boron	0.1
Iron	<0.1
Manganese	<0.05
Carbonate	None detected
Bicarbonate	225
Chloride	51
Sulphate	30
Nitrate	None detected
Fluoride	0.5
 Total Dissolved Solids	 416
 Total Solids (residue) @ 103° C	 358
 pH = 7.4	

Figure C-1

RECRUIT SOFT WATER SYSTEM

APPENDIX D

STEAM GENERATOR SPECIFICATIONS

22 MILLION BTU/HR STEAM GENERATOR

DESCRIPTION

CE Natco Model Number STOGF-22M-2500 steam generator is a skid mounted, oil or gas fired unit rated at 22,000,000 Btu/hr and designed for 2500 psig working pressure with an 80% steam quality. It was constructed in full accordance with the ASME Power Boiler Code, Section I, and the applicable California Safety Orders.

The convective heating section of the generator consists of 14 vertical rows of two inch single pass tubes. Total extended surface area is approximately 1920 ft². The convection section can transfer approximately 13,000,000 Btu/hr.

The radiant heating section consists of three inch tubes with a total effective radiant heating surface area of 966 ft². Radiation can transfer approximately 9,000,000 Btu/hr.

Feedwater is supplied to the unit by a Wheatley Model HP-125M, motor driven, positive displacement pump with a design capacity of 40 GPM at 2630 psig. The feedwater is preheated by steam from 90 to 250°F in a 22.4 ft² surface area double pipe heat exchanger capable of transferring 3,600,000 Btu/hr.

Combustion air is provided by a 20 hp, 460 volt, three phase, 3450 RPM motor driven combustion blower.

The burner assembly is North American Model 6131-32.2HFA, capable of utilizing either fuel oil or gas. Ignition is initially achieved electrically. Either steam or air may be used for fuel oil atomization. Prior to atomization, the oil is heated in a water-steam/oil heat exchanger. Piped in series downstream of this heat exchanger is a 10KW, 460 volt, three phase electric fuel oil heater designed for use during start-up operations.

The entire system is protected during operation by a control system which will initiate system shut-down if any of the following conditions prevail:

1. Power failure
2. Flame failure
3. Low steam pressure
4. High steam pressure
5. Low feed pump crankcase oil pressure
6. High steam temperature
7. High tube temperature
8. Low instrument air pressure
9. Low Water flowrate
10. High burner throat temperature
11. Low fuel oil temperature
12. Low fuel oil pressure
13. High stack temperature
14. Low steam temperature
15. Burner throat open
16. Low blower pressure
17. High atomizing pressure
18. Low atomizing pressure
19. Low feedpump crankcase level
20. High feedpump crankcase level

50 MILLION BTU/HR STEAM GENERATOR
DESCRIPTION

CE Natco Model Number STGF-50M-2500 steam generator is a skid mounted, oil or gas fired unit rated at 50,000,000 Btu/hr and designed for 2500 psig working pressure with an 80% steam quality. It was constructed in full accordance with the ASME Power Boiler Code, Section I, and the applicable California Safety Orders.

The convection heating section of the generator consists of 15 vertical rows of three inch single pass tubes. Total extended surface area is approximately 8420 ft². The convection section can transfer approximately 35,000,000 Btu/hr.

The radiant heating section consists of three inch single pass tubes with an effective radiant heating surface area of 2125 ft². Radiation can transfer approximately 15,000,000 Btu/hr.

Feedwater is supplied to the unit by a Wheatley Model HP-250M, motor driven, positive displacement pump with a design capacity of 104 GPM at 2800 psig. The feedwater is preheated by steam from 90 to 250°F in a 52.5 ft² surface area double pipe heat exchanger capable of transferring 8,000,000 Btu/hr.

Combustion air is provided by a 50 hp, 460 volt, three phase, 1800 RPM motor driven combustion blower.

The burner assembly is manufactured by North American Burner and is capable of utilizing either fuel oil or gas. Ignition is initially achieved electrically. Either steam or air may be used for fuel oil atomization. Prior to atomization, the oil is heated in a water-steam/oil heat exchanger. Piped in series downstream of this heat exchanger is a 20KW, 460 volt, three phase electric fuel oil heater designed for use during start-up operations.

The entire system is protected during operation by a control system which will initiate system shut-down if any of the following conditions prevail:

1. Power failure
2. Flame failure
3. Low steam pressure
4. High steam pressure
5. Low feedpump crankcase oil pressure
6. High steam temperature
7. High tube temperature
8. Low instrument air pressure
9. Low water flow rate
10. High burner throat temperature
11. Low fuel oil temperature
12. Low fuel oil pressure
13. High stack temperature
14. Low steam temperature
15. Burner throat open
16. Low blower pressure
17. High atomizing pressure
18. Low atomizing pressure
19. Low feedpump crankcase level
20. High feedpump crankcase level

APPENDIX E

FUEL ANALYSES

TABLE E-1
LOW SULFUR FUEL OIL ANALYSIS
SUPPLIER M

Gravity, °API	23.5
Flash Point, °F	270
Viscosity, SSU @ 100	300
Viscosity, SSF @ 122	20
Water and Sediment, percent	.05
Pour Point, °F	60-70
Sulphur, percent	0.40
BTU/Lb.	19,200
BTU/Bbl.	6,140,000
Nitrogen, percent	0.28

TABLE E-2
LOS ALAMOS LACT CRUDE OIL ANALYSIS

Gravity, °API	15.0
Flash Point, °F (PMCC)	<46
Sulfur, percent	4.56
Nitrogen, percent	0.96
Water, percent	0.99
Ash, percent	0.0526
BTU/Lb.	18,364
BTU/Bbl.	6,200,000

	<u>Viscosity</u>			
	100° F	120°F	140°F	160° F
Kinematic, cs	1,086	403	206	129
S.S.U. (Saybolt)	5,030	1,869	956	599

APPENDIX F

STEAM DISTRIBUTION SYSTEM

Figure F-1

-63-

ERDA PROJECT LOCATION

50 MM BTU/HOUR STEAM GENERATOR,
INJECTION WELLHEADS AND
W.H-205 PRODUCING WELL

Figure F-2

LEGEND

- (1) --- 6" STEAM HEADER FROM GENERATOR
- (2) --- CONVAL 2" BLOCK VALVE
- (3) & (7) --- 3000 LB. PRESSURE GAUGE
- (4) & (8) --- THERMOMETER
- (5) --- THORNHILL-CRAVER POSITIVE CHOKE
- (6) --- UNIBOLT COUPLING
- (9) --- 2" INJECTION LINE TO WELLHEAD

ERDA PROJECT
STEAM INJECTION MANIFOLD
DETAIL

Figure F-3

- ① - 2 1/2" MASTERGATE
- ② - 2" MASTERGATE
- ③ - 2" CONVAL BLOCK VALVES
- ④ - 2" CONVAL CHECK VALVE
- ⑤ - 2" COUPLING
- ⑥ - 2" BARCO BALL JOINT
- ⑦ - 2" CONVAL ANNULUS VALVE

ERDA PROJECT
WELLHEAD DETAIL

APPENDIX G

WELL DATA HISTORIES

WILLIAMS HOLDING 25-25

Drilling History

Drilling rig moved in and spudded a 9-7/8" hole on December 16, 1974. Drilled ahead with no problem to 2551' on December 20. At 2551', ran in and cored to 2571'. Fill was found after coring, so the hole was circulated clean before taking another core from 2571' to 2589'. A 9-7/8" bit was run to open the hole from 2551' to 2589', after which the third core was taken from 2589' to 2609'. The fourth and final core was taken from 2609' to 2625', followed by a 9-7/8" bit run to open the hole from 2589' to total depth of 2625'. The hole was approximately vertical. During drilling and coring, mud properties averaged as follows: mud weight, 72 lbs/ft³; funnel viscosity, 51 seconds. Drilling rate averaged 369 ft/day.

At T.D., ran a Dresser-Atlas Dual Induction log and an Epilog suite, after which 60 joints of 7", 23# S0095 used buttress casing were run to 2563' on December 23. The casing was equipped with a solid cement guide shoe, a fillup valve on top of the shoe joint, one metal basket placed over four 1/2" holes, and five latch-on centralizers. The casing was cemented in place with 1100 ft³ Class "G" cement containing 1:2 perfalite and 40% silica flour, and treated for 12 hours setting time, followed by 100 ft³ luminite cement premixed with 20% silica flour and treated for 1500 psi compressive strength in 4 hours. The cement was displaced with 583 ft³ mud, and 250 ft³ cement returns were recorded. The casing was stretched 25" by pulling 260,000 lbs, and the rig shut down for Christmas.

On December 26, the cement and shoe was drilled out, the wellbore fluid changed over to KCl-polymer mud, and a 14" hole opener run. The hole was opened from 2563' to 2625'.

Williams Holding 25-25

The following day the wellbore fluid was changed over to lease water containing 2 sacks of Kelzan, and 87 ft. of 5-1/2", 17# N-80 LT&C liner was landed at 2625'. The liner had 30 mesh slots from 2548' to 2620' and centralizers were located on the bottom and middle joints. The liner was then gravel flow packed with 99 ft³ 10x16 Texas gravel through a port collar at 2540'. Thirteen cubic feet were backscuttled out.

Tubing, rods, and a pump were run and the rig was released.

DUAL INDUCTION FOCUSED LOG

PROXIMITY LOG - MINILOG WITH CALIPER

WILLIAMS HOLDING 25

COMPENSATED DENSILOG WITH
COMPENSATED NEUTRON LOG

ACOUSTILOG

WILLIAMS HOLDING 25
NEUTRON LIFETIME LOG

CORRELATION CURVE	DEPTH	COUNTS PER MINUTE
		GATE 1 400 To 600 μ Sec. ----- GATE 2 700 To 900 μ Sec. ----- $\Delta T = 300 \mu$ Sec.
MONITOR		SIGMA 10 ²¹ BARNS/cm ²
		50 30 10
	2500	
	2600	
		TOP OF SL - 2547'

WILLIAMS HOLDING 25

EPILOG

DEPTH	LITHOLOGIC CHARACTERISTICS	FLUID ANALYSIS	POROSITY AND FLUIDS % BULK VOLUME		FORMATION % BULK VOLUME		
			HYDROCARBON	WATER	CLAY	QUARTZ	POROSITY
	Rwa (NLL)	NLL WATER SATURATION					
		WATER SATURATION					
0		100 %	0	50 %	0	SHALE	OTHER
	PERMEABILITY INDEX	HYDROCARBON VOLUME	NLL	%	WATER		
10 ⁴		$\phi \cdot S_{hr}$	.25	50	0		
		HYDROCARBON WEIGHT					
		$\phi \cdot S_{hr} \cdot \rho_h$	.25

GETTY OIL COMPANY

CORE DESCRIPTION
 WILLIAMS HOLDING 25-25
SECTION 25 - 9N/33W

3" Christiansen Diamond Rubber-Sleeve Cores
 December 20-22, 1974

The following cores were cut in 2-1/2 foot sections for shipment to EPR. Description is only of cuts at ends of 2-1/2 foot sections. E-log measurements were 2' to 3' deeper than core depths and T.D.

<u>CORE NO.</u>	<u>DEPTH</u>	<u>RECOVERY</u>	<u>DESCRIPTION</u>
1	<u>Interval:</u>	<u>2551-2571</u>	<u>Total Recovery: 19' 4"</u>
	2551-53-1/2	4" Est.±	Siltstone - Sandy, medium gray firm. No fluorescence.
		2' 2"±	Oil Sand - Silty, soft, fine-grained, black, with frequent white sub-angular quartz grains. Has fair to good order, black cut and reddish brown fluorescence. Cut fluorescence is bright yellow.
	2553-1/2-56	2-1/2'±	Oil Sand - As above. Fair odor and black cut. Has "salt and pepper" texture. This is fine to medium grained, poorly sorted.
	2556-58-1/2	2-1/2'±	Oil Sand - As above. Fine to medium grained had light gas expansion (1/16"). Fair odor and black cuts.
	2558-1/2-61	2-1/2'±	Oil Sand - As above. Fair odor and black cut.
	2561-63-1/2	2-1/2'±	Oil Sand - As above. With 1/8" expansion at top. Fair odor and black cut.
	2563-1/2-66	2-1/2'±	Oil Sand - As above with no expansion. Fair odor and black cut.
	2566-68-1/2	2-1/2'±	Oil Sand - As above, but slightly firmer. Fair odor and black cut.
	2568-1/2 to 2570'-4"	1'-10"	Oil Sand - As above. Fair odor, black cut and reddish brown fluorescence.

