Field Verification of CO₂-Foam

Annual Report

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ABSTRACT

The East Vacuum Grayburg/San Andres Unit (EVGSAU), operated by Phillips Petroleum Company, is the site selected for a comprehensive evaluation of the use of foam for improving the effectiveness of a CO₂ flood. The four-year project, jointly funded by the EVGSAU Working Interest Owners (WIO), the U.S. Department of Energy (DOE), and the State of New Mexico, began in late 1989. The Petroleum Recovery Research Center (PRRC), a division of the New Mexico Institute of Mining and Technology (NMIMT), is providing laboratory and research support for the project. A Joint Project Advisory Team (JPAT) composed of technical representatives from several major oil companies provides input, review, and guidance for the project.

This third annual report details various aspects of the CO₂-Foam Field Verification Pilot test at EVGSAU. The report presents: 1) an overview of the operating plan for the project, 2) details of the foam injection schedule and design criteria, 3) a discussion of the data collection program and performance criteria to be used in evaluating successful application of foam for mobility control in the EVGSAU CO₂ project, and 4) preliminary results from the field injection test.

Specific items discussed in the foam injection design include the determination of surfactant volume and concentration, selection of the surfactant-alternating-gas (SAG) injection sequence for foam generation, field facilities, operations during foam injection, and contingency plans. An extensive data collection program for the project is discussed including production testing, injection well pressure and rate monitoring, injection profiles, production well logging, observation well logging program, and both gas and water phase tracer programs.

OBJECTIVES

This project is a cooperative industry-university-government effort to transfer laboratory research technology to a field demonstration test. The primary goal of the project is to evaluate the use of foam for mobility control in a field-scale CO₂ flood.

The objectives of this project are to: 1) conduct reservoir studies, laboratory tests, simulation runs, and field tests to evaluate the use of foam for mobility control or fluid diversion in a New Mexico CO₂ flood, and 2) evaluate the concept of CO₂-foam in the field by using a reservoir where CO₂ flooding is ongoing, characterizing the reservoir, modeling the process, and verifying the effectiveness. Seven tasks were identified for the successful completion of this four-year project: 1) evaluate and select a field site, 2) develop an initial site-specific plan, 3) conduct laboratory CO₂-foam mobility tests, 4) perform reservoir simulations, 5) design the foam slug, 6) implement a field test, and 7) evaluate results.

INTRODUCTION

The EVGSAU, located about 15 miles northwest of Hobbs in Lea County is the site of the first full-scale miscible carbon dioxide injection project in the state of New Mexico. Table 1 lists EVGSAU reservoir and fluid characteristics¹. CO₂ injection at EVGSAU began in September, 1985. The CO₂ project area covers 5000 acres developed using an 80-acre inverted nine-spot flood pattern. The total CO₂ injection rate is about 30 MMcf/D. A water-alternating-gas (WAG) ratio of 2:1 (time basis) is used in the project, resulting in about one-third of the project area being on CO₂ injection at any one time. In any given area, a WAG cycle consists of about four months of CO₂ injection followed by eight months of water injection. This results in approximately 1.5 to 2% hydrocarbon pore volume (HCPV) CO₂

injection and 3 to 4% HCPV brine injection per WAG cycle. The project is currently in the seventh WAG cycle. The tertiary oil response at EVGSAU to date has been very favorable. As shown in Fig. 1, the waterflood decline established prior to CO₂ injection has been arrested, and oil production for the Unit has held approximately constant near the current 9000 BOPD over the past six years.

While the overall project performance has been very encouraging, certain wells/patterns have shown anomalously high CO₂ production. This has resulted in isolated cases of poor pattern sweep efficiency, inefficient CO₂ utilization, and increased recycling costs and compression requirements. The CO₂ Foam Field Verification Pilot was designed to evaluate the application of foam mobility control technology for controlling the excessive CO₂ production problems in a field-scale CO₂ flood project.

SUMMARY OF PRIOR PROGRESS

SITE SELECTION AND CHARACTERIZATION

Details of the progress achieved during the first two years of this project are contained in prior annual reports.^{2,3} Following is a summary of that progress. During the first year of the project, the Petroleum Recovery Research Center (PRRC) identified the East Vacuum Grayburg/San Andres Unit (EVGSAU), operated by Phillips Petroleum Company (PPCo), as appropriate for the proposed work. Representatives from the PRRC and PPCo prepared an initial site-specific plan for the proposed work at the EVGSAU, which was approved by the EVGSAU Working Interest Owners (WIO) in June 1990. A Joint Project Advisory Team (JPAT), representing several of the EVGSAU WIO companies, serves as a technical steering committee that acts in an advisory capacity.

A pattern in the EVGSAU CO₂ flood was selected to test the efficacy of using surfactant-generated foam to reduce CO₂ mobility. The location of the pattern selected for the foam pilot test is shown in Fig. 2. This pattern was selected for the field trial based on the following criteria:

- 1) the pattern has shown excessive CO₂ breakthrough in one of the production wells (3332-032); the remainder of the wells in the pattern have shown more typical CO₂ response.
- 2) the reservoir geology in the pattern area is representative of most of the EVGSAU reservoir to allow results from the pilot to be scaled up to the entire Unit;
- 3) the injection well in the pattern (3332-001) has sufficient injectivity to reduce the chance of the well becoming pressure-limited during foam injection.

An observation well was drilled to improve reservoir characterization in the pattern area, to serve as an observation well, and to provide core material for laboratory tests. The location of the observation well (3332-003) in the pilot pattern, about 150 feet from the WAG injector, is shown in Fig. 2. This well was sponge cored to provide current oil saturation information, as well as additional details on the reservoir geology in the pattern area.

A geological characterization of the pilot area and surrounding patterns was assembled for the history matching and reservoir simulation studies that are in progress. The EVGSAU produces primarily from the San Andres Formation. At EVGSAU, the San Andres can be divided into upper and lower sections by the Lovington sandstone/siltstone. The San Andres sections consist of a series of shallowing-upward carbonate sequences, each typically 20 to 30 feet thick, which have been extensively

dolomitized. Total gross reservoir thickness ranges from 200 to 300 feet. A geologic study of the EVGSAU reservoir identified twelve zones which are laterally continuous across the foam pilot area (Fig. 3). Zone C (shown subdivided into C1, C2, and C3 on the type log in Fig. 3) is the major flow unit within the pilot area. Zones D and E show good porosity development and high oil saturation, but are less permeable and take only a small fraction of the fluid injected into this pattern. The A and B zones show little or no reservoir potential in this area, while the zones below the Lovington have good porosity and permeability, but have high water saturation in the pilot area. Falloff tests from most of the EVGSAU injection wells show an extended period of linear flow behavior, which is interpreted as fracture flow in the reservoir. However, the excessive CO₂ breakthrough problems do not appear to be simply the result of direct fracture communication between injectors and producers.

