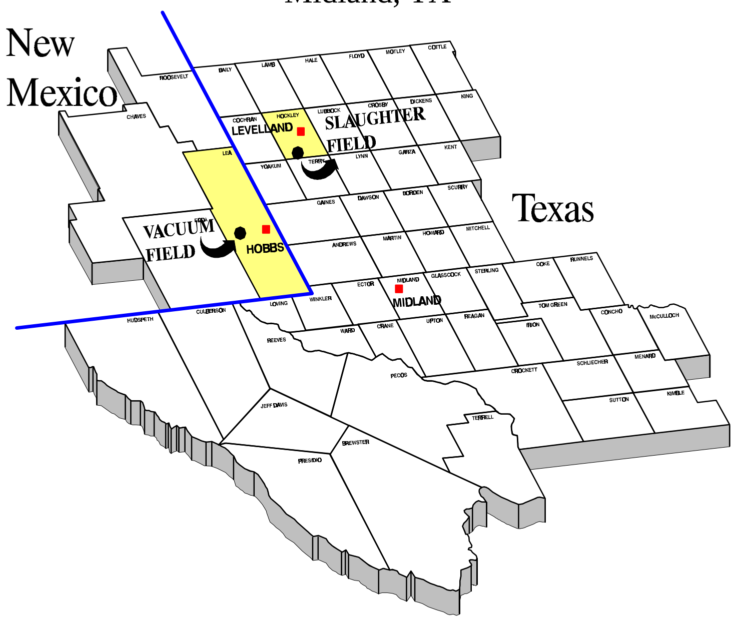
ANNUAL TECHNICAL PROGRESS REPORT

*****   1997   *****

CO_2 HUFF-n-PUFF PROCESS IN A LIGHT OIL SHALLOW SHELF CARBONATE RESERVOIR

(No. DE-FC22-94BC14986--18)

Texaco Exploration & Production Inc.
Midland, TX



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ABSTRACT

The application of cyclic CO_2, often referred to as the CO_2 Huff-n-Puff process, may find its niche in the maturing waterfloods of the Permian Basin. Coupling the CO_2 Huff-n-Puff process to miscible flooding applications could provide the needed revenue to sufficiently mitigate near-term negative cash flow concerns in the capital-intensive miscible projects. Texaco Exploration & Production Inc. and the U. S. Department of Energy have teamed up in an attempt to develop the CO_2 Huff-n-Puff process in the Grayburg and San Andres formations which are light oil, shallow shelf carbonate reservoirs that exist throughout the Permian Basin. This cost-shared effort is intended to demonstrate the viability of this underutilized technology in a specific class of domestic reservoir.

A significant amount of oil reserves are located in carbonate reservoirs. Specifically, the *carbonates* deposited in *shallow shelf* (SSC) environments make up the largest percentage of known reservoirs within the Permian Basin of North America. Many of these known resources have been under waterflooding operations for decades and are at risk of abandonment if crude oil recoveries cannot be economically enhanced[1,2]. The selected sites for this demonstration project are the Central Vacuum Unit waterflood in Lea County, New Mexico and the Sundown Slaughter Field in Hockley County, Texas.

Miscible CO_2 flooding is the process of choice for enhancing recovery of light oils[3] and already accounts for over 12% of the Permian Basin's daily production.[4] There are significant probable reserves associated with future miscible CO_2 projects. However, many are marginally economic at current market conditions due to large up-front capital commitments for a peak response, which may be several years in the future. The resulting negative cash-flow is sometimes too much for an operator to absorb. The CO_2 Huff-n-Puff process is being investigated as a near-term option to mitigate the negative cash-flow situation--allowing acceleration of inventoried miscible CO_2 projects when coupled together.

The CO_2 Huff-n-Puff process is a proven enhanced oil recovery technology in Louisiana-Texas Gulf-coast sandstone reservoirs[5,6]. Application seems to mostly confine itself to low pressure sandstone reservoirs[7]. The process has even been shown to be moderately effective in conjunction with steam on heavy California crude oils[8,9]. A review of earlier literature[5,10,11] provides an excellent discussion on the theory, mechanics of the process, and several case histories. Although the technology is proven in light oil sandstones, it continues to be a very underutilized enhanced recovery option for carbonates. However, the theories associated with the CO_2 Huff-n-Puff process are not lithology dependent.

It was anticipated that this project would show that the application of the CO_2 Huff-n-Puff process in shallow shelf carbonates could be economically implemented to recover appreciable volumes of light oil. The goals of the project were the development of guidelines for cost-effective selection of candidate reservoirs and wells, along with estimating recovery potential.

This project had two defined budget periods. The first budget period primarily involved tasks associated with reservoir analysis and characterization, characterizing existing producibility

problems, and reservoir simulation of the proposed technology. The final budget period covers the actual field demonstration of the proposed technology. Technology transfer spans the entire course of the project. This report covers the concluding tasks performed under the second budget period, particularly with regards to the final demonstration site at Sundown Slaughter Unit. Details of tasks conducted under the first budget period and initial tasks of the second budget period for the initial field demonstration at Central Vacuum Unit were reported in previous annual reports[12,13,14].

