VACUUM GLORIETA EAST UNIT

UNITIZATION AND WATERFLOOD DEVELOPMENT PLAN

VACUUM GLORIETA POOL
LEA COUNTY, NEW MEXICO

BEFORE EXAMINER CATANACH
OIL CONSERVATION DIVISION
PHILLIPS PETROLEUM COMPANY
EXHIBIT NO. 6
CASE NO. 10485 AND 10486

MARCH, 1993

INTRODUCTION

The Vacuum Glorieta Pool was discovered on January 9, 1963 with the completion of the Texaco, New Mexico "O" State well No. 12 located in Section 36, T-17-S, R-34-E of Lea County, New Mexico. The New Mexico Oil Conservation Commission defined the Vacuum Glorieta Pool to start at the top of the Glorieta formation and end at the top of the Blinebry formation. The type log from the Mobil Bridges State Well No. 95 is provided in **figure 1** with the designated formation tops and depths. The Vacuum Glorieta Geologic Sub-committee further defined the interval into Upper and Lower Paddock formations which are also shown on the type log.

The Working Interest Owners of the Vacuum Glorieta Pool formed an Engineering and Geological Technical Committee to characterize the Glorieta Pool. On February 12, 1991, the Working Interest Owners approved the Technical Committee's Report dated November 1990. On this same date, the Working Interest Owner's agreed to divide the Pool into two EOR study areas because of distinct reservoir and geologic characteristics found between the east and west portions of the pool. A map showing the Vacuum Glorieta West Unit and the Proposed Vacuum Glorieta East unit is shown in **figure 2**.

The proposed Vacuum Glorieta East Unit encompasses 4,240 surface acres in parts of T-17-S and T-18-S of R-35-E in Lea County, New Mexico. A base map of the proposed unit boundary is shown in **figure 3**. The proposed unit contains 94 current Glorieta completions and as of January 1, 1992, has produced 43.4 MMBO. The 1991 production averaged 60,330 BOPM or 1978 BOPD. A plot of historical oil, gas, and water production is provided in **figure 4**.

The proposed unitized interval is from the top of the Glorieta to the top of the Blinebry or approximately 5800 feet to 6200 feet as shown on the type log (**figure 1**). The Upper Paddock is the dominate pay within this interval. It is present over the entire proposed unit area and is approximately 100 feet below the top of the Glorieta. The lower Paddock is present in only the extreme south west portion of the unit and is not targeted for EOR development in the VGEU.

Below is table that lists the reservoir properties and fluid characteristics for the proposed VGEU as determined from the November 1990 Engineering-Geological Technical Committee Report.

Surface Area, Acres	4,240
Depth, feet	5,800
Formation Type	Dolomite
Reservoir Temperature, F	119
Bubble Point Pressure, PSI	2,260
Oil formation Volume Factor at BPP, RB/STB .	1.306
Oil Viscosity at BPP, cp	0.622
Solution GOR at BPP, SCF/STB	552
Average Net Pay, feet	58
Average Porosity, %	10.1
Average Initial Water Saturation, %	27.3
Geometric Average Permeability, md	3.1
Original Oil in Place, MSTBO	107,296

RESERVOIR DEVELOPMENT PLAN

RESERVOIR DEVELOPMENT PLAN

WATERFLOOD DEVELOPMENT:

The Vacuum Glorieta East Unit waterflood development will occur in four stages starting in fourth quarter of 1993 and ending in 1996. Development will include drilling a total of 41 new wells, conversion of 15 existing wells to water injection, and the reactivation of 9 shut-in producers. The waterflood development plan is provided in a plat format in **figure** 5 and in a tabular format in **table** 1. A detailed summary of the unit waterflood development schedule is discussed in a following section labeled "Development/Investment Schedule".

Approximately 70% of the Vacuum Glorieta East Unit will come under waterflood. This development is consistent with the two distinct depletion mechanisms influencing the Vacuum Glorieta Pool. The east and south flanks of the pool have been influenced by water encroachment, while the central and western portions of the field have been depleted by solution gas drive. This is evident by the widely varying GOR, water cut and recovery efficiencies experienced in wells across the field. Waterflood development will begin in the northwest portion of the unit where oil rates are typically low and progress toward the central portion where many wells are producing at top allowable and near top allowable rates. The south and east flanks of the unit will be held for future CO_2 flood development.

The waterflood will be developed on a 40 acre five spot pattern. The unit is currently drilled on 40 acre proration units. Therefore, 31 twenty acre infill injection wells will be drilled to complete the waterflood pattern. This includes six lease line injectors to be drilled on the VGEU-VGWU border. New injectors are preferable to existing well conversions. The new injection wells will have superior wellbore integrity, which will ensure that injection fluid remains in zone making the flood more efficient. Four replacement wells will also be drilled. They will replace wells that have been plugged and abandoned or have production casing less than 4 1/2" diameter.

Six infill producing wells will be drilled and cored in fourth quarter of 1993. They are located in areas where acceleration of primary reserves is economic and will provide a boost to cash flow. Additionally, they are located across the field and should represent a good cross section of geologic and petrophysical environments in the Vacuum Glorieta Pool. The core analysis will be used to modify the waterflood model, improve waterflood response, and plan CO_2 development. These six wells will be converted to water injection wells in late 1996. A detail of the core analysis is provided in a following section.

All newly drilled wells will be completed with 5 1/2" casing set at the base of the Paddock and cemented to the surface. Typically, 8 5/8" surface casing will be set in the rustler anhydrite just above the Salado salt section and cemented to surface. However, in areas where waterflow from the Salado salt section exists, an additional string of intermediate casing will be set and cemented to surface. This is anticipated in only three wells. All well completion diagrams are detailed in **figures 15 to 19**.

CO_2 FLOOD DEVELOPMENT:

Field wide CO_2 injection is anticipated to start in 1998. By 1998, two important events will have occurred. One is that significant VGEU waterflood response data and core analysis data will have been gathered and analyzed. The second is that the waterflood portion of the field will have reached the CO_2 miscibility pressure of 1426 psi. CO_2 flood development will require drilling 9 infill injection wells, drilling 6 replacement wells, converting 3 producers to injection, and reactivating 6 producers. See **figure 6** for proposed CO_2 development plat. Pressured CO_2 could be purchased from the East Vacuum Grayburg San Andres Unit and distributed through the EVGSAU CO_2 distribution system. Most of this system will be utilized. However some new injection line and all new injection wellheads will be required. CO_2 contaminated gas and gas liquids may be sent to the East Vacuum Liquids Recovery Plant for liquid extraction and CO_2 processing. The CO_2 flood development will be a stand alone project. Its development will require a detailed technical study and separate development plan. A Unit Technical Committee will be formed in 1996 to study CO_2 flood development and make recommendations to the Working Interest Owners by mid 1997.

DISCRETIONARY WELL DEVELOPMENT:

The east half of section 31 and part of section 5 will not be under any planned development initially. This area is characterized as having low cumulative oil recovery and low producing rates. Based on current geological and reservoir data, this area appears to have marginal waterflood potential. Fortunately, this area will be flanked with water injectors on the north, east and west sides. The producing wells in this discretionary area will be monitored as the waterflood progresses. If the wells close to the water injectors respond favorably, a plan to develop this acreage will be proposed to the Working Interest Owners. This may involve drilling 11 infill wells, drilling 8 replacement wells, and reactivating 10 producers. See **figure 7** for discretionary well development plat. Development of the discretionary area will be a stand alone project contingent on Working Interest Owner approval.

RESERVOIR MODEL
SIMULATION

RESERVOIR MODEL SIMULATION

A full field, fully implicit, three dimensional model was developed to study and to evaluate the various producing mechanisms in the east half of the Vacuum Glorieta Pool. This model provided a basis for describing the depletion mechanism as well as predicting waterflood and CO2 flood potential. The model was constructed with a 95 X 55 X 3 grid covering the entire proposed Vacuum Glorieta East Unit area. The model components were based upon geological data presented in the November 1990 "Vacuum Glorieta Engineering - Geological Technical Committee Report.

Model components were adjusted to roughly match cumulative oil production on a well by well basis, but primary emphasis was placed on overall field performance. Particular interest was given to matching the overall oil rate decline, GOR trends, and water cut. The model was not designed to study detailed response on a well by well basis, but to study the overall field depletion and EOR response.

The reservoir model was run in prediction mode throughout the history matching phase. Key elements which were adjusted to provide a sufficient history match include the strength of the water influx mechanism and the volume of original oil in place. A strong aquifer was added to the northeast, east, and southeast flanks of the unit boundary. This was required to match the slowly increasing water cuts, declining GOR trend, and favorable oil decline rate experienced in the eastern portion of the pool. Water influx alone was not sufficient to match the overall reservoir performance. The volumetric oil in place was adjusted upwards to match the cumulative oil production and obtain a suitable history match. Plots of the oil, GOR, and water cut history matches are provided in **figure 8**.

This model was used to generate waterflood forecasts based on the history match.

WATERFLOOD FORECAST

<u>WATERFLOOD FORECAST</u>

Three injection patterns were considered: a 160 acre inverted 9 spot, an 80 acre five spot, and a 40 acre five spot which involved drilling one additional injector per pattern. The 40 acre five spot was chosen as the best pattern because the 20 acre infill injectors increased inter-well connectivity, improved overall sweep efficiency, and maximized oil recovery. The 40 acre five spot pattern was introduced into the reservoir model and used as the basis for all of the waterflood prediction cases.

Waterflood reserves were forecast using risk analysis of several model predictions in which certain debatable waterflood parameters were varied. These parameters are the reservoir volume, the strength of the aquifer on the east half of the field, and the water injection rate. A total of twelve waterflood sensitivity forecasts were generated. A base case reservoir volume was developed from the model history match. This volume was reduced 27 % to create a low reservoir volume case. On each of these two cases the strength of the aquifer was varied from strong to moderate to non-existent during the waterflood phase generating six distinct forecasts. A further sensitivity was run on each of these cases by limiting the maximum water injection rate to 500 bpd/well and to 750 bpd/well. The parameter variations are illustrated on a decision tree provided in **figure 9**. One additional sensitivity case was run in which the initial water saturation was raised from 27 % to 37 %. This lowered the ultimate recovery by 25 %, but increased waterflood response time. The over all effect on project economics was minimal.

A most probable waterflood response was generated from the twelve waterflood sensitivity cases. Each of the waterflood parameters (reservoir volume, aquifer strength, and injectivity) was assigned a percentage reflective of its probability of occurrence. The most probable waterflood forecast was generated by weight averaging the annual oil volume from each of the twelve waterflood predictions based on these probabilities. The probability factors of each parameter and the weighted average formula are provided in **figure 10**. The most probable waterflood response forecast is illustrated in tabular form in **table 2** and graphically in **figures 11 and 12**. The forecasted oil rate peaks in 1999 at 4987 BOPD and accumulates 20,530,141 BO (including primary oil) over the 27 year life of the project. This is the waterflood response that should be used to calculate waterflood economics.

CORE ANALYSIS
PROGRAM

CORE ANALYSIS PROGRAM

INTRODUCTION:

The 1993 development plan for the Vacuum Glorieta East Unit consists of drilling six infill producers. The six infill wells will be cored through the unitized interval with total cored footage ranging from 1500 to 1800 feet. The objective of the coring program is to provide the detailed reservoir characterization necessary to fully understand the complex geology and reservoir heterogeneities of the Glorieta and Paddock formations in the Unit area. Detailed reservoir characterization will be accomplished using the new core analysis data described below as well as data from previous studies of the ten cores taken by Exxon, Shell, Mobil, Texaco, and Phillips. The routine and special core analysis data gathered on the new cores will assist in waterflood management and CO_2 flood design.

METHODS:

Core analysis methods will consist of the following: routine core analysis, special core analysis for geological properties, and additional special core analysis for reservoir properties. Routine core analysis and geologic special core analysis will be performed on all six new cores. Special core analysis for reservoir properties will be conducted on representative samples of the primary flow units taken from two native state cores that best depict the reservoir intervals contributing to waterflood response. The two native state cores will be chosen from the six well coring package.

ROUTINE CORE ANALYSIS:

The routine core analysis will consist of whole core modified Dean Stark analysis and will include Boyle's law porosity, grain density, residual water saturation, residual oil saturation, as well as maximum and 90 degree permeability. In addition, the data will be presented in tabular and graphic format. Special core analysis samples will be identified and removed from the intervals that best represent the primary flow units. If necessary, additional samples will be preserved for future special core analysis. The remaining core will be slabbed. The core photography protocol will consist of whole core photographs under ultraviolet light and slabbed core photographs in daylight.

SPECIAL CORE ANALYSIS (GEOLOGIC CHARACTERIZATION):

The special core analysis for geologic characterization will include identification of lithofacies types, determination of depositional environments, and delineation of significant diagenetic events from core description and petrographic analysis. Petrographic analysis will include thin section description and scanning electron microscopy with EDS. In addition, porosity types, pore sizes, and pore geometry will be identified and described using thin sections, SEM, and pore casts. Pore geometry characterization will include the determination of aspect ratio (pore size/pore throat size), pore size distribution, coordination number (number of pore throats per pore), and porosity distribution (layered, random, etc.).

The primary objective of this detailed geological work is to validate and further define the four major facies types found in the unitized interval and to tie these facies to the primary flow units. The primary flow units will be defined by porosity and permeability relationships and distinguished by lithologic character and log signature.

The major facies types present are: quartz sandstone, pelletal mudstone, skeletal packestone-wackestone, and oolitic-pelletoidal grainstone. The three carbonate facies types exist as limestone or dolomite depending on their location in the unit. In general, the carbonate facies are dolomitized in the northern half of the unit while occurring primarily as limestones in the southern half of the unit. The special geologic core analysis will better define the diagenetic events controlling the distribution of carbonate lithologies throughout the unit. Furthermore, this analysis will also provide predictive rock type (lithofacies) models to further elucidate the porosity-permeability relationships found in the core data.

SPECIAL CORE ANALYSIS (RESERVOIR PROPERTIES):

Special core analysis for reservoir properties will include Amott's wettability, capillary pressure, relative permeability, confining stress porosity, confining stress permeability and CO2-reservoir fluid compatibility. The CO2-reservoir fluid compatibility tests will be performed selectively on primary flow unit samples from the two native state cores. The following list describes the special core analysis techniques and respective parameters to be determined: 1) Amott wettability and end point relative permeability (Keo @ Swi and Kew @ Sro), 2) Formation resistivity factor and cementation exponent at confining pressure, 3) Formation resistivity index and saturation exponent at confining pressure, 4) Mercury injection - capillary pressure and pore size distribution up to 2000 psia. 5) Air-brine capillary pressure up to 70 psi, 6) Confining pressure gas permeability, 7) Pore volume compressibility, 8) Steady state water-oil relative permeability, 9) Unsteady state water-oil and gas-oil relative permeability, and 10) Carbon dioxide core flood and residual oil saturation to CO2.

PRODUCTION AND
INJECTION FACILITIES

PRODUCTION AND INJECTION FACILITIES

PRODUCTION FACILITIES:

All produced oil, gas, and water will be gathered into two tank battery facilities. The west tank battery will be located in Section 31 at the present Shell site, and the east tank battery will be located in Section 27 at the present Phillips site. See **figure 13**. All existing Shell and Phillips tankage and equipment will be phased out and replaced with new equipment.

Each new tank battery will have a 10' X 28' production treater that is anticipated to eliminate the need for a free water knockout. Each battery will have one 500 barrel oil sales tank, a 1000 barrel oil divert tank, and a 2000 barrel oil overflow tank. All the oil tanks will be constructed of coated steel. A vapor recovery unit will be installed on the oil tanks and will discharge tank vapors to the gas sales line. Water from the production treater will first go to a 2000 barrel skim tank and then to a 2000 barrel suction tank where it will be pumped to the East Vacuum Grayburg San Andres Unit central tank battery for treatment and re-injection. A 2000 barrel water overflow tank is also provided for emergency use. All water tanks will be constructed of fiberglass. All tankage will be equipped with automatic gauging and alarms. Each tank will be set on a leak detection foundation made of Drisco lined concrete. Any leaking fluid will flow to the perimeter of the tank and be visible. There will be four test treaters located at each battery. Each test treater will be dedicated to a separate test header and have a 500 barrel oil test tank to ensure more accurate oil tests. Both batteries will be equipped with night time lighting for personnel safety and site security. A detailed schematic of the tank battery layout is provided in **figure 14**.

PRODUCING WELLS AND FLOWLINES:

All newly drilled producing wells will be completed with 5 1/2" casing per the attached **figure 15**. All new producers will be equipped with Lufkin beam pumping units and electric motors or submersible pumps as conditions warrant. The producing wells will be connected to either the east or west tank battery per **figure 13**. Wells anticipated to produce less than 150 BFPD will have 2" flowlines. Those anticipated to produce over 150 BFPD will be equipped with 3" flow Lines. All flowlines will be constructed of SDR-7 Marlex line pipe converting to steel linepipe 100' from the tank battery. All flow lines will be equipped with high pressure shut downs. These are located at the wellhead and shut down the lift equipment to protect the marlex flowline from high pressure. Existing steel flowlines will be phased out and abandoned within the first two years.