Within the foam pilot pattern area, the zones designated as C2 and C3 (Fig. 3) contain intervals with very high permeability. For example, a five-foot interval in Zone C2 from the observation well core averages almost 250 millidarcies. Oil saturations obtained from the sponge core in this interval were consistently less than 5% PV, indicating they had probably been contacted by a large volume of CO₂. Injection profiles taken in the WAG injector show almost two-thirds of the injected fluids entering Zone C2 and the lower portion of Zone C3. In contrast, Zone E, which shows high porosity and good oil saturation, is indicated to be taking less than 5% of the injected fluid. One of the primary objectives of the foam injection is to divert a larger percentage of the injected CO₂ into these lower permeability zones which are not being efficiently processed in the current WAG operation.

The production history for the foam injection pilot pattern is shown in Fig. 4. Note that the pattern gas production increased sharply in early 1987 when Well 3332-032, a side producer in the nine-spot pattern (shown in Fig. 2, located to the southwest of the injection well), began to flow spontaneously in

response to CO₂ injection. This producer had previously been open to production, however it was not being pumped because of excessive WOR during the pre-CO₂ waterflood period. Since 1987, the 3332-032 well has been capable of flowing following each CO₂ injection cycle. Although this well has not received any special monitoring during the CO₂ flood prior to initiating the foam project, production records indicate the apparent time lag between the beginning of the CO₂ injection half-cycle and the increase in gas-oil ratio (GOR) in Well 3332-032 has varied from about 6 to 14 weeks. CO₂ production rates from Well 3332-032 at the end of the past two CO₂ injection half-cycles have been 25-30% of the average CO₂ injection rate into the pattern injector (Well 3332-001). Favorable changes in the CO₂ production response characteristics in Well 3332-032 will be an important indicator of successful foam treatment in this pattern.

SURFACTANT SELECTION

Surfactant System Design

Several significant issues arose during the initial project design discussions. The first was whether the objective of the foam project should be directed toward near-well fluid diversion or more in-depth mobility control throughout the pattern. Preliminary laboratory data indicated surfactant adsorption would be in the range of 600 to 1800 pounds of active surfactant adsorbed per acre-foot of bulk formation volume contacted. Based on economic considerations, it was decided to design the project primarily for near-well fluid diversion using a smaller (approximately 1% HCPV), higher surfactant concentration foam slug rather than attempt to control mobility throughout the pattern using a larger volume slug with a lower surfactant concentration.

During the second year of the project, sufficient laboratory data were collected to enable the selection of a commercial surfactant for the field test.³⁻⁶ Three criteria were used in our surfactant selection process: 1) the effectiveness of the surfactant in reducing CO₂ mobility in coreflood experiments, 2) the amount of surfactant lost to adsorption onto the reservoir rock, and 3) the ability of the surfactant to stabilize aqueous-phase bubble films or foam lamellae in dense CO₂ at reservoir conditions. The principal goal of this work is to select the surfactant and the concentration of that surfactant to be used in the field tests. From an evaluation of all the results collected for this project, surfactant cost data, and other factors such as surfactant handleability, a consensus of the JPAT representatives favored the selection of Chevron Chaser CD-1045® for the field test at EVGSAU. While there was some difference of opinion regarding optimum surfactant concentration, the JPAT representatives agreed that 2500 ppm CD-1045® should be used for both a pre-foam pad to satisfy surfactant adsorption in the reservoir as well as for the surfactant solution used during a surfactant-altering-gas (SAG) cycle of the field test.

The initial project design called for an 80% quality foam to be injected during the first half of a CO₂ injection cycle in the normal WAG process, followed by straight CO₂ injection for the remainder of the CO₂ portion of that WAG cycle. The objective was to fit the foam injection into the normal WAG cycle rotation in the pattern as much as possible so that any changes in pattern performance due to non-foam, operational changes would be minimized. During a normal CO₂ WAG half-cycle in this pattern, the limiting injection rate of 1000 RB/D results in approximately 2% pattern HCPV of CO₂ being injected per WAG cycle. Thus, a nominal 1% HCPV foam slug was selected. This size foam slug was considered to be large enough to reduce the probability that the project would fail or yield inconclusive results due to insufficient quantity of chemical being injected (allowing for dilution, out of zone injection, surfactant adsorption, etc. being larger than anticipated). The selection of 80% foam quality was based

on the successful laboratory results obtained at PRRC using this quality. Again, it was not the purpose of this field trial to attempt to economically optimize the foam process, but rather to prove the technology in a field application.

PROGRESS DURING THE CURRENT YEAR

Results of laboratory work leading to the selection of a specific foaming surfactant for application at EVGSAU and additional background on the project were presented⁷ at the SPE/DOE Eighth Symposium on EOR in April 1992. A second paper⁸ outlining the field operating plans, design criteria, foam injection schedule, data collection program, and performance criteria was presented at the 1992 SPE Annual Technical Conference and Exhibition.

LABORATORY RESULTS

Additional adsorption tests with Chevron Chaser CD-1045[®] were conducted to help in designing the foam process. These data were used in determining the size of the surfactant prepad slug. Tests were conducted for one cycle adsorption-desorption, for two cycles of adsorption-desorption, and for three cycles of adsorption-desorption. The core tests were done by the flow-through method and surfactant concentration of the effluent from the core was measured indirectly by using the refractometer. A standard solution of 1000 ppm or 2500 ppm CD-1045[®] was flowed through the core until the effluent concentration reached the injected solution concentration (adsorption curve was determined). Then, the core was flushed with the brine until the zero surfactant concentration in the effluent was reached (desorption curve was determined). Based on a mass balance, the amounts of adsorption and desorption and the amount of surfactant retained were determined (see Table 2). Experimental results show that the

adsorption value does not change substantially by changing the injection fluid concentration from 1000 ppm to 2500 ppm CD-1045®. This is probably because these concentrations are above the critical micelle concentration (CMC) of CD-1045®, which is between 600 and 700 ppm at the reservoir temperature of 101°F. Generally, the amount of surfactant adsorption on the rock increases as the concentration increases up to the CMC point, but climbs much less rapidly above the CMC point for most surfactants.

