A PROFILE CONTROL PROGRAM UTILIZED IN THE SACROC UNIT CO_2 INJECTION PROGRAM

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The Kelly Snyder field is located in Scurry County, Texas, as shown on Fig. 1. This field is one of the major oil reservoirs in the United States. After discovery in 1948, the field was produced by solution gas drive until 1954 when a recommendation by the Scurry Area Canyon Reef Operators' Committee was implemented. The recommendation was to install a centerline water injection program to restore and maintain reservoir pressure above the bubble point. In March 1953 the SACROC Unit was formed and the proposed injection program was started in September 1954. Although this water injection program worked quite well, SACROC owners continued to look for ways to further improve recovery from the reservoir. In 1968, after careful study of several possible miscible displacement processes, a SACROC reservoir engineering committee recommended a miscible carbon dioxide injection program for the Unit to increase the ultimate recovery from the reservoir.

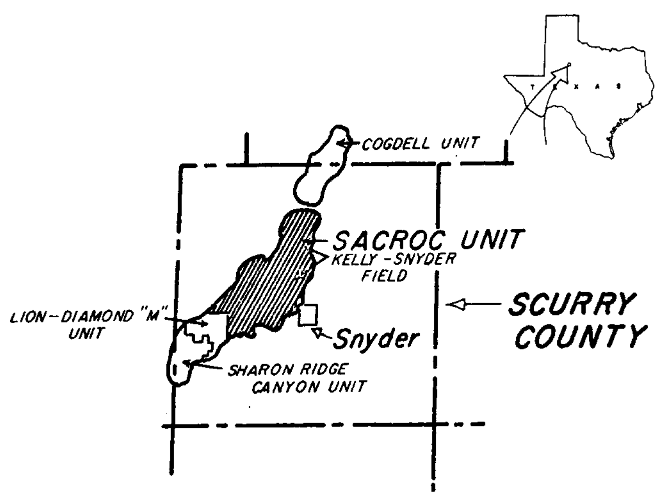

FIG 1—CANYON REEF FIELDS IN SCURRY COUNTY

The next three years were required to prepare for the carbon dioxide injection. The field was divided into 202 inverted nine-spot pattern areas and three phase areas which would be processed with CO_2 on a separate time schedule consistent with the CO_2 supply, as shown in Fig. 2. To commence injection it was necessary to install compression facilities and a CO_2 pipeline to transport 200,000 MCF/D of CO_2 from several extraction plants in the Val Verde Basin area of southwest Texas and to prepare the Phase I area for injection by installing a field injection system, exposing the entire reef in the producers, and preparing the pattern injectors for injection.

With the work completed, CO_2 injection began in January 1972. Downhole injection surveys were run frequently during the early life of the project, and poor profile coverage was discovered in many of the injectors. The problem became very critical when CO_2 breakthrough occurred during June 1972, more than a year before the CO_2 removal facilities were complete, requiring curtailment of production. It became evident that correction of these poor profiles was necessary to avoid cycling the expensive CO_2 and to avoid further production curtailments due to CO_2 breakthrough.

Since several methods are available for improving injection well profiles, the Unit Operator tested and evaluated several different methods. Open-hole packers were installed in several wells, but frequent failures occurred due to packer movement or CO_2 permeation of the packer rubber. Several types of polymer profile improvement jobs were performed with little success. The only control method which has proven to be consistently effective for controlling downhole injection profiles is the installation of a liner across the reef, followed by the installation of downhole flow control equipment.

Since the success of profile control equipment is dependent on the degree of stratification of the reservoir, two wells in the Phase II pattern were selected for tests to evaluate the liner and flow control equipment. Two Phase II wells were selected because CO_2 injection had not commenced in this Phase area and the complications of CO_2 breakthrough from surrounding injectors could be avoided in our evaluation. Location of the pattern areas for the two wells, SACROC Unite Well 37#2 and SACROC Unit Well 49#2, is shown on Fig. 2. This area is characterized by thick pay sections. SACROS Unit Well 37#2 has 601 gross feet of pay and SACROC Unite Well 49#2 has 496 feet.