WATER SUPPLY AND INJECTION SYSTEM:

The maximum expected water injection rate is 31,000 BWPD. This will occur in 1997 when the full waterflood area is developed, and much of the reservoir is undergoing fill-up. Injection rate will slowly wane and stabilize at about 24,000 BWPD. See **table 3** for water injection and water production forecast.

Subject to EVGSAU Working Interest Owner approval, the Vacuum Glorieta East Unit will purchase pressured water from the EVGSAU which overlays much of the VGEU area. The EVGSAU water distribution system will be utilized wherever feasible. However, additional injection lines will be installed as required see **figure 20**. New injection lines will be buried 2 1/2" 2000 psi fiberglass. The EVGSAU water injection system has the 31,000 BWPD spare pump capacity and can deliver water to both units sufficiently at 1300 psi wellhead pressure. EVGSAU will be mixing produced water from the Paddock, Glorieta and San Andres, as well a fresh water make-up to supply injection water to both units. Water compatibility tests were run which indicate that mixing these waters will produce some precipitates, mainly calcium sulfate. This scaling tendency is reduced by dilution with the fresh water. However, the injection water will be chemically treated to protect the injection facilities and wells.

WATER INJECTION WELLS:

All newly drilled injection wells will be completed with 5 1/2" casing per the attached **figures 16 and 17**. Each injector is designed to inject a minimum of 750 BWPD. They will be equipped with internally plastic coated 8RD tubing and a nickel coated Baker A-3 Lok-Set packer. The surface wellhead and injection assembly is designed for 2000 psi service and will include a master valve, flow tee, check valve, strainer, manual choke, and turbine meter. See **figure 21** for injection assembly detail.

FLUID METERING:

Daily fluid production will be metered at each of the two tank batteries. Oil will be metered through a LACT unit into the oil sales line. Water will be metered through a Halliburton flow meter located between the production treater and water storage tank. Gas will be measured by the Gas Purchaser utilizing a orifice plate meter run and flow totalizer. Individual well tests will be run at each of the four testing facilities located at each of the two tank batteries. Oil, gas and water will be separated a the test heater treater and measured separately. Oil test rate will be metered through a Halliburton flow meter in conjunction with a 500 barrel test tank for more accurate oil test results. Water rate will be measured with a Halliburton flow meter. Gas rate will be measured through an orifice plate meter run and Barton differential meter. The well test facilities are designed to test producing wells within the waterflood area every two to three weeks and to test wells outside the waterflood area quarterly. A producing fluid level will be recorded with every well test. Injection water rate will be metered at each wellhead using a Halliburton turbine meter. Pressure will be measured with a calibrated liquid filled gauge. Injection well rate and pressure will be recorded weekly and reported monthly.

AUTOMATION AND SYSTEM ALARMS:

Pump off controllers will be installed on all producing wells within the waterflood area, and on wells outside the waterflood area that produce over 10 BOPD. The pump off controllers will monitor well performance and control pumping time to optimize oil production. Each POC will be coupled with a Remote Telemetry Unit that will transmit down time statistics to the Vacuum Field operations office located in Buckeye, NM. The injection system and wells will be controlled manually using the Halliburton meter and choke at the wellhead. If warranted, injection well Supervisory Control and Data Acquisition automation equipment may be installed in the future as a stand alone project.

A wide array of alarms will be installed at each of the two tank batteries. High level alarms will be installed on the water overflow tank, water suction tank, 500 bbl oil sales tank, and oil divert tank. The production treater and test treaters will have high level alarms, oil in water alarms, water in oil alarms, and high pressure alarms. All tanks will have automatic gauging systems. The LACT and vapor recovery units will each have shut down alarms, and the instrument air system will have a low pressure alarm.

DEVELOPMENT/
INVESTMENT SCHEDULE

DEVELOPMENT/INVESTMENT SCHEDULE

Development of the proposed VGEU will occur over a four year period described below and shown graphically on **figure 22**. The following schedule is based on a VGEU unitization date of September 1, 1993.

YEAR 1993:

Year 1 will include preliminary tank battery construction at the new VGEU East and West tank battery locations. Phase out of existing tank batteries will begin with the elimination of six locations. Six new infill producers will be drilled, cored, completed, and tied into the appropriate tank battery.

YEAR 1994:

Year 2 will complete the construction of the East and West tank batteries and tank battery automation. The twelve remaining tank batteries will be eliminated, and all existing wells will be tied into the new batteries. Installation and connection of the VGEU produced water lines to the EVGSAU injection system will be complete. Installation and connection of water injection lines to the EVGSAU system will begin with the connection of fifteen VGEU injection wells. Installation of producing well automation will begin. Four shut-in producers will be reactivated, and fifteen new injection wells will be drilled and completed (ten infill, two replacement, and three lease line wells). Water injection will begin by mid-year.

YEAR 1995:

In year 3, four wells will be converted from producers to water injection. Thirteen new water injectors will be drilled and completed (ten infill and three lease line) for a total of seventeen additional injection well tie-ins to the EVGSAU water injection system. One replacement producer will be drilled and completed.

YEAR 1996:

In year 4, eleven wells will be converted to water injection. Five new infill injection wells will be drilled and completed for a total of sixteen additional tie-ins to the EVGSAU water injection system. This completes the VGEU/EVGSAU injection system tie-ins, at a total of 48. In addition, four shut-in producers will be reactivated, and one replacement producer will be drilled, completed and equipped. Increased lift equipment will be installed on five producing wells. VGEU waterflood development will be essentially complete by year end 1996.

YEARS 1997 - 2007:

Increased lift equipment will be installed on an additional fifty-six producing wells over this time period. A year by year break down of increased lift equipment is tabulated in **table 4**.

ANNUAL CAPITAL EXPENDITURES:

The annual capital expenditures for the above development schedule are summarized below. All dollar amounts are in 1993 M$.

Year	Tangibles	Intangibles	Totals
1993	$ 1,016	$ 2,034	$ 3,050
1994	$ 3,903	$ 4,413	$ 8,316
1995	$ 1,680	$ 3,535	$ 5,215
1996	$ 1,552	$ 2,152	$ 3,704
1997-2001	$ 4,063	$ 587	$ 4,650
Total	$12,214	$12,721	$24,935

A detailed investment schedule is provided in **table 5**, and a summary of the drilling cost estimates is provided in **table 6**.

OPERATING COSTS

OPERATING COSTS

WELL OPERATING COSTS:

Annual operating cost projections are shown in detail in **table 7**. The Premises used for the operating costs are outlined below.

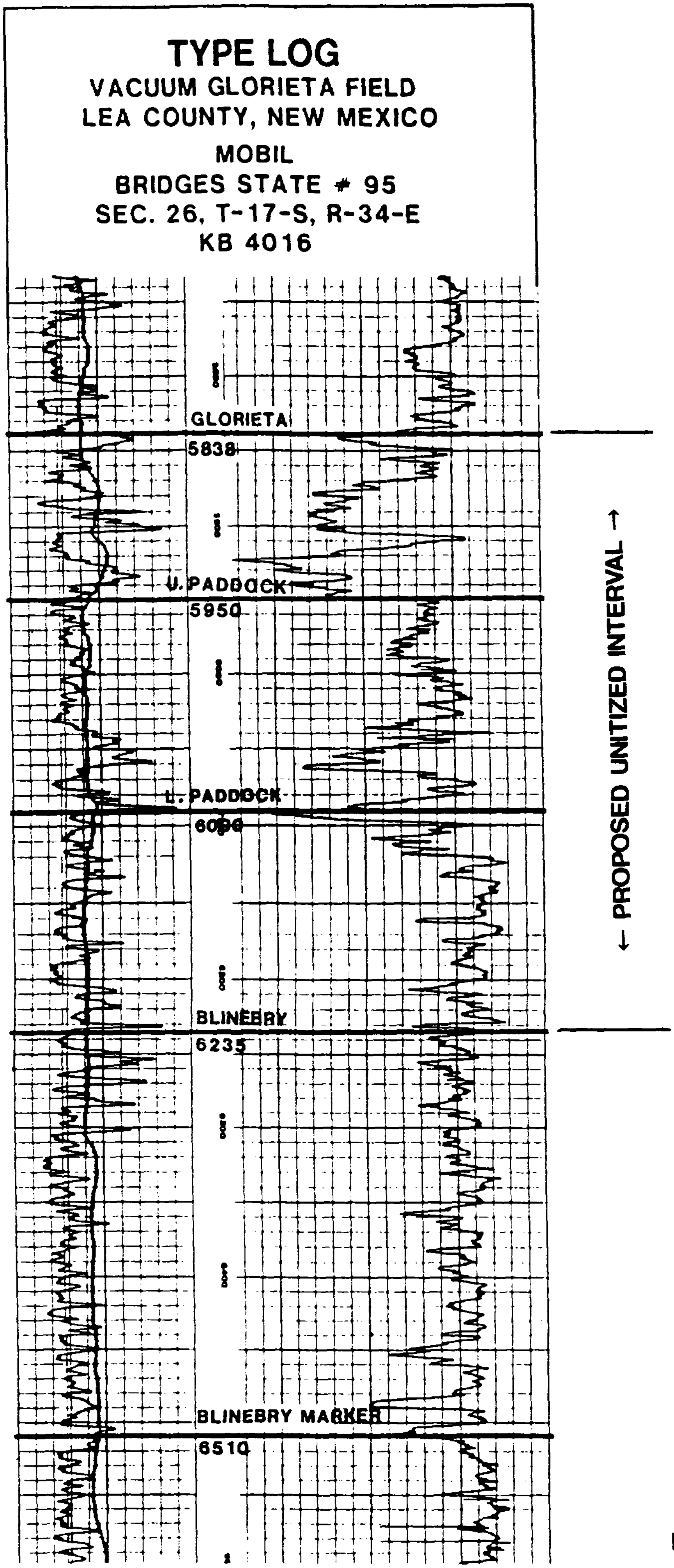
Well Operations:	Annual cost per well ($ M 1993)
Primary Producer	$ 18.0
Waterflood Producer	$ 30.0
Injection well	$ 10.0

PURCHASED INJECTION WATER:

The treatment, pressuring, and transportation of produced water and water make-up for the VGEU waterflood will be supplied by the East Vacuum Grayburg San Andres Unit. This service is estimated to cost $ 0.09 per barrel of water injected. This price is contingent on EVGSAU Working Interest Owner approval.

FIGURES

LIST OF FIGURES



TYPE LOG
VACUUM GLORIETA FIELD
LEA COUNTY, NEW MEXICO
MOBIL
BRIDGES STATE # 95
SEC. 26, T-17-S, R-34-E
KB 4016
GLORIETA
5838
U. PADDOCK
5950
L. PADDOCK
BLINEBRY
6235
BLINEBRY MARKER
6510
← PROPOSED UNITIZED INTERVAL →

FIGURE 1

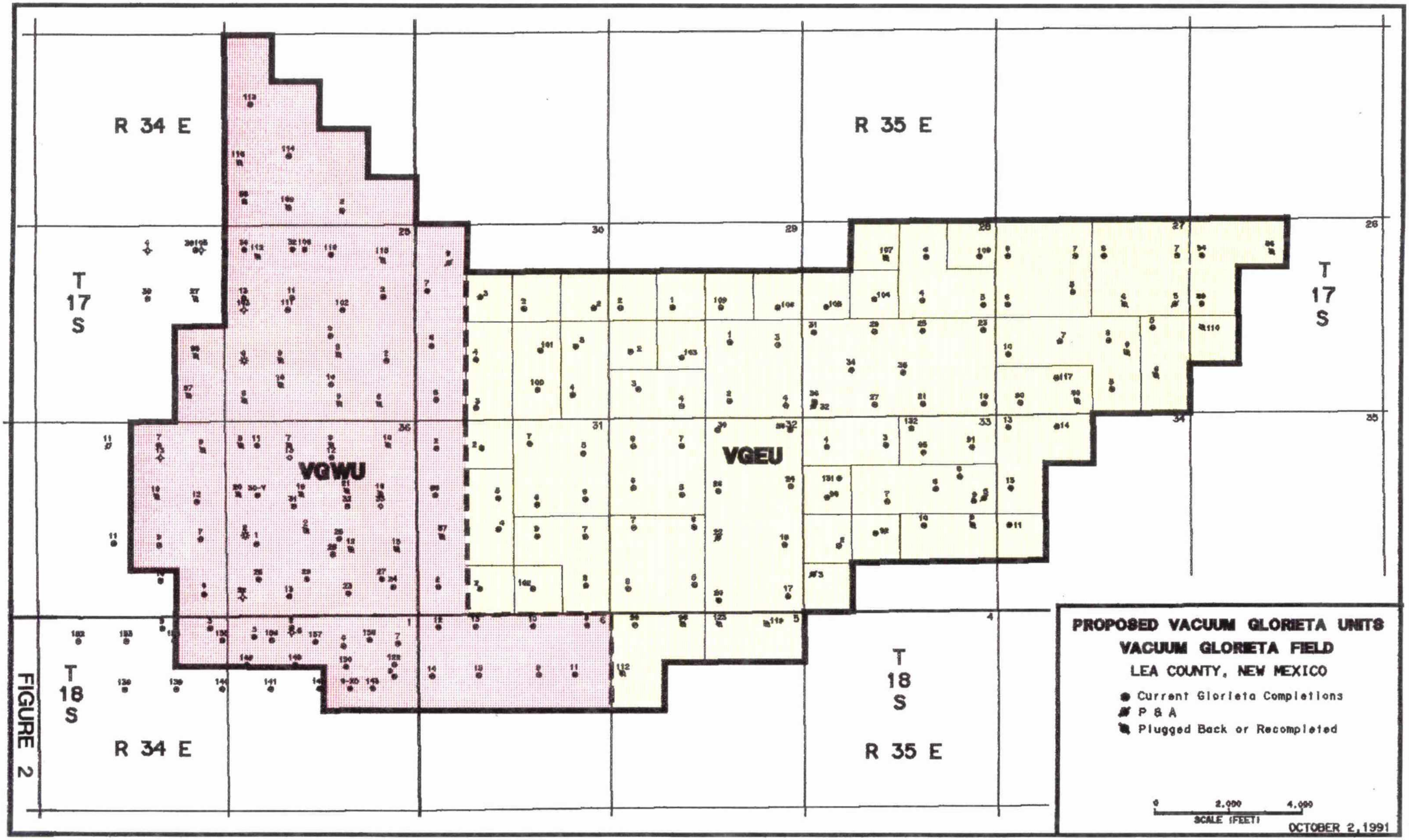

R 34 E
R 35 E
T 17 S
T 18 S
VGWU
VGEU
PROPOSED VACUUM GLORIETA UNITS
VACUUM GLORIETA FIELD
LEA COUNTY, NEW MEXICO
Current Glorieta Completions
P & A
Plugged Back or Recompleted
0
2,000
4,000
SCALE (FEET)
OCTOBER 2, 1991