The results show that most of the surfactant was retained during the first cycle of the adsorption-desorption process and that smaller levels of retention were observed from repeated cycles. The degree of retention changed from core to core, but the data in Table 2 gave a basis for determining the size of the prepad slugs. The data show that it might be reasonable to reduce the size of the subsequent prepad slugs following the initial prepad to about 50% of the first prepad.

FOAM SLUG DESIGN

Another issue debated during project design planning was the method of injecting the foam slug, i.e., coinjection of surfactant and CO₂ vs. alternate injection of slugs of surfactant and CO₂ (SAG). Consideration was given to the degree of mixing in the tubulars vs. that occurring during flow in the formation, possible gravity segregation of fluids over the injection interval, differential surface injection pressures of CO₂ vs. surfactant solution, possible use of downhole mixers, loss of injectivity, etc.

Although the laboratory results indicated that simultaneous injection of surfactant solution and CO₂ was desirable, operational problems were anticipated with co-injection in that line pressure varies considerably between water and CO₂. Thus, a rapid SAG injection mode was selected that is expected to closely approach the benefits achieved by simultaneous injection. This rapid SAG process involves

a three-day cycle of water (3000 RB) followed by a twelve-day cycle of CO₂ (12,000 RB) to give an approximate 80% quality foam. The three- and twelve-day cycles were selected over a more rapid cycle because this schedule can be maintained throughout the project. Because the mechanical characteristics of a SAG may cause changes in injection pressure, a baseline period of a rapid WAG was performed.

Based on average pattern properties, a 1% HCPV foam slug would occupy a cylindrical volume around the injection well with a radius of about 100 feet. However, considering (1) the geologic description of the pattern, (2) saturation, porosity, and permeability data obtained from the observation well sponge core (located about 150 feet from the injection well), (3) the injection profile in the foam injector, and (4) estimates of the probable geometry of a high permeability zone (based on production response and geologic data), and not making any allowance for adsorption - induced delay, surfactant could be expected to propagate several hundred feet away from the injection well in a high permeability zone during the surfactant injection period.

At the design surfactant concentration of 2500 ppm, the average surfactant adsorption measured in coreflood tests was approximately 835 pounds per acre-foot. The sacrificial surfactant pad is designed to satisfy this level of surfactant adsorption in the reservoir volume to be occupied by the 1% HCPV foam slug. The design called for approximately 90,000 pounds of active surfactant to be injected in the sacrificial adsorption slug during the three month period immediately preceding injection of the foam slug. The total surfactant required for the project design (adsorption slug plus foam slug) was about 105,000 pounds of active surfactant. Thus, about 85% of the total surfactant to be injected during the project was needed to satisfy adsorption. Reservoir simulation of the foam pattern will be conducted to further refine these initial estimates of foam propagation.

OPERATING PLAN

A formal project schedule and detailed operating procedures were developed in a series of open discussions at JPAT project meetings. A meeting of the JPAT was held in Hobbs, NM on April 8, 1992, to finalize plans for the surfactant injection program and to approve contingency plans for responding to a number of operational scenarios. Prior to the initiation of the rapid SAG cycle, a meeting of the JPAT was held in Houston, TX on July 7, 1992, to review results obtained during the surfactant prepad injection and to finalize plans for foam generation.

Project Schedule

The final operating plan is necessarily a compromise between the desire to conduct a controlled experiment in the field and the need to mesh the foam project operations into the ongoing WAG operations of a full-field CO₂ flood project at EVGSAU. The resulting project schedule is shown as Fig. 5.

The project schedule can be characterized in three phases: 1) an extensive pre-foam pattern conditioning and data gathering period, 2) the foam injection period, and 3) a production monitoring period. DOE sponsorship of the "Field Verification of CO₂ Foam" project (DOE Grant No. DE-FG21-89MC26031) covers a four-year project period. Actual field operations extend over a 3-year period with the first year dedicated to sampling, coring, surfactant selection, and foam pattern conditioning; the second year being slated for surfactant injection (with the possibility of more than one foam generation cycle, depending on project funding and reservoir response); and the third year concentrating on production monitoring and evaluation of foam performance.

Monitoring and Project Evaluation

The collection of pre-foam baseline data is important for the subsequent evaluation of performance of the CO₂-foam test. These data include well injectivity, injection profiles, CO₂ breakthrough in producers, pressure transient tests, interwell tracers, and production well testing of the eight wells in the pattern area collected on a weekly basis. The rapid WAG cycle was started in September 1991 and was completed in December 1991, followed by the three-month CO₂ injection cycle. At that time, the baseline testing was completed.

Several methods will be used to verify successful development of mobility control and/or fluid diversion with the surfactant foam system:

- 1) Injectivity response in the foam pattern injection well will be carefully monitored by measuring injection rates and pressures and by monitoring any changes in the injection profile;
- 2) Pressure falloff tests will be run to monitor wellbore condition (skin) and to attempt to measure changes in the in-situ fluid mobility;
- 3) Time sequence logging runs will be made through fiberglass casing in the observation well to monitor changes in reservoir fluid flow or fluid distribution;
- 4) Production characteristics of the "offending" well (3332-032) in the pattern will be closely monitored for changes in GOR and oil production response after injection of the foam slug;

- 5) Water phase and gas phase tracers will be injected both during the baseline cycle and the foam injection cycle to observe changes in fluid flow patterns.

Surface Facilities and Equipment

Surface facilities for foam injection are fairly simple and required no changes to the existing injection meter run. A schematic of the facilities is shown in Fig. 6. In the future, since the surface facilities needed to handle the surfactant are fairly simple, it is anticipated that all of this equipment could be truck- or trailer-mounted to facilitate individual well treatments.

Surfactant is delivered in bulk 5500 gallon (131 bbl) lots via a tanker truck. Since enough storage capacity is needed on location to handle a new shipment without being critically low on surfactant, a standard 210-bbl fiberglass tank was selected. The tank is connected via 1-inch tubing through a strainer to a variable stroke length Bran-Lubbe injection pump. This pump was selected for its ability to change injection rate easily, as it was anticipated that the surfactant injection rate might need to be reduced during the foam generation period. Since the surfactant injection period during foam generation SAG cycles is only three days, a manual control on the pump was considered to be adequate for maintaining a steady surfactant concentration (versus automating the pump with a rate controller). The pump is connected to the existing injection line with 1/2-inch stainless steel tubing to a port downstream of the injection meter and pressure transducer. Thus, the injection meter measures only the injection water and not the combination of surfactant and water.