After selection of the two test wells, workover operations were begun to install the liner and flow control equipment. Both wells were completed with 5-1/2 in. casing in 4-3/4 in. open hole, so underreaming was necessary in order to run liners of sufficient size to allow for downhole flow control equipment. Work started on SACROC Unit Well

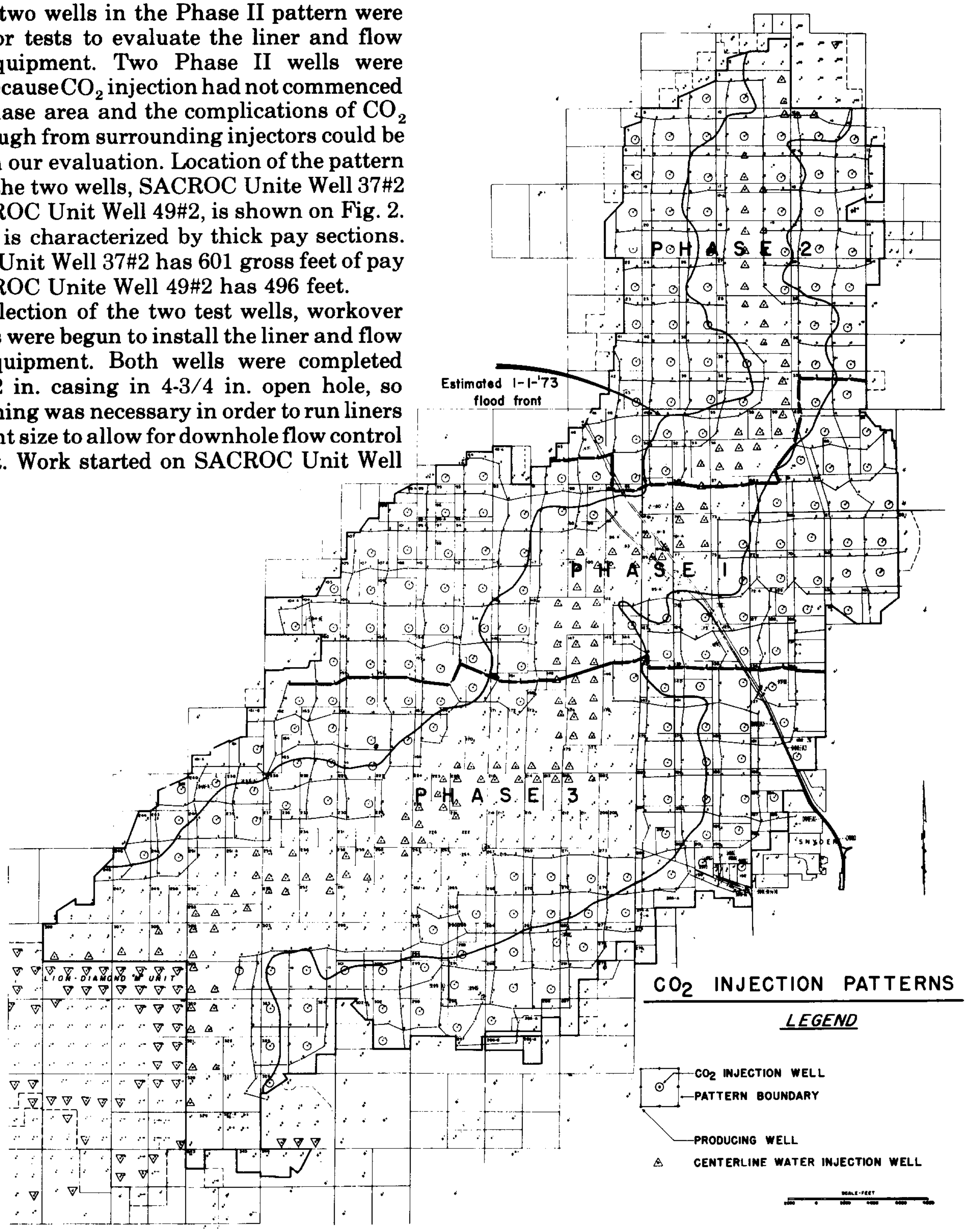

FIG. 2—CO_2 INJECTION PATTERNS, SACROC UNIT

37#2 in February 1973. Two-hundred eighty-seven feet of Canyon Reef limestone was underreamed from 4-3/4 in. to 6-1/8 in. hole in five days. Then 480 ft of 4-1/2 in., 10.23 lb/ft., FJ-40 liner was run and landed across the open-hole section. The liner, with no hanger or packoff equipment, was cemented with 55 sacks of Class "C" cement with 0.75% turbulence inducer. This cement did not circulate above the liner top and it was necessary to cement-squeeze the liner top with 75 sacks Class "C" cement with 0.75% turbulence inducer. After running a cement bond log, it was necessary to cement-squeeze twice more to improve the bond.