FIGURE 2

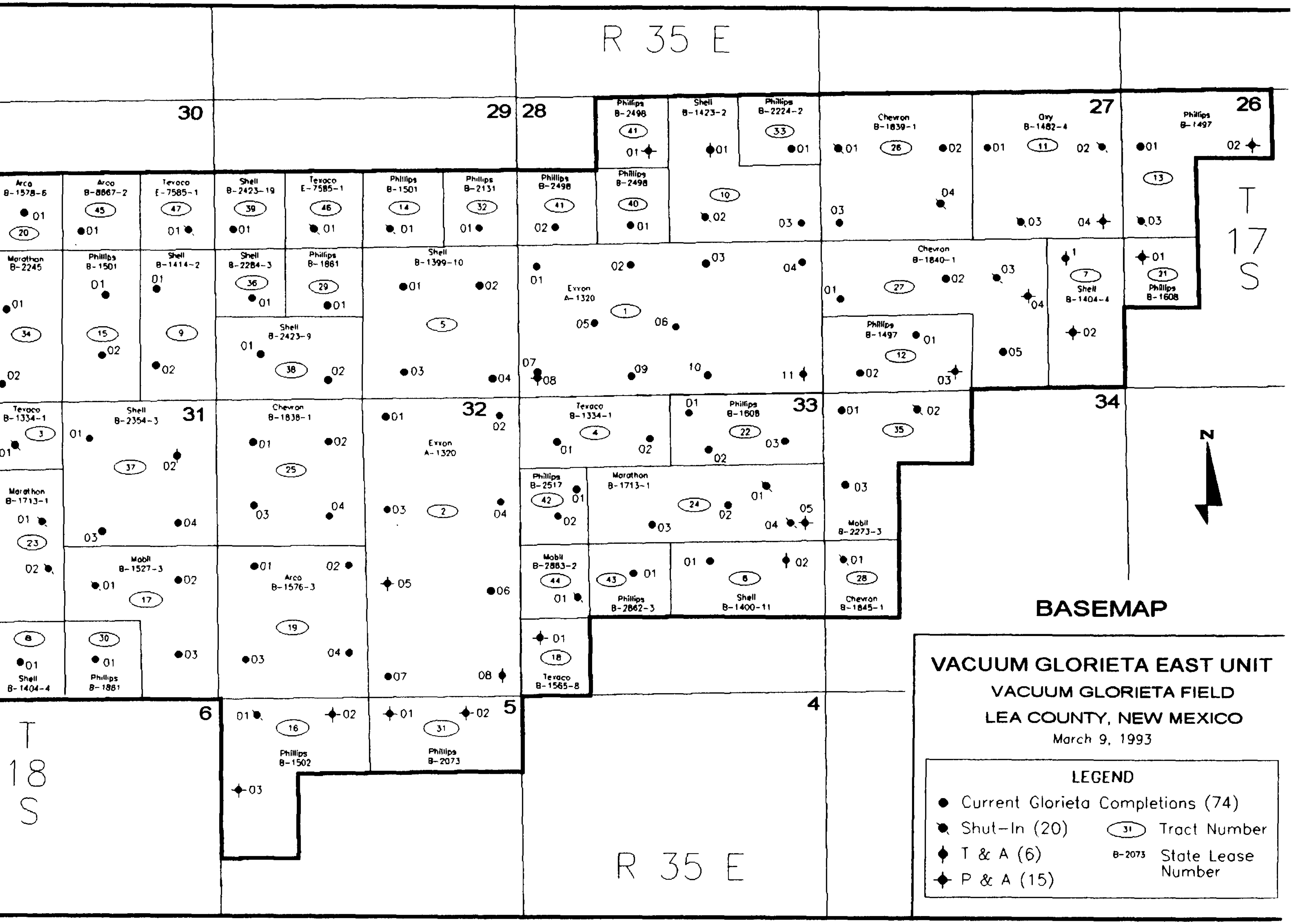

BASEMAP
VACUUM GLORIETA EAST UNIT
VACUUM GLORIETA FIELD
LEA COUNTY, NEW MEXICO
March 9, 1993
LEGEND
Current Glorieta Completions (74)
Shut-In (20)
T & A (6)
P & A (15)
31 Tract Number
B-2073 State Lease Number
R 35 E
T 17 S
T 18 S
N

FIGURE 3

VACUUM GLORIETA EAST UNIT
HISTORICAL PRODUCTION

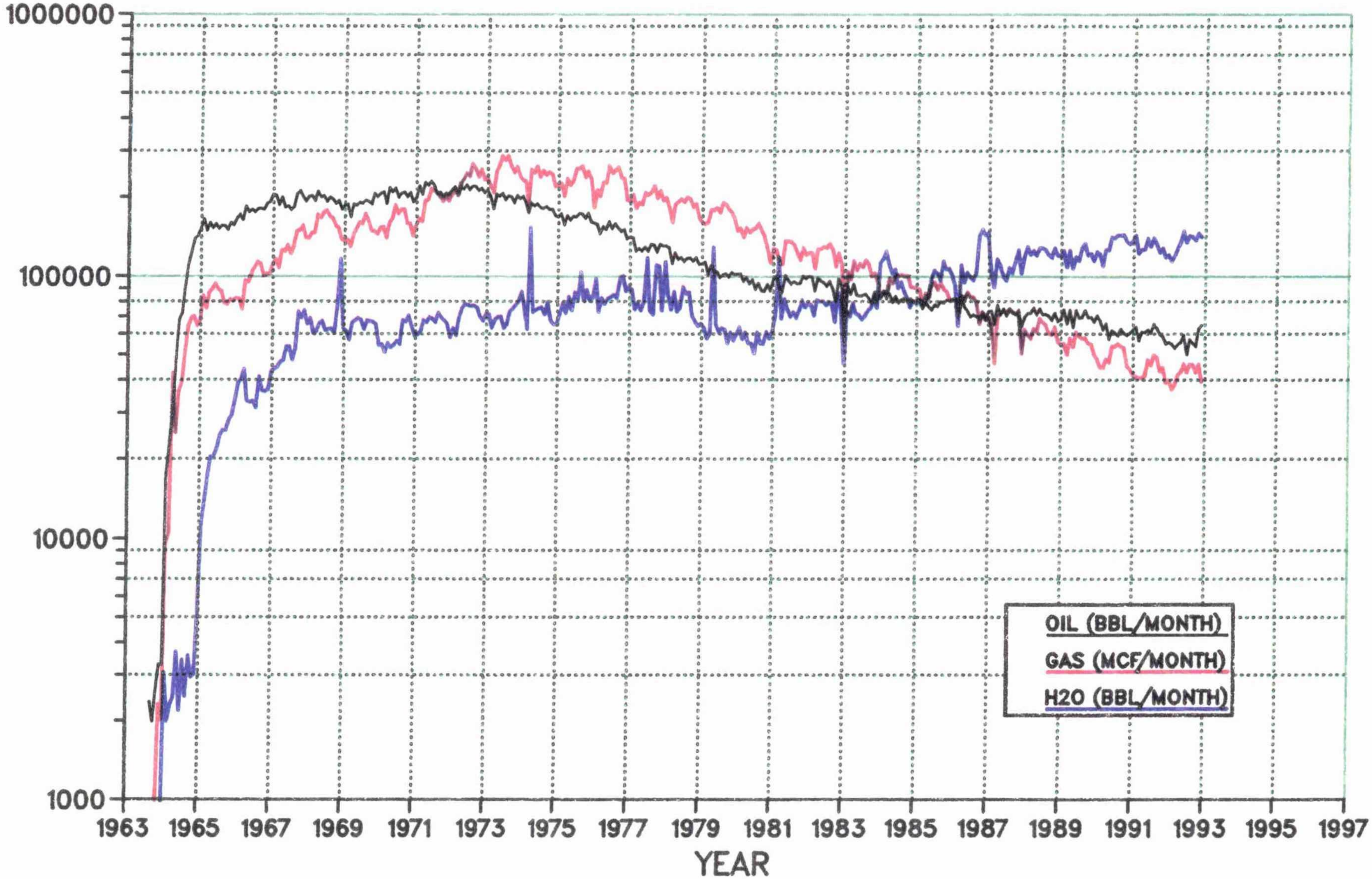


FIGURE 4

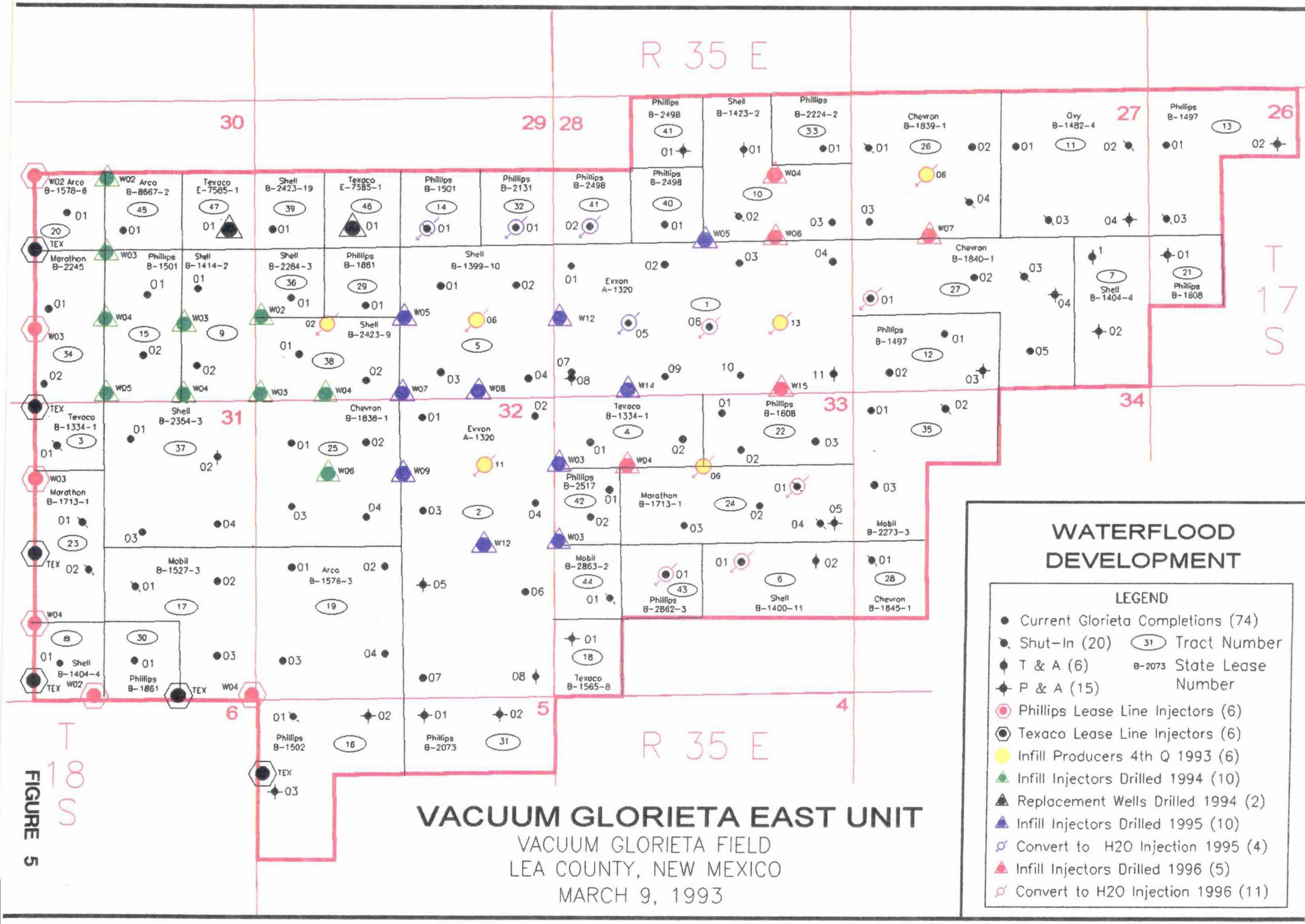
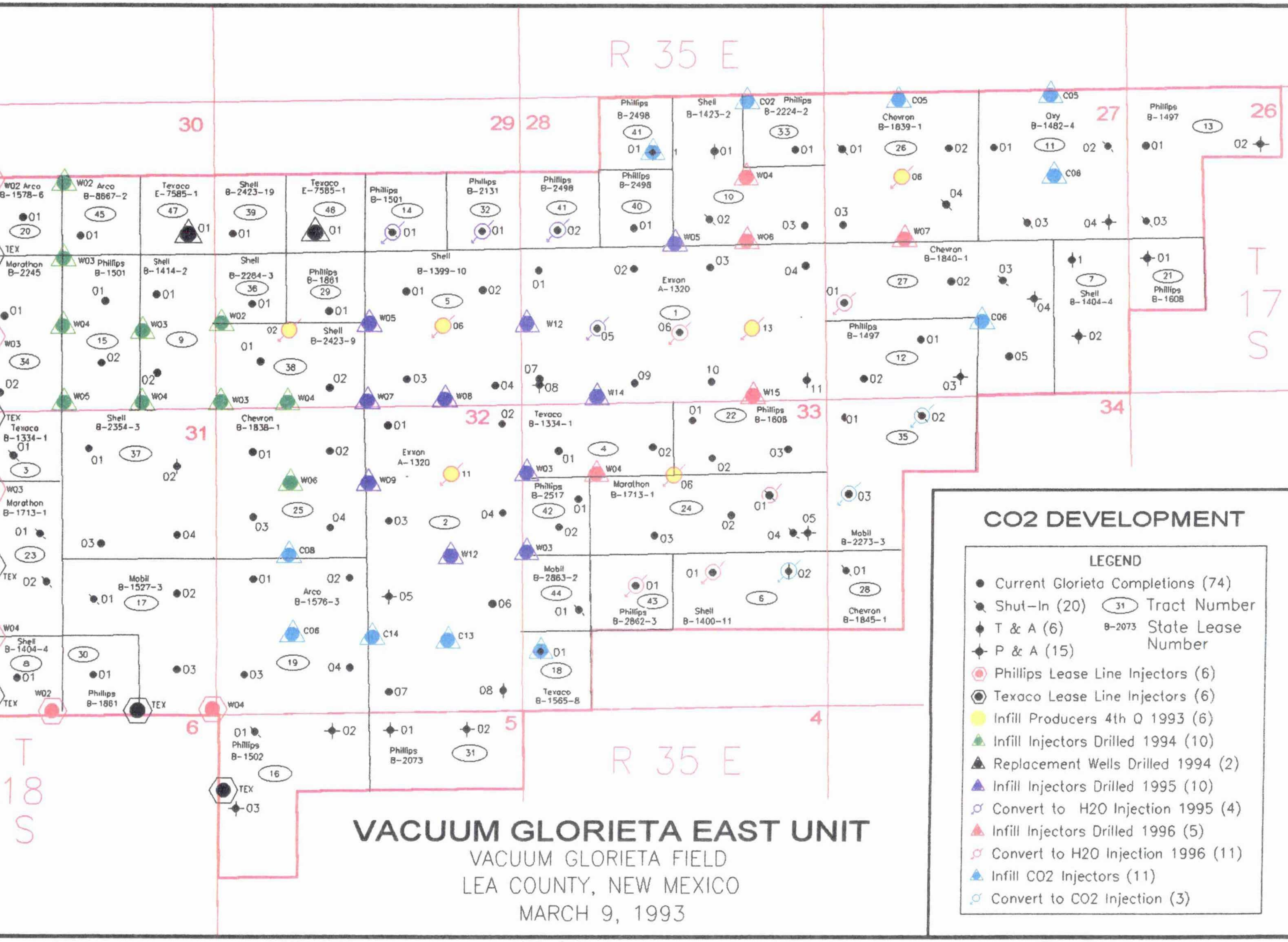

VACUUM GLORIETA EAST UNIT
VACUUM GLORIETA FIELD
LEA COUNTY, NEW MEXICO
MARCH 9, 1993
WATERFLOOD
DEVELOPMENT
LEGEND
Current Glorieta Completions (74)
Shut-In (20)
T & A (6)
P & A (15)
31 Tract Number
B-2073 State Lease Number
Phillips Lease Line Injectors (6)
Texaco Lease Line Injectors (6)
Infill Producers 4th Q 1993 (6)
Infill Injectors Drilled 1994 (10)
Replacement Wells Drilled 1994 (2)
Infill Injectors Drilled 1995 (10)
Convert to H2O Injection 1995 (4)
Infill Injectors Drilled 1996 (5)
Convert to H2O Injection 1996 (11)
R 35 E
T 17 S
T 18 S
30
29
28
27
26
31
32
33
34
6
5
4

FIGURE 5



VACUUM GLORIETA EAST UNIT
VACUUM GLORIETA FIELD
LEA COUNTY, NEW MEXICO
MARCH 9, 1993
CO2 DEVELOPMENT
LEGEND
Current Glorieta Completions (74)
Shut-In (20)
T & A (6)
P & A (15)
Tract Number
B-2073 State Lease Number
Phillips Lease Line Injectors (6)
Texaco Lease Line Injectors (6)
Infill Producers 4th Q 1993 (6)
Infill Injectors Drilled 1994 (10)
Replacement Wells Drilled 1994 (2)
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Convert to H2O Injection 1995 (4)
Infill Injectors Drilled 1996 (5)
Convert to H2O Injection 1996 (11)
Infill CO2 Injectors (11)
Convert to CO2 Injection (3)
R 35 E
T 17 S
T 18 S
30
29
28
27
26
31
32
33
34
6
5
4