Each tanker truck shipment of surfactant had a quality control certificate issued by the manufacturer upon loading to document the chemical's content, activity, and specific gravity. In addition, routine

quality control checks were made on the delivered product by the operator prior to injection. There was some concern that the viscous (approximately 200 cp.) surfactant would not mix adequately with the injection brine in the 35 feet of 2-inch injection line upstream of the wellhead sampling point, and an in-line mixer might be needed. However, the surfactant concentration measured on multiple samples taken at the injection wellhead during the first few weeks of injection were consistent and the samples were clear and uniform, indicating no significant problems with mixing. Based on these sampling results it was concluded that an in-line mixer was not needed.

Injection Schedule

The project schedule (Fig. 5) called for injection of the foam slug to begin in mid-July, 1992. The nominal 1% HCPV, 80% quality foam slug was to be injected using a rapid SAG (surfactant-alternating-gas) injection scheme of five SAG cycles with 12,000 res. bbls. CO₂ and 3000 res. bbls. of 2500 ppm active surfactant in injection brine for each SAG cycle. At the historical limiting injection rates of 1000 RB/D, this would be a SAG cycle of 12-days on CO₂, followed by 3-days of surfactant solution. The foam slug would then be followed by straight CO₂ injection for the remainder of the normal CO₂ half-cycle in the fieldwide WAG operation. The decision on when to switch back to the brine injection half-cycle would be dictated by the response to foam injection.

Use of the rapid SAG process for injection of the foam slug raised the concern that even without any surfactant addition or foam generation, the change in normal WAG cycle operations might produce a change in pattern flood behavior, thus complicating interpretation of the pilot results. To reduce this possible complication, the project design was expanded to include a "baseline" WAG cycle prior to the

surfactant foam injection cycle. During the baseline cycle, all operations were conducted and monitored exactly as planned for the foam injection cycle, except no surfactant was injected.

The baseline CO₂ injection cycle began on September 25, 1991 with the injection of a series of five rapid WAG cycles. Each cycle consisted of 12 days on CO₂ and 3 days on water at 1000 RB/D for each fluid. The rapid WAG was followed by straight CO₂ injection from December 10, 1991 to February 28, 1992. Following injection profiles and falloff testing, brine injection was resumed March 14, 1992 (Fig. 7) in preparation for the field foam test.

Contingency Plans

In view of the problems inherent in implementing any emerging technology in a field application, it was clear that a key element of the operating plan had to be operational flexibility. While it is not possible to anticipate and prepare for all possibilities, the JPAT members and the Operator did identify several potential problem areas.

Injectivity Reduction

It was anticipated that injectivity would be reduced, perhaps dramatically, if a strong foam was generated near the injection well. Interpretation of the test response would be much easier if a constant injection rate could be maintained throughout all phases of the project. The injection well in the foam pattern had been injecting water at the limiting rate of 1000 RB/D at a surface injection pressure of 600-750 psi. The maximum surface injection pressures allowed at EVGSAU are 1350 psi for water injection and 1800 psi for CO₂ injection (per New Mexico Oil Conservation Division regulations).

Recent step rate tests conducted in this area of the field indicate that the formation parting pressure is above these limits. Project operations would attempt to hold the injection rate constant at 1000 RB/D, while allowing the surface injection pressure to rise to the field limits. If injectivity declines further, it would be necessary to let the injection rate decline.

As discussed later in the section on the Data Collection Program, multiple injection profiles were run during the SAG injection phase to help evaluate the injection rate and pressure response. The period of rapid SAG would continue for five cycles or until the injectivity declines to the point that the rate must be cut back to 250 RB/D. At this point the SAG injection would be terminated and immediately followed with a period of CO₂ injection until a total volume of CO₂ equal to the pre-foam CO₂ volume has been injected. Since the CO₂ injection rate would probably be reduced as a result of foam generation, it was not possible to specify an exact time period for this CO₂ injection. Injection of an equal volume of CO₂ in the WAG cycles both before and after foam generation would result in a better comparison of production response in the foam pattern.

Adsorption Slug Surfactant Breakthrough

The exact quantity of surfactant needed to satisfy adsorption is uncertain due to the fact there is a large range in the laboratory measurements of adsorption, and the flow paths in the foam pattern are not known. If the injected surfactant is confined to a small channel directed toward the offending well (EVGSAU 3332-032), then it might be possible for the large pre-foam surfactant slug to propagate to the offending producer. It was decided to inject the adsorption surfactant until either it was produced from the offending well, indicating that adsorption had been satisfied over the complete length of the high permeability flow channel, or for the three-month period needed to satisfy adsorption requirements of the

1% HCPV foam slug to follow. This would introduce enough surfactant to allow foam to be generated at depth in the reservoir.

In the event that surfactant is propagated through the reservoir and foam generation occurs in the production separators, a de-foamer would be injected downstream of the wellhead that will allow the de-foamer to work in the flowline prior to reaching the separation facilities. We did not plan to inject any de-foamer into the injection well; however, it is available as a last resort if total injectivity is lost.

Laboratory testing was conducted to determine if any emulsification problems could arise in the producing facilities, and an appropriate de-emulsifier would be available, if needed. The weekly water samples will aid in forecasting emulsion problems as well as determining if/when surfactant may have propagated through the reservoir to the producing well(s).

DATA COLLECTION PROGRAM

The CO₂ Foam Field Verification Project will focus on two main questions: 1) is a foam generated in situ which effectively reduces the mobility of injected CO₂, and 2) is the foam effective in producing an improvement in the pattern sweep efficiency and/or production performance? An effort will be made to estimate the amount of incremental oil which may ultimately be produced as a result of foam injection. This will be difficult, but it is important to assess the economic potential of foam for future applications. The following outlines the program of data collection and analyses for monitoring and evaluation of the foam injection project.

Injection Well Tests

Rate and pressure data are taken once a day on the foam pattern injection well (3332-001). During surfactant injection, a wellhead injection pressure recorder was installed to monitor pressure continuously. An increase in injection pressure is probably the most important indication that foam is forming downhole. The baseline CO₂ injection half-cycle ended when Well 3332-001 was shut in for a falloff test in early March, 1992. The well went back on water injection March 14, 1992. Surface injection pressure built up to about 750 psi. This is about 150 psi above the injection pressure at the end of the baseline water injection half-cycle prior to the rapid WAG and baseline CO₂ injection.