After the squeeze work was complete, 27 intervals totaling 359 ft were perforated with two jets per foot. The perforations were selectively treated with approximately 20 gal./ft of 20% hydrochloric acid. After each interval had been treated, the intervals were grouped between good permeability barriers according to the neutron log. Each group of intervals was swabbed and a bottomhole pressure buildup was run. The well was then placed on injection with one injection packer set above the pay interval. At the same time this work was being done on SACROC Unit Well 37#2, the same procedure was being followed in a workover on SACROC Unit Well 49#2. After completion of this work the wells were placed on alternating CO_2 and water injection.

The first downhole injection profiles on the two wells were run approximately three weeks after they were placed on injection. The profiles were run using two gamma counters to measure the velocity of radioactive material which was ejected in the well stream. The results of these two surveys are shown in Figs. 3 and 4. Although these profiles do not show extremely bad coverage, further profile improvement was justifiable due to the large hydrocarbon pore volumes of the patterns and high cost of the CO_2. Approximately four weeks after the first injection profiles were run, downhole flow control equipment was run in both wells.

The equipment which was run in SACROC Unit Well 37#2 consisted of five hydrostatic packers, four side pocket mandrels, and one seating nipple as shown in Fig. 5. The equipment run in SACROC Unit Well 49#2 is shown in Fig. 6. Hydrostatic packers were particularly suited to this application because they can be set and released without rotating. Three 5-1/2 in. and two 4-1/2 in. packers were necessary to separate the pay zone in SACROC Unit Well 37#2 into the five selected