The 1995 Annual Report[13] provided some conclusions to some of the work previously reported. Specifically, the report dealt predominantly with, 1) parametric simulation exercises, 2) site-specific simulation; history matching the waterflood and forecasted recovery, and 3) initial results from the field demonstration of the process at CVU.

The 1996 Annual Report[14] provided the final results from the field demonstration at CVU, its history match via computer simulations, cost and economic considerations, and relevant conclusions.

The 1997 Annual Report will focus on the results of the second demonstration site at the Sundown Slaughter Unit. Original plans were to select eight demonstration sites at CVU representing a wide range of reservoir characterization. Parametric simulations found that due to the nature of the near-wellbore environment/conditions, reservoir heterogeneity would have little effect on the resulting recovery efficiency. Near-wellbore saturations of oil and water and the CO_2 injection volume was found to be the more dominate factor in recovery. Therefore, it was determined that no more than four demonstration sites, instead of eight, would accomplish the goals of the project. Furthermore, these same findings suggest that the demonstration site can be moved to the SSU without the need to perform the detailed reservoir characterizations performed for CVU. TEPI proposed, and the DOE approved the second demonstration site in early 1997.

A successful demonstration of the CO_2 Huff-n-Puff process could have wide application. The proposed technology promises several advantages. It was hoped that the CO_2 Huff-n-Puff process might bridge near-term needs of maintaining the large domestic resource base of the Permian Basin until the mid-term economic conditions support the implementation of more efficient, and prolific, full-scale miscible CO_2 projects.

EXECUTIVE SUMMARY

Texaco Exploration and Production Inc. (TEPI) was awarded a contract from the Department of Energy (DOE) during the first quarter of 1994. This contract is in the form of a cost-sharing Cooperative Agreement (Project). The goal of this joint Project is to demonstrate the Carbon Dioxide (CO_2) Huff-n-Puff (H-n-P) process in waterflooded, light oil, shallow shelf carbonate (SSC) reservoirs (Grayburg and San Andres formation) within the Permian Basin. The selected sites are the TEPI operated Central Vacuum Unit (CVU) waterflood in Lea County, New Mexico and the Sundown Slaughter Unit (SSU) in Hockley County, Texas. The CVU produces from the Grayburg and San Andres formations while SSU produces primarily from the San Andres Formation.

The Sundown Slaughter Unit is currently under miscible CO_2 flood in the eastern portion of that field while the rest of the field is still under waterflood. TEPI has recently implemented a full-scale miscible CO_2 project in the CVU. However, the current market precludes acceleration of such capital intensive projects in many similar reservoirs. This is a common finding throughout the Permian Basin SSC reservoirs. In theory, it is believed that the "immiscible" CO_2 Huff-n-Puff process might bridge the longer-term "miscible" projects with near-term results. A successful implementation would result in near-term production, or revenue, to help offset cash outlays of the capital intensive miscible CO_2 project. The DOE partnership provides some relief to the associated Research & Development risks, allowing TEPI to evaluate a proven Gulf-coast sandstone technology in a waterflooded carbonate environment. A successful demonstration of the proposed technology would likely be replicated within industry many fold--resulting in additional domestic reserves.

The principal objective of the CVU and SSU CO_2 Huff-n-Puff projects is to determine the feasibility and practicality of the technology in a waterflooded SSC environment. The results of parametric simulation of the CO_2 Huff-n-Puff process at CVU, coupled with reservoir characterization, assisted in determining if this process was technically and economically ready for field implementation. The ultimate goal was to develop guidelines based on commonly available data that operators within the oil industry could use to investigate the applicability of the process within other fields. The technology transfer objective of the project is to disseminate the knowledge gained through an innovative plan in support of the DOE's objective of increasing domestic oil production and deferring the abandonment of SSC reservoirs. Tasks associated with this objective are carried out in what is considered a timely effort.

The application of CO_2 technologies in Permian Basin carbonates may do for the decade of the 1990's and beyond, what waterflooding did for this region beginning in the 1950's. With an infrastructure for CO_2 deliveries already in place, a successful demonstration of the CO_2 Huff-n-Puff process could have wide application. The proposed technology promises a number of economical advantages. Profitability of marginal properties could be maintained until such time as pricing justifies a full-scale CO_2 miscible project. It could maximize recoveries from smaller isolated leases, which could never economically support a miscible CO_2 project. The process, when applied during the installation of a full-scale CO_2 miscible project could mitigate up-front negative cash-flows, possibly to the point of allowing a project to be self-funding and increase

horizontal sweep efficiency at the same time. Since most full-scale CO_2 miscible projects are focused on the "sweet spots" of a property, the CO_2 Huff-n-Puff process could concurrently maximize recoveries from non-targeted acreage. An added incentive for the early application of the CO_2 Huff-n-Puff process is that it could provide an early measure of CO_2 injectivity of future full-scale CO_2 miscible projects and improve real-time recovery estimates--reducing economic risk. It is hoped that the CO_2 Huff-n-Puff process might bridge near-term needs of maintaining the large domestic resource base of the Permian Basin until the mid-term economic conditions support the implementation of more efficient, and prolific, full-scale miscible CO_2 projects.