FIGURE 6

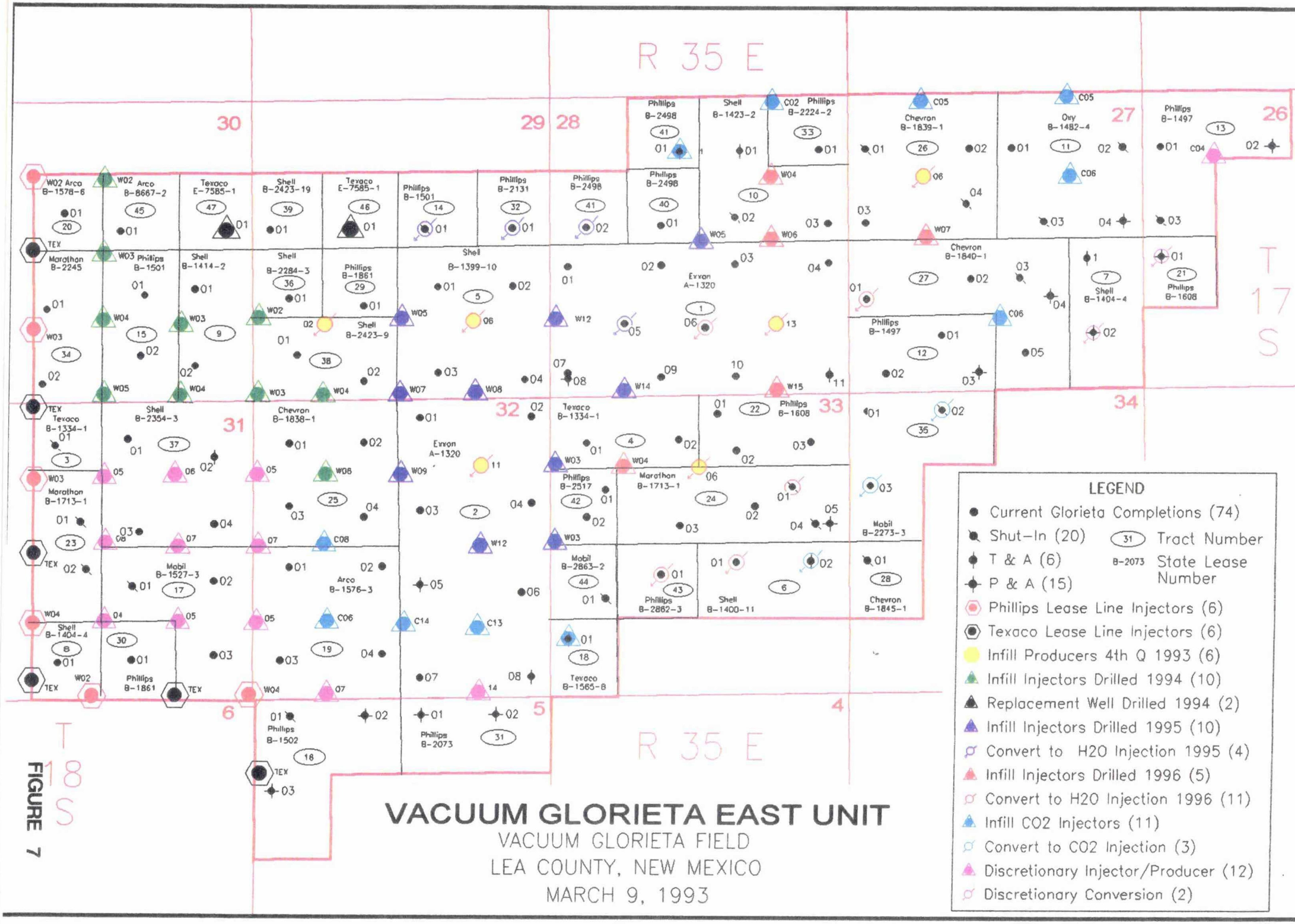

R 35 E
T 17 S
T 18 S
VACUUM GLORIETA EAST UNIT
VACUUM GLORIETA FIELD
LEA COUNTY, NEW MEXICO
MARCH 9, 1993
LEGEND
Current Glorieta Completions (74)
Shut-In (20)
T & A (6)
P & A (15)
Tract Number
State Lease Number
Phillips Lease Line Injectors (6)
Texaco Lease Line Injectors (6)
Infill Producers 4th Q 1993 (6)
Infill Injectors Drilled 1994 (10)
Replacement Well Drilled 1994 (2)
Infill Injectors Drilled 1995 (10)
Convert to H2O Injection 1995 (4)
Infill Injectors Drilled 1996 (5)
Convert to H2O Injection 1996 (11)
Infill CO2 Injectors (11)
Convert to CO2 Injection (3)
Discretionary Injector/Producer (12)
Discretionary Conversion (2)

FIGURE 7

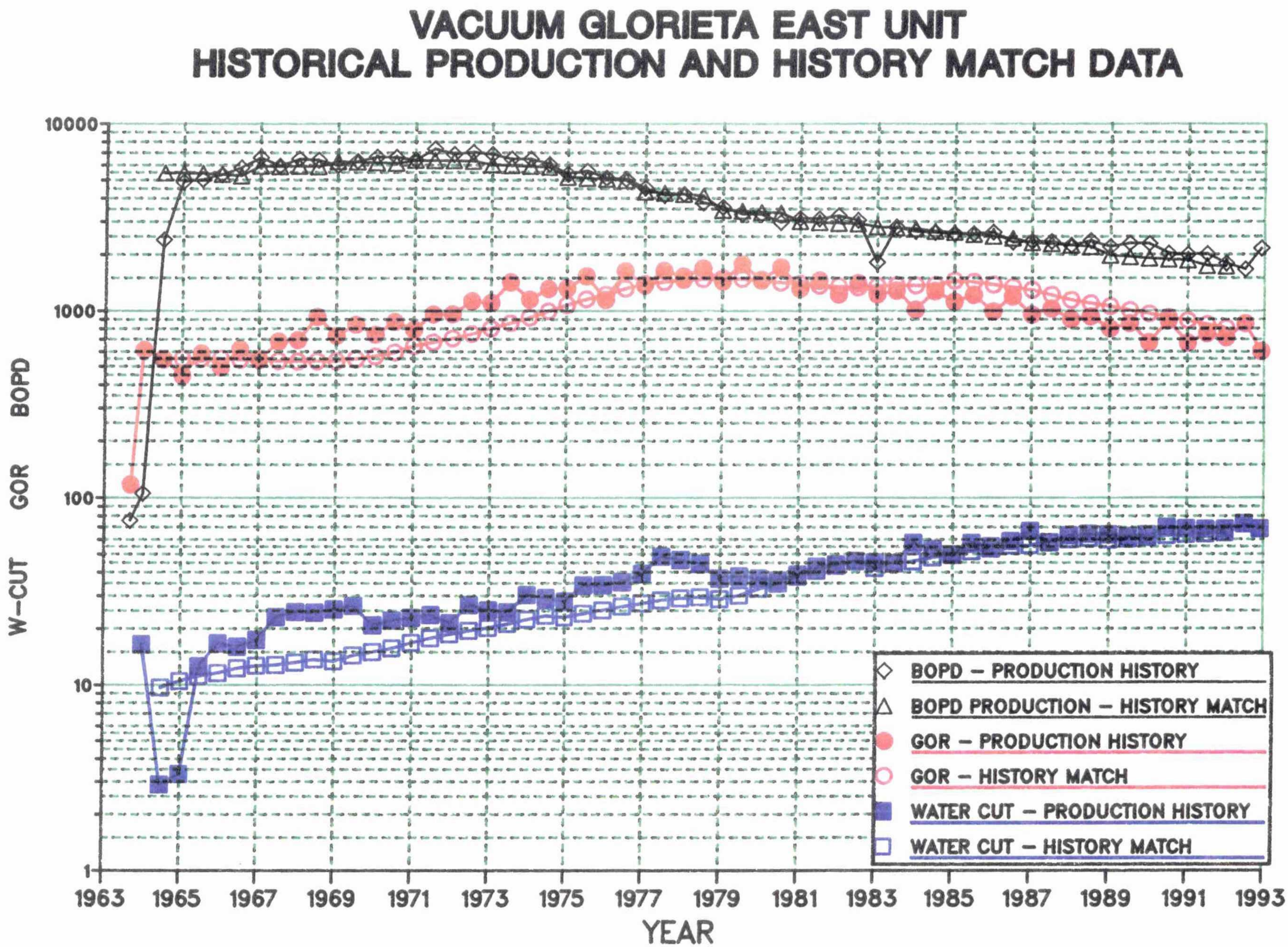

VACUUM GLORIETA EAST UNIT
HISTORICAL PRODUCTION AND HISTORY MATCH DATA
10000
1000
100
10
1
BOPD
GOR
W-CUT
1963
1965
1967
1969
1971
1973
1975
1977
1979
1981
1983
1985
1987
1989
1991
1993
YEAR
BOPD – PRODUCTION HISTORY
BOPD PRODUCTION – HISTORY MATCH
GOR – PRODUCTION HISTORY
GOR – HISTORY MATCH
WATER CUT – PRODUCTION HISTORY
WATER CUT – HISTORY MATCH

FIGURE 8

VACUUM GLORIETA EAST UNIT

WATERFLOOD PARAMETER VARIATION TREE

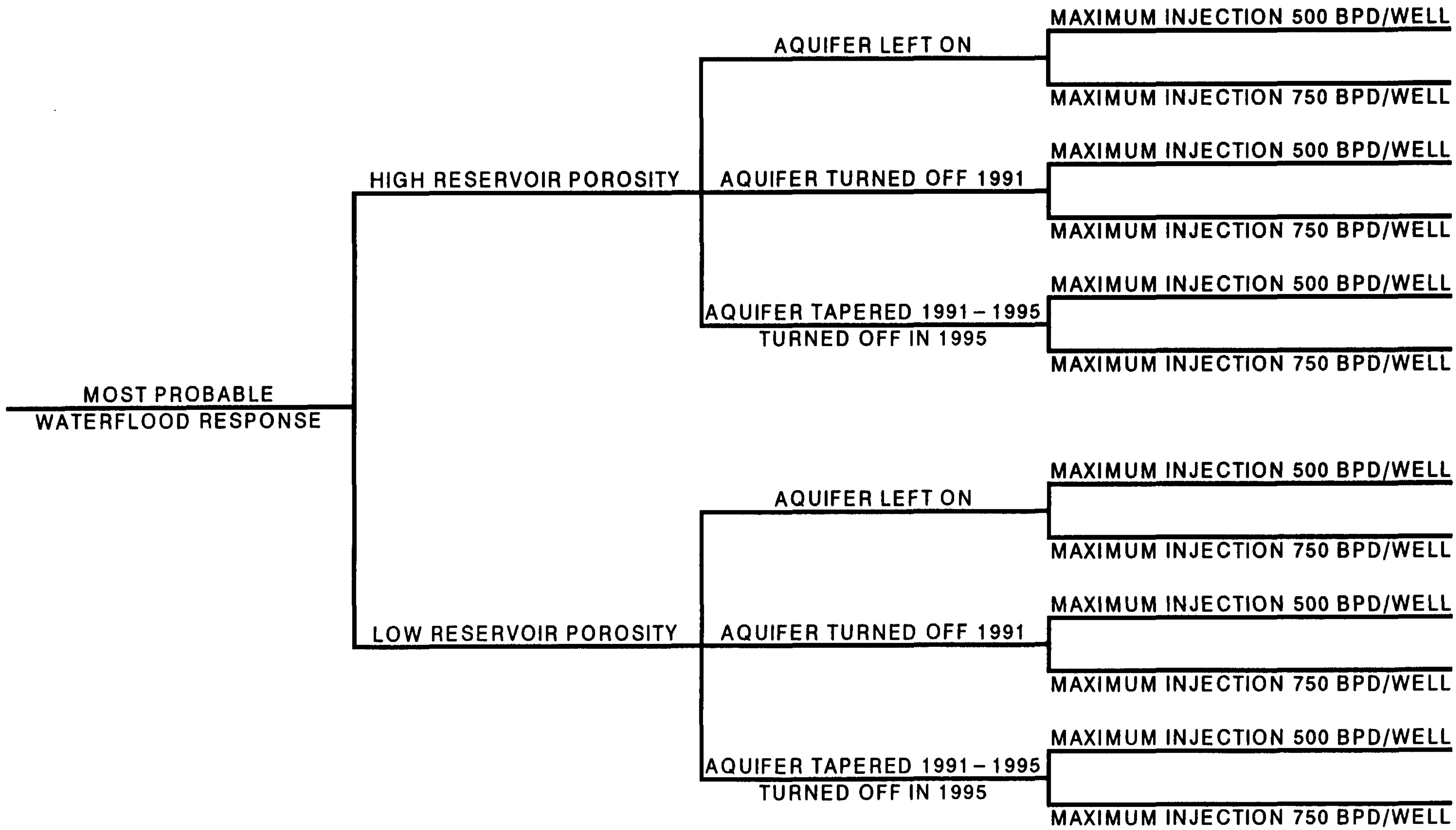
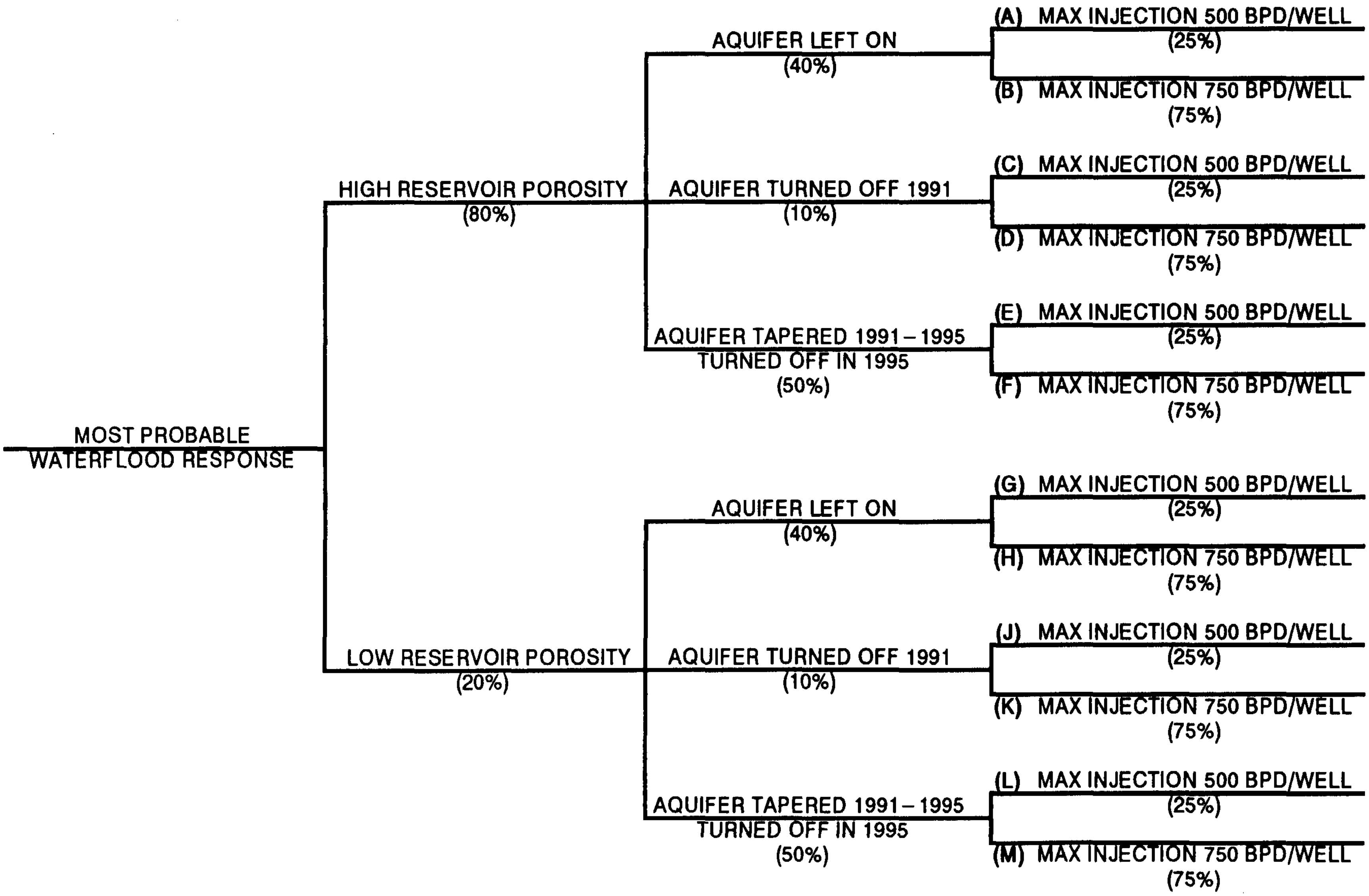


FIGURE 9

VACUUM GLORIETA EAST UNIT

WATERFLOOD PARAMETER VARIATION TREE

PROBABILITY OF OCCURANCE FACTORS AND WEIGHTED AVERAGE FORMULA



MOST PROBABLE WATER FLOOD RESPONSE $= [0.8\{0.4(0.25A+0.75B)+0.1(0.25C+0.75D)+0.5(0.25E+0.75F)\}] + [0.2\{0.4(0.25G+0.75H)+0.1(0.25J+0.75L)+0.5(0.25M+0.75N)\}]$