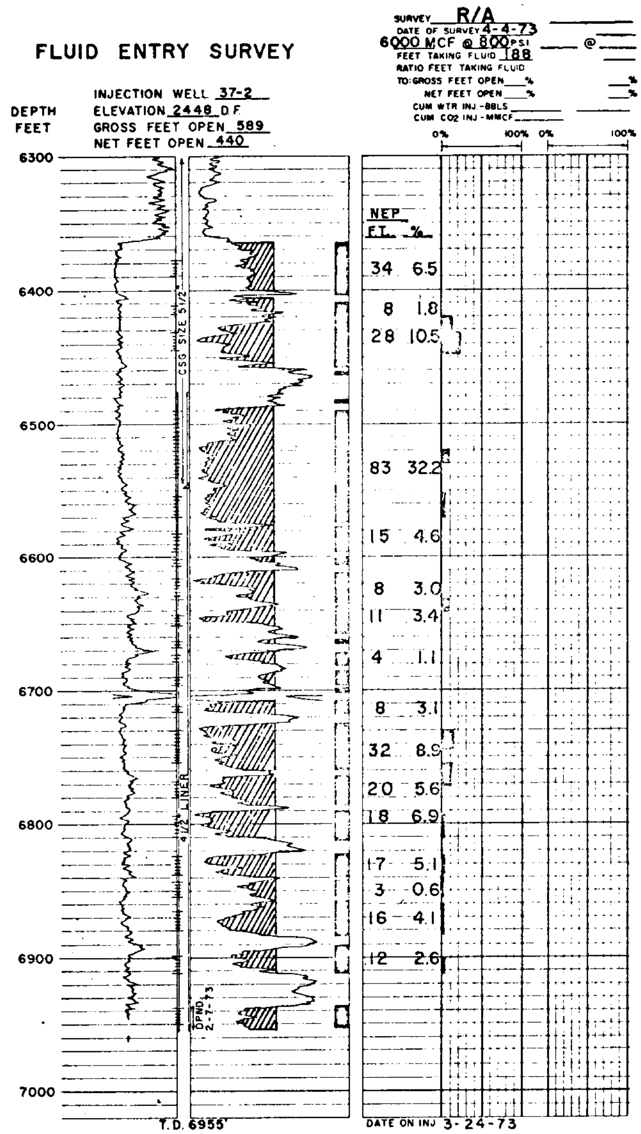

FIG. 3—FLUID ENTRY SURVEY

intervals. The side pocket mandrels used were of two sizes; two mandrels were landed inside the 5-1/2 in. casing, and two smaller mandrels were run in the 4-1/2 in. liner. Equalizing plugs were run in place in all four mandrels. All packers, mandrels, and the 2-3/8 in. spacer tubing were internally and externally plastic-coated. This flow control equipment was run into the well on 2-7/8 in. internally plastic-coated tubing. After the depth was checked with a wire line, a plug was set in the seating nipple and the packers were set by pressuring up on the tubing.

After the plugs were pulled, chokes were installed in the side pocket mandrels to obtain the optimum downhole injection profile. These chokes

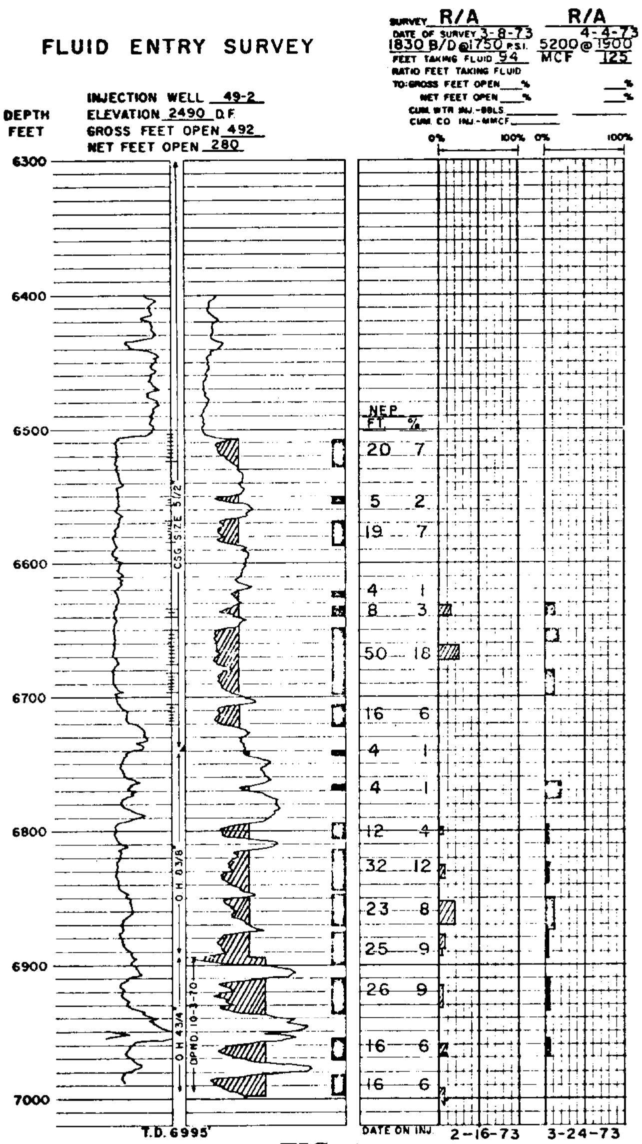

FIG. 4

latched into the side pocket mandrels and were fitted with disks which could be drilled to any size orifice desired up to 3/8-in. maximum. The choke sizes could be changed as the downhole injection profiles indicated by removing the chokes with a wireline unit and installing a different size choke.

Both test wells were placed on CO_2 injection immediately after the well work was complete. After injection of 1.5% of the pattern hydrocarbon pore volume, the wells were switched to water injection and were alternately switched after every 1.5% hydrocarbon pore volume of fluid type injection thereafter. Since the optimum injection profile required that 1.5% HCPV be injected into each zone of the well each cycle, it was often