Simulation results suggested that reservoir characterization of flow units is not as critical for a CO_2 Huff-n-Puff process as for a miscible flood. Entrapment of CO_2 by gas hysteresis was considered the dominant recovery factor for a given volume of CO_2. The repetitive application of the process was found to be unwarranted in a waterflooded environment.

The findings to date show that the field demonstration did not perform as forecast at CVU. The forecast assumed that large trapped gas saturation would occur. The incremental oil recovered was only equivalent to the deferred production during the injection and soak periods. Furthermore, it is apparent that 100% of the injected CO_2 is being recovered. These are the trademarks for the lack of trapped gas saturation—or very short-lived gas trapping. Previous simulation work indicated that trapped gas saturation was the mechanism required for success. Several possibilities exist for this deficiency. First, the water may have dissolved the CO_2 saturation. Secondly, the absence of trapped gas saturation might be due to pore-throat size, porosity-type, lithologic characteristics, or a combination of these factors that are not currently understood. In addition, based on simulation exercises, it is apparent that there may be a rate dependency component to the ultimate success and efficiency of this technology. Simulation results indicate that the oil production rate is increased when the gas production rate is increased. This suggests that a well be equipped for high gas production rates rather than attempting to initially flow a well before returning production equipment to the wellbore. Restricting the gas rate restricts the oil production rate. Furthermore, since a gas disposal restriction existed at CVU and it lacks the capacity to trap gas, it should not be considered for further demonstrations. It is interesting to note that near-wellbore gas trapping of CO_2 has been cited as one possible cause of reduced injectivity following Water-Alternating-Gas (WAG) injection methods employed in many miscible CO_2 floods. The offset East Vacuum Grayburg San Andres Unit miscible CO_2 flood, operated by Phillips, is one of the few Permian Basin CO_2 floods that has not experienced any appreciable reduction in injectivity. There has been no reduction during 12 years of WAG operations even though many of the other Permian Basin shallow shelf carbonate reservoirs experience 30 to 50 percent reductions in water injectivity following the introduction of CO_2 to the reservoirs. If it can be inferred that reduced injectivity in WAG operations is related to gas trapping, then Vacuum field is not a good candidate for further testing of the Huff-n-Puff technology. Oxy has been experimenting with Huff-n-Puff technology in the Welch field of West Texas. Oxy's Huff-n-Puff results have been favorable enough to expand their program. An offset miscible CO_2 flood within the Welch field showed reduced injectivity in WAG operations. This further suggests that the technology should be applied to another reservoir that has documented WAG injectivity reductions to validate the hypothesis. Slaughter Field is such a reservoir in the San Andres formation. Texaco has seen reduced injectivity in its' wells that are currently under miscible flood in the Eastern part of the Field. Altura has also experienced reduced injectivity in its' wells in the Slaughter Estate Unit which is adjacent to SSU.

The Huff-n-Puff technology might become a valuable indicator of potential injection rates when designing a miscible CO_2 flood. Injectivity is one of the main parameters affecting the economics of these large-scale projects. The failure of the Huff-n-Puff might indicate favorable expectations of injection, whereas a positive response may suggest injectivity reductions--thus the need for the parallel implementation of the Huff-n-Puff technology.

An associated lifting cost benefit at CVU was realized during the demonstration resulting from the reduction in electrical load. Even though the oil recovery was equivalent to the deferred production, it was recovered during a period that experienced no electrical costs during the injection, soak and flowing periods. Once the well was returned to pumping, it has continued to experience reduced electrical costs due to reduced water production.

Pursuit of a second demonstration site, amenable to gas trapping, resulted in moving the second, and final demonstration site to the SSU. It is also a shallow shelf carbonate reservoir that is currently under pattern CO_2 injection in the Eastern portion of the field. SSU has experienced very pronounced injection hysteresis effects, suggesting the ability for CO_2 to form near-wellbore gas saturation. The lack of this phenomenon at CVU is the principal reason for the lack of response to the first demonstration cycle. The final demonstration site of this project was conducted in the western portion of the SSU where CO_2 flooding operations have not yet been expanded, therefore having no influence on production or interpretation of these demonstration results.