FIGURE 10

VACUUM GLORIETA EAST UNIT
HISTORICAL PRODUCTION AND FORECASTS

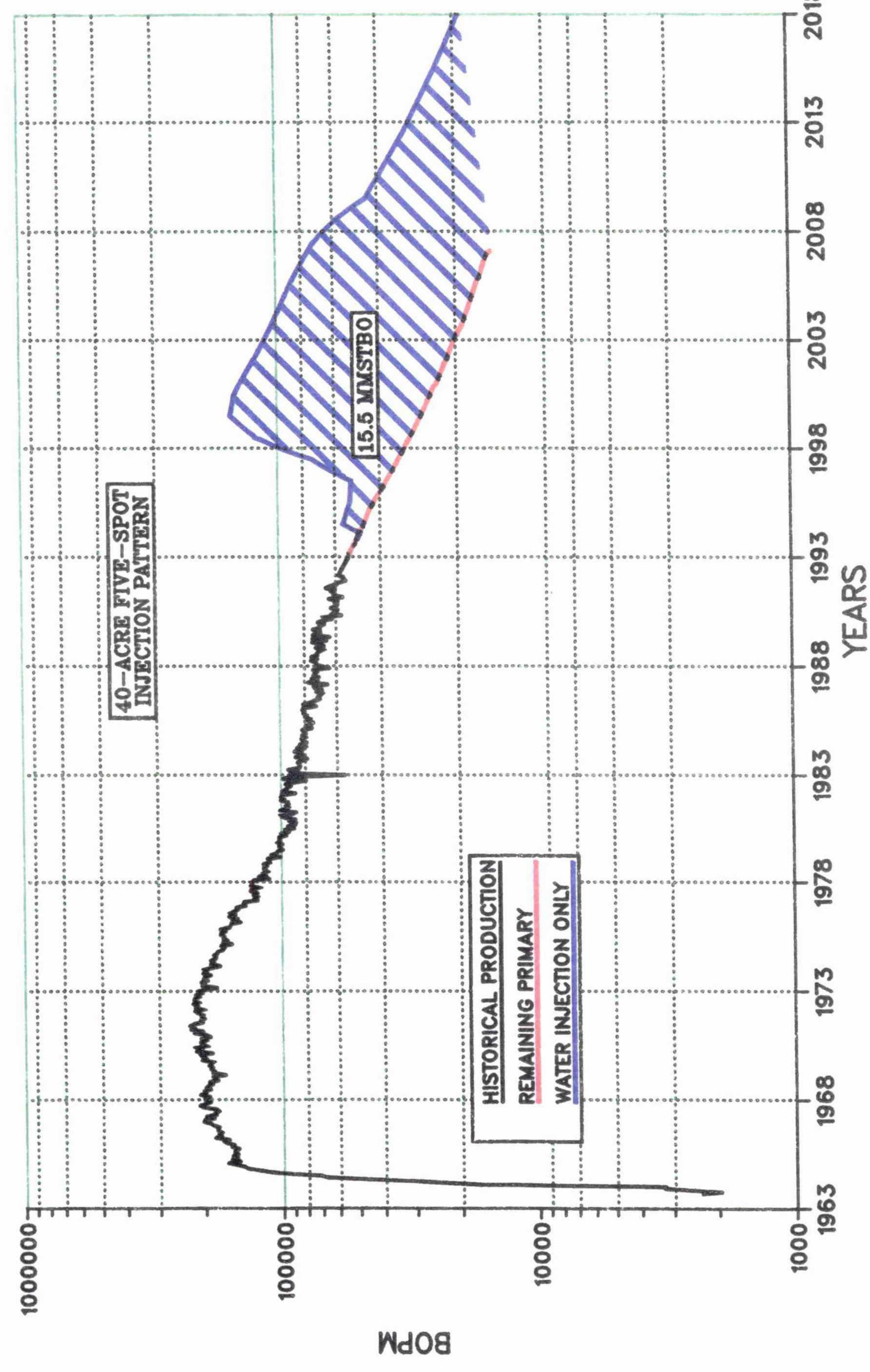


FIGURE 11

VACUUM GLORIETA EAST UNIT
HISTORICAL PRODUCTION AND FORECASTS

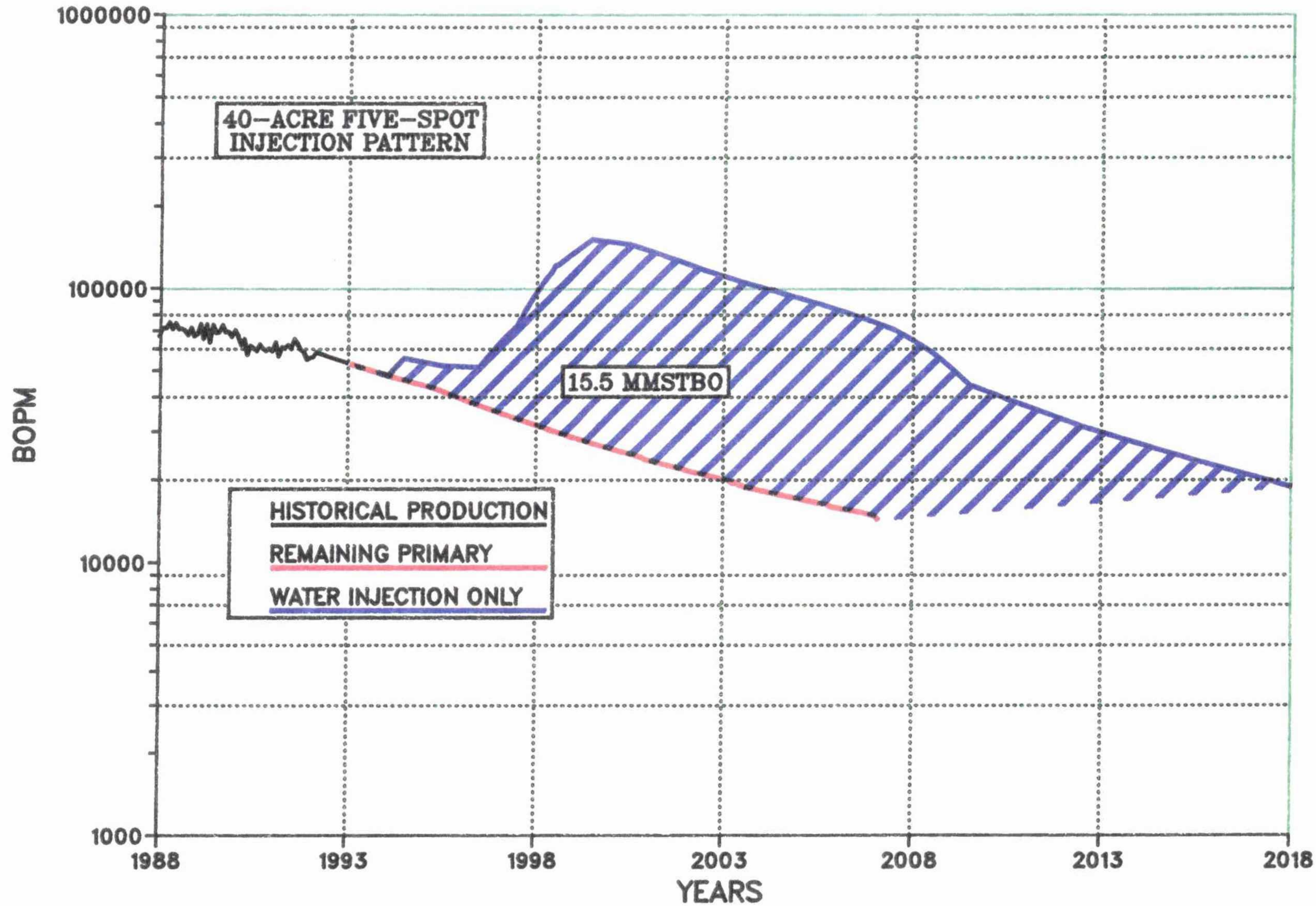


FIGURE 12

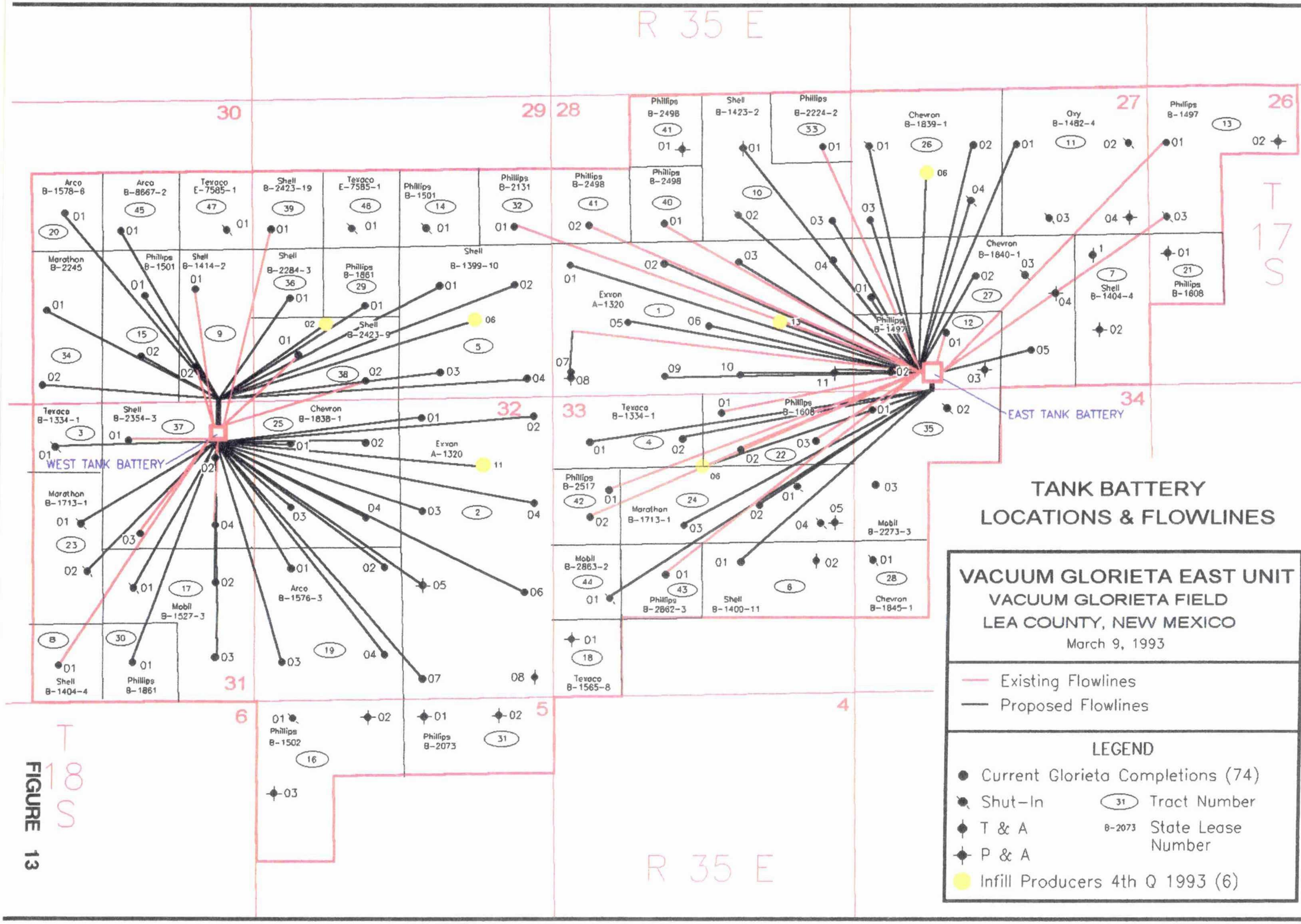

TANK BATTERY
LOCATIONS & FLOWLINES
VACUUM GLORIETA EAST UNIT
VACUUM GLORIETA FIELD
LEA COUNTY, NEW MEXICO
March 9, 1993
Existing Flowlines
Proposed Flowlines
LEGEND
Current Glorieta Completions (74)
Shut-In
Tract Number
T & A
State Lease Number
P & A
Infill Producers 4th Q 1993 (6)
R 35 E
T 17 S
T 18 S
WEST TANK BATTERY
EAST TANK BATTERY