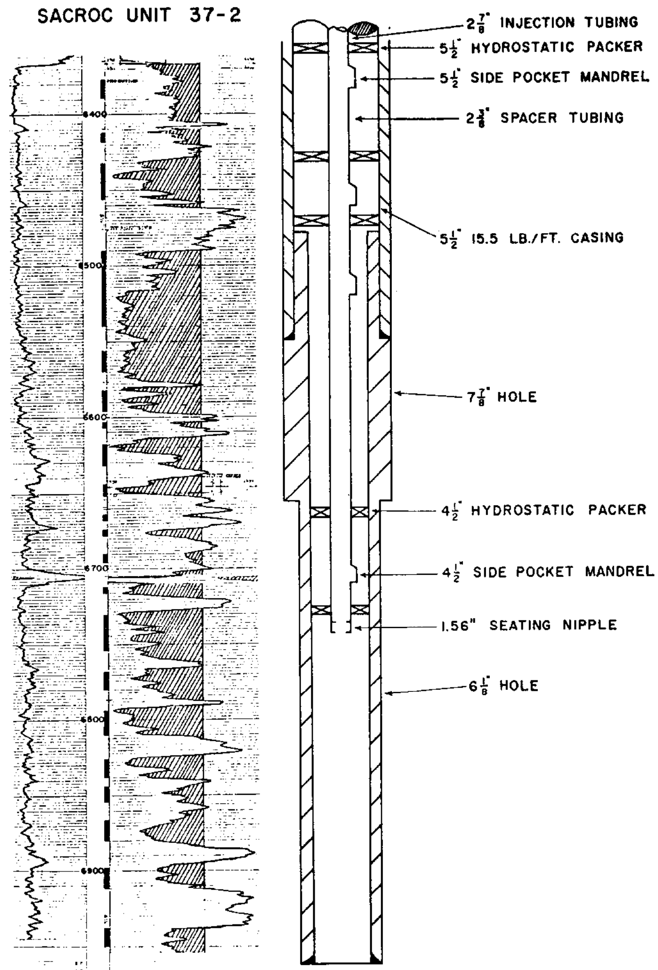

FIG. 5

necessary to plug one or more zones of the well near the end of a cycle to allow injection-deficient zones to catch up. This procedure also required an injection profile survey after every wireline job to evaluate the results of that wireline job.

The expense of frequent profiles and wireline operations was further increased by scale and corrosion problems. After 13 months' operation, the equipment was pulled out of SACROC Unit Well 37#2 to repair a leak in the 2-3/8 in. spacer tubing. Corrosion was noted on most downhole components and necessitated exchanging three of the packers and all side pocket mandrels. This corrosion is believed to be caused by the injection water, not the CO_2. After eighteen months of operation, SACROC Unit Well 49#2 had to be pulled to remove iron sulfide deposits which had accumulated on top of the seating nipple and would not allow the bottom choke to be changed.

Operating costs on the two wells have been very high, with each well costing approximately $1000

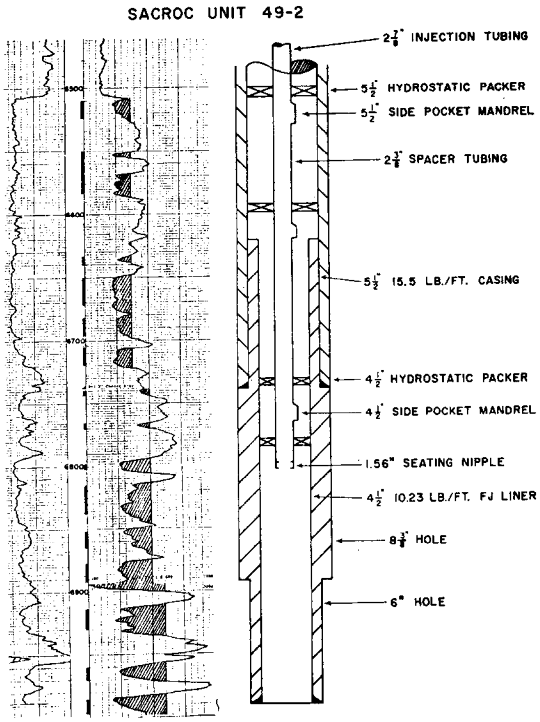

FIG. 6

per month to operate, not including the pulling jobs. These costs break down to $600 per month for the injection profile surveys, $360 per month for the wireline work on the side pocket mandrels, and $40 per month for work on the plugs and chokes.