<u>CORE NO.</u>	<u>DEPTH</u>	<u>RECOVERY</u>	<u>DESCRIPTION</u>
2	<u>Interval: 2571-2589</u>		<u>Total Recovery: 16' 9"</u>
	2571-73-1/2	2-1/2'±	Oil Sand - Black, soft, silty, fine-medium grained, poorly sorted with angular quartz grains. Has fair odor, black cut (coffee).
	2573-1/2-76	2-1/2'±	Oil Sand - As above, with grayish silt streaks. Has "salt and pepper" texture. Has fair odor black cut.
	2576-76'-5"	5"	Oil Sand - As above, had good gas flare (with match-30 Sec.) and at top had 1/8" expansion. Good odor.
	<u>Void</u>		Had a 28" Void (gassy) at this depth (probable "droppage"). Note "folded" sleeve below.
	2576'5" to 2579'	2'-7"	Oil Sand - As at 2576'. Has fair odor, black cut.
	2579-81-1/2	2-1/2'±	Oil Sand - As above, but grayish-black, and more silty. Fair odor, black cut.
	2581-1/2-84	2-1/2'±	Oil Sand - As above, with more black color. Had 1/8" expansion top and bottom. Fair odor, and black cut.
	2584-86-1/2	2-1/2'±	Oil Sand - As above, with light silt streaks. Had 1/4" expansion at bottom. Fair odor and black cut.
	2586-1/2-2587'-9"	1'-3"	Oil Sand - As above. Had 1/4" expansion at top, with light gas flare. Good odor and black cut.
3	<u>Interval: 2589 to 2609</u>		<u>Total Recovery: 19'0"</u>
	2589-91-1/2	2-1/2'± (22")	8" Shale or fill (estimated) Oil Sand - Grayish-black, soft, fine to medium grained, poorly sorted with some silty streaks and "salt and pepper" texture with quartz grains. Fair odor and black cut.
	2591-1/2-94	2-1/2'±	Oil Sand - As above. Top had 6" gas flare (est) and 1/2" expansion at cut. Good odor and black cut.

<u>CORE NO.</u>	<u>DEPTH</u>	<u>RECOVERY</u>	<u>DESCRIPTION</u>
	2594-96-1/2	2-1/2'±	Oil Sand - As above, with 3/8" expansion. Fair odor and black cut.
	2596-1/2-99	2-1/2'±	Oil Sand - As above, with more "salt and pepper" texture. Had light gas flare. Fair odor and black cut.
	2599- 2601-1/2	2-1/2'±	Oil Sand - As above, with light gas flare. Fair odor and black cut.
	2601-1/2- 2604	2-1/2'±	Oil Sand - As above, with gas flare. Had fair odor and black cut.
		(10")	Void. Note folded sleeve. Core below is "elevated".
	2604-06-1/2	2-1/2'±	Oil Sand - As at 2601-1/2, (without flair). Fair odor and black cut, but is grayer and siltier in streaks.
	2606-1/2-08	1-1/2'±	Oil Sand - As above, with fair odor and coffee cut.
4	<u>Interval: 2609'-2625' ±</u>		<u>Total Recovery: 17-1/4"</u>
	2609-11-1/2	2-1/2'±	Oil Sand - Dark grayish-brown, silty, soft, fine to medium grained, poorly sorted with "salt and pepper" texture. Fair odor, black cut, reddish-brown fluorescence.
	2611-1/2-14	2-1/2'	Oil Sand - As above.
	2614-16' 3"	2'-3"	Oil Sand - As above, with more light "salt and pepper" texture. Had gas flare at top and bottom. Fair odor, black cut.
	30" Void	(30")	Void in core. Next core down was elevated for dropage.
	2616-1/4- 2618-3/4	2-1/2'±	Oil Sand - As at 2614. Had 15" gas flare at top (void), and at bottom. Fair odor and black cut.
	2618-3/4- 2621-1/4	2-1/2'±	Oil Sand - As at 2614. Had light gas flare at both ends.

Getty Oil Company
WH 25-25
Dec. 20-22, 1974
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<u>CORE NO.</u>	<u>DEPTH</u>	<u>RECOVERY</u>	<u>DESCRIPTION</u>
	2621-1/4- 2623-3/4	2-1/2'±	Oil Sand - As at 2614, but slightly darker oil sand. No gas flare. Fair odor and black cut.
	(2623-3/4- 2626-1/4) *	2-1/2'±	Oil Sand - As above (at 2621-1/4) had light gas flare at bottom. Fair odor and coffee cut.

*Note: This recovery is 1-1/4" over "cored footage".

Cores described by A.C.H. and R.A.H.

WILLIAMS HOLDING 25
CORE ANALYSIS DATA

Cores taken using rubber sleeve coring equipment in water base mud. One-inch diameter horizontal plugs mounted in thin-walled metal jackets with fine-mesh end screens using 700 psig tri-axial pressure. Saturations determined by Dean-Stark extraction using toluene.

Sample	Depth (Feet)	Perm. (md.)	Porosity (Per Cent)	Residual Saturation (Per Cent Pore)		Sample Description
				Oil	Total Water	
1	2551-52	5910	38.2	40.1	44.2	Sand; Dark Brown, fine grained, dark staining
2	2552-53	8000	38.3	59.1	22.9	Same
3	2553-54	7200	37.5	57.2	25.1	Same
4	2554-55	6470	37.1	58.1	25.3	Same
5	2555-56	6470	38.1	59.7	20.3	Same
6	2556-57	7350	37.3	60.8	21.7	Same
7	2557-58	7350	38.2	63.5	20.7	Same
8	2558-59	8480	37.9	60.5	20.8	Same
9	2559-60	8340	38.1	67.3	19.8	Same
10	1560-61	8500	37.2	67.4	19.3	Same
11	1561-62	7200	38.2	61.4	20.4	Same
12	1562-63	7800	37.5	60.6	19.8	Same
13	1563-64	6300	36.3	62.2	23.4	Same
14	1564-65	7600	38.0	56.6	26.3	Same
15	1565-66	6470	37.8	59.7	20.8	Same
16	1566-67	5930	38.2	56.9	20.7	Same
17	1567-68	6550	38.4	57.8	21.3	Same
18	1568-69	4940	37.7	55.7	22.3	Same
19	2569-70	6550	36.7	57.4	23.6	Same
20	2571-72	4950	33.6	47.2	40.9	Same

<u>Sample</u>	<u>Depth (Feet)</u>	<u>Perm. (md.)</u>	<u>Porosity (Per Cent)</u>	<u>Residual Saturation (Per Cent Pore)</u>		<u>Sample Description</u>
				<u>Oil</u>	<u>Total Water</u>	
21	2572-73	5230	35.2	45.9	34.3	Same
22	2573-74	4770	35.3	48.7	33.6	Same
23	2574-75	5240	36.3	48.0	26.0	Same
24	2575-76	4630	35.3	40.7	32.7	Same
25	2576-77	5240	36.7	46.7	37.8	Same
26	1577-78	4280	35.2	42.3	35.4	Same
27	1578-79	4000	34.3	47.6	34.4	Same
28	1579-80	4170	34.8	42.3	40.4	Same
29	1580-81	4760	36.3	51.4	28.4	Same
30	1581-82	5340	35.3	55.4	33.0	Same
31	1582-83	6300	37.3	54.6	27.4	Same
32	1583-84	4750	36.2	53.0	27.7	Same
33	1584-85	4400	35.6	51.6	36.2	Same
34	1585-86	5540	36.4	48.6	29.1	Same
35	1586-87	1705	31.9	35.7	59.1	Same
36	2587-88	5730	36.0	45.7	32.2	Same
37	2589-90	5230	34.5	40.6	33.8	Same
38	2590-91	6470	36.5	54.8	32.9	Same
39	2591-92	5220	36.0	52.8	37.1	Same
40	2592-93	6100	35.5	57.5	30.5	Same
41	2593-94	4150	34.2	51.4	37.0	Sand; Brown, fine grained, shaley inclusions, dark staining
42	2594-95	3920	36.2	47.3	36.9	Same
43	2595-96	4750	35.2	55.3	30.0	Same
44	2596-97	5400	37.2	46.3	30.0	Same
45	2597-98	4400	35.0	55.9	26.4	Same
46	2598-99	5400	36.8	52.5	27.0	Same
47	2599-00	6050	37.7	49.8	23.7	Same
48	2600-01	5400	37.2	49.0	27.4	Same
49	2601-02	6300	38.8	49.0	21.7	Same

<u>Sample</u>	<u>Depth (Feet)</u>	<u>Perm. (md.)</u>	<u>Porosity (Per Cent)</u>	<u>Residual Saturation (Per Cent Pore)</u>		<u>Sample Description</u>
				<u>Oil</u>	<u>Total Water</u>	
50	2602-03	4160	37.4	48.8	25.6	Same
51	2603-04	6120	38.2	45.2	26.9	Same
52	2604-05	7200	35.8	52.9	29.0	Same
53	2605-06	5900	38.4	48.3	24.2	Same
54	2606-07	5730	37.4	50.0	31.9	Same
55	2607-08	5380	35.3	47.2	37.7	Same
56	2609-10	5930	37.5	52.4	38.8	Same
57	2610-11	5920	37.0	62.7	29.4	Same
58	2611-12	7600	37.4	59.1	22.3	Same
59	2612-13	7180	38.0	41.9	36.0	Same
60	2613-14	6450	37.5	51.4	30.8	Same
61	2614-15	6480	37.4	51.3	25.9	Sand; brown, fine grained, dark staining
62	2615-16	6480	37.7	50.0	25.6	Same
63	2616-17	4880	36.0	50.4	29.0	Same
64	2617-18	5420	36.0	49.4	29.3	Same
65	2618-19	6750	37.9	53.1	24.0	Same
66	2619-20	6830	38.3	52.4	24.5	Same
67	2620-21	6470	37.4	50.3	29.3	Same
68	2621-22	6470	38.4	48.3	23.5	Same
69	2622-23	6980	37.6	55.4	25.8	Same
70	2623-24	5740	38.5	51.0	22.6	Same
71	2624-25	5230	35.4	38.6	39.4	Sand; brown, fine grained, shaley inclusions; dark staining
72	2625-26	6470	36.6	54.8	28.0	Same

GETTY OIL COMPANY

WELL: WH 25-25

Report of Geochemical Analysis

Received: May 21, 1975

<u>Radicals</u>	<u>Milligrams Per Liter</u>	<u>Grains per U.S. Gallon</u>	<u>Reacting Value</u>	<u>Per Cent</u>
Sodium, (Na)	2,100	123.	91.30	46.78
Ammonium, (NH ₄)	60	3.51	3.33	1.71
Calcium, (Ca)	34	1.99	1.70	0.87
Magnesium, (Mg)	15	0.87	1.23	0.63
Barium, (Ba)	1	0.04	0.01	0.01
Iron, (Fe) (total)	2	0.12	-	-
Sulfate, (SO ₄)	TR < 5	0	-	-
Chloride, (Cl)	1,515	88.48	42.72	21.89
Hydroxide, (OH)	0	-	-	-
Carbonate, (CO ₃)	0	-	-	-
Bicarbonate, (HCO ₃)	3,300	193.	54.09	27.72
Borate, (B ₄ O ₇)	55	3.22	0.71	0.36
Iodide, (I)	6	0.37	0.05	0.03
Silica, (SiO ₂)	45	2.63	-	-
*Organic Acids	50	2.92	-	-
Salinity as Salt, (NaCl)	2,495			
Total Solids	7,180			
Specific Gravity	1.007 @ 60°F			
Resistivity	124 Ohm Cm @ 75°F			
pH Value	7.75			

<u>Groups</u>		<u>Chemical Character</u>	
Alkalies	48.49%	Primary Salinity	43.84%
Earths	1.51%	Secondary Salinity	0 %
Strong Acids	21.92%	Primary Alkalinity	53.14%
Weak Acids	28.08%	Secondary Alkalinity	3.02%

Type Sample:
Field:
Zone and Sands:

*Included in Bicarbonates

WILLIAMS HOLDING 26-25Drilling History

Drilling rig moved in and spudded a 9-7/8" hole on April 19, 1974. Drilled ahead with a conventional drilling assembly to total depth of 2595', and then conditioned hole for logging. During drilling, mud properties averaged as follows: mud weight, 72 lbs/ft³; funnel viscosity, 44 seconds. Drilling rate averaged 511 ft/day.