FIGURE 13

PLOTTING lee 10-MAR-1993 08:59 zpswrk:lee.plt

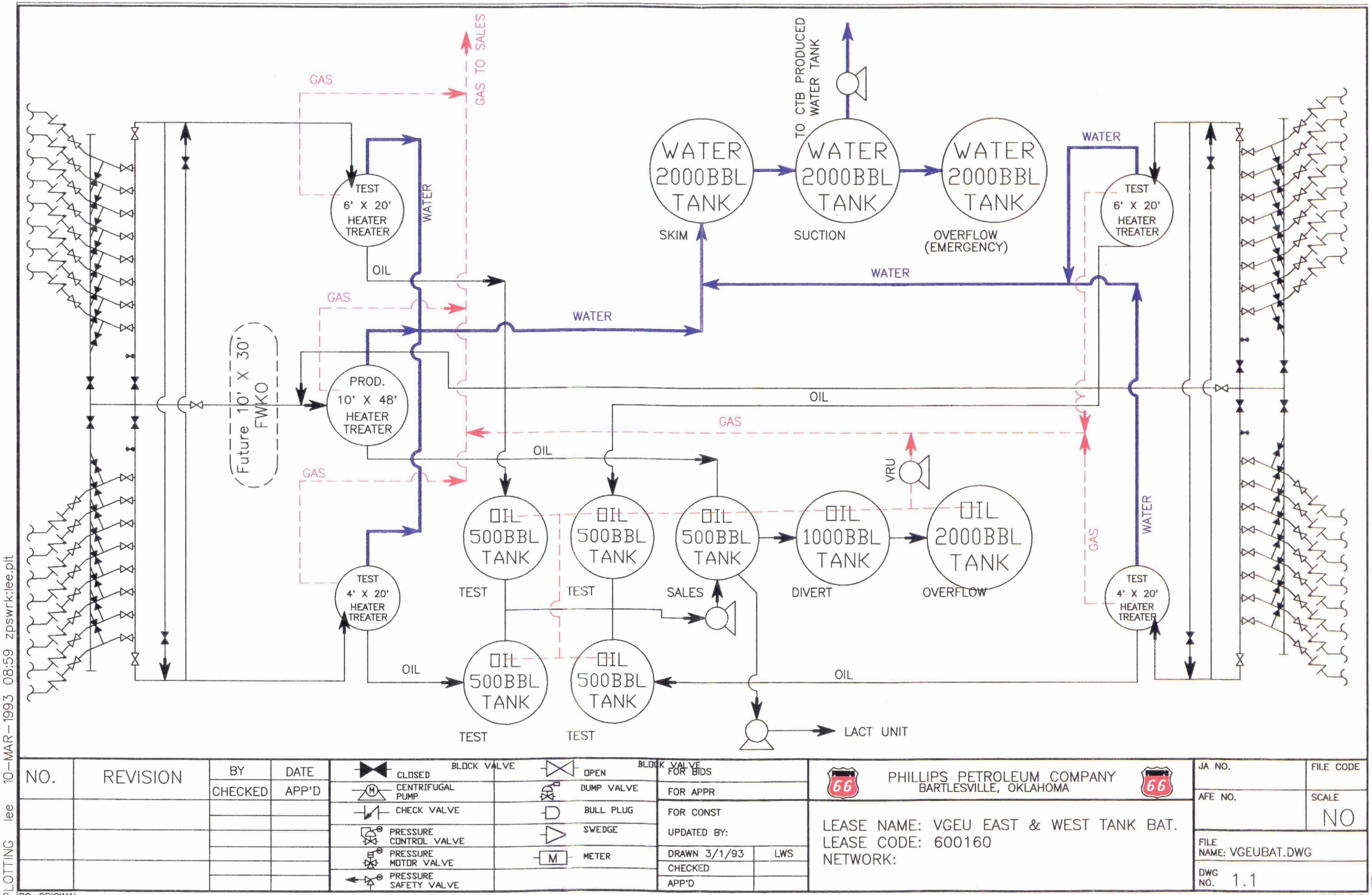


FIGURE 14

VACUUM GLORIETA EAST UNIT

WELL COMPLETION DIAGRAM IN NON-WATERFLOW AREA

5-1/2" PRODUCING WELL

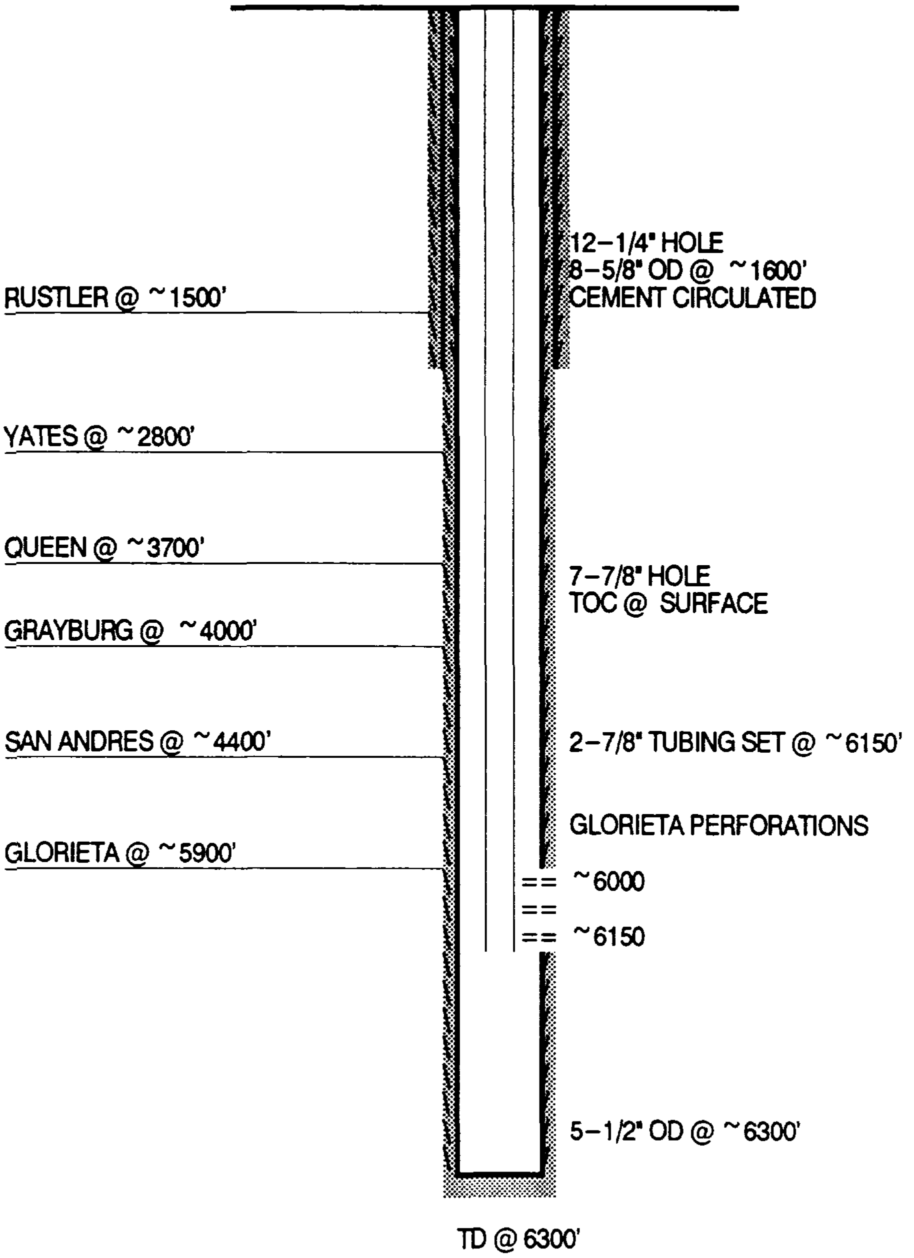


FIGURE 15

VACUUM GLORIETA EAST UNIT

WELL COMPLETION DIAGRAM IN NON-WATERFLOW AREA

5-1/2" INJECTION WELL

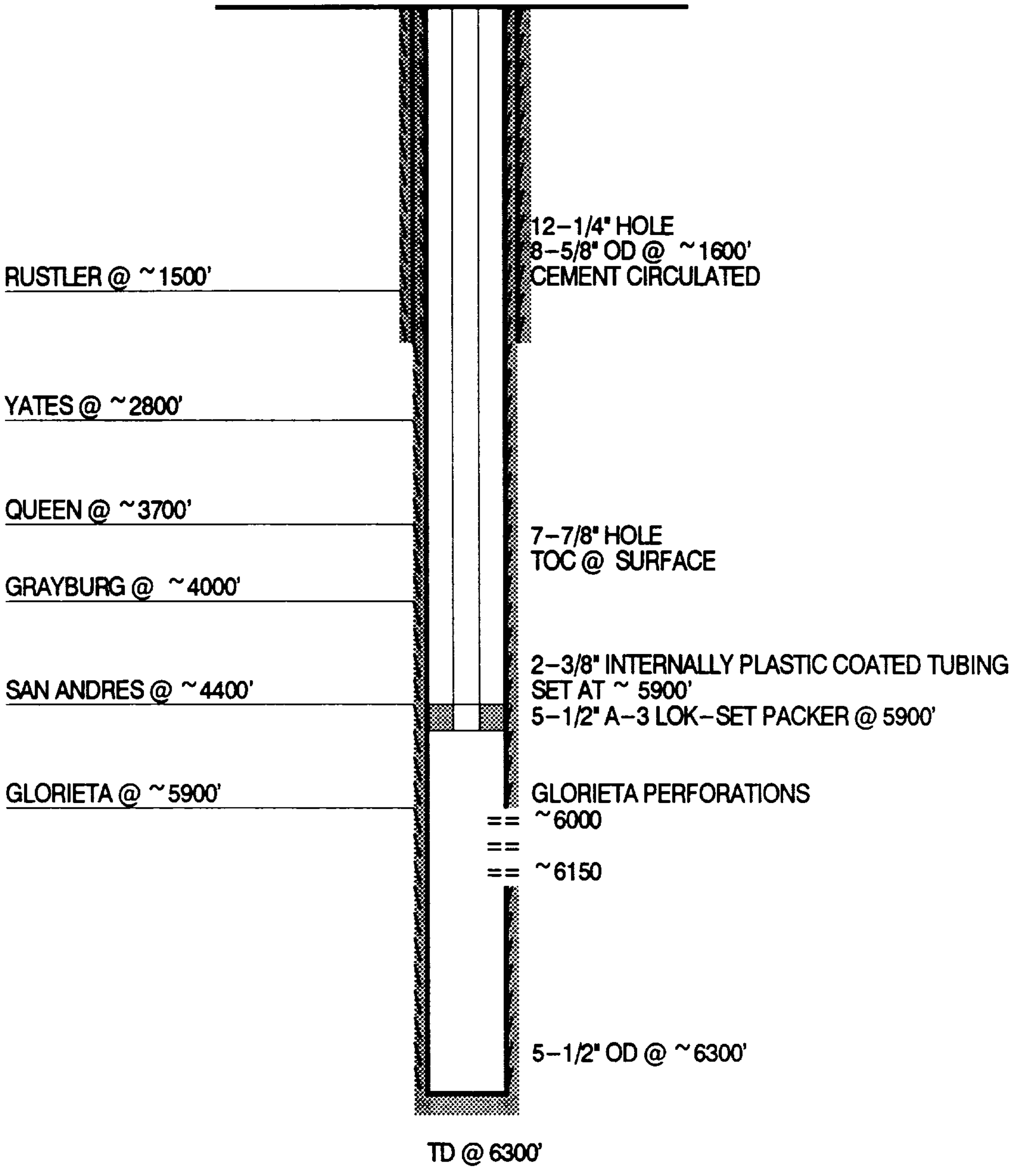


FIGURE 16

VACUUM GLORIETA EAST UNIT

WELL COMPLETION DIAGRAM IN WATERFLOW AREA

5-1/2" INJECTION WELL

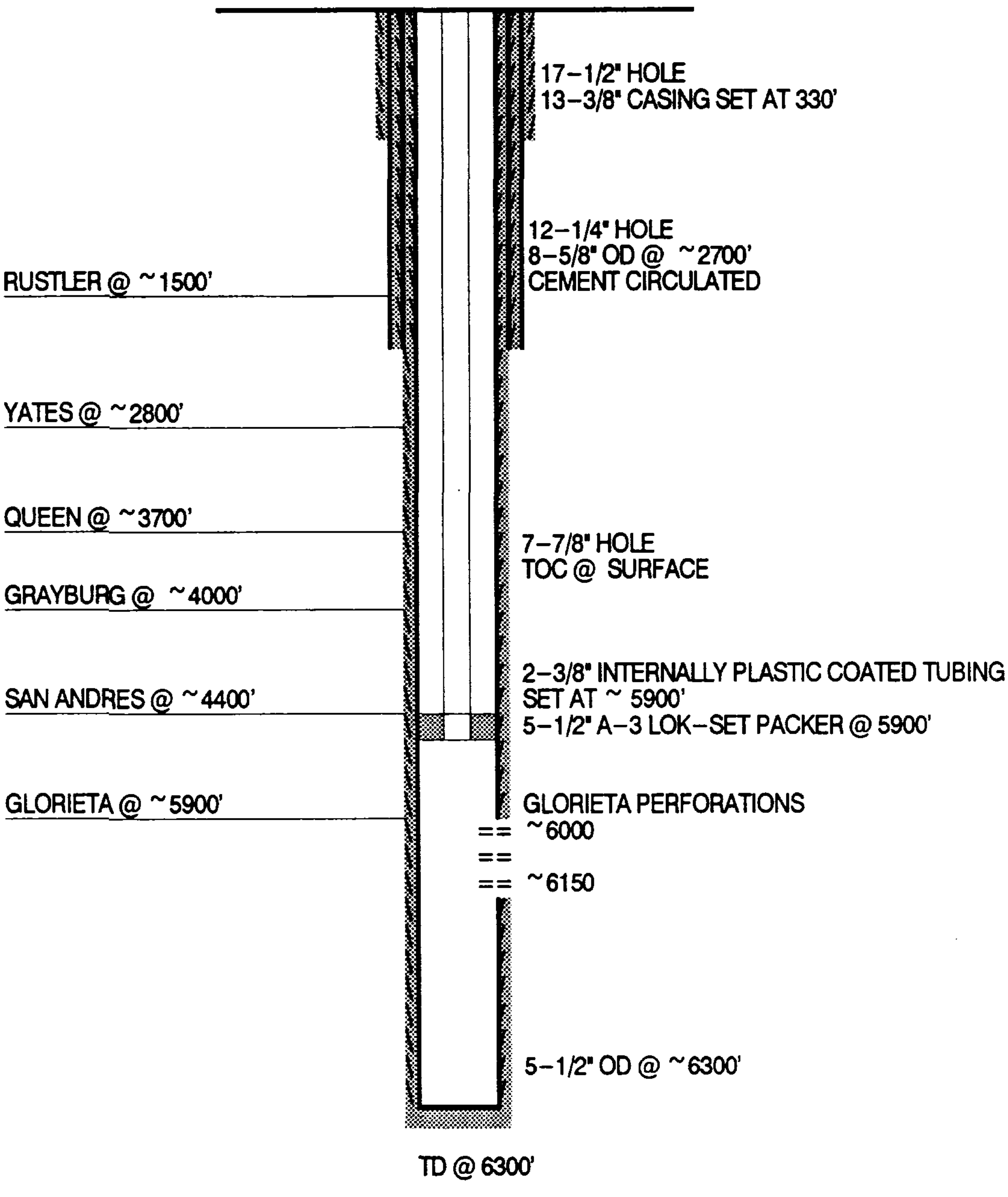


FIGURE 17

VACUUM GLORIETA EAST UNIT

WELL COMPLETION DIAGRAM

4-1/2" INJECTION WELL

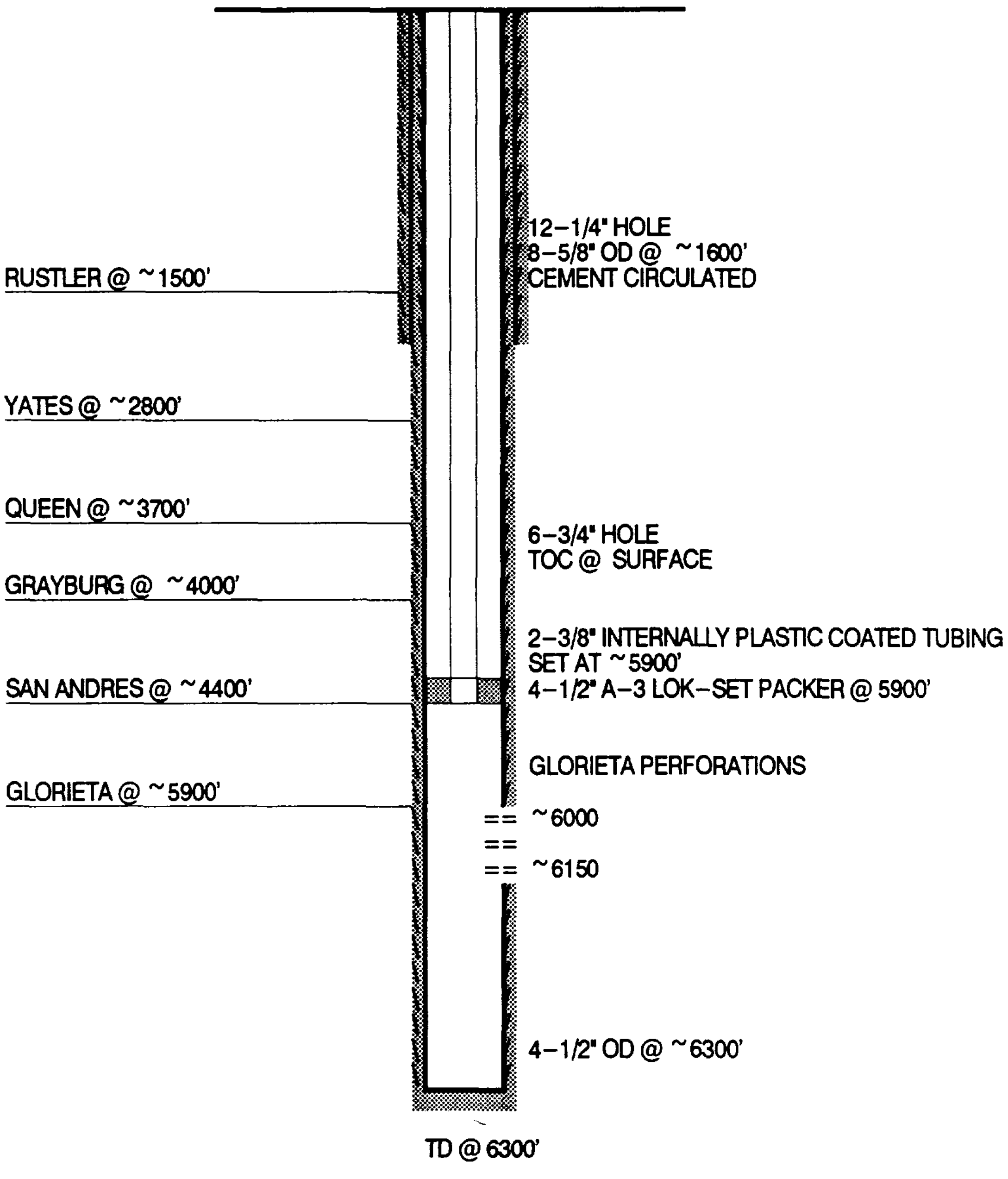


FIGURE 18

VACUUM GLORIETA EAST UNIT

WELL COMPLETION DIAGRAM

4-1/2" PRODUCING WELL

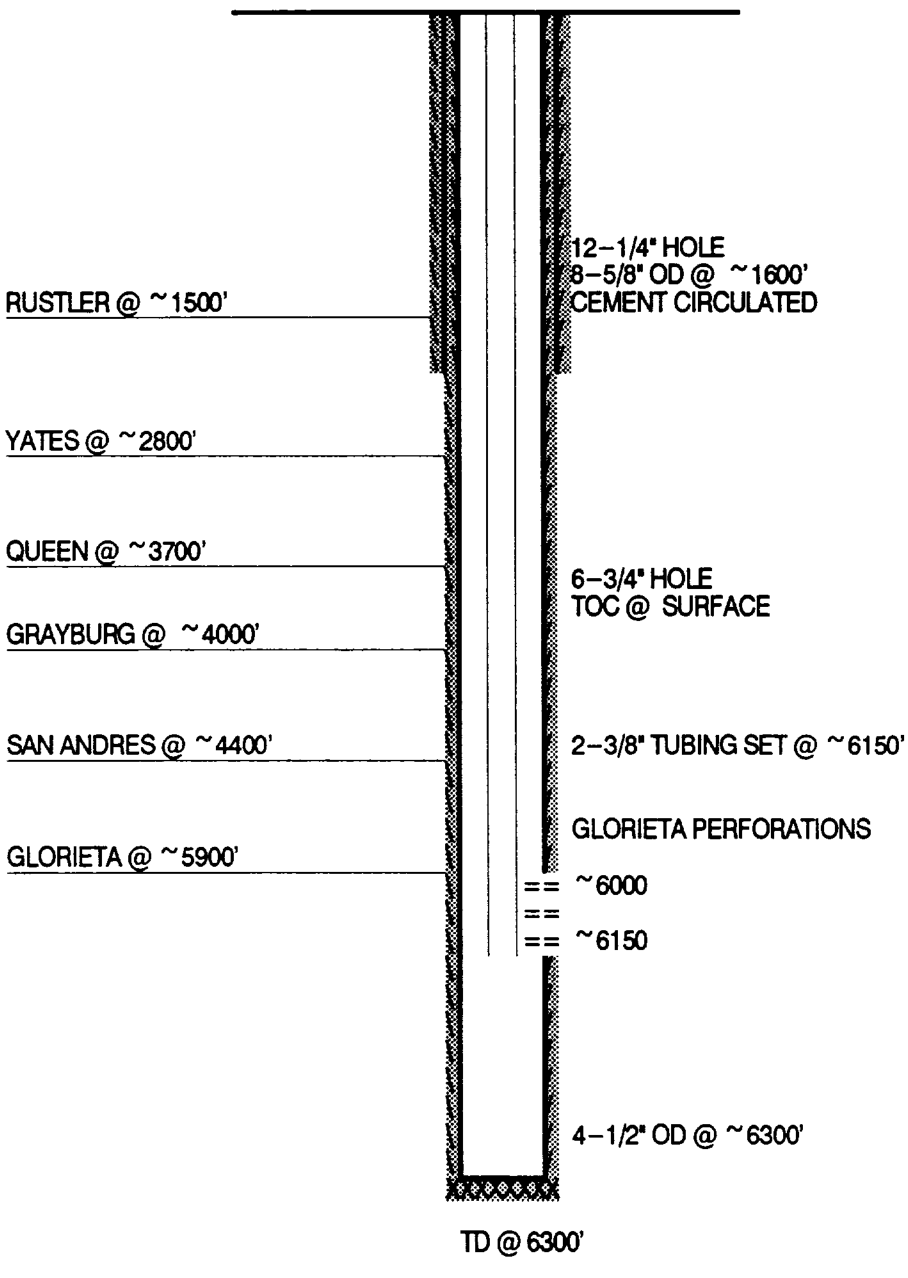


FIGURE 19

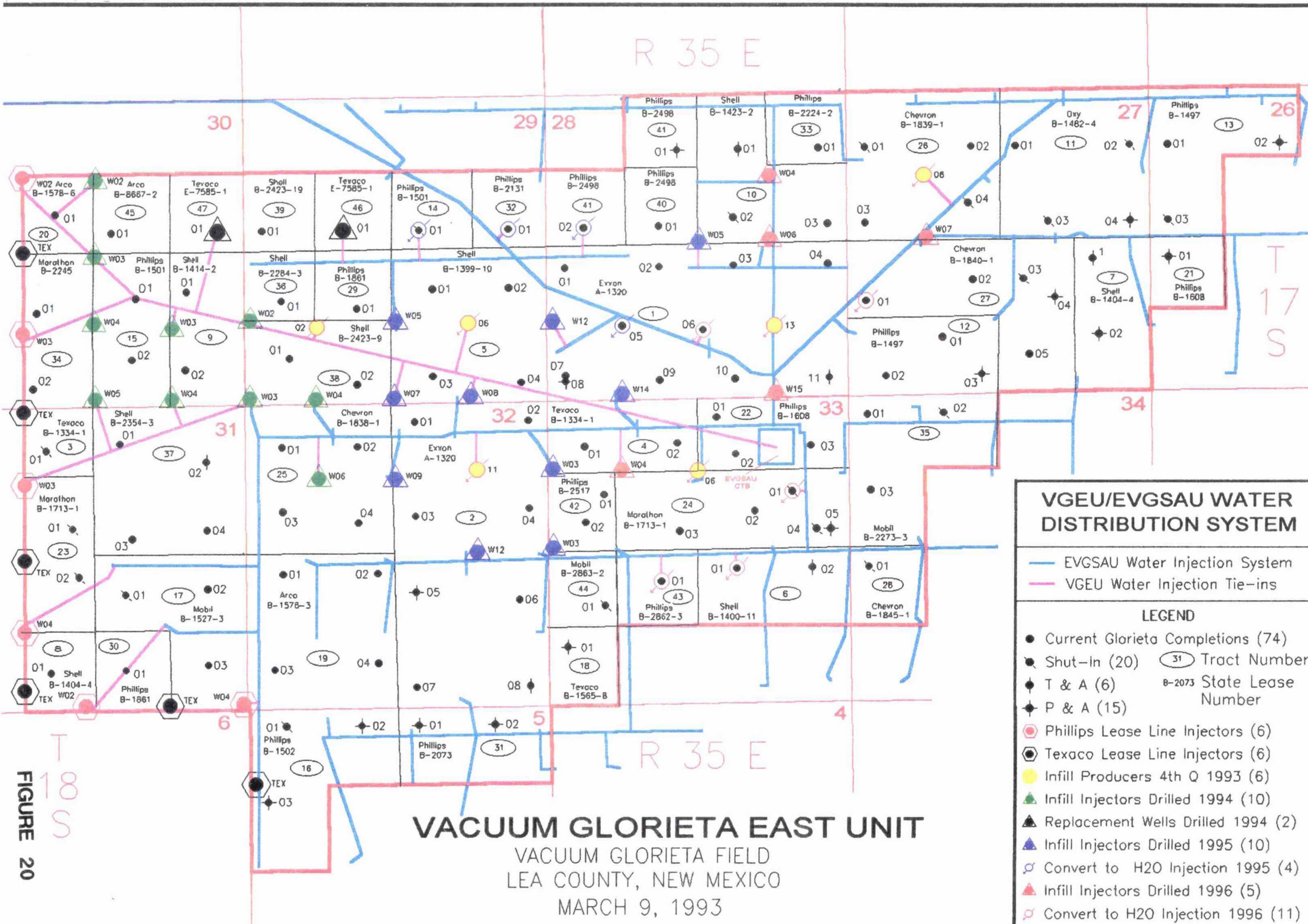

VACUUM GLORIETA EAST UNIT
VACUUM GLORIETA FIELD
LEA COUNTY, NEW MEXICO
MARCH 9, 1993
VGEU/EVGSAU WATER DISTRIBUTION SYSTEM
EVGSAU Water Injection System
VGEU Water Injection Tie-ins
LEGEND
Current Glorieta Completions (74)
Shut-In (20)
T & A (6)
P & A (15)
Tract Number
State Lease Number
Phillips Lease Line Injectors (6)
Texaco Lease Line Injectors (6)
Infill Producers 4th Q 1993 (6)
Infill Injectors Drilled 1994 (10)
Replacement Wells Drilled 1994 (2)
Infill Injectors Drilled 1995 (10)
Convert to H2O Injection 1995 (4)
Infill Injectors Drilled 1996 (5)
Convert to H2O Injection 1996 (11)
R 35 E
T 17 S
T 18 S

FIGURE 20

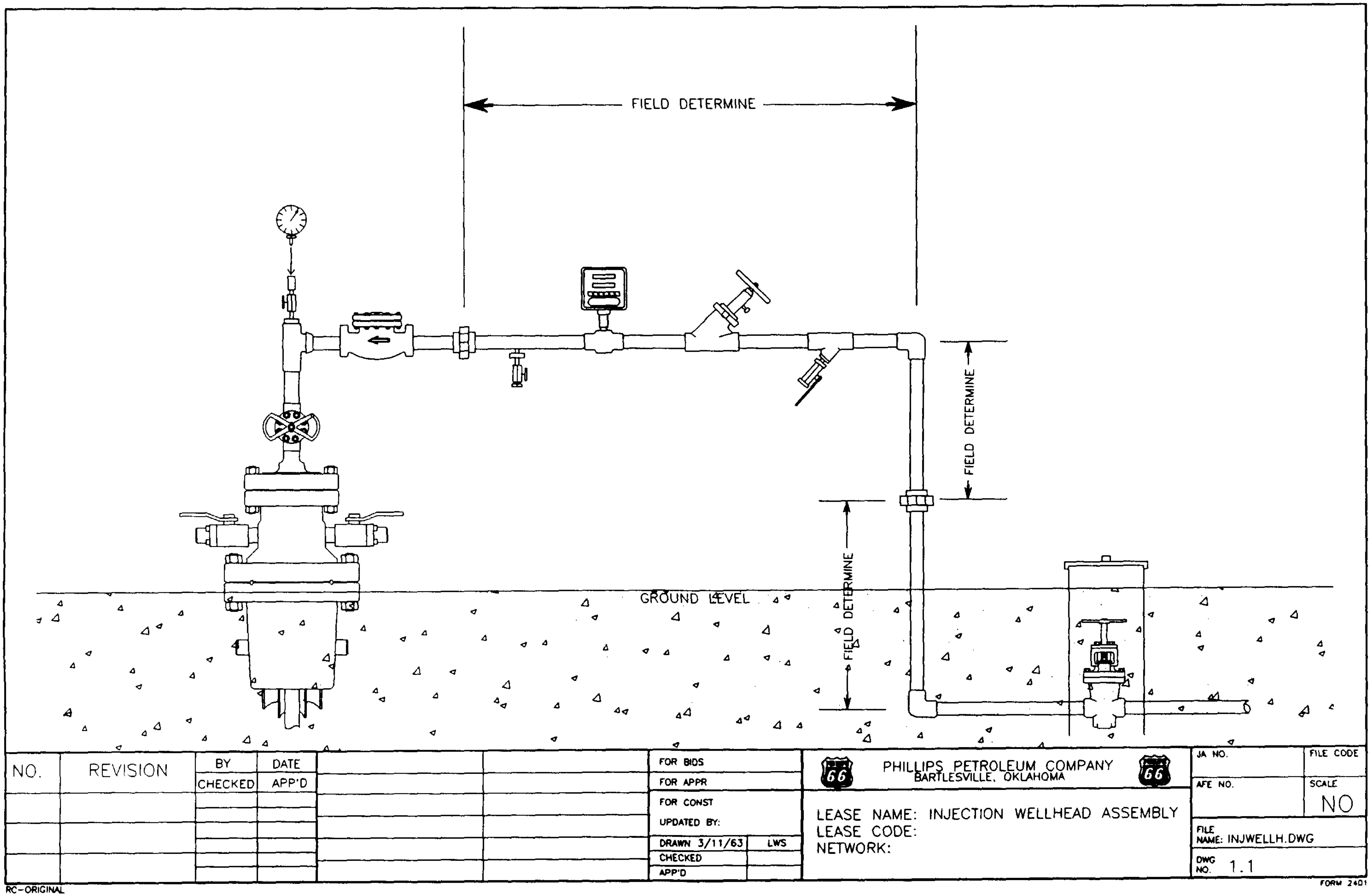

FIELD DETERMINE
FIELD DETERMINE
FIELD DETERMINE
GROUND LEVEL
NO.
REVISION
BY
CHECKED
DATE
APP'D
FOR BIDS
FOR APPR
FOR CONST
UPDATED BY:
DRAWN 3/11/63
LWS
CHECKED
APP'D
PHILLIPS PETROLEUM COMPANY
BARTLESVILLE, OKLAHOMA
LEASE NAME: INJECTION WELLHEAD ASSEMBLY
LEASE CODE:
NETWORK:
JA NO.
FILE CODE
AFE NO.
SCALE
NO
FILE NAME: INJWELLH.DWG
DWG NO. 1.1
FORM 2401
RC-ORIGINAL

FIGURE 21

Vacuum Glorieta East Unit Development Schedule - 11 March 1993 (V-DEV-1)

Task Name	Start Date	End Date
PPCo Approval	26-Apr-93	26-Apr-93