INTRODUCTION

SSU Development History[15]

The Slaughter Field was discovered in 1937 by The Texas Company (Texaco). The field borders the town of Sundown, Texas and is about 40 miles southwest of Lubbock, Texas. The discovery well was the J.E. Guerry No. 1 located in Tract 83, Block 38 of the Zavala County School Lands in Hockley County, Texas (**Fig 1**). Upon initial completion the well tested at a rate of 770 BOPD with a Gas-Oil Ratio (GOR) of 620 Mscf of gas per barrel of oil. The well is now referred to as Sundown Slaughter Unit No. 1001. Field development occurred in stages. The first stage of development occurred with drilling in the 1940's and 1950's with the field developed on 35 acre spacing. The wells were produced via solution gas drive. In 1959 waterflooding operations

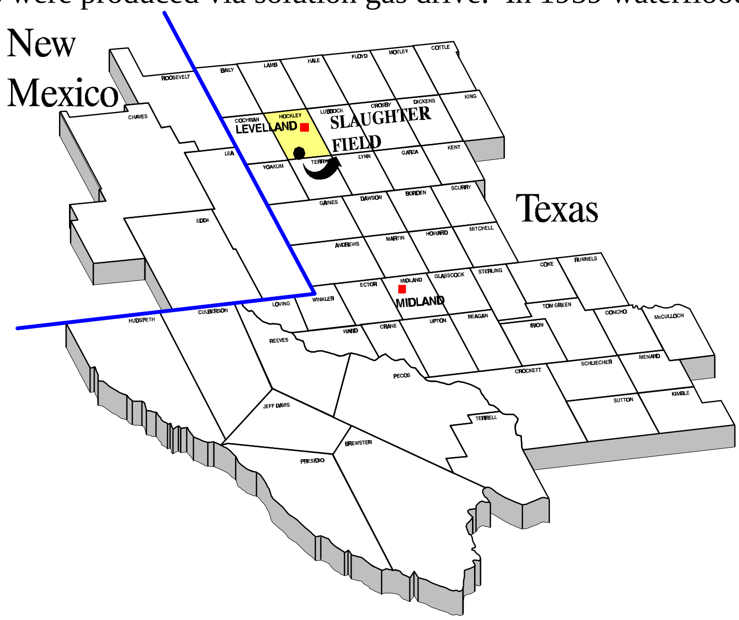

Fig. 1: Regional location of Sundown Slaughter Unit.

began. In the 1970's additional drilling occurred, reducing the well spacing to 17.7 acres. Additional drilling, particularly horizontal wells, is continuing in the 1990's. In 1993, nine properties were unitized and in January, 1994, miscible CO_2 flooding operations began in the eastern portion of the SSU. The CO_2 flood was designed to progress in three contiguous phases. Phase one includes 211 wells in the eastern part of the SSU. Phase two includes 164 wells in the central part of the SSU, and phase three includes 173 wells in the western part of the SSU. Flood expansion is currently proceeding into the phase two area. To-date, primary plus secondary recovery operations produced approximately 36% of the Original Oil-In-Place (OOIP = 440 MM stock tank barrels). Current field production is about 6000 BOPD, including about 4000 BOPD of incremental tertiary production (**Fig. 2**).