An injection profile is run in Well 3332-001 at the end of each cycle of injection, with more frequent profiles run during the foam generation period, as indicated on the Project Schedule (Fig. 5). The injection profiles are used to detect any significant changes in the intervals taking injection fluids. The profile is developed from a log of temperature, tracer intensities, velocities and casing caliper.

Falloff tests were conducted to provide data on effective formation properties and wellbore condition (skin) during the foam project. It was also hoped that falloff tests would provide a direct measurement of fluid mobility changes in the reservoir as a result of foam injection. As indicated in the project schedule, two falloffs were performed prior to foam injection and one is planned after injection of the foam slug.

Pattern Production

The eight wells in the foam pattern (Fig. 3) are production tested once a week. Testing began on a weekly basis in February 1991, more than a year before foam injection began. While the pattern production performance may be one of the most important criteria in evaluating success, it is also one of the most difficult to measure consistently and accurately over the life of the project. Normal operations are maintained in the eight foam pattern producers as much as possible, however some production swings have occurred due to routine equipment change outs in some wells.

Fig. 4 shows the foam pattern production history. A reduction in producing GOR vs. CO₂ injection is expected to be one of the first positive indications that the foam injection has succeeded in altering CO₂ mobility and flow patterns in the reservoir. Well 3332-032 has shown the greatest CO₂ production in this pattern and is expected to show the first changes in GOR behavior if the foam treatment is successful.

Flowing production logs are run at the end of each injection cycle in the "offending" well (3332-032), as indicated in the Project Schedule (Fig. 5). The production log consists of flowing temperature, one-hour decay temperature, two-hour decay temperature, crossflow checks, radioactive tracer, flowing capacitance, and shut-in capacitance. An indication of successful foam performance would be increased production from less prolific zones in the offending well that are not now contributing very much due to the high pressure and large volume of gas produced from the high permeability zones (Zone C2 and the lower portion of Zone C3), as shown in Fig. 8. About 60% of the produced fluids are indicated to be coming out of these zones so the production log profile is very similar to the injection tracer survey.

Observation Well Logging

An observation well (3332-003) was drilled about 150 feet west of the foam pattern injection well (Fig. 2). The following log suite was run in the observation well at the time it was completed:

Open Hole:

Compensated neutron/density log

Induction log

Sonic log

Dual laterolog

Repeat formation tester

Cased Hole:

Compensated neutron log

Cement evaluation log

Induction log

Pulsed neutron capture log

At the end of each injection cycle an induction log and a compensated neutron log are run to check for saturation changes. During the rapid WAG and CO₂ injection in the baseline cycle (prior to any surfactant injection), observation well logging runs indicated changes in water and gas saturations in response to the injection into Well 3332-001 (Fig. 9). As a result, the scheduled frequency of logging in the observation well was increased during the foam injection SAG period as indicated in the Project Schedule (Fig. 5). It is hoped that foam injection will produce measurable changes in the timing, magnitude, and/or location of saturation changes at the observation well, which can then be related to

changes in flow patterns and sweep efficiency. Fig. 9 shows results of a series of logging runs made in the observation well during the baseline cycle. These logs indicate that the largest saturation changes are occurring in the same high permeability zones where the maximum fluid injection and production are seen in Wells 3332-001 and 3332-032, respectively.

Interwell Tracers and Fluid Sampling

An interwell tracer program was designed to show any changes in fluid transit times from the injector to the producers as a result of foam generation. Tracers were injected in early December 1991 after the rapid WAG portion of the baseline cycle. The two tracers injected were Krypton 95 (one curie) in the gas phase and Tritium (nine curies) in the water phase. An additional tracer of 0.15 curies of Cobalt 60 was injected in the water phase just prior to the start of the adsorption slug of surfactant in mid-April 1992. If the surfactant does propagate through the reservoir, the difference in arrival times between the non-adsorbing radioactive tracer (Co-60) and the surfactant may help quantify surfactant adsorption in the reservoir.

Gas samples are collected from the two side producers in the foam pattern that have shown the most rapid and severe CO₂ breakthrough problems. Produced gas samples are taken daily for five weeks, twice per week for about three months, and weekly thereafter. Water samples are taken from all eight pattern producers on the same frequency. Results from these tracers will be compared to a similar set of tracers to be injected after the rapid SAG portion of the foam injection cycle.

Water samples are being taken at the injection wellhead to monitor the surfactant concentration in the injection brine. Produced water samples are being taken on a weekly basis from the offending well

(3332-032), specifically for the purpose of analyzing for the presence of surfactant. If surfactant is detected, then more frequent sampling will be done to monitor the produced surfactant concentration vs. time. This information will aid in predicting and combatting emulsion and foaming problems in the surface equipment. In addition, the water samples being taken from the other seven pattern production wells for tracer analysis are being saved, and would be available for analysis for surfactant content in the event that surfactant breakthrough was suspected.

RESULTS OF THE FIELD TEST

Injection Well Results

The pre-foam surfactant pad injection was started in April 14, 1992 and completed on July 14, 1992. The injected surfactant concentration was maintained close to the design of 2500 ppm. Injection well profile tests indicate that the surfactant solution was leaving the wellbore in the higher permeability zones that had previously received water only. A typical injection well profile for Well 3332-001 is shown in Fig. 8. Approximately 65% of the injected fluid is entering Zone C2 and the lower portion of Zone C3, which are the higher permeability zones at EVGSAU. This distribution of injected fluids is consistent with the permeability distribution obtained from analysis of the reservoir core taken from the observation well located 150 ft from the injector. Fig. 7 shows the injection well performance through the baseline period and into the injection of the pre-pad surfactant solution. These data suggest that the rapid WAG may have reduced the mobility of water slightly, but no significant changes in pressure were observed after initiation of the surfactant solution.

Following the three months of pre-foam surfactant pad, water was injected for three days to displace the surfactant solution from the immediate vicinity of the wellbore. On July 17, 1992, the rapid SAG cycle began.

Injection rates and pressures were monitored daily at the pattern injector (Well 3332-001). Fig. 10 shows the injection well performance from the baseline period through the surfactant adsorption slug and into the rapid SAG cycle. At the injection rate of 1000 BWPD, wellhead pressure typically increases when the injection is switched from water to CO₂. This behavior is quite evident during the rapid WAG cycle. The higher injection pressures during the rapid SAG cycle is attributed to in-situ foam generation. An expanded plot of the rate and pressure data for the rapid SAG cycle is shown in Fig. 11. At the completion of the rapid SAG cycle, the surface pressures will be converted to bottomhole conditions so that injectivities and Hall Plots can be used to monitor results of the test.