WI Owners Approval	24-May-93	24-May-93
Project Approval	4-Aug-93	4-Aug-93
Premise Review	26-Apr-93	7-Jun-93
Production Facilities	8-Jun-93	3-Jan-95
Design	8-Jun-93	31-Dec-93
Procurement	1-Jul-93	1-Jul-94
Prepare Site-East & West Btry	1-Sep-93	1-Nov-93
Construct West Header	1-Oct-93	30-Nov-93
Construct West Battery	1-Dec-93	31-May-94
Eliminate Btry-1,2,3,4,5,8	1-Nov-93	31-Dec-93
Eliminate Btry- 6 & 7	1-Jun-94	30-Jun-94
Construct East Header	4-Jan-94	28-Feb-94
Construct East Battery	2-May-94	31-Oct-94
Eliminate Btry-11,12,14,16,18	1-Feb-94	31-Mar-94
Eliminate Btry- 13,15,17	3-Oct-94	30-Nov-94
Eliminate Btry - 9 & 10	1-Dec-94	3-Jan-95
Waterflood Construction	4-Jan-94	2-May-94
Injection Line Connections	1-Apr-94	1-Aug-94
Drilling Operations	1-Oct-93	15-May-96
6 Infill Producers	1-Oct-93	31-Dec-93
1 Replacement Producer	1-Jun-95	30-Jun-95
10 Infill Injectors	1-Apr-94	30-Aug-94
2 Replacement Injectors	1-Sep-94	30-Sep-94
3 Lease Line Injectors	3-Oct-94	16-Nov-94
10 Infill Injectors	1-Mar-95	31-Jul-95
3 Lease Line Injectors	1-Aug-95	15-Sep-95
1 Replacement Producer	15-Feb-96	1-Mar-96
5 Infill Injectors	1-Mar-96	15-May-96
Conversions/Workovers	2-May-94	15-May-97
Reactivate 4 SI Producer	2-May-94	30-Jun-94
Convert 4 Prod to Injectors	3-Apr-95	1-May-95
Reactivate 4 SI Producers	1-Apr-96	31-May-96
Convert 11 Prod to Injectors	3-Jun-96	3-Sep-96
Reactivate 1 SI Producer	1-May-97	15-May-97
Increased Lift Capacity	1-Jul-96	28-Feb-01

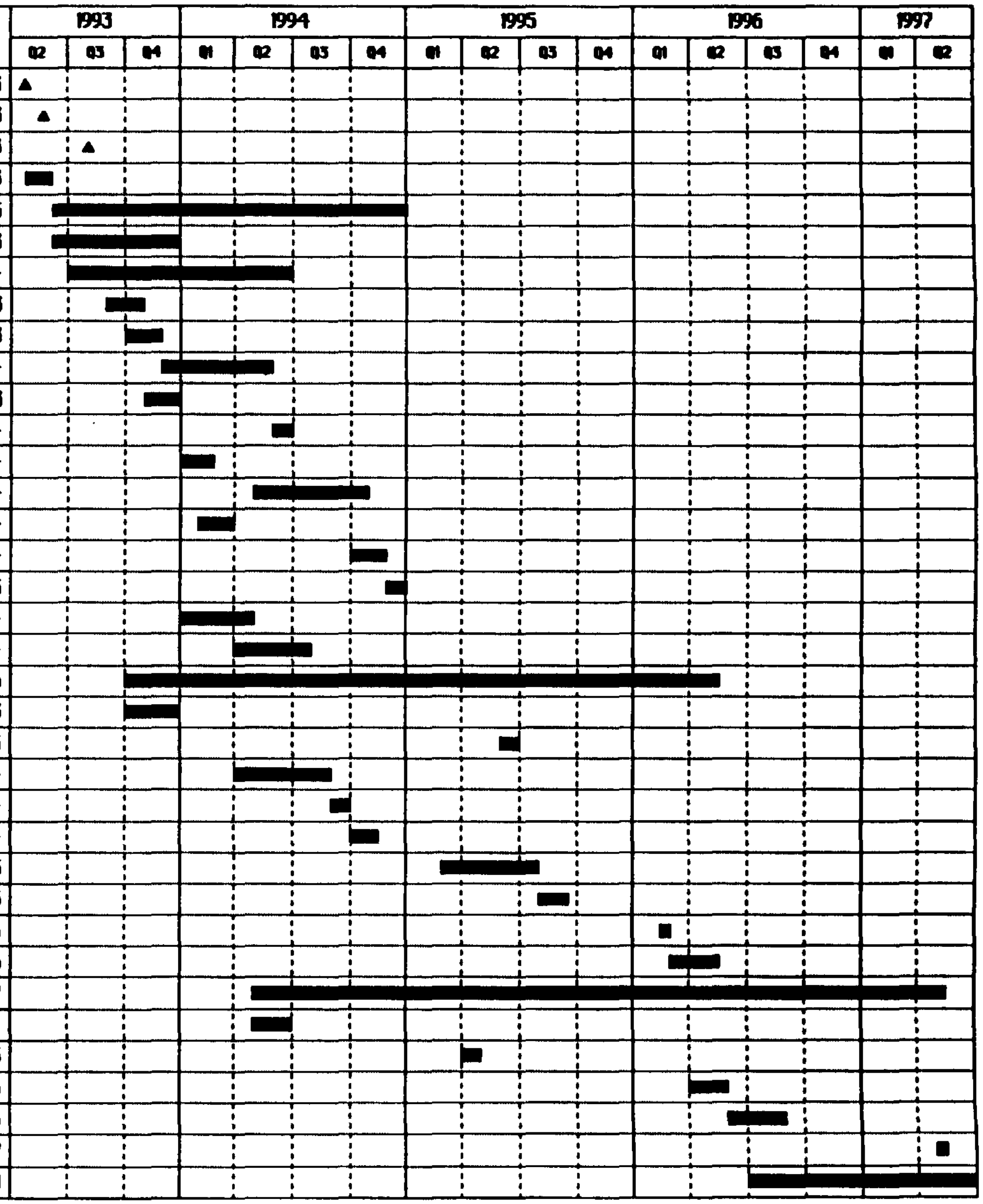


FIGURE 22

TABLES

LIST OF TABLES

VACUUM GLORIETA EAST UNIT

DEVELOPMENT SCHEDULE

DEVELOPMENT ACTIVITY	1993	1994	1995	1996	1997	1998	1999	2000	2001
DRILL/COMPLETE WATER INJECTION WELL*		10	10	5					
CONVERT WELL TO WATER INJECTION			4	11					
DRILL/COMPLETE PRODUCING WELL**	6								
DRILL/COMPLETE REPLACEMENT INJECTION WELL		2							
DRILL/COMPLETE REPLACEMENT PRODUCTION WELL			1	1					
DRILL/COMPLETE LEASE LINE INJECTION WELLS		3	3						
REACTIVATE/EQUIP SHUT IN PRODUCER		4		4	1				
INSTALL INCREASED LIFT ON PRODUCER				5	13	21	9	11	2