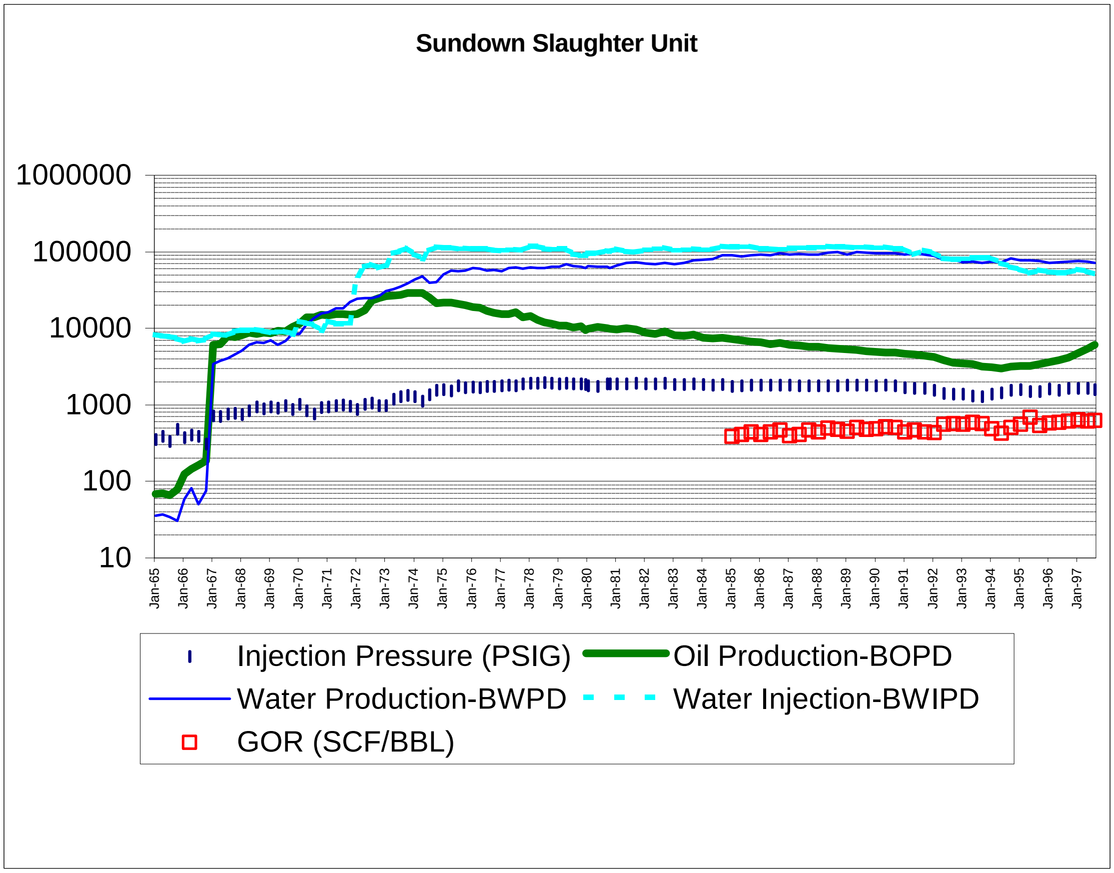

Fig. 2: Sundown Slaughter Unit production and injection history.

There are currently eight active CO_2 floods in Slaughter Field, including the SSU. Four of these projects are adjacent to SSU (**Fig. 3**). Amoco was the first operator in Slaughter Field to initiate a full-scale CO_2 flood. That occurred in 1984 following a successful pilot flood.

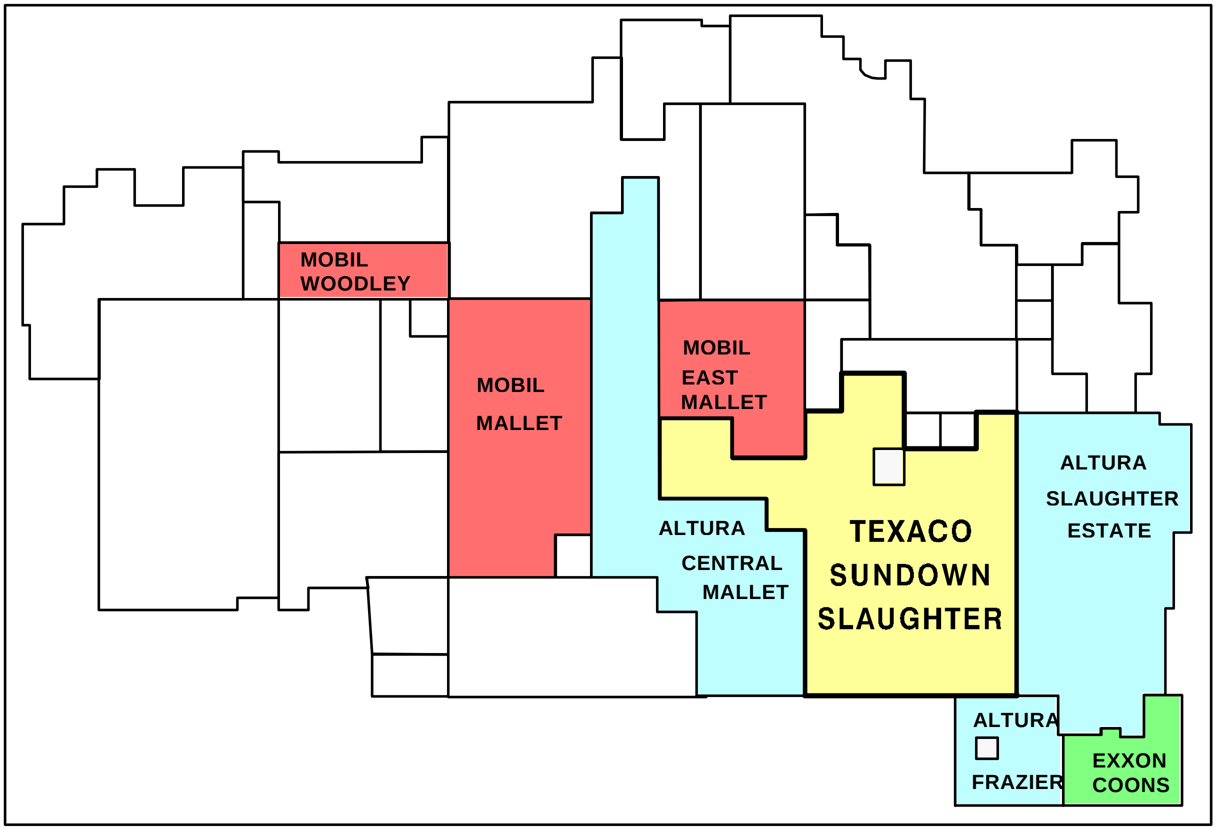

Fig 3: Unitized Acreage of Slaughter Field, Hockley Co., Texas.