Several injection profiles were obtained in the rapid SAG cycle during both CO₂ and surfactant solution injection. These profiles suggest that all fluids are continuing to enter the higher permeability zones although a slight decrease (10-15%) has occurred in the highest permeability "C" Zone.

Production Well and Observation Well Performance

Production from the eight wells in the foam pattern is monitored weekly. As expected, no significant production changes in the pattern wells have been observed at this early stage of the foam injection test. As of early September, no surfactant had been detected in any of the producing wells in the pattern.

The tritium tracer injected in December (just prior to CO₂ injection) was not observed in the offending producing well until after 10 months (the end of September 1992). Thus, the channeling is not be as severe as initially believed. With the exception of the tritium recently observed in the offending well, neither the water phase nor gas phase tracers injected have been detected in fluid samples taken and analyzed as of September 1992. This indicates there is not a direct fracture communication between the injector and the producers in this pattern.

The logging runs in the observation well are showing saturation changes when different fluids are injected into the nearby injection well. When foam was being generated, the observation well was logged once a week for about 4 to 6 weeks. A series of logging runs made in the observation well during the baseline cycle indicated that the largest saturation changes are occurring in the same high permeability zones where the maximum fluid injection and production are seen in Wells 3332-001 and 3332-032, respectively. All of these results are consistent with the geological interpretation of the pattern area.

RESERVOIR SIMULATION STUDIES

Work has continued at the University of Houston on the simulation of the field test at the EVGSAU; a progress report from Dr. John Killough is included in Appendix A. These studies have progressed on three fronts: reformulating the mechanistic foam model, developing a modified simulator for CO₂-foam, and building the history match model for the field pilot area. Work has continued on the modifications to the VIP-MISC simulator to include foam mechanisms. Several simulations have been performed with this model to allow its use in the field pilot study. Work has continued on the history match.

The modifications to the VIP-MISC simulator include the ability to inject surfactant, adsorb surfactant on the rock, and increase viscosity of the gas phase for foam generation. Surfactant is injected at a specified concentration in the water phase. The concentration of surfactant is then tracked throughout the simulation. A Langmuir-isotherm treatment has been used for the surfactant adsorption, similar to that used in the PRRC mechanistic foam simulator.⁹ To simulate the generation of foam, gas viscosity is modified based on gas velocity and surfactant concentration. Several simulations have been performed in a finely-gridded five-spot pattern model to better understand the flow characteristics of foam on a field-scale basis. These results will be used to generate pseudo foam properties for the pilot simulation study.

The field-pilot history match model has been constructed based on the data provided by PPCo. The model consists of a 31x31 grid in nine separate layers for a total of 8649 grid blocks. The field pilot pattern of nine wells and the surrounding sixteen wells have been included in the model. Nine maps for each layer that include net thickness, porosity thickness, and structure were digitized to form this model. Derived porosity values were used to calculate permeabilities from the permeability-porosity correlations provided by PPCo. For the first thirty years of the simulation, the history consists of primary depletion. This period was simulated using the average pressure history of the full field. The history match of the waterflood and WAG portions of the project was then conducted in an attempt to match produced volumes.

Computer simulation studies will be continued. The modifications to the commercial simulator to include foam mechanisms are essentially completed. Foam properties for the pilot study should be completed in the near future. The history matching of the pattern area has been completed, and the foam pilot predictions will begin during the fall of 1992.

PROJECT PLANS

The fifth cycle of foam generation, which will complete the rapid SAG injection test, is scheduled to be completed in early October 1992. Plans then call for three months of CO₂ injection. The injection well and the producing wells in the pattern area will continue to be monitored.

The next JPAT meeting was scheduled on November 9, 1992, to discuss progress of the test and to establish the future course of action. In particular, the desirability of a second foam generation test will be addressed.

SUMMARY AND CONCLUSIONS

Monitoring for the foam field test involves a data collection program designed to evaluate the reduction of mobility of the injected CO₂ and the improvement in pattern sweep efficiency and/or production performance. Injection rates and pressures are monitored daily at the pattern injector (Well 3332-001). Oil, water, and gas production is monitored weekly for the eight producing wells in the pattern. At the end of each cycle, an injection well profile is obtained to assess where fluids are leaving the wellbore, production logs are obtained in the offending producing well (3332-032) to determine where fluids are entering that wellbore, and logging of the observation well (3332-003) is conducted to monitor saturation changes at that wellbore. Before and after the foam test, both water phase and gas phase tracer are injected in Well 3332-001. Results of all of these tests are used to monitor the effects of the foam injection and to detect any significant changes in fluid flow through different intervals in the reservoir.

Evidence from the injection well tracer log, the production log from Well 3332-032 (Fig. 8), and the results of the monitor logging runs in the observation well (Fig. 9), all indicate that most of the fluid movement in this pattern is occurring in the high permeability zones (C2 and C3), as assumed in the foam design. Results from interwell tracer tests indicate there is not a direct fracture communication between the injector and the producers in this pattern.

The design approved by the JPAT for the EVGSAU field test includes the injection of three months of a pre-foam surfactant pad, followed by the injection of an 80% quality CO₂-foam during four months of a rapid surfactant-alternating-gas (SAG) cycle. The surfactant pad both satisfies the adsorption and compensates for the adsorption-induced retardation of the surfactant band. This should result in effective utilization of surfactant for foam generation. The rapid SAG cycle, consisting of three days of surfactant solution injection followed by 12 days of CO₂, was selected to avoid operational problems of coinjection while achieving the benefits of simultaneous injection.

As expected, no significant changes in either injection pressure or profile were observed as a result of the sacrificial surfactant injection. The lower injectivity observed during the rapid SAG cycle is attributed to in-situ foam generation.

Several injection profiles were obtained in the rapid SAG cycle during both CO₂ and surfactant solution injection. These profiles suggest that all fluids are continuing to enter the higher permeability zones although a slight decrease (10-15%) has occurred in the highest permeability "C" Zone.

Production from the eight wells in the foam pattern is monitored weekly. As expected, no significant production changes in the pattern wells have been observed at this early stage of the foam injection test.