At T.D., ran a Dual Induction-Focused log, Acoustilog, Densilog, Proximity-Minilog, and a Neutron Lifetime log. After logging was completed, ran 60 joints 7", 23# N-80 HCS Hydril casing to 2477'. The casing was equipped with a solid guide shoe, a fillup collar on top of the shoe joint, one metal basket over four 1/2" holes cut 3 ft. above the shoe, one latch-on centralizer at the middle and one on top of the shoe joint, one centralizer 50-60 ft. above the top of the shoe joint, and two at 100' intervals after the last centralizer. The casing was cemented in place with 1100 ft³ Class "G" cement containing 1:2 perfalite and 40% silica flour, and treated for 12 hours setting time, followed by 100 ft³ luminite cement premixed with 20% silica flour and treated for 1500 psi compressive strength in four hours. Cement was displaced with 548 ft³ water, and 88 ft³ cement returns were recorded. After 4 hours, the casing was stretched 16" by pulling 200,000 lbs.

On April 26, changed over to lease water, drilled out the float collar and cement to 2462', and circulated the hole clean. Ran in and jet perforated four 1/2" holes at 2455' for water shut-off, and with a packer set at 2394', tested for one hour. The test was approved by the Division of Oil and Gas. After testing, moved packer up to 2268', broke down formation at 14 ft³/min

Williams Holding 26-25

with 1250 psi, and squeezed WSO holes with 60 ft³ luminite cement premixed with 20% silica flour. The following day the top of the cement was found at 2410', and cement was drilled out to 2462'. The holes were then tested to 1000 psi. After testing, the shoe was drilled out and the hole cleaned out to 2595'. A cement tool was run in and the bottom of the well was plugged back with 25 ft³ luminite cement premixed with 20% silica flour. After 4 hours the top of the cement was found at 2550'. The wellbore fluid was then changed over to KCl polymer mud.

Following the changeover a 14" underreamer was run and the hole was opened from 2477' to 2550'. Then 105' of 5-1/2", 17# N-80 extreme line liner with gravel packing tools was run to 2550'. The liner was equipped with one latch-on centralizer in the middle of the second and the bottom joints. From 2450' to 2540' the liner was 40 mesh slotted. The liner was then circulation gravel packed with 58 ft³ 8-12 gravel.

After gravel packing the wellbore fluid was changed back to lease water, tubing, rods, and pump were run, and the rig released.

WILLIAMS HOLDING 26

DUAL INDUCTION FOCUSED LOG

WILLIAMS HOLDING 26

PROXIMITY LOG - MINILOG WITH CALIPER

WILLIAMS HOLDING 26
 COMPENSATED DENSILOG WITH
 COMPENSATED NEUTRON LOG

GAMMA RAY & CALIPER		DEPTH	COMPENSATED DENSILOG	
48	API UNITS	168	CORRECTION	
			.5 0 +.5 BULK DENSITY-GRAMS CC	
6	HOLE SIZE - INCHES	16	1.75 2.75 59% 39% 24% 9% 0%	
			COMPENSATED NEUTRON POROSITY 54% 39% 24% 9% 0%

WILLIAMS HOLDING 26

ACOUSTILOG

WILLIAMS HOLDING 26
NEUTRON LIFETIME LOG

EPILOG

DEPTH	LITHOLOGIC CHARACTERISTICS	FLUID ANALYSIS	POROSITY AND FLUIDS % BULK VOLUME		FORMATION % BULK VOLUME		
			HYDROCARBON	WATER	CLAY	QUARTZ	POROSITY
	Rwa (NLL)	NLL WATER SATURATION					
		WATER SATURATION					
0	5	100 %	0	50 %	0	SHALE	OTHER
	PERMEABILITY INDEX	HYDROCARBON VOLUME	NLL	%	WATER		
10 ⁴	.10	$\phi \cdot S_{hr}$	.25	50	0		
		HYDROCARBON WEIGHT					
	0	$\phi \cdot S_{hr} \cdot \rho_h$	.25

WILLIAMS HOLDING 35-25Drilling History

Drilling rig moved in and spudded a 9-7/8" hole on May 23, 1974. Drilled ahead with no problems to total depth of 2495'. Hole was approximately vertical. During drilling, mud weight averaged 71 lbs/ft³ and funnel viscosity averaged 42 seconds. Drilling rate averaged 818 ft/day. While making a wiper run on the last day of drilling, circulation was lost and then regained at 1500'.

On May 26, a Dresser-Atlas Dual Induction-Focused log was run, after which 61 joints of 7", 23# N-80 HCS Hydril casing were run to 2434'. The casing was equipped with a solid cement guide shoe, a fillup collar on top of the shoe joint, and one metal basket over four 1/2" holes located 3 ft. above bottom. Five latch-on centralizers were run; one at the middle and on top of the shoe joint, one 50'-60' above the top of the shoe joint, and two at 100' intervals from the last centralizer. The casing was cemented in place with 1100 ft³ Class "G" cement containing 1:2 perfalite and 40% silica flour, and treated for 12 hours setting time, followed by 100 ft³ luminite cement premixed with 20% silica flour and treated for 1500 psi compressive strength in 4 hours. Cement was displaced with 540 ft³, and good returns were recorded.

After six hours the casing was stretched 15-1/2". The cement remaining in the 7" casing was drilled out to the shoe with a 6" bit and scraper. While drilling out, the rotary table shaft twisted off.

After rig repairs, a 6" hole was drilled to 2495', and the wellbore fluid changed over to KCl mud. A 14" underreamer was run and the hole opened from 2434' to 2495'. Seventy-five feet

Williams Holding 35-25

of 5-1/2", 17# N-80 extreme line liner was landed at 2495'. Sixty-one feet of the liner was 40 mesh slotted, and the liner was equipped with one latch-on centralizer in the middle of the second and bottom joint. The liner was then gravel flow packed with 126 sacks 8x12 gravel. Five sacks were backscuttled out and a lead seal adaptor was set over the liner.

The wellbore fluid was changed over to lease water after which tubing, pump, and rods were run. The rig was then released on May 31.

WILLIAMS HOLDING 35
DUAL INDUCTION FOCUSED LOG

SPONTANEOUS POTENTIAL Millivolts	DEPTH	RESISTIVITY ohms - m ² /m				
<div style="text-align: center;"> $\rightarrow 10 \leftarrow +$ </div>		SHALLOW FOCUSED LOG				
		.2	1.0	10	100	1000
		MEDIUM INDUCTION LOG				
		.2	1.0	10	100	1000
		DEEP INDUCTION LOG				
		.2	1.0	10	100	1000

WILLIAMS HOLDING 36-25Drilling History

Drilling rig moved in and rigged up on January 6, 1975. On January 7, 3:30 a.m. spudded a 9-7/8" hole and drilled to 730' where mud pump engine failed. After repairs drilling continued to 930'. At 930' began directionally drilling with a Dynadrill to 1110'. Resumed drilling with the conventional drilling assembly and continued to 1983' on January 11. At this depth directionally drilled with a Dynadrill to 2055', at which time the Dynadrill was pulled and drilling resumed with the normal drilling assembly and continued to 2370'.

On January 13, cored from 2370' to 2390' with a 7-1/2" core barrel, recovering 17-1/2' oil sand. Cored again from 2390' to 2410' and recovered 15-1/2' oil sand. At this time a 9-7/8" bit was run to open the 7-1/2" hole from 2370' to 2410'. Coring continued the next day from 2410' to 2430', and 19'8" oil sand was recovered. Ran in once again and cored from 2430' to 2448', recovering 18-1/2" oil sand. After coring, a 9-7/8" bit opened the 7-1/2" hole from 2410' to total depth of 2448'. Bottom hole location 98' south, 195' west of surface location. During drilling and coring, mud properties averaged as follows: mud weight, 72 lbs/ft³; funnel viscosity, 47 seconds; fluid loss, 7.2cc. Drilling rate averaged 301 ft/day, and maximum hole angle was 11.25° from vertical.

On January 15 a Dresser-Atlas Epilog suite was run, and on the following day 55 joints 7", 23# & 26# S0095 used Buttress casing were run to 2371'. The casing was cemented in place with 965 ft³ Class "G" cement containing 1:2 perfolite and 40% silica flour, and treated for 12 hours setting time, followed by 100 ft³ luminite cement pre-mixed with 20% silica flour and treated

Williams Holding 36-25

for 1500 psi compressive strength in 4 hours. Cement was displaced with 533 ft³ mud, and 15 ft³ cement returns were recorded. After 6 hours the casing was stretched 19" by pulling 260,000 lbs. The wellbore fluid was then changed over to lease salt water and cement was drilled out from 2331' to 2371'.

The next day the wellbore fluid was changed to KCl-polymer mud. A 14" hole opener was run opening hole from 2371' to 2448'. With open ended drill pipe at 2448', 27 ft³ luminite cement with 20% silica flour was equalized, and after 4 hours the top of the cement was found at 2425'.

A 4" bit was run and cement drilled out from 2425' to 2435', after which a 14" hole opener was run, opening the hole again from 2371' to 2435'. The wellbore fluid was changed to water containing two sacks of Kelzan, and two joints of 5-1/2", 17# K-55 liner with gravel packing tools were landed at 2435'. The liner was 30 mesh slotted from 2356' to 2430', and was equipped with centralizers in the center of the bottom and middle joints. The liner was then gravel flow packed with 99 ft³ 10x16 Texas gravel. After testing and circulating the hole clean, tubing, rods, and a pump were run.

The rig was released the following day, January 20, 1975.

DUAL INDUCTION FOCUSED LOG

SPONTANEOUS POTENTIAL Millivolts	DEPTH	RESISTIVITY ohms - m ² /m				
<div data-bbox="255 585 422 649"> $\rightarrow 10 \leftarrow +$ </div>		SHALLOW FOCUSED LOG				
		MEDIUM INDUCTION LOG				
		DEEP INDUCTION LOG

PROXIMITY LOG - MINILOG WITH CALIPER

RESISTIVITY Ohms m ² /m	DEPTH	RESISTIVITY Ohms m ² /m
<p>MICRO INVERSE 1" x 1"</p> <p>10 0</p>		
<p>MICRO NORMAL 2"</p> <p>10 0</p>		
<p>HOLE SIZE - INCHES</p> <p>7 9 11 13 15</p>		
		<p>PROXIMITY LOG</p> <p>1 10 100 1000</p>

WILLIAMS HOLDING 36

COMPENSATED DENSILOG WITH
COMPENSATED NEUTRON LOG

WILLIAMS HOLDING 36

ACOUSTILOG

S.P. or G/R & Caliper	DEPTH	ACOUSTILOG $T_1 - R_1 - Z - R_2 - T_2$
Millivolts - <=> + API UNITS		SPECIFIC ACOUSTIC TIME Micro Seconds Per Foot
HOLE SIZE - INCHES 7 9 11 13 15		175 75

NEUTRON LIFETIME LOG

TOP OF 310-2355'

2400

EPILOG

DEPTH	LITHOLOGIC CHARACTERISTICS	FLUID ANALYSIS	POROSITY AND FLUIDS % BULK VOLUME		FORMATION % BULK VOLUME		
			HYDROCARBON	WATER	CLAY	QUARTZ	POROSITY
		NLL WATER SATURATION					
	Rwa (NLL)						
0		WATER SATURATION					
5		100 %	0	50 %	0	SHALE	OTHER
	PERMEABILITY INDEX	HYDROCARBON VOLUME	NLL	%	WATER		
10 ⁴		$\phi \cdot S_{hr}$	.25	50	0		
		HYDROCARBON WEIGHT					
		$\phi \cdot S_{hr} \cdot \rho_h$	.25

GETTY OIL COMPANY
CORE DESCRIPTION
WILLIAMS HOLDING 36-25
SECTION 36 - 9N/33W

3" Christiansen Diamond Rubber-Sleeve Cores.