Geology[15,16]

The Slaughter Field lies on the Northwest shelf of the Midland Basin (**Fig. 4**). The producing zone is the same San Andres Formation found at CVU which is a sequence of carbonates and evaporites deposited in a marine environment. It is Permian in age and is also a shallow shelf carbonate reservoir. In Slaughter Field, the San Andres is about 1500 feet thick and is divided into an upper and lower section by a radioactive siltstone called the Pi Marker. The upper San Andres is composed of 600 feet of interbedded dolomites, evaporites, and siliclastics. The lower San Andres is 900 feet thick and is composed of cyclic dolomites and evaporites. It is the lower part of the San Andres that is the hydrocarbon-bearing interval. The pay is subdivided into the Mallet Pay (M1, M2, M3, & M4) and the Slaughter Pay (S1, S2, S3, & S4). The S2 is the interval that is currently being CO_2 flooded in the eastern part of the SSU (**Fig. 5**) and is the dominant producing interval in Slaughter Field. It occurs at a depth of about 5000’. The oil-bearing (pay) zone is a heterogenous anhydritic dolomite. The reservoir trap is stratigraphic with porosity disappearing updip to the north. The downdip reservoir boundary is caused by the pay zones dipping below the oil-water contact.

The reservoir was deposited as carbonate muds and sands in shallow waters along an arid coastline. During detailed core studies by Texaco, three distinct facies were identified based upon their depositional environment. The facies were identified as the sabkha (supratidal), intertidal, and subtidal. The sabkha is supratidal, consisting of nodular anhydrite with intervening dolomudstones and has very low permeability. It serves as top seals, flow barriers within the pay and updip lateral seals. The intertidal facies consists of algal-laminated, anhydritic, dolomudstones and dolopackstones. These deposits form in high intertidal to low supratidal environments. Porosity and permeability in the intertidal facies is greater than that in the sabkha facies but less than that in the subtidal facies. The subtidal facies was deposited below mean low tide environments and consists of bioclastic and pelletal packstones to grainstones. These rocks have the highest porosity and permeability, and form the productive intervals (pay) of the reservoir.

The San Andres produces a 33 degree API oil. Porosity and permeability average 12% and 5 md, respectively. The average gross pay thickness is about 100 feet while the net pay averages 87 feet. Initial water saturation in Slaughter field averaged about 23%. It is estimated that waterflood residual oil saturation is greater than 50% of the original oil-in-place (OOIP) which would leave a large target for teriary oil recovery, although there is certainly a wide range of waterflood residual oil saturations in different parts of the field. As in CVU it is this large target that Texaco hopes to produce via the Huff-n-Puff method.

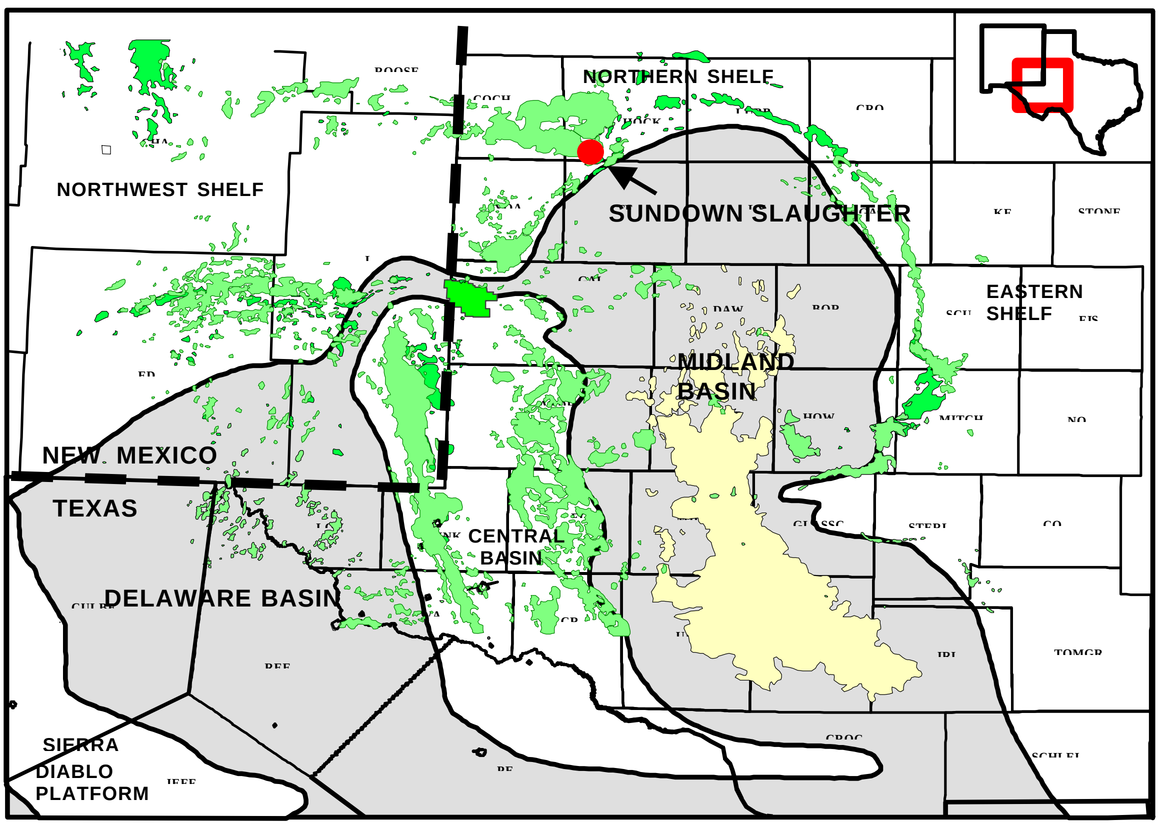

Fig. 4: Permian Basin and relative position of Slaughter field.

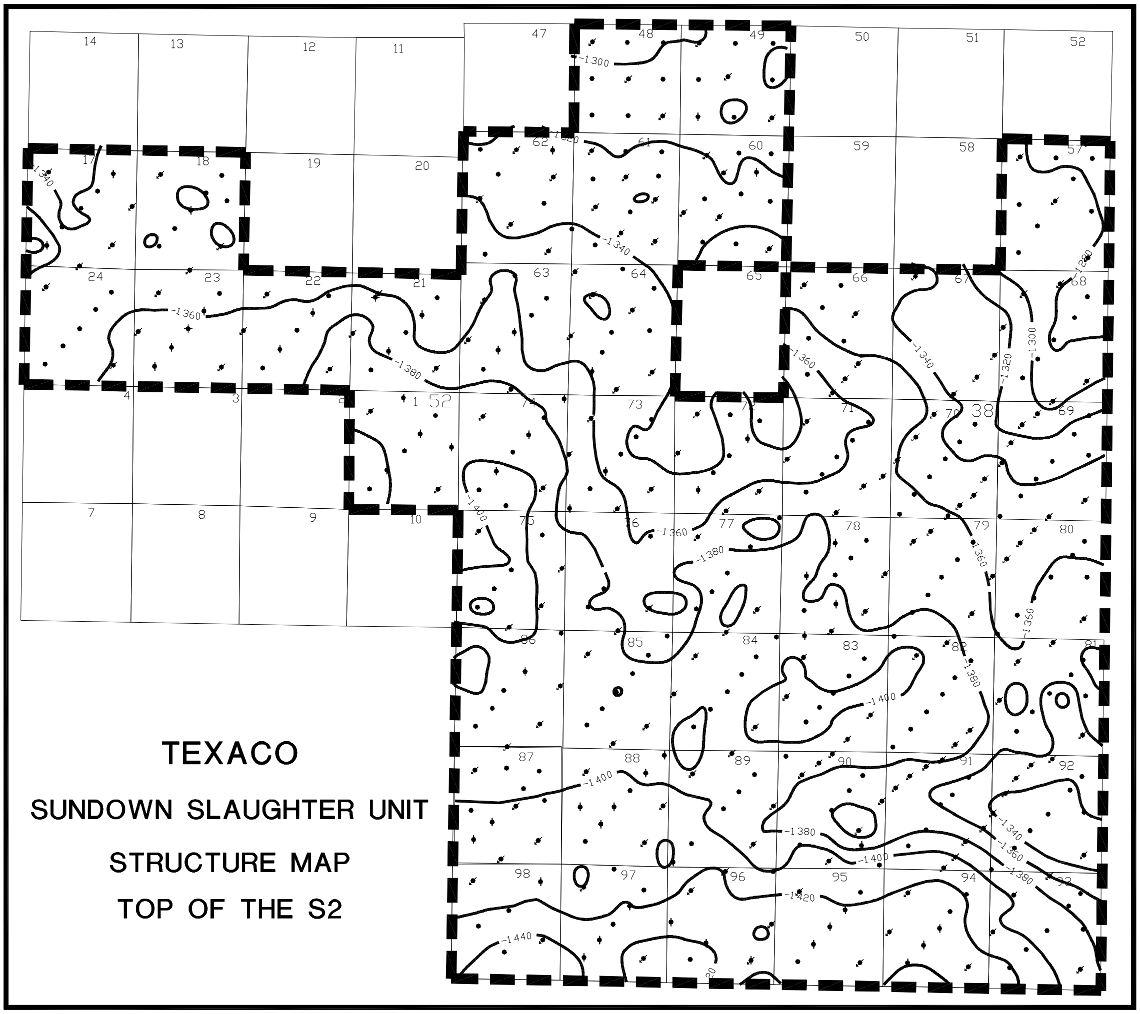

Fig. 5: Limits of Sundown Slaughter Unit with structural contours on San Andres S2 (Subsea, ft).

Brief of Project & Technology Description

This project has two defined budget periods. This report concludes a discussion of work predominantly initiated and covered in the 1996 Annual Report[14]; reporting on work completed under the second budget period. The first budget period primarily involved tasks associated with reservoir analysis and characterization, characterizing existing producibility problems, and reservoir simulation of the proposed technology at CVU. The second, and final budget period incorporates the actual field demonstration of the technology, history matching the results in the case of CVU, and an evaluation of costs and economical considerations for both the CVU and SSU demonstration sites. Results for CVU were reported in the 1996 Annual Report. This 1997 Annual Report will focus on the results of the test at SSU.