Success of this type of profile control work must consider the results obtained from both the injection well and surrounding producers. Profile coverage at the well bore, as determined from the injection profile surveys, has improved since the installation of the downhole flow control equipment and based on the test results can be effectively managed. However, the cost for this control work is expensive and must be justified based on the results obtained from the producing wells. The first CO_2 breakthrough occurred in SACROC Unit Well 49#5, the west offset to SACROC Unit Well 49#2, approximately seven months after CO_2 injection began. Figure 7 shows how the CO_2 production was controlled initially by plugging Zone 3 in SACROC Unit Well 49#2. This control was no longer possible after two cycles, indicating either crossflow in the reservoir or breakthrough from another zone. CO_2 breakthrough has now occurred in five offset wells. The CO_2 cut on these wells has remained fairly low, with the highest cut recorded being 8% of the gas stream in SACROC Unit Well 55#3. The performance of these two pattern areas in terms of

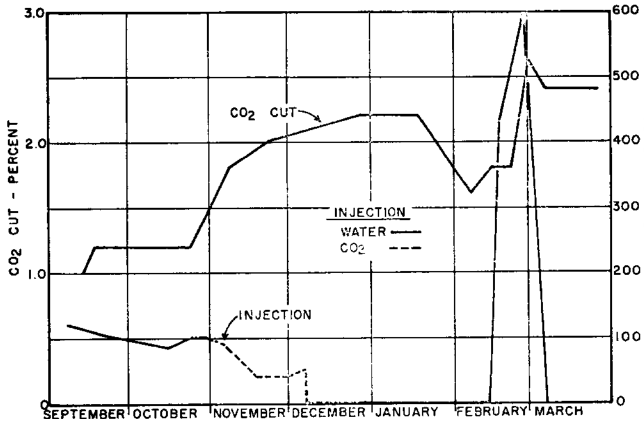

FIG. 7

the CO_2 production rates have been substantially better than the average pattern for the Phase I area to date without this type of control, as shown in Fig. 8. As a result of the apparent success in the two initial test wells, additional downhole flow control equipment has already been run in several injectors which are causing severe CO_2 breakthrough with the producing CO_2 cut being stabilized or reduced in most cases. Although the method does look very promising as a means of controlling the injection profile, final justification for this extensive control work must result in favorable economics. To date we do not believe sufficient producing data is available to fully evaluate the program. However, we do believe the results to date are sufficient to justify running of liners to assist in the control of injection fluids with limited downhole wireline choke control work. Such a program has been recommended by a SACROC Unit Engineering Study Group for the Phase II area. Figure 9 shows this recommended program.

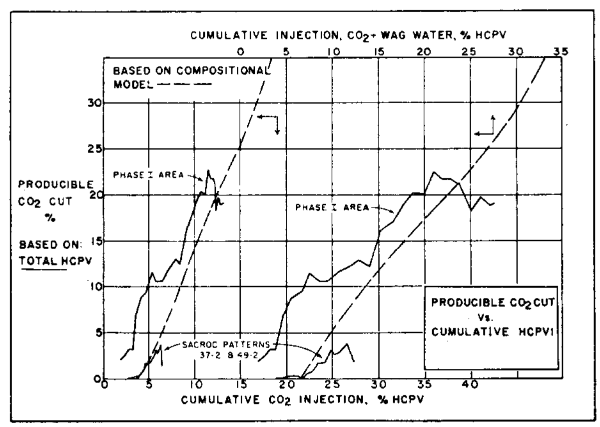

FIG. 8

PHASE II

INJECTION PROGRAM

1. INITIATE CO2 INJECTION IN OPEN HOLE.
2. CONTINUE WAG IN OPEN HOLE: ATTEMPT TO MAINTAIN ZONAL WAG RATIO IN RANGE OF 1/1 TO 3/1.
3. INJECT TO A ZONAL MAXIMUM OF 20% HCPV CO2 BASED ON THE SUB-PATTERN HCPV.
4. RUN LINER, SELECTIVELY PERFORATE TO OPTIMIZE PROFILE. CONTINUE WAG AND MONITOR PROFILE.
5. RUN DOWNHOLE ISOLATION EQUIPMENT TO OPTIMIZE PROFILE.
6. CONTINUE WAG AT 1/1 TO 3/1 RATIO TO MAXIMIZE THE CO2 VOLUME INJECTED INTO EACH ISOLATION INTERVAL ACCORDING TO GUIDELINES CURRENTLY BEING DEVELOPED BY THE COMPOSITIONAL SIMULATOR.

FIG. 9