Jan. 13-14, 1975

<u>CORE #</u>	<u>DEPTH</u>	<u>RECOVERY</u>	<u>DESCRIPTION</u>
1	<u>Interval: 2370'-2390'</u>		<u>Total Recovery: 17' 6"</u>
	<u>Top had 28" Fill of Shale Pieces</u>		
	2370-72-1/2	2-1/2' +	Shale & Sand - Top 1'. 1-1/2' mushy sand (?) w/3" solid piece sand on bottom.
	2372-1/2- 2374' 9"	12' 3"	Oil Sand - Soft, black, fine to medium grained, silty good odor. 10" silty, mushy streak 2373- 2374+ coffee cut.
	-----	-----	10" Void at 2374' 9" w/gas at cut.
	2374' 9"- 2377	2' 6"	Oil Sand - As above w/salt and pepper texture. Fair odor and looks drier.
	2377-2379-1/2	2' 6"	Oil Sand - As above. Bottom 3" mushy.
	2379-1/2-2382	2' 6"	Oil Sand - Black, soft, silty, fine to medium grained. Fair odor. Better saturated than at 2377. Gassy at cut, 3" mushy spot at 2381-1/2±. Coffee cut.
	2382-2384-1/2	2' 6"	Oil Sand - As above, w/lt. gray silty streaks. Gas at top, w/ 1/4" expansion. Fair odor. Good cut.
	2384-1/2- 2387	2' 6"	Oil Sand - As above. Gas at cut, 1/8" expansion. Sand has occa- sional light gray silty sand streaks which give a light coffee cut.
	2387-2387-1/2	6"	Oil Sand - As above. 1/4" expan- sion. Coffee cut. Fair odor.

CORE

<u>#</u>	<u>DEPTH</u>	<u>RECOVERY</u>	<u>DESCRIPTION</u>
2	<u>Interval: 2390-2410'</u>		<u>Total Recovery: 15'</u>
	<u>Note: 5' Void at top of sleeve.</u>		
	2390-2392-1/2	2-1/2'±	Oil Sand - Soft, black, fine to medium grained, silty, fair odor, coffee cut. 2391-2391-1/2 - soft and mushy.
	2392-1/2-2395	2-1/2'±	Oil Sand - As above. Light gas at cut, 2" expansion.
	2395-2397-1/2	2-1/2'±	Oil Sand - As above, but had hard 2" cobble at top. Gassy, w/2" expansion at cut. Fair odor. Coffee cut. 2396-1/2 - 3" mushy spot.
	2397-1/2-2400	2-1/2'±	Oil Sand - As above, 2" expansion and gassy at cut.
	2400-2402-1/2	2-1/2'±	Oil Sand - As above, gassy with 1/2" expansion at top.
	2402-1/2-2405	2-1/2'±	Oil Sand - As above, gassy with 1/2" expansion at cut.
	2405		Oil Sand - (at bottom of core). As above - Fair odor, perhaps slightly lighter cut - dark amber.
3	<u>Interval: 2410-2430'</u>		<u>Total Recovery: 19' 8"</u>
	<u>Note: Description is at end cuts only.</u>		
	2410-2412-1/2	2-1/2'±	Oil Sand - Soft, black, silty, with sub-angular quartz grains, fine to medium grained. Fair odor. Coffee cut.
	2412-1/2-2415	2-1/2'±	Oil Sand - As above, with salt and pepper texture. Fair odor, coffee cut. Good gas flare at cut.
	2415-2417-1/2	2-1/2'±	Oil Sand - As above, fair odor, coffee cut, gassy at cut.
	2417-1/2-2420	2-1/2'±	Oil Sand - As above, gassy at cut.

<u>CORE #</u>	<u>DEPTH</u>	<u>RECOVERY</u>	<u>DESCRIPTION</u>
	2420-2422-1/2	2-1/2'±	Oil Sand - As above, gassy with 1/4" expansion at cut. Fair odor, black cut.
	2422-1/2-2425	2-1/2'±	Oil Sand - As above, with few light gray silty pods. Fair odor, coffee cut. 1/4" expansion at cut, but no gas.
	2425-2427-1/2	2-1/2'±	Oil Sand - As above, 1/8" expansion, no gas.
	2427-1/2- 2429' 8"	2' 2"	Oil Sand - As above, gassy at cut. Has 4" void or "mushy" spot at 2428-1/2. Fair odor, and coffee cut.
	2429' 8"		Oil Sand - (Bottom sample) - As above, fair odor, coffee cut.
4	<u>Interval: 2430-2448'</u>		<u>Total Recovery: 18-1/2 - less voids (?)</u>
<u>Note: Description is of end cuts only.</u>			
	2430-2432-1/2	2-1/2'±	Oil Sand - Soft, black, silty, fine to medium grained, with sub-angular quartz grains, fair odor and black cut. Has gas at bottom (flared) with 1/2" expansion. Had 6" void or mushy spot at 2431-1/2'.
	2432-1/2-2435	2-1/2'±	Oil Sand - As above "with salt and pepper texture". Fair odor and black cut. Had 3" mushy spot at 2433'. Had gas flares.
	2435-2437-1/2	2-1/2'±	Oil Sand - As above with gas flare at top and 1/4" expansion at bottom. Fair odor and black cut.
	2437-1/2- 2439-1/2	2'	Oil Sand - As above, with 3" mushy spot at 2438' and void of 6" at bottom, having a gas flare when lit. Fair odor and black cut.

Getty Oil Company
WH 36-25
Jan. 13-14, 1975
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<u>CORE</u> <u>#</u>	<u>DEPTH</u>	<u>RECOVERY</u>	<u>DESCRIPTION</u>
2439-1/2-2441	1-1/2		Oil Sand - As above. Had 6" oil sand (then 12" void) and then 12" oil sand from 2440-2441'. Fair odor and black cut.
2441-2443-1/2	2-1/2'±		Oil Sand - As above. Had gas flare and 3/4" expansion at bottom. Fair odor and black cut.
2443-1/2-2446	2-1/2'±		Oil Sand - As above. Had gas flare and 1-1/2" expansion at bottom. Fair odor and black cut.
2446-2448-1/2	2-1/2'±		Oil Sand - As above. Had gas at top and expansion as above. Fair odor and black cut.

Cores described by A.C.H. and R.A.H.

WILLIAMS HOLDING 36
CORE ANALYSIS DATA

Cores taken with rubber sleeve coring equipment in water base mud. One-inch diameter horizontal plugs mounted in thin-walled metal jackets with fine-meshed end screens using 700 psig tri-axial pressure. Saturations determined by Dean-Stark extraction using toluene.

<u>Sample</u>	<u>Depth (Feet)</u>	<u>Perm. (md.)</u>	<u>Porosity (Per Cent)</u>	<u>Residual Saturation (Per Cent Pore)</u>		<u>Sample Description</u>
				<u>Oil</u>	<u>Water</u>	
1	2372-73	990	34.7	55.5	41.9	Sand; brown-black spotting; very fine grained, silty, muddy, dark staining, very dull gold fluorescence
2	2373-74	1020	37.2	54.8	40.8	Sand; brown, fine-medium grained, silty, muddy, dark staining, dull gold fluorescence
3	2374-75	1420	34.2	64.2	34.2	Sand; brown, fine-medium grained, silty, dark staining, very dull gold fluorescence
4	2375-76	4540	39.0	58.8	22.1	Sand; brown, fine-medium grained, dark staining, very dull gold fluorescence
5	2376-77	5270	39.8	60.3	24.6	Sand; brown, fine-medium grained, silty, dark staining, dull gold fluorescence
6	2377-78	3420	38.1	53.8	29.7	Sand; brown, fine-medium grained, silty, dark staining, dull gold fluorescence

<u>Sample</u>	<u>Depth (Feet)</u>	<u>Perm. (md.)</u>	<u>Porosity (Per Cent)</u>	<u>Residual Saturation (Per Cent Pore)</u>		<u>Sample Description</u>
				<u>Oil</u>	<u>Total Water</u>	
7	2378-79	4420	38.9	55.5	28.1	Same
8	2379-80	4710	38.0	63.4	26.7	Same
9	2380-81	2690	37.7	51.0	30.6	Same
10	2381-82	2000	36.0	50.8	39.6	Same
11	2382-83	4460	37.5	64.1	27.4	Same
12	2383-84	3950	36.2	54.9	33.3	Same
13	2384-85	2550	34.7	46.0	44.2	Same
14	2385-86	2620	35.4	39.3	44.1	Sand, brown, medium- fine grained, silty, dark staining, dull gold fluorescence
15	2386-87	2730	36.3	53.6	35.3	Same
16	2387-88	2830	36.8	44.7	39.8	Same
17	2392-1/2- 93	2820	36.0	44.2	44.2	Same muddy
18	2393-94	3380	36.3	50.5	35.1	Same
19	2394-95	1835	37.7	48.0	42.8	Same
20	2395-96	2510	34.5	41.4	45.5	Same
21	2396-97	1725	37.1	51.9	37.9	Sand; brown, fine- medium grained, dark staining, dull gold fluorescence
22	2397-98	2725	35.7	50.8	35.5	Same
23	2398-99	3900	37.0	53.5	35.1	Same
24	2399-00	1860	33.8	37.6	51.0	Same
25	2400-01	3320	36.7	63.6	27.4	Same
26	2401-02	4020	38.3	54.2	35.4	Same
27	2402-03	4670	38.0	56.5	30.6	Same
28	2403-04	4970	39.1	58.0	28.6	Same
29	2404-05	2810	37.0	59.6	26.7	Same
30	2410-11	3080	38.0	44.7	31.5	Same

<u>Sample</u>	<u>Depth (Feet)</u>	<u>Perm. (md.)</u>	<u>Porosity (Per Cent)</u>	<u>Residual Saturation (Per Cent Pore)</u>		<u>Sample Description</u>
				<u>Oil</u>	<u>Total Water</u>	
31	2411-12	2950	36.7	47.5	33.5	Same
32	2412-13	3660	38.4	50.1	32.9	Same
33	2413-14	3020	37.0	47.4	38.5	Same
34	2414-15	2965	37.3	48.1	31.6	Same
35	2415-16	3280	37.6	55.2	29.5	Same
36	2416-17	3750	38.3	49.3	31.2	Same
37	2417-18	3970	38.6	52.2	32.0	Same
38	2418-19	3070	37.5	51.2	29.7	Same
39	2419-20	1840	36.7	41.0	38.6	Same
40	2420-21	3860	36.8	54.2	28.5	Same
41	2421-22	3250	36.1	51.7	29.5	Sand; brown, fine- medium grained, dark staining, very dull gold fluorescence
42	2422-23	2610	36.9	50.8	32.5	Same
43	2423-24	2840	36.7	50.6	28.1	Same
44	2424-25	2390	34.5	55.2	31.4	Same
45	2425-26	3290	37.1	51.6	25.8	Same
46	2426-27	2530	36.4	48.0	29.2	Same
47	2427-28	2150	36.5	49.8	27.9	Same
48	2428-29	2540	38.0	44.7	36.0	Same
49	2429- 29-1/2	2750	36.1	53.0	32.0	Same
50	2430-31	3375	37.4	55.3	30.1	Same
51	2431-32	4230	36.9	56.9	31.4	Same
52	2432-33	3755	37.7	56.5	28.8	Same
53	2433-34	3600	37.3	58.0	26.8	Same
54	2434-35	3930	38.3	54.2	23.6	Same
55	2435-36	5780	37.7	54.9	19.9	Same
56	2436-37	5780	36.0	55.6	27.7	Same

<u>Sample</u>	<u>Depth (Feet)</u>	<u>Perm. (md.)</u>	<u>Porosity (Per Cent)</u>	<u>Residual Saturation (Per Cent Pore)</u>		<u>Sample Description</u>
				<u>Oil</u>	<u>Total Water</u>	
57	2437-38	4120	38.2	47.8	28.7	Same
58	2438-39	3950	37.6	55.3	33.3	Same
59	2439- 39-1/2	3960	37.7	49.1	33.2	Same
60	2440-41	2985	37.8	58.3	34.1	Same
61	2441-42	3970	36.7	57.2	33.6	Same
62	2442-43	3400	36.4	53.9	35.2	Same
63	2443-44	3370	37.4	53.2	33.3	Same
64	2444-45	3070	36.0	55.8	31.9	Same
65	2445-46	4200	37.0	61.5	30.2	Same
66	2446-47	4455	38.0	64.9	23.9	Same
67	2447-48	4360	39.1	65.5	25.3	Same
68	2448-49	4070	36.7	57.8	29.2	Same