* CORE GLORIETA IN 10% OF INFILL INJECTORS
**CORE GLORIETA IN ALL INFILL PRODUCERS

TABLE 1

VACUUM GLORIETA EAST UNIT

RISK WIEGHTED WATER FLOOD FORECAST

DATE	ANNUAL TOTAL OIL PRODUCED (BOPY)	ANNUAL PRIMARY OIL PRODUCED (BOPY)	ANNUAL WATERFLOOD OIL PRODUCED (BOPY)	ANNUAL TOTAL GAS PRODUCED (MCFY)	AVERAGE DAILY OIL PRODUCED (BOPD)
1994	669,066	551,866	117,200	539,936	1,833
1995	627,215	501,515	125,700	476,056	1,718
1996	619,354	445,339	174,015	442,838	1,697
1997	881,642	398,952	482,690	524,577	2,415
1998	1,440,727	359,437	1,081,290	417,811	3,947
1999	1,820,263	326,203	1,494,060	518,775	4,987
2000	1,749,870	297,955	1,451,915	533,710	4,794
2001	1,571,754	271,369	1,300,385	487,244	4,306
2002	1,401,932	250,312	1,151,620	441,609	3,841
2003	1,269,181	228,721	1,040,460	399,792	3,477
2004	1,159,899	211,859	948,040	365,368	3,178
2005	1,060,390	197,735	862,655	334,023	2,905
2006	955,842	183,962	771,880	301,090	2,619
2007	851,152	14,361	836,791	268,113	2,332
2008	703,952	0	703,952	221,745	1,929
2009	534,460	0	534,460	168,355	1,464
2010	473,220	0	473,220	149,064	1,296
2011	423,070	0	423,070	133,267	1,159
2012	376,635	0	376,635	118,640	1,032
2013	342,375	0	342,375	107,848	938
2014	311,240	0	311,240	98,041	853
2015	283,145	0	283,145	89,191	776
2016	258,960	0	258,960	81,572	709
2017	237,805	0	237,805	74,909	652
2018	218,820	0	218,820	68,928	600
2019	202,600	0	202,600	63,819	555
2020	188,715	0	188,715	59,445	517
TOTAL	20,530,141	4,239,586	16,393,698	7,485,766	

TABLE 2

VACUUM GLORIETA EAST UNIT

PRODUCED AND INJECTED WATER FORECAST

DATE	ANNUAL WATER PRODUCED (BBLS)	ANNUAL WATER INJECTED (BBLS)	ANNUAL INJECTION MAKE-UP (BBLS)	AVERAGE DAILY WATER PRODUCED (BWPD)	AVERAGE DAILY WATER INJECTED (BWPD)	AVERAGE DAILY WATER MAKE-UP (BWPD)
1993	1,255,000	0	(1,255,000)	3,438	0	(3,438)
1994	1,320,000	0	(1,320,000)	3,616	0	(3,616)
1995	1,465,000	1,049,340	(415,660)	4,014	2,875	(1,139)
1996	1,680,000	4,428,705	2,748,705	4,603	12,133	7,531
1997	2,480,000	7,832,576	5,352,576	6,795	21,459	14,665
1998	4,086,000	11,278,403	7,192,403	11,195	30,900	19,705
1999	5,483,000	11,161,616	5,678,616	15,022	30,580	15,558
2000	6,191,000	10,882,782	4,691,782	16,962	29,816	12,854
2001	6,660,000	10,445,589	3,785,589	18,247	28,618	10,371
2002	7,001,000	10,076,200	3,075,200	19,181	27,606	8,425
2003	7,287,000	9,835,943	2,548,943	19,964	26,948	6,983
2004	7,483,000	9,546,937	2,063,937	20,501	26,156	5,655
2005	7,646,000	9,198,290	1,552,290	20,948	25,201	4,253
2006	7,780,000	8,979,287	1,199,287	21,315	24,601	3,286
2007	7,891,000	8,879,973	988,973	21,619	24,329	2,710
2008	7,986,000	8,831,244	845,244	21,879	24,195	2,316
2009	8,068,000	8,807,180	739,180	22,104	24,129	2,025
2010	8,137,000	8,795,706	658,706	22,293	24,098	1,805
2011	8,197,000	8,790,407	593,407	22,458	24,083	1,626
2012	8,250,000	8,788,344	538,344	22,603	24,078	1,475
2013	8,297,000	8,787,495	490,495	22,732	24,075	1,344
2014	8,337,000	8,787,495	450,495	22,841	24,075	1,234
2015	8,374,000	8,787,495	413,495	22,942	24,075	1,133
2016	8,407,000	8,787,495	380,495	23,033	24,075	1,042
2017	8,436,000	8,787,495	351,495	23,112	24,075	963
2018	8,463,000	8,787,495	324,495	23,186	24,075	889
2019	8,487,000	8,787,495	300,495	23,252	24,075	823
2020	8,509,000	8,787,495	278,495	23,312	24,075	763
TOTAL	183,656,000	227,908,482	44,252,482			

TABLE 3

VACUUM GLORIETTA EAST UNIT
INCREASED LIFT EQUIPMENT INSTALLATIONS

ESTIMATED INSTALLATION SCHEDULE

YEAR	INSTALL LUFKIN 640 PUMPING UNIT	INSTALL SUBMERSIBLE PUMP EQUIPMENT
1993		
1994		
1995		
1996	4	1
1997	10	3
1998	15	6
1999	7	2
2000	8	3
2001	1	1
TOTAL:	45 WELLS	16 WELLS

TABLE 4

VACUUM GLORIETA EAST UNIT
DEVELOPMENT / INVESTMENT SCHEDULE

WATER FLOODING ONLY	YEAR 1993 ($M)*			YEAR 1994 ($M)*			YEAR 1995 ($M)*			YEAR 1996 ($M)*			YEAR 1997-2001 ($M)*			TOTALS
	Tangibles	Intangibles	Total	Tangibles	Intangibles	Total	Tangibles	Intangibles	Total	Tangibles	Intangibles	Total	Tangibles	Intangibles	Total	
New Producing Wells (6)	$805.65	$1,824.30	$2,629.95			$0.00			$0.00			$0.00			$0.00	$2,629.95
Demand Producing Wells (1)			$0.00			$0.00	$134.30	$210.65	$344.95			$0.00			$0.00	$344.95
Demand Producing Wells (1)			$0.00			$0.00			$0.00	$134.30	$210.65	$344.95			$0.00	$344.95
Reactivate SI Producers (4)			$0.00	$112.00	$100.00	$212.00			$0.00			$0.00			$0.00	$212.00
Reactivate SI Producers (4)			$0.00			$0.00			$0.00	$112.00	$100.00	$212.00			$0.00	$212.00
Reactivate SI Producers (1)			$0.00			$0.00			$0.00			$0.00	$28.00	$25.00	$53.00	$53.00
New Injection Wells (10)			$0.00	$680.75	$1,971.25	$2,652.00			$0.00			$0.00			$0.00	$2,652.00
New Injection Wells (10)			$0.00			$0.00	$680.75	$2,158.10	$2,838.85			$0.00			$0.00	$2,838.85
New Injection Wells (5)			$0.00			$0.00			$0.00	$340.40	$1,079.05	$1,419.45			$0.00	$1,419.45
Demand Injection Wells (2)			$0.00	$136.15	$394.25	$530.40			$0.00			$0.00			$0.00	$530.40
Lease Line Injectors (3)			$0.00	$204.25	$591.40	$795.65			$0.00			$0.00			$0.00	$795.65
Lease Line Injectors (3)			$0.00			$0.00	$319.85	$630.85	$950.70			$0.00			$0.00	$950.70
Inj. Wells Conversions (4)			$0.00			$0.00	$160.00	$240.00	$400.00			$0.00			$0.00	$400.00
Inj. Wells Conversions (11)			$0.00			$0.00			$0.00	$440.00	$552.00	$992.00			$0.00	$992.00
Install Increased Lift (5)			$0.00			$0.00			$0.00	$357.75	$48.85	$406.60			$0.00	$406.60
Install Increased Lift (13)			$0.00			$0.00			$0.00			$0.00	931.25	127.45	$1,058.70	$1,058.70
Install Increased Lift (21)			$0.00			$0.00			$0.00			$0.00	1507.5	207.1	$1,714.60	$1,714.60
Install Increased Lift (9)			$0.00			$0.00			$0.00			$0.00	644.5	88.15	$732.65	$732.65
Install Increased Lift (11)			$0.00			$0.00			$0.00			$0.00	$789.25	$108.30	$897.55	$897.55
Install Increased Lift (2)			$0.00			$0.00			$0.00			$0.00	144.75	20.2	$164.95	$164.95
Tank Batteries (2)	$105.00	$95.00	$200.00	$1,380.00	$550.00	$1,930.00			$0.00			$0.00			$0.00	$2,130.00
Automation – Producers			$0.00	$403.20	$99.30	$502.50	$140.80	$24.20	$165.00	$32.00	$5.50	$37.50	$6.40	$1.10	$7.50	$712.50
Automation – Tank Batteries			$0.00	$132.00	$42.00	$174.00			$0.00			$0.00			$0.00	$174.00
Flowline Tie–ins	$105.50	$114.90	$220.40	$351.10	$318.30	$669.40	$143.80	$136.40	$280.20	$50.00	$42.00	$92.00	$11.50	$9.50	$21.00	$1,263.00
Water Tie–Ins w/ EVGSAU			$0.00	$503.70	$346.50	$850.20	$100.50	$134.50	$235.00	$85.20	$114.30	$199.50			$0.00	$1,284.70
WATERFLOOD TOTAL :	$1,016.15	$2,034.20	$3,050.35	$3,903.15	$4,413.00	$8,316.15	$1,680.00	$3,534.70	$5,214.70	$1,551.65	$2,152.35	$3,704.00	$4,063.15	$586.80	$4,649.95	$24,835.15

* ALL INVESTMENTS IN 1993 DOLLARS

TABLE 5

VACUUM GLORIETA EAST UNIT
DRILLING COST SUMMARY

DESCRIPTION	INJECTION WELL NOT CORED	INJECTION WELL NOT CORED WATER FLOW AREA	INJECTION WELL CORED	PRODUCER NOT CORED	PRODUCER CORED
Well Head	$7,000	$7,000	$7,000	$5,000	$5,000
Casing	$40,075	$78,615	$40,075	$40,075	$40,075
Tubing	$23,000	$23,000	$23,000	$12,000	$12,000
Downhole Equipment	$2,500	$2,500	$2,500	$9,700	$9,700
Other	$1,500	$1,500	$1,500	$1,500	$1,500
Total Drill & Complete Tangibles :	$74,075	$112,615	$74,075	$68,275	$68,275
Drilling Contractor – Footage & Daywork	$71,000	$74,150	$90,000	$71,000	$90,000
Drilling Mud, Mud Logging and Water	$16,700	$16,700	$16,700	$16,700	$16,700
Coring & Core Analysis	$0	$0	$74,420	$0	$74,420
Casing & Cementing	$24,000	$31,000	$24,000	$24,000	$24,000
Logging, Perforating, & Stimulation	$24,500	$24,500	$24,500	$32,000	$32,000
Trucking, Dirt Work, & Damages	$10,500	$10,500	$10,500	$10,500	$10,500
Completion Services	$26,000	$29,000	$26,000	$35,000	$35,000
Other Drilling Costs & Rental Equip.	$13,425	$13,435	$13,425	$13,425	$13,425
Total Drill & Complete Intangibles :	$186,125	$199,285	$279,545	$202,625	$296,045
Total Drill & Complete Cost	**$260,200**	**$311,900**	**$353,620**	**$270,900**	**$364,320**
Surface Equipment	$5,000	$5,000	$5,000	$74,000	$74,000
Total Well Cost	**$265,200**	**$316,900**	**$358,620**	**$344,900**	**$438,320**

TABLE 6

VACUUM GLORIETA EAST UNIT

ESTIMATED ANNUAL OPERATING COSTS
(1993 $$)

YEAR	WELL OPERATIONS: PRODUCERS OUTSIDE OF WATERFLOOD AREA COUNT	COST	PRODUCERS INSIDE OF WATERFLOOD AREA	COST	INJECTORS COUNT	COST	TOTAL WELL COST ($)	PURCHASED PRESSURIZED INJECTION WATER FROM EVGSAU VOLUME (BBLS)	COST ($)	TOTAL ANNUAL OPERATING COST ($)
1993	14	$252,000	57	$1,026,000	0	$0	$1,278,000	0	$0	$1,278,000
1994	14	$252,000	68	$1,224,000	15	$150,000	$1,626,000	0	$0	$1,626,000
1995	16	$288,000	66	$1,188,000	32	$320,000	$1,796,000	1,049,340	$94,441	$1,890,441
1996	16	$288,000	67	$1,206,000	48	$480,000	$1,974,000	4,428,705	$398,583	$2,372,583
1997	16	$288,000	68	$2,040,000	48	$480,000	$2,808,000	7,832,576	$704,932	$3,512,932
1998	16	$288,000	68	$2,040,000	48	$480,000	$2,808,000	11,278,403	$1,015,056	$3,823,056
1999	16	$288,000	68	$2,040,000	48	$480,000	$2,808,000	11,161,616	$1,004,545	$3,812,545
2000	16	$288,000	68	$2,040,000	48	$480,000	$2,808,000	10,882,782	$979,450	$3,787,450
2001	16	$288,000	68	$2,040,000	48	$480,000	$2,808,000	10,445,589	$940,103	$3,748,103
2002	16	$288,000	68	$2,040,000	48	$480,000	$2,808,000	10,076,200	$906,858	$3,714,858
2003	16	$288,000	68	$2,040,000	48	$480,000	$2,808,000	9,835,943	$885,235	$3,693,235
2004	16	$288,000	68	$2,040,000	48	$480,000	$2,808,000	9,546,937	$859,224	$3,667,224
2005	16	$288,000	68	$2,040,000	48	$480,000	$2,808,000	9,198,290	$827,846	$3,635,846
2006	16	$288,000	68	$2,040,000	48	$480,000	$2,808,000	8,979,287	$808,136	$3,616,136
2007	12	$216,000	68	$2,040,000	48	$480,000	$2,736,000	8,879,973	$799,198	$3,535,198
2008	8	$144,000	68	$2,040,000	48	$480,000	$2,664,000	8,831,244	$794,812	$3,458,812
2009	4	$72,000	68	$2,040,000	48	$480,000	$2,592,000	8,807,180	$792,646	$3,384,646
2010	0	$0	68	$2,040,000	48	$480,000	$2,520,000	8,795,706	$791,614	$3,311,614
2011	0	$0	66	$1,980,000	48	$480,000	$2,460,000	8,790,407	$791,137	$3,251,137
2012	0	$0	64	$1,920,000	48	$480,000	$2,400,000	8,788,344	$790,951	$3,190,951
2013	0	$0	62	$1,860,000	48	$480,000	$2,340,000	8,787,495	$790,875	$3,130,875
2014	0	$0	60	$1,800,000	48	$480,000	$2,280,000	8,787,495	$790,875	$3,070,875
2015	0	$0	58	$1,740,000	48	$480,000	$2,220,000	8,787,495	$790,875	$3,010,875
2016	0	$0	56	$1,680,000	48	$480,000	$2,160,000	8,787,495	$790,875	$2,950,875
2017	0	$0	54	$1,620,000	48	$480,000	$2,100,000	8,787,495	$790,875	$2,890,875
2018	0	$0	52	$1,560,000	48	$480,000	$2,040,000	8,787,495	$790,875	$2,830,875
2019	0	$0	50	$1,500,000	48	$480,000	$1,980,000	8,787,495	$790,875	$2,770,875
2020	0	$0	48	$1,440,000	48	$480,000	$1,920,000	8,787,495	$790,875	$2,710,875
TOTALS:		$4,392,000		$50,304,000		$12,470,000	$67,166,000	227,908,482	$20,511,763	$87,677,763

TABLE 7