The fifth cycle of foam generation, which will complete the rapid SAG injection test, was scheduled to be completed in early October 1992. Plans then call for three months of CO₂ injection. The injection well and the producing wells in the pattern area will continue to be monitored. Future plans call for the continued monitoring of the project to evaluate project performance as well to assess the desirability of a second foam generation test.

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Table 1. EVGSAU Reservoir and Fluid Characteristics¹

Type Formation	dolomite
Depth (ft)	4400
Reservoir Temperature (°F)	101
Original Reservoir Pressure (psig)	1613
Current Average Reservoir Pressure (psig)	2100
Average Net Pay (ft)	71
Average Porosity (%)	11.7
Average Permeability (md)	11.0
Oil Gravity (°API)	38
OOIP (MMSTBO)	297
Unit Area (acres)	7025
CO₂ Project Area (acres)	5000

Table 2. Adsorption Tests with Chevron Chaser CD-1045®

Soln. Conc. (ppm)	Core from Well #	K (md)	ϕ (%)	Adsorption (lbs/acre-ft)								
				Ad1	De1	Ret1	Ad2	De2	Ret2	Ad3	De3	Ret3
1000	2913-011	1.6	16.2	1154	515	639						
1000	3328-002	18.0	14.0	500	204	296						
1000	3328-002	17.0	12.0	439	204	235						
1000	3328-002	16.0	14.0	553	317	236						
2500	3332-003	60.0	13.0	488	190	298	284	174	110			
2500	3332-003	43.0	16.0	412	412	755	451	319	132			
2500	3332-003	45.0	11.0	852	323	529	439	336	103	426	387	39

Ad: Adsorption

De: Desorption

Ret: Retention = Adsorption - Desorption

Fig. 1. EVGSAU Production History

EVGSAU WAG Section Area

Fig. 2. Location of the EVGSAU Foam Pilot Area

Fig. 3. Geological Zones in the EVGSAU Foam Pilot Area

Fig. 4. Foam Pattern Performance History (8 producers/1 injector)

1991

TASK	J	F	M	A	M	J	J	A	S	O	N	D
Drill/Core 3332-003												
BASELINE CYCLE:												
Water Injection												
Rapid WAG (CO ₂ /Water)												
CO ₂ Injection												
TESTING:												
Prod Log - 3332-032												
Inj. Profile - 3332-W001												
Observation Well Log												
Fall-Off Test												
Tracer Injection												
JPAT Meetings												

1992

TASK	J	F	M	A	M	J	J	A	S	O	N	D
BASELINE CYCLE:												
Water Injection												
Rapid WAG (CO ₂ /Water)												
CO ₂ Injection												
FOAM CYCLE:												
Water Injection												
Adsorption Slug (Wtr/Surf)												
Rapid SAG (CO ₂ /Wtr/Surf)												
CO ₂ Injection												
TESTING:												
Prod Log - 3332-032												
Inj. Profile - 3332-W001												
Observation Well Log												
Fall-Off Test												
Tracer Injection												
JPAT Meetings												

Fig. 5. EVGSAU CO₂ Foam Project Schedule

Fig. 6. EVGSAU Foam Injection Equipment Layout

Fig. 7. Injection Well 3332-001 Pressure and Rate History

Fig. 8. Well 3332-001 Injection Profile and Well 3332-032 Production Log

Fig. 9. Sequential Logging Runs in Observation Well 3332-003
(All Runs Relative to Base log Run of March 20, 1991)

Fig. 10. Well 3332-001 Injection Pressure and Rate
July 1, 1991 - September 30, 1992

Fig. 11. Well 3332-001 Injection Pressure and Rate
July 1, 1992 - September 30, 1992

APPENDIX A

APPENDIX A

RESERVOIR SIMULATION OF THE EAST VACUUM GRAYBURG/ SAN ANDRES CO₂-FOAM FIELD VERIFICATION

ABSTRACT

Simulation of the East Vacuum/Grayburg San Andres CO₂-Foam Field Pilot Verification has progressed in three areas: the field pilot history match model, scaleup of the mechanistic foam model to field level, and development of the modified VIP-MISC model for CO₂-foam. We have achieved an acceptable history match of both the waterflood (1980-1985) and CO₂-WAG flood (1986-1992) portions of the field history. Overall field cumulative water production agreed well with historical data; several of the wells had excellent matches of historical cumulative water and CO₂ production. Most matches were of good quality with a few of the producers showing only a fair match of historical production. The MVIP model was modified to account for the apparent increase in gas viscosity with the generation of foam. We have verified that WAG injection can be modeled accurately with this simplified viscosity modification concept on the field level.

FIELD PILOT HISTORY MATCH

The field-pilot history-match model was constructed based on the data provided by Phillips and Masera Corporation. The model consists of a 31x31 grid, as shown in Fig. 1, in nine separate layers for a total of 8649 grid blocks. Nine maps for each layer net thickness, porosity thickness, and structure were digitized to form this model. Derived porosity values were used to calculate permeabilities from

the permeability-porosity correlations provided by Phillips. Two layers of the previous description (Zones A and B from the type log) were eliminated since it was observed that little or no production occurred from these layers. Thus, the final model contained seven separate layers. The field pilot pattern of nine wells and the surrounding sixteen wells were included in the model. For the first thirty years of the simulation, the history consists of primary depletion. This period has been successfully simulated using the average pressure history of the full field.

The twelve-year period of waterflood and CO₂-WAG flood was simulated in two phases. First, the six-year waterflood period was matched. Initial simulations showed that, in general, water production was low compared to historical data. An example of the initial simulation for Well 33-04 is shown in Fig. 2; the match was originally poor with breakthrough late by over two years. The matching process for this period consisted of manipulations of completion kh values followed by manipulation of interwell permeabilities. The completion kh's were varied until no further gain was possible. At that time, interwell injector-producer permeabilities were modified to achieve better cumulative water production behavior. Fig. 3 shows the match after increasing the permeability between the central injector and Well 33-4. As shown in this figure, the match is excellent for both breakthrough and average water/oil ratio (WOR) for the producer. Because the oil production rate is fixed based on the historical data, the slope of the cumulative water curve represents the WOR at any given time.

The next stage of the history match consisted of a match of the CO₂ production for the WAG injection period from 1986-1992. Again, the first simulations of this period showed poor match of field performance with some wells producing little or no CO₂ and others producing ten times the historical level. To match this behavior, additional modifications were made to the interwell permeabilities. It was found that fortuitously, the CO₂ production was dominated by permeabilities in Zones C-3 and C-2

(model layers 1 and 2) while the water production was dominated by Zone C-1 (model layer 3). For this reason changes to permeabilities in Zones C-3 and C-2 had little effect on the water production history for the pattern with only one exception (Well 8-5). Figs. 4-10 compare historical and simulated solvent (CO_2) production. As shown in the figures, the match is quite good for most of the wells for both breakthrough and GOR (slopes of the curves) after breakthrough. These seven wells represent those surrounding the central producer. Well 1-1 is not shown since it was shut-in during this period.