It was anticipated that detailed reservoir characterization and a thorough waterflood review would help identify sites for the field demonstration(s). Numerical simulation would help define the specific volumes of CO_2 required, best operational practices, and expected oil recoveries from the demonstration sites.

Basic Theory and Objective. Under certain conditions the introduction of CO_2 can be very effective at improving oil recovery. This is most apparent when operating at pressures above the minimum miscibility pressure (MMP) of the system. As depicted in **Fig. 6**, recovery efficiencies are notably less under immiscible conditions.

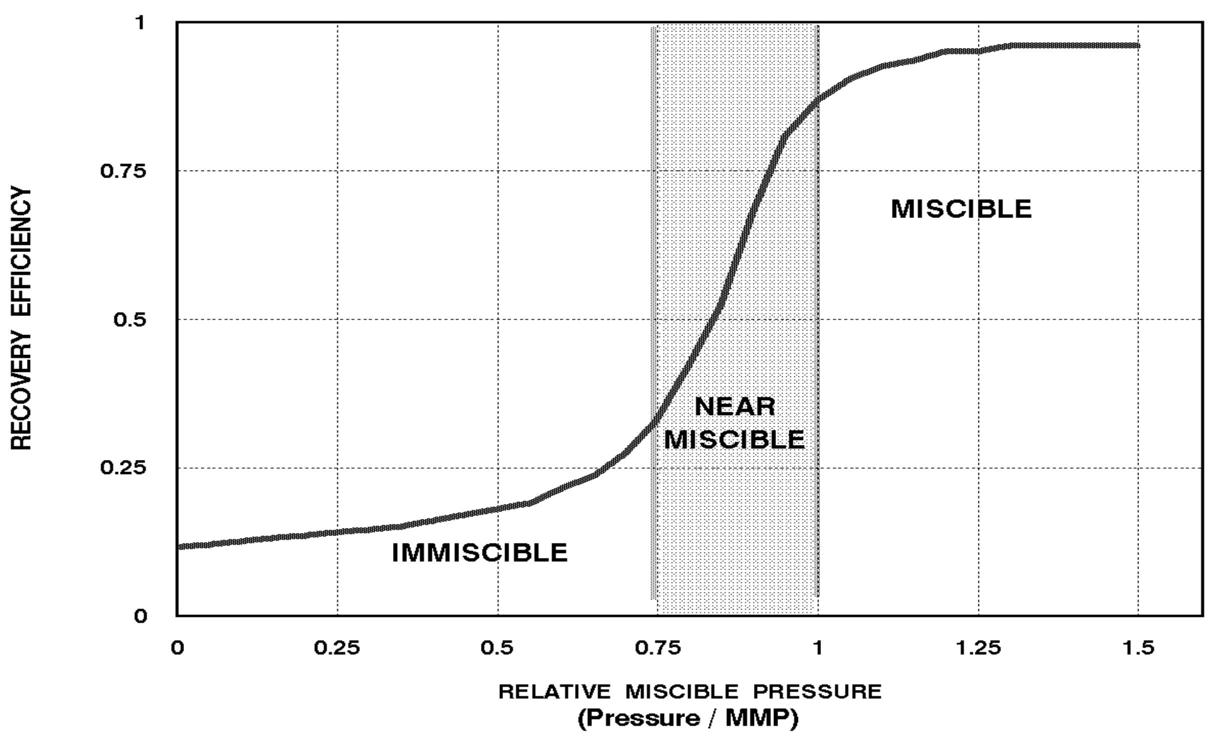

Fig. 6: Generalized Recovery Efficiency vs. Relative Minimum Miscibility Pressure.

The CO_2 Huff-n-Puff process has traditionally been applied to pressure depleted reservoirs. The CO_2 is injected down a production wellbore in an immiscible condition. Theoretically the CO_2 displaces the majority of the mobile water within the wellbore vicinity, while bypassing the oil-in-place. The CO_2 then absorbs into both the oil and remaining water. The water will absorb CO_2 quickly but only a relatively limited quantity. Conversely, the oil can absorb a significant volume of CO_2 although it is a much slower process. For this reason the producing well is shut-in for what is termed a soak period. This soak period is typically 1-4 weeks depending upon fluid properties and reservoir conditions. During this soak period the oil will experience swelling, viscosity and interfacial tensions will decrease, and the relative mobility of the oil will therefore increase. Once the well is returned to production, the swelled oil will flow toward the wellbore (pressure sink). Incremental production normally returns to its base level within six months. Previous work has shown that diminishing returns would be expected with each successive application. Most wells are exposed to no more than two or three cycles of the CO_2 Huff-n-Puff process.

The vast majority of field trials have been conducted in low-pressure environments. Trials in moderate water-drive reservoirs have met with limited success. **Fig. 7** shows a linear relation between these reservoir-drive mechanisms and recovery efficiency developed by TEPI from Gulf-