GETTY OIL COMPANY

WELL: WH 36-25
Report of Geochemical Analysis
Received: May 21, 1975

<u>Radicals</u>	<u>Milligrams Per Liter</u>	<u>Grains per U.S. Gallon</u>	<u>Reacting Value</u>	<u>Per Cent</u>
Sodium, (Na)	3,150	184.	136.94	47.20
Ammonium, (NH ₄)	75	4.38	4.16	1.43
Calcium, (Ca)	41	2.40	2.05	0.71
Magnesium, (Mg)	23	1.34	1.89	0.65
Barium, (Ba)	1.5	0.08	0.02	0.01
Iron (Fe) (total)	5.6	0.33	-	-
Sulfate, (SO ₄)	TR < 5	-	-	-
Chloride, (Cl)	3,380	197.	95.32	32.86
Hydroxide, (OH)	0	-	-	-
Carbonate, (CO ₃)	0	-	-	-
Bicarbonate, (HCO ₃)	2,970	173.	48.68	16.78
Borate, (B ₄ O ₇)	75	4.40	0.97	0.33
Iodide, (I)	11	0.67	0.09	0.03
Silica, (SiO ₂)	50	2.92	-	-
*Organic Acids	55	3.21	-	-
Salinity as Salt, (NaCl)	5,570			
Total Solids	9,835			
Specific Gravity	1.009 @ 60°F			
Resistivity	80 Ohm Cm @ 75°F			
pH Value	7.46			

<u>Groups</u>		<u>Chemical Character</u>	
Alkalies	40.63%	Primary Salinity	65.78%
Earths	1.37%	Secondary Salinity	0 %
Strong Acids	32.89%	Primary Alkalinity	31.48%
Weak Acids	17.11%	Secondary Alkalinity	2.74%

Type Sample:
Field:
Zone and Sands:

*Included in Bicarbonates

WILLIAMS HOLDING 105-25Drilling History

Drilling rig moved in and spudded a 9-7/8" hole on August 11, 1975. Drilling was continued to 866', at which time directional drilling began. Dynadrilled from 866' to 1044', and then resumed drilling with a normal drilling set-up to 1536'. At this depth directional drilling began again and continued with a Dynadrill to 1763'. Drilled ahead with a normal drilling set-up to 2334', at which time directionally drilling with a Dynadrill again commenced and continued to 2460'. The hole was reamed, and drilling with a normal set-up was resumed and continued to total depth of 2592'. During drilling, mud properties averaged as follows: mud weight, 70 lbs/CF; funnel viscosity, 55 seconds; fluid loss, 8.3cc. Drilling rate averaged 480 ft/day, and the highest angle from vertical was 13°. Bottom hole location 309' north, 7' east of surface location.

At T.D., a Dresser-Atlas Dual Induction-Focused log and a Compensated Density-Gamma Ray log was run. The following day 7", 23# N-80 Buttress casing was run to 2528'. The casing was equipped with a bullplug guide shoe on bottom, a cement basket over four 1/2" holes located just above shoe, and a fillup valve on top of the shoe joint. Five latch-on centralizers were located on every other joint for the first nine joints. The casing was cemented in place with 1340 ft³ Class "G" cement containing 1:2 perfolite and 40% silica flour, and treated for 12 hours setting time, followed by 100 ft³ luminite cement premixed with 20% silica flour, and treated for 1500 psi compressive strength in four hours. The cement was displaced with 550 ft³ mud and 160 ft³ cement returns were recorded. After six hours the casing was stretched 25-1/2" by pulling 258,000 lbs.

Williams Holding 105-25

On August 17, the shoe was drilled out, and after changing the wellbore fluid over to Polymer mud, a hole opener was run. The hole was opened to 12" from 2528' to 2592'. The well was then circulated clean, and a caliper log was run. The rest of the day and all of the next was spent waiting on the gravel packer. During this time the hole was rescraped from 2528' to 2592' and circulated clean.

On August 19, 4 joints of 5-1/2", 17# flush joint liner and gravel packing tools were run. The second and third joints were 40 mesh slotted, and open-hole centralizers were located on the bottom and second from bottom joints. The liner was then pressure gravel packed with 45 ft³ 10x16 San Simeon gravel. One cubic foot gravel was circulated out after the operation and the gravel pack tools were pulled. After setting a lead seal drive on an adaptor over the liner at 2470', the rig was released.

WILLIAMS HOLDING 105
DUAL INDUCTION FOCUSED LOG

SPONTANEOUS POTENTIAL Millivolts	DEPTH	RESISTIVITY ohms - m ² /m				
<div style="text-align: center;"> $\rightarrow$ 10 $\leftarrow$ + </div>		SHALLOW FOCUSED LOG .2 1.0 10 100 1000				
		MEDIUM INDUCTION LOG .2 1.0 10 100 1000				
		DEEP INDUCTION LOG .2 1.0 10 100 1000

WILLIAMS HOLDING 105

COMPENSATED DENSITY LOG

GAMMA RAY & CALIPER		DEPTH	BULK DENSITY GRAMS/CC	
			CORRECTION	CORRECTION
0	API UNITS	100	1.75	2.75
			54%	0%
			39%	
			24%	
			9%	
			DENSITY SANDSTONE POROSITY	
6	HOLE SIZE - INCHES	16

WILLIAMS HOLDING/RECRUIT FEE 204-25Drilling History

Drilling rig moved in and spudded a 9-7/8" hole on August 29, 1975. Drilled ahead to 200' and began directionally drilling with a Dynadrill. Dynadrilled from 200' to 448'. At 448' changed over to a conventional drilling assembly with a 9-7/8" bit and reamed from 228' to 448'. Began directionally drilling with a Dynadrill again at 448', and continued directionally drilling to 636'. Resumed drilling with the conventional drilling assembly and drilled to 1856'. At this depth began directionally drilling with a Dynadrill, and continued to 1925'. Resumed drilling with the normal drilling setup and drilled ahead to total depth of 2621'. Bottom hole location 319' north, 323' west of surface location. During drilling, mud properties averaged as follows: mud weight, 71 lbs/ft³; funnel viscosity, 53 seconds; fluid loss, 9.2cc. Drilling rate averaged 427 ft/day, and maximum angle attained was 14.75° from vertical.

After reaching T.D. on September 3, ran a Dresser-Atlas Dual Induction-Focused log. Following logging, drill pipe was hung at 2621' and 33 ft³ luminite cement with 20% silica flour was displaced with 195 ft³ mud.

On September 4, the cement was found at 2580', and was drilled out to 2600'. Then 7", 23# N-80 Buttress casing was run to 2537'. The casing was equipped with a bullplug guide shoe on bottom, a cement basket over four 1/2" holes located just above the shoe, and a fillup valve on top of the shoe joint. Five latch-on centralizers were located on every other joint for the first nine joints. The casing was cemented in place with 1350 ft³ Class "G" cement consisting of 1:2 perfalite and 40% silica flour, and treated for 12 hours setting time, followed by 100 ft³ luminite cement premixed with 20% silica flour and treated for 1500 psi compressive strength in 4 hours. The cement was displaced with 574 ft³ mud

Williams Holding/Recruit Fee 204-25

and 300 ft³ returns were recorded. After six hours the casing was stretched 26" by pulling 338,000 lbs.

The following day, after running a 6-1/8" bit and drilling out cement, the wellbore fluid was changed over to KCl-polymer mud. A 12" hole opener was run to open hole from 2537' to 2600', after which a Caliper log was run. After logging, 153' 5-1/2", 17# liner with gravel packing tools was run. The liner was 40 mesh slotted from 2542' to 2596', and equipped with one open hole centralizer on bottom and one on the middle of the second joint from bottom. The liner was then pressure gravel packed with 91 ft³ gravel. One ft³ of gravel has backscuttled out.

On September 6, a lead seal adaptor was set over the liner, and the rig released.

WILLIAMS HOLDING/
RECRUIT FEE 204

DUAL INDUCTION FOCUSED LOG

WILLIAMS HOLDING/
RECRUIT FEE 204

COMPENSATED DENSITY LOG

GAMMA RAY & CALIPER		DEPTH	BULK DENSITY GRAMS/CC				
			CORRECTION		CORRECTION		
					- .25 0 + .25		
0	API UNITS	100	1.75				2.75
			54%	39%	24%	9%	0%
			DENSITY SANDSTONE POROSITY				
6	HOLE SIZE - INCHES	16	NOTE: This log is apparently miscalibrated.

WILLIAMS HOLDING 205-25Drilling History

Drilling rig moved in and spudded a 9-7/8" hole on January 25, 1975. Drilled ahead with no problems to 2556' on January 29. At 2556', ran core barrel and cored to 2576', recovering 16-1/2'. Continued coring from 2576' to 2596', and then ran a 9-7/8" bit to open the hole from 2556' to 2596'. The next day coring continued from 2596' to 2616', and 20' oil sand was recovered. Ran core barrel again from 2616' to 2636', recovering 19-1/2 feet oil sand. The core barrel was followed by a 9-7/8" bit to open the hole from 2596' to 2636'.

On January 31 cored once again from 2636' to 2640', recovering 4' oil sand. This was followed by a 9-7/8" bit, which opened the hole from 2636' to total depth of 2640'. Well was approximately vertical. During drilling and coring, mud properties averaged as follows: mud weight, 71.5 lbs/ft³; funnel viscosity, 44 seconds. Drilling rate averaged 371 ft/day.

At T.D., ran a Dresser-Atlas Dual Induction-Focused log, after which 63 joints of 7", 26# Speedtite, 23# N-80 Buttress, and 23# S0095 casing was run to 2583'. The casing was equipped with a cement guide shoe, a fillup valve on top of the shoe joint, one metal basket over four 1/2" holes, and latch-on centralizers. The casing was cemented in place with 1090 ft³ Class "G" cement containing 1:2 perfalite and 40% silica flour, and treated for 12 hours setting time, followed by 100 ft³ luminite cement premixed with 20% silica flour and treated for 1500 psi compressive strength in four hours. The cement was displaced with 590 ft³ mud, and 200 ft³ returns were recorded. After six hours the casing was stretched 16" by pulling 260,000 lbs.

The wellbore fluid was then changed over to lease water to drill out cement from 2532' to 2583'. After drilling out cement, a 6" hole was drilled from 2640' to 2647', and the wellbore fluid was changed back to KCl-polymer mud.

Williams Holding 205-25

The following day, February 2, a Dresser-Atlas Epilog suite was run. On February 3, the hole was opened with a 14" underreamer from 2583' to 2647', and after changing over to polymer treated salt water, an attempt to run the liner was made. However, the adaptor wouldn't go through the top joint of casing. The next day a new adaptor was acquired, and 102' of 5-1/2", 15.5# K-55 liner was landed at 2647'. The liner was 30 mesh slotted from 2555' to 2642', and was equipped with centralizers in the center of the bottom and middle joints. The top joint of the liner was Ventura flush joint. The liner was then gravel flow packed with 65 ft³ 10x18 San Simeon gravel and the hole circulated clean.

On February 5 the gravel packing tools were pulled and tubing, pump, and rods were run. The following day, February 6, the rig was released.

WILLIAMS HOLDING 205

DUAL INDUCTION FOCUSED LOG

SPONTANEOUS POTENTIAL Millivolts	DEPTH	RESISTIVITY ohms - m ² /m				
<div data-bbox="263 655 431 706"> $\rightarrow 10 \leftarrow +$ </div>		SHALLOW FOCUSED LOG				
		.2	1.0	10	100	1000
		MEDIUM INDUCTION LOG				
		.2	1.0	10	100	1000
		DEEP INDUCTION LOG				
		.2	1.0	10	100	1000

PROXIMITY LOG - MINILOG WITH CALIPER

RESISTIVITY Ohms m ² /m	DEPTH	RESISTIVITY Ohms m ² /m
MICRO INVERSE 1" x 1"		
MICRO NORMAL 2"		
HOLE SIZE - INCHES 7 9 11 13 15		PROXIMITY LOG 1 10 100 1000

WILLIAMS HOLDING 205

COMPENSATED DENSILOG WITH
COMPENSATED NEUTRON LOG

ACOUSTILOG

S.P. or G/R & Caliper	DEPTH	ACOUSTILOG $T_1 - R_1 - R_2 - T_2$
Millivolts - ↔ + API UNITS		SPECIFIC ACOUSTIC TIME Micro Seconds Per Foot
HOLE SIZE - INCHES 7 9 11 13 15		
		175 75

WILLIAMS HOLDING 205
NEUTRON LIFETIME LOG

CORRELATION CURVE	DEPTH	COUNTS PER MINUTE
		GATE 1 400 To 600 μ Sec.
		GATE 2 700 To 900 μ Sec.
		$\Delta T = 300 \mu$ Sec.
MONITOR		SIGMA 10 ²¹ BARN/cm ²
		50 30 10

EPILOG

DEPTH	LITHOLOGIC CHARACTERISTICS	FLUID ANALYSIS	POROSITY AND FLUIDS % BULK VOLUME		FORMATION % BULK VOLUME		
			HYDROCARBON	WATER	CLAY	QUARTZ	POROSITY
		NLL WATER SATURATION					
	Rwa (NLL)						
		WATER SATURATION					
0		100 %	0	50 %	0	SHALE	OTHER
	PERMEABILITY INDEX	HYDROCARBON VOLUME	NLL	%	WATER		
10 ⁴		$\phi \cdot S_{hr}$	.25	50	0		
		HYDROCARBON WEIGHT					
		$\phi \cdot S_{hr} \cdot \rho_h$	.25

GETTY OIL COMPANY
CORE DESCRIPTION
WILLIAMS HOLDING 205-25
SECTION 25 - 9N/33W

3" Christensen Diamond Rubber-Sleeve Core

Jan. 29-31, 1975

<u>CORE #</u>	<u>DEPTH</u>	<u>RECOVERY</u>	<u>DESCRIPTION</u>
1	Interval: 2556-2576*		Total Recovery: 16-1/2'
	2565-1/2-2568	2-1/2'	Oil Sand - As at bottom - 2565-1/2 with oil sand becoming brownish-black on bottom. Had good odor, black cut, gas flare, and reddish brown fluorescence.
	2568-2570-1/2	2-1/2'	Oil Sand - Soft, brownish-black, silty, fine to medium grained. Had good odor, black cut, light gas flare, and 1/8" to 1/4" (bot.) expansion.
	2570-1/2-2571-1/2	1'	Oil Sand - As above, with slight "salt and pepper" texture.

			Had 30" void at 2571-1/2'
	2571-1/2-2572-1/2	1'	Oil Sand - as at 2570-1/2. Fair odor and black cut.
<p>*Note: Removed 3" piece of shale at 2558, and took pictures of fracture pattern.</p> <p>Also, e-log may not match description, where e-log (Run #1) shows S1-B at 2568'.</p>			
2	Interval: 2576-2596		Total Recovery: 20'*
	2576-2578-1/2	2-1/2'*	Oil Sand - Soft, silty, fine to medium grained, with salt and pepper texture. Mushy spot (2") at 2577'*. Fair odor, black cut.
	2578-1/2-81	2-1/2'*	Oil Sand - as above. Has 2" mushy spot at 2579' and 3" mushy spot at 2580'*, and fair odor and black coffee cut.
	2581-2583-1/2	2-1/2'	Oil Sand - as above. Has 2" soft spot at 2583. Fair odor and black cut.

<u>CORE</u> <u>#</u>	<u>DEPTH</u>	<u>RECOVERY</u>	<u>DESCRIPTION</u>
	2583-1/2-86	2-1/2'*	<u>Oil Sand</u> - As above. Has 3" mushy spot* at 2584, and 5" mushy spot at 2584-1/2*. Fair odor and black cut.
	2586-2588-1/2	2-1/2'	<u>Oil Sand</u> - As above. Fair odor and black cut.
	2588-1/2-91	2-1/2'	<u>Oil Sand</u> - As above with a few light gray silty streaks. Has 2" soft spot at 2590. Fair odor and black cut.
	2591-93-1/2	2-1/2'*	<u>Oil Sand</u> - As at 2588-1/2. Has mushy and partially void interval 2591-1/2 to 2593.* Fair odor and black cut.
	2593-1/2-96	2-1/2'	<u>Oil Sand</u> - As above, with 2" soft spot at 2595. Had 1/2 expansion at top and more silty streaks. Fair odor and black cut.

*Note: Mushy spots are partially void and core may be short of depth.

3	<u>Interval: 2596-2616</u>	<u>Total Recovery: 19' 4"</u>	
	Had 3" fill and top 2" oil sand taken from core (loose).		
	2596-2598-1/2	2-1/2'	<u>Oil Sand</u> - Soft, brownish-black, silty, fine to medium grained. Had 1/2 expansion on bottom with gas flare. Fair odor and black cut.
	2598-1/2-2601	2-1/2'	<u>Oil Sand</u> - As above, with expansion top and bottom. When core is exposed a while, it gets a "salt and pepper" texture. Good odor and black cut. Has soft spot at 2599'.
	2601-2603-1/2	2-1/2'	<u>Oil Sand</u> - As above. Had gas and 3" (total) expansion at top cut with gas and 1" expansion at bottom. Good odor and black cut.

CORE #	DEPTH	RECOVERY	DESCRIPTION
	2603-1/2- 2605'-10"	2-1/2'	<u>Oil Sand</u> - As above. Had expansion (1")+gas at top cut. Had mushy spot at 2604' after expansion. Good odor and black cut.

	Had 13" void (note folded sleeve)		
	2605'-10" 2608	2'-2"	<u>Oil Sand</u> - As above, fair odor and black cut.
	2608-2610-1/2	2-1/2'	<u>Oil Sand</u> - As above. Had 1/4 to 3/8" expansion with gas at ends. Fair odor and black cut.
	2610-1/2-2613	2-1/2'	<u>Oil Sand</u> - As above. Had 3/8" + expansion gas release. Fair odor and black cut.
	2613- 2615'-4"	2-1/3'	<u>Oil Sand</u> - As above. Had 1" expansion at top with gas flare. Fair odor and black cut.
4	<u>Interval: 2616-2636</u>		<u>Total Recovery: 19'-11"</u>
	2616-2618-1/2	2-1/2'	<u>Oil Sand</u> - Dark grayish-black, soft, silty, fine to medium grained with "salt and pepper" texture. Fair odor and black cut.
	2618-1/2-2621	2-1/2'	<u>Oil Sand</u> - As above, with good gas flare (when lit). Good odor and cut.
	2621-2623-1/2	2-1/2'	<u>Oil Sand</u> - As above, with good gas flare.
	2623-1/2-2626	2-1/2'	<u>Oil Sand</u> - As above with good gas flare. Fair odor and cut.
	2626-2628-1/2	2-1/2'	<u>Oil Sand</u> - As above with good gas flare. Fair odor and black cut.
	2628-1/2-2631	2-1/2'	<u>Oil Sand</u> - As above, with good gas flare. Fair odor and black cut.
	2631-2633-1/2	2-1/2'	<u>Oil Sand</u> - As above, with good gas flare. Fair odor and black cut.

Getty Oil Company
 WH 205-25
 Jan. 29-31, 1975
 Page 4

CORE #	DEPTH	RECOVERY	DESCRIPTION
	2633-1/2- 2635'-11"	2'-5"	<u>Oil Sand</u> - As above, with no flare, fair odor and black cut.
5	<u>Interval: 2636-2640</u>		<u>Total Recovery: 4'-1"</u>
	2636-2637-1/2 + (6" fill)	1-1/2'± (+6"±)	<u>Oil Sand</u> + est. 6" fill (shaly pieces at top) oil sand is grayish black, soft, fine to medium grained with "salt and pepper" texture. Fair odor and black cut and reddish-brown fluorescence.
	2637-1/2- 2639'-10"	2'-4"	<u>Oil Sand</u> - As above. Bottom sample has a few light gray clay pods, with oil sand in pieces. Fair odor and coffee cut.
	2639'-10" 2640'-1"	0'-3"	<u>Oil Sand</u> - As at 2636'+. Has fair odor and black cut, and poor reddish-brown fluorescence. (This piece was 10'± below 2639'-10" where it was drilled to "set off" or "tie-up" core.)

GETTY OIL COMPANY
WILLIAMS HOLDING 205-25
SECTION 25 - 9N/33W

1" Dresser-Atlas Sidewall Samples*

February 2, 1975

<u>DEPTH</u>	<u>RECOVERY</u>	<u>DESCRIPTION</u>
2640-1/2	1-1/4"	<u>Oil Sand</u> - Dark grayish-brown, soft, silty, fine to medium grained, poorly sorted with "salt and pepper" texture. Good odor and brown oil stain on solvent pad.
2641	1-1/4"	<u>Oil Sand</u> - As above, with light greenish-gray silty sand streaks (to 1/8") which show light stain. Fair odor.
2641-1/2	1-1/8"	<u>Oil Sand</u> - As above, with gray streaks appearing dryer and irregular in more mottled pattern. Fair odor and brown stain.
2642	1-3/8"	<u>Oil Sand</u> - As at 2640-1/2, with more medium subangular quartz grains. Good odor and stain.
2642-1/2	1-1/4"	<u>Oil Sand</u> - As above, but finer grained. Fair odor and dark brown stain.
2643	1-1/2"	<u>Oil Sand</u> - As at 2641', fine grained with a few grayish silty sand streaks. Poor odor and brown stain.
2643-1/2	1-1/2"	<u>Oil Sand</u> - As above, with very thin gray streaks. Fair odor and brown stain.
2644	1-1/4"	<u>Oil Sand</u> - As at 2640-1/2, but "dirtier" and more silty. Fair odor and dark brown stain.
2644-1/2	no Rec	
2645	no Rec	
2645-1/2	1-1/2"	<u>Oil Sand</u> - As above at 2644, with fair odor and brown stain.
2646	1-1/2"	<u>Oil Sand</u> - As at 2643-1/2, with thin mottled gray streaks. Has fair odor and brown stain.
2646-1/2	no Rec	

*Note: All samples sent to Core Lab, Bakersfield.

Described by: A.C.H.

WILLIAMS HOLDING 205
CORE ANALYSIS DATA

Cores taken with rubber sleeve coring equipment in water base mud. One-inch diameter horizontal plugs mounted in thin-walled metal jackets with fine-mesh end screens using 700 psig tri-axial pressure. Saturations determined by Dean-Stark extraction using toluene.

<u>Sample</u>	<u>Depth (Feet)</u>	<u>Perm. (md.)</u>	<u>Porosity (Per Cent)</u>	<u>Residual Saturation (Per Cent Pore)</u>		<u>Sample Description</u>
				<u>Oil</u>	<u>Total Water</u>	
1	2557-58	8.9	29.4	33.8	54.1	Sand; brown, fine grained, well cemented fine gray sand, cross bedding
2	2559-60	151	35.5	0.0	78.7	Sand; Light tan, very fine grained, silty, light staining
3	2560-61	178	31.3	0.0	75.5	Same
4	2561-62	560	35.0	10.7	80.8	Sand; brown, very fine grained, very silty, light tan, laminated, dark staining
5	2562-63	320	35.0	21.9	66.0	Sand; brown, very fine grained, vory silty, dark staining
6	2563-64	990	34.8	11.3	75.2	Sand; brown, gray, fine grained, dark steaked stain
7	2564-65	1980	35.7	25.0	63.7	Same
8	2565-66	2970	36.8	19.3	68.6	Same
9	2566-67	3915	36.3	28.6	57.0	Sand; brown, fine grained, dark stain

<u>Sample</u>	<u>Depth (Feet)</u>	<u>Perm. (md.)</u>	<u>Porosity (Per Cent)</u>	<u>Residual Saturation (Per Cent Pore)</u>		<u>Sample Description</u>
				<u>Oil</u>	<u>Total Water</u>	
10	2567-68	5340	36.9	42.9	45.0	Sand; brown, fine grained, gray sand laminated, dark streaked stain
11	2568-69	8330	37.7	64.1	25.0	Sand; brown, fine grained, dark stain
12	2569-70	4880	38.1	70.7	21.9	Same
13	2570-71	4880	38.1	72.5	17.7	Same
14	2571-72	6980	39.0	70.0	22.6	Same
15	2572-73	6650	38.3	64.3	24.6	Same
16	2576-77	8730	39.1	53.5	22.0	Same
17	2577-78	8330	39.7	55.8	24.4	Same
18	2578-79	8980	38.7	62.2	20.4	Same
19	2579-80	8080	39.3	62.3	20.3	Same
20	2580-81	8240	39.0	55.5	23.0	Sand; brown, fine grained/gray sand inclusions, dark staining
21	2581-82	6950	39.5	60.5	20.9	Sand; brown, fine grained; dark stain
22	2582-83	8040	38.5	65.8	15.9	Same
23	2583-84	8940	39.7	58.6	28.0	Same
24	2584-85	7410	38.7	59.3	19.1	Same
25	2585-86	8940	39.4	64.4	16.6	Same
26	2586-87	7410	39.0	61.8	17.5	Same
27	2587-88	8940	39.8	62.2	17.6	Same
28	2588-89	5700	39.8	59.0	28.3	Same
29	2589-90	3320	36.7	47.9	40.2	Same
30	2590-91	6410	37.6	58.1	23.5	Same
31	2591-92	5230	37.0	44.3	33.6	Same
32	2592-93	5930	38.8	50.4	37.0	Same

<u>Sample</u>	<u>Depth (Feet)</u>	<u>Perm. (md.)</u>	<u>Porosity (Per Cent)</u>	<u>Residual Saturation (Per Cent Pore)</u>		<u>Sample Description</u>
				<u>Oil</u>	<u>Total Water</u>	
33	2593-94	5550	35.6	51.3	33.9	Same
34	2594-95	6180	37.0	55.2	31.5	Same
35	2595-96	5880	33.1	48.2	27.7	Sand; brown, fine grained/gray dense shale inclusions, dark stain
36	2596-97	6650	36.6	49.6	32.2	Sand; brown, fine grained, dark stain
37	2597-98	6280	37.2	47.6	37.3	Same
38	2598-99	6840	36.9	53.2	32.1	Same
39	2599-00	6650	37.6	52.8	35.0	Same
40	2600-01	5380	37.5	54.4	31.3	Same
41	2601-02	5550	38.5	53.3	32.8	Same
42	2602-03	4170	38.0	49.4	37.9	Same
43	2603-04	6470	37.9	50.6	31.3	Sand; brown, fine grained dark stain
44	2604-05	5540	36.5	58.7	25.5	Same
45	2605-06	7180	36.8	59.3	24.8	Same
46	2606-07	5870	35.8	55.8	29.3	Same
47	2607-08	6280	36.6	53.0	32.1	Same
48	2608-09	4490	36.3	52.5	34.3	Same
49	2609-10	3590	34.0	48.0	34.1	Same
50	2610-11	5080	36.5	51.7	32.9	Same
51	2611-12	5870	36.5	54.5	27.4	Same
52	2612-13	4440	37.9	55.0	34.4	Same
53	2613-14	5850	38.6	57.3	29.5	Same
54	2614-15	5540	38.0	46.8	38.4	Same
55	2616-17	5080	36.9	55.3	26.5	Same
56	2617-18	4620	36.6	55.6	26.3	Same
57	2618-19	5380	37.6	57.6	28.2	Same
58	2619-20	5920	36.5	56.1	26.1	Same

<u>Sample</u>	<u>Depth (Feet)</u>	<u>Perm. (md.)</u>	<u>Porosity (Per Cent)</u>	<u>Residual Saturation (Per Cent Pore)</u>		<u>Sample Description</u>
				<u>Oil</u>	<u>Total Water</u>	
59	2620-21	4940	36.0	58.7	23.2	Same
60	2621-22	5080	37.3	58.5	26.5	Same
61	2622-23	6280	36.9	56.3	25.1	Same
62	2623-24	4940	36.7	57.1	22.1	Same
63	2624-25	6650	36.9	62.0	22.5	Same
64	2625-26	5600	37.5	57.5	26.9	Same
65	2626-27	5540	36.6	60.4	20.9	Same
66	2627-28	6470	36.8	60.2	20.9	Same
67	2628-29	7570	35.9	63.2	20.2	Same
68	2629-30	7410	36.5	57.5	21.2	Same
69	2630-31	6840	36.5	56.7	22.5	Same
70	2631-32	6480	37.4	59.6	25.2	Same
71	2632-33	7380	36.7	61.5	21.2	Same
72	2633-34	6480	37.6	56.2	21.7	Sand; brown, fine grained/fine gray sand inclusions, dark stain
73	2634-35	6470	37.3	60.3	24.1	Sand; brown, fine grained, dark stain
74	2635-36	4280	35.3	44.7	33.7	Same
75	2636-37	8030	36.0	56.2	22.4	Same
76	2637-38	5930	37.2	54.7	25.0	Same
77	2638-39	6850	36.1	59.5	20.8	Same
78	2639-40	4800	35.5	47.5	33.3	Same

SIDEWALL SAMPLE ANALYSIS

<u>Sample</u>	<u>Depth (Feet)</u>	<u>Perm. (md.)</u>	<u>Porosity (Per Cent)</u>	<u>Residual Saturation (Per Cent Pore)</u>		<u>Sample Description</u>
				<u>Oil</u>	<u>Total Water</u>	
1	2640-1/2	1070	33.5	36.2	50.3	Sand; brown, fine grained/gray sand inclusions, dark stain, very dull fluorescence
2	2641	830	32.8	28.0	51.2	Same
3	2641-1/2	770	33.5	28.5	52.1	Same
4	2642	1350	33.7	40.8	44.3	Same
5	2642-1/2	1590	33.0	39.6	38.0	Sand; brown, fine grained, dark stain, very dull fluorescence
6	2643	1160	32.2	36.2	48.6	Same
7	2643-1/2	1410	33.7	40.4	45.1	Same
8	2644	1680	31.1	50.9	33.7	Same
9	2645-1/2	860	33.3	36.9	47.4	Sand; brown, fine grained/gray sand inclusions, dark stain, very dull fluorescence
10	2646	1270	33.0	39.3	49.6	Sand; brown, fine grained/fine gray sand inclusions, dark stain, very dull fluorescence

GETTY OIL COMPANY

WELL: WH 205-25

Report of Geochemical Analysis

Received: May 21, 1975

<u>Radicals</u>	<u>Milligrams Per Liter</u>	<u>Grains per U.S. Gallon</u>	<u>Reacting Value</u>	<u>Per Cent</u>
Sodium, (Na)	2,340	137.	101.79	47.42
Ammonium, (NH ₄)	50	2.92	2.77	1.29
Calcium, (Ca)	34	1.99	1.70	0.79
Magnesium, (Mg)	13	0.76	1.07	0.50
Barium, (Ba)	TR < 1	-	-	-
Iron, (Fe) (total)	3.5	0.20	-	-
Sulfate, (SO ₄)	TR < 5	-	-	-
Chloride, (Cl)	1,970	115.	55.55	25.88
Hydroxide, (OH)	0	-	-	-
Carbonate, (CO ₃)	0	-	-	-
Bicarbonate, (HCO ₃)	3,115	182.	51.05	23.78
Borate, (B ₄ O ₇)	50	2.90	0.64	0.30
Iodide, (I)	12	0.67	0.09	0.04
Silica, (SiO ₂)	35	2.04	-	-
*Organic Acids	85	4.96	-	-
Salinity as Salt, (NaCl)	3,245			
Total Solids	7,705			
Specific Gravity	1.008 @ 60°F.			
Resistivity	109 Ohm Cm @ 75°F.			
pH Value	7.82			

<u>Groups</u>		<u>Chemical Character</u>	
Alkalies	48.71%	Primary Salinity	51.84%
Earths	1.29%	Secondary Salinity	0 %
Strong Acids	25.92%	Primary Alkalinity	45.58%
Weak Acids	24.08%	Secondary Alkalinity	2.58%

Type Sample:
Field:
Zone and Sands:

*Included in Bicarbonates.

WILLIAMS HOLDING 206-25Drilling History

Drilling rig moved in and spudded a 9-7/8" hole on August 20, 1975. Drilled ahead to 510' and lost circulation. Continued drilling from 510' to 783' mixing mud lost circulation materials. At 783', ran in hole with open end 4-1/2" drill pipe and hung pipe at 527'. After pumping in 109 ft³ Class "G" cement with 1:4 perfalite, ran in to 586' but could not find cement. Pulled up to 525', but could not maintain circulation. Pulled up to 403' and had circulation. Lowered drill pipe to 465' and again lost circulation. With drill pipe at 527', pumped in 109 ft³ Class "G" cement with 1:4 perfalite with no cement returns. After 3 hours a 9-7/8" bit was run to 464' with no circulation and no cement found. Open ended drill pipe was hung at 527', and the cementing procedure repeated.

After six hours, a 9-7/8" bit was run and hit firm cement at 402 ft. The cement was drilled out and normal drilling resumed from 783 ft to 1391 ft.

On August 23, began directionally drilling with a Dynadrill and drilled from 1391' to 1558'. At 1558', resumed drilling with a normal drilling set-up, and continued to 1954'. At this depth, ran Dynadrill and directionally drilled to 2070'. Resumed drilling with a normal drilling set-up and drilled ahead to total depth of 2648'. Bottom hole location 74' north, 146' west of surface location. During drilling, the mud properties averaged as follows: mud weight, 70 lbs/C.F.; funnel viscosity, 61 seconds; fluid loss, 8cc. Drilling rate averaged 370 ft/day, and maximum angle attained was 11° from vertical.

At T.D., a Dresser-Atlas Dual Induction-Focused log and a Compensated Density-Gamma Ray log were run, after which 67 joints 7", 23# N-80 Buttress casing were run to 2573 ft. The casing was

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equipped with a bullplug guide shoe on bottom, a cement basket over four 1/2" holes located just above the shoe, and a fillup valve on top of the shoe joint. Five latch-on centralizers were located on every other joint for the first nine joints. The casing was cemented in place with 1360 ft³ Class "G" cement containing 1:2 perfalite and 40% silica flour, and treated for 12 hours setting time, followed by 100 ft³ luminite cement premixed with 20% silica flour and treated for 1500 psi compressive strength in 4 hours. The cement was displaced with 583 ft³ mud, and 160 ft³ cement returns were recorded. After six hours the casing was stretched 21" by pulling 200,000 lbs. However, when the slips were set, both conductor and casing slipped down the hole. The casing was restretched 9" with 200,000 lbs pull. After drilling out the baffle and shoe, the wellbore fluid was changed over to polymer mud and a hole opener was run. The hole was opened to 12" from 2573' to 2648'.

The hole opener was pulled and a Caliper log was run, after which 4 joints of 5-1/2", 17# flush joint liner with gravel packing tools was run. The second and third joints of the liner were 40 mesh slotted. Open hole centralizers were located on the bottom and the second from bottom joints. The casing was then pressure gravel packed with 60 ft³ 10x16 San Simeon gravel. After the gravel packing, the tools were pulled and a lead seal drive on an adaptor was set over liner. The well was circulated clean, and the rig was released 6:30 a.m. on August 29, 1975.

WILLIAMS HOLDING 206

DUAL INDUCTION FOCUSED LOG

WILLIAMS HOLDING 206

COMPENSATED DENSITY LOG

GAMMA RAY & CALIPER		DEPTH	BULK DENSITY GRAMS/CC	
			CORRECTION	CORRECTION
			- .25	0 + .25
0	API UNITS	100	1.75	2.75
			54 %	39 % 24 % 9 % 0 %
			DENSITY SANDSTONE POROSITY	
6	HOLE SIZE - INCHES	16

WILLIAMS HOLDING 305-25Drilling History

Drilling rig moved in and spudded a 9-7/8" hole on August 31, 1975. Drilled ahead with no problems to 850' on September 1. At 850' began directionally drilling with a Dynadrill, and drilled ahead to 1087'. Resumed drilling with normal drilling set-up and drilled ahead to total depth of 2411'. Bottom hole location 227 ft north, 107 ft east of surface location. During drilling, the mud properties averaged as follows: mud weight, 73 lbs/ft³; funnel viscosity, 52 seconds; fluid loss, 9.8cc. Drilling rate averaged 393 ft/day, and the maximum well angle from vertical was 11.75°.

On September 5, ran a Dresser-Atlas Dual Induction-Focused log, but the tool stopped at 1876'. The tool was pulled, and the hole reamed from 1858' to 1930'. The logging tools were then rerun and the well successfully logged.

After logging, 60 joints of 7", 23# N-80 Bullress casing were run to 2340'. The casing was equipped with a bullplug guide shoe on bottom, a cement basket over four 1/2" holes located just above the shoe, and a fillup valve on top of the shoe joint. Five latch-on centralizers were located on every other joint for the first nine joints. The casing was cemented in place with 1240 ft³ Class "G" cement containing 1:2 perfalite and 40% silica flour, and treated for 12 hours setting time, followed by 100 ft³ luminite cement premixed with 20% silica flour and treated for 1500 psi compressive strength in four hours. The cement was displaced with 522 ft³ mud, and 285 ft³ of cement returns were recorded. After six hours the casing was stretched 27-1/2" by pulling 335,000 lbs.

On September 7, the drilling fluid was changed over to lease water and the cement and shoe were drilled out. After changing over to polymer mud, ran hole opener and opened 9-7/8" hole to 12" from 2340' to 2411'. The well was then circulated clean and a

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Caliper log was run. Four joints of 5-1/2", 17# liner were run with gravel packing tools. The second and third joints of the liner were 40 mesh slotted. The liner was also equipped with one centralizer on bottom and one on the middle of the second joint from bottom. The liner was then pressure gravel packed with 95 ft³ 10x18 San Simeon gravel. Five cubic feet of gravel was back-scuttled.

The following day the gravel pack tools were pulled, and a lead seal drive on an adaptor was set over the liner. The liner was cleaned out, and the rig released.

DUAL INDUCTION FOCUSED LOG

SPONTANEOUS POTENTIAL Millivolts	DEPTH	RESISTIVITY ohms - m ² /m
<div><div>-</div><div>→</div><div> </div><div>10</div><div> </div><div>←</div><div>+</div></div>		SHALLOW FOCUSED LOG
		<div><div>.2</div><div>1.0</div><div>10</div><div>100</div><div>1000</div></div>
		MEDIUM INDUCTION LOG
		<div><div>.2</div><div>1.0</div><div>10</div><div>100</div><div>1000</div></div>
		DEEP INDUCTION LOG
		<div><div>.2</div><div>1.0</div><div>10</div><div>100</div><div>1000</div></div>

WILLIAMS HOLDING 305

COMPENSATED DENSITY LOG

GAMMA RAY & CALIPER		DEPTH	BULK DENSITY GRAMS/CC				
			CORRECTION		CORRECTION		
					- .25	0	+ .25
0	API UNITS	100	1.75				2.75
			54%	39%	24%	9%	0%
			DENSITY SANDSTONE POROSITY				
6	HOLE SIZE - INCHES	16

WILLIAMS HOLDING 825-25Drilling History

Drilling rig moved in and spudded a 9-7/8" hole on October 2, 1975. Lost circulation was a problem between 253' and 849', however circulation was maintained by using cottonseed hulls and tapon as lost circulation materials. Began directionally drilling with a Dynadrill at 849', and continued to 1081'. Resumed drilling with normal drilling set-up and drilled ahead to total depth of 2724'. Bottom hole location 299' north and 12 ft east of surface location. During drilling, mud weight, funnel viscosity, and fluid loss averaged 72 lbs/ft³, 53 seconds, and 8.8cc, respectively. Drilling rate averaged 383' per day. Maximum angle from vertical: 10.75°.

At T.D., a Schlumberger Dual-Induction-Laterlog was run, after which 70 joints of 7", 23# N-80 Buttress casing were run. The casing was equipped with a bullplug guide shoe on bottom, a cement basket over four 1/2" holes located just above the shoe, and a fillup valve on top of the shoe joint. Centralizers were located on every other joint for the first nine joints. The casing was cemented in place with 1300 ft³ of Class "G" cement containing 1:2 perfalite, 40% silica flour, and additives to result in a 12 hour setting time, followed by 100 ft³ of luminite cement pre-mixed with 20% silica flour and treated for 1500 psi compressive strength in four hours. The cement was displaced with 621 ft³ of mud and 160 ft³ of cement returns were recorded. After six hours the casing was stretched 26 1/2" by pulling 280,000 lbs. over the casing weight.

A bit and scraper was then run after changing over to polymer mud. The top of the cement plug was recorded at 2705'. A Neutron correlation log was then run, and four 3/4" holes per foot were shot from 2641' to 2661' using a jet perforator. The perforations were washed with a circulating washer, and the drilling rig was released on October 11.

Williams Holding 825-25

On October 23, 1975, a workover rig was moved in to finish the completion operations. Four 3/4" holes per foot were shot from 2661' to 2671' and these perforations were also washed. Following the wash, 3 joints of 3-1/2", 9.3# J-55 liner were run with gravel packing tools. The second joint of the liner was 30 mesh wire screen. Four centralizers located 15' apart were used on the liner. The liner was then pressure gravel packed with 39 ft³ 10x18 San Simeon gravel, after which a lead seal drive on an adaptor was set over the liner. The well was circulated clean and the wellbore fluid changed over to fresh water. The rig was released midnight, October 26, 1975.

WILLIAMS HOLDING 825

DUAL INDUCTION - LATEROLOG 8

WILLIAMS HOLDING 826-25Drilling History

Drilling rig moved in and spudded a 9-7/8" hole October 26, 1975. Lost circulation was almost immediately a problem, but circulation was maintained by adding lost circulation materials. At 829' on October 28, began directionally drilling with a Dynadrill and continued to 1177'. Resumed drilling with a normal drilling set-up to 1965'. At 1965', again changed over to a directional drilling set-up and Dynadrilled from 1965' to 2141'. Continued drilling from 2141' with a normal drilling set-up to 2367', and then again directionally drilled with Dynadrill from 2367' to 2477'. Resumed drilling with a normal drilling set-up and drilled ahead to total depth of 2707'. Bottom hole location 296' south and 38' west of surface location. During drilling operation, the mud properties averaged as follows: weight, 72#; funnel viscosity, 52 seconds; and fluid loss, 9cc. Drilling rate averaged 380' per day. Maximum well angle from vertical: 12°.

On November 2, 1975, ran Dresser-Atlas Dual Induction-Focused log, after which 7", 23# N-80 Buttress casing was run to 2704'. The casing was equipped with a bullplug guide shoe on bottom, a cement basket over four 1/2" holes located just above the shoe, and a fillup valve on top of the shoe joint. Latch-on centralizers were located on every other joint for the first nine joints. The casing was cemented in place with 1290 ft³ Class "G" cement containing 1:2 perfalite and 40% silica flour, and treated for 12 hours setting time, followed by 100 ft³ luminite cement premixed with 20% silica flour and treated for 1500 psi compressive strength in four hours. Cement was displaced with 606 ft³ of mud, and 120 ft³ cement returns were recorded. After 6 hours the casing was stretched 24-1/2" by pulling 334,000 lbs.

Williams Holding 826-25

Ran into hole with 6-1/8" bit and scraper, drilled out to 2689', changed over to polymer mud, and circulated hole clean. Using a Neutron log and collar locator for correlation, jet perforated four 3/4" holes per foot from 2645' to 2675'. Following the perforating the holes were washed with a circulation washer.

The well was circulated clean, after which 3 joints of 3-1/2", 9.3# J-55 liner were run with gravel packing tools. The second joint of the liner was 30 mesh wire screen. Four centralizers located 15' apart were used. The liner was then pressure packed with 17 sacks of 10x18 San Gimeon gravel, however the packer would only unset after pressuring below it to 1000 psi. The lead seal and adaptor set 12 ft high, and it became necessary to pull the liner and adaptor.

After re-running drill pipe and circulating the hole clean, the liner and gravel pack tools were re-run and the liner was successfully pressure gravel packed with 15 sacks of 10x18 gravel. The gravel packing tools were then pulled, and a lead seal drive on adaptor was set over the liner.

The hole was circulated clean and the rig was released at 2:00 p.m. on November 6.

DUAL INDUCTION FOCUSED LOG

WILLIAMS HOLDING 925-25Drilling History

Drilling rig moved in and spudded a 9-7/8" hole on October 11, 1975. Drilled ahead to 250' and lost circulation. However, the mud was conditioned and circulation was thereafter maintained using lost circulation materials. Began directionally drilling with a Dynadrill at 883' and continued to 1176'. Resumed drilling with a normal drilling set-up at 1176' and continued to 1795'. At 1795' began directional drilling with a Dynadrill. Dynadrilled from 1795' to 1959'. Resumed drilling with a normal drilling set-up and drilled ahead to total depth of 2765'. Bottom hole location 22' south, 324' west of surface location. During drilling, mud properties averaged as follows: weight, 71 lbs/ft³; funnel viscosity, 50 seconds; fluid loss, 8.8cc. Drilling rate averaged 320' per day. Maximum well angle from vertical: 11.5°.

On October 19, ran Dresser-Atlas Dual Induction-Focused log and Compensated Density log, after which 73 joints of 7", 23# N-80 Buttress casing were run to 2765'. The casing was equipped with a bullplug guide shoe on bottom, a cement basket over four 1/2" holes located just above the shoe, and a fillup valve on top of the shoe joint. Five latch-on centralizers were located on every other joint for the first nine joints. The casing was cemented in place with 1320 ft³ Class "G" cement containing 1:2 perfalite and 40% silica flour, and treated for 12 hours setting time, followed by 100 ft³ of luminite cement premixed with 20% silica flour treated for 1500 psi compressive strength in four hours. The cement was displaced with 625 ft³ mud, and 170 ft³ cement returns was recorded. After six hours the casing was stretched 24" by pulling 280,000 lbs.

A Neutron correlation log was run, and four 3/4" holes per foot were jet perforated from 2697' to 2727'. Following the perforating, the holes were washed with a circulation washer.

Williams Holding 925-25

After circulating the hole clean, 3 joints of 3-1/2", 9.3# J-55 liner were run with gravel pack tools. The second joint of the liner was 30 mesh wire screen. Four centralizers located 15' apart were used. However, the packing tool pins would not shear, making it necessary to pull tools and liner.

On October 22, after circulating the hole clean, re-ran gravel pack tools and liner and pressure gravel packed with 14 sacks 10x18 San Simeon gravel. After pulling the tools, a lead seal drive on an adaptor was set over liner. The hole was then circulated clean, and the rig was released.

WILLIAMS HOLDING 925
DUAL INDUCTION FOCUSED LOG

WILLIAMS HOLDING 935-25Drilling History

Drilling rig moved in and rigged up December 24, 1975. Spudded 9-7/8" hole on December 26. Drilled ahead with no problems to 894'. At 894' began directionally drilling with a Dynadrill and continued to 1260'. Resumed drilling with normal drilling set-up and drilled from 1260' to total depth of 2673' on December 31, 1975. Bottom hole location 20' north, 303' east of surface location. During drilling, mud properties averaged as follows: weight, 75 lbs/ft³; funnel viscosity, 50 seconds; fluid loss, 9cc. Drilling rate averaged 437 ft per day. Maximum well angle from vertical: 11.5°.

At T.D. a Schlumberger Dual Induction-Laterolog was run, after which 7", 23# N-80 Hydril HCS casing was run to 2670'. The casing was equipped with a bullplug guide shoe on bottom, a cement basket over four 1/2" holes located just above the shoe, and a fillup valve on top of the shoe joint. Five latch-on centralizers were located on every other joint for the first nine joints. Thermal couples were welded to casing at 2000', 1400', 800', 300', and 100' depths.

The casing was cemented in place with 1270 ft³ Class "G" cement containing 1:2 perfalite and 40% silica flour, and treated for 12 hours setting time, followed by 100 ft³ luminite cement premixed with 20% silica flour treated for 1500 psi compressive strength in 4 hours. The cement was displaced with 600 ft³ water. The casing was stretched 29" by pulling 280,000 lbs.

On January 2, a cement bond log was run, and good cement was recorded at 1600'. Four 1/2" holes were then shot at 1580', and with a fullbore set at 1438', 200 ft³ Class "G" cement containing 1:2 perfalite and 3% CaCl₂ was displaced with 94 ft³ fresh water.

Williams Holding 935-25

There was no circulation. Another cement bond log was run which showed cement at 1466'. Four more 1/2" holes were shot at 1450', and with a fullbore at 1317', 300 ft³ Class "G" cement as above was displaced with 87 ft³ water. Surface cement returns of 90 ft³ were recorded.

A bit and scraper were run, cleaning out to 2653'. The casing was pressure tested, the wellbore fluid was changed over to polymer mud, and a cement bond log was run. After the bond log, a Neutron correlation log was run, and four 3/4" holes per foot were jet perforated from 2595' to 2625'. The perforations were then washed with a circulation washer.

Three joints of 3-1/2", 9.3# J-55 liner were run with gravel packing tools. The second joint of the liner was 30 mesh wire screen. The liner was pressure gravel packed with 20 sacks 10x18 San Simeon gravel, after which a lead seal drive on an adaptor was set over liner.

The well was circulated clean, tubing run, and the rig released January 6.

DUAL INDUCTION - LATEROLOG 8