Fig. 11 shows the simulated water production from the first stage of the match for Well 8-5, and Fig. 12 shows the degradation of the match when final interwell permeabilities were used. It was found that both solvent and water production for this well were dominated by permeabilities in Zone C-1 (layer 3). For this reason, the match that better reflected the solvent production will be used for future predictive cases.

Figs. 13-27 show the final match of the waterflood performance for all wells in the pattern with the exception of Well 8-5 mentioned above. In general, all wells had good to excellent matches with the exception of the side wells. These simulations used the final interwell permeabilities obtained from both stages of the history matching.

Fig. 28 compares historical and simulated cumulative water production for the entire twenty-five well pattern. As shown in the figure, the breakthrough and first several years are virtually identical. After four years, there is a slight difference in overall produced water-oil ratio that results in a cumulative water production about ten percent low at the beginning of the WAG flood in September, 1985.

FIELD-SCALE SIMULATION OF THE FOAM PROCESS

To better understand the simulation of the CO₂-foam process, the mechanistic model MFS of Eric Chang at the PRRC in New Mexico has been utilized. In particular, we have been investigating the effect of radial, near-well, flow on foam generation. To accomplish this the mechanistic model has been modified to include radial geometry instead of the original cartesian geometry. Coefficients and finite difference cell volumes were modified to include these radial (R-Z) effects. Modifications have also been made to the VIP-MISC model to include the effect of foam generation.

MFS provides a robust model for foam flow simulation in porous media, but it is too expensive for field-scale simulation. The bubble population balance not only magnifies the problem dimension, but it also retards the simulation time. The MFS also has limited applications such as immiscible displacement, no gas solution into the oil, production well, etc. Thus, there is still a need to find a simpler model of representing foam behavior in porous media. This section gives a preliminary result on search the reasonable model.

The large-scale simulator we chose is MVIP (Miscible Vectorized Implicit Program) from Western Atlas Integrated Technologies. This simulation can model miscible flood performance and provides for four phases: liquid hydrocarbon (oil), vapor hydrocarbon (gas), solvent, and water. Solvent miscibility with the oil is controlled by a pressure-dependent mixing parameter. Solvent miscibility with the gas is controlled by a separate mixing parameter. The use of mixing parameters permits the macroscopic modeling of viscous fingering and the bypassing the oil.

For simultaneous injection of surfactant and gas, the model should at least take into account the changes due to water saturation and rock permeability. As known in the literature, the foam mobility decreases with decreasing gas fraction and the dependence on the rock permeability is such that the mobility is greater in rocks of higher permeability and approaches asymptotic values. So far, as long as a WAG process is considered, the above model is suitable to represent the foam behavior in the porous media.

CONCLUSIONS AND FUTURE WORK

The history match and scaleup portions of the CO₂-foam pilot simulation study have been completed. The history match achieved an acceptable level with most wells in the good to excellent range for comparison of historical and simulated cumulative water and solvent production. The comparison of the mechanistic foam simulator and the modified MVIP model showed that acceptable results could be obtained using the field-scale simulator. Future work consists of predictions of pilot CO₂-foam flood performance using the history-matched model with the modified version of MVIP.

0.159

WATER SATURATION (FRACTION)

1.0

2070(DAYS), SEPT 1, 1985

FRONT XY PLANE FOR Z = 3

GRID FAULT SHALE WELL NUMBER SHADE CONTOU PLANE SPECTR ASPECT REDRA

Figure 1

WATER PRODUCTION RATE FOR WELL # 7 / 33-04

Figure 2

WATER PRODUCTION RATE FOR WELL # 7 / 33-04

Figure 3

SOLVENT PRODUCTION RATE FOR WELL #7 / 33-04

Figure 4

SOLVENT PRODUCTION RATE FOR WELL #8 / 32-21

Figure 5

SOLVENT PRODUCTION RATE FOR WELL #9 / 32-02

Figure 6

SOLVENT PRODUCTION RATE FOR WELL #12 / 32-32

Figure 7

SOLVENT PRODUCTION RATE FOR WELL #17 / 8-5

Figure 8

SOLVENT PRODUCTION RATE FOR WELL #18 / 1-10

Figure 9

SOLVENT PRODUCTION RATE FOR WELL #19 / 1-4

Figure 10

Water Production Rate FOR WELL # 17 / 08-05

Figure 11

Water Production Rate FOR WELL # 17 / 08-05

Figure 12

WATER PRODUCTION RATE FOR WELL # 2 / 33-01

Figure 13

WATER PRODUCTION RATE FOR WELL # 4 / 56-02

Figure 14

WATER PRODUCTION RATE FOR WELL # 6 / 33-03

Figure 15

WATER PRODUCTION RATE FOR WELL # 7 / 33-04

Figure 16

WATER PRODUCTION RATE FOR WELL # 8 / 32-21

Figure 17

WATER PRODUCTION RATE FOR WELL # 9 / 32-02

Figure 18

WATER PRODUCTION RATE FOR WELL # 10 / 21-02

Figure 19

WATER PRODUCTION RATE FOR WELL # 12 / 32-32

Figure 20

WATER PRODUCTION RATE FOR WELL # 14 / 1-1

Figure 21

WATER PRODUCTION RATE FOR WELL # 16 / 08-02

Figure 22

WATER PRODUCTION RATE FOR WELL # 18 / 01-10

Figure 23

R PRODUCTION RATE FOR WELL # 19 / 0

Figure 24

R PRODUCTION RATE FOR WELL # 20 / 0

Figure 25

WATER PRODUCTION RATE FOR WELL # 22 / 01-09

Figure 26

R PRODUCTION RATE FOR WELL # 24 / 0

Figure 27

COMPARISON OF HISTORICAL AND SIMULATED CUMULATIVE WATER PRODUCTION FOR EVGSAU

Figure 28

This cover stock is 30% post-consumer waste
and 30% pre-consumer waste, and is recyclable.

Field Verification of CO₂-Foam

Annual Report

**F. David Martin
John P. Heller
William W. Weiss**

November 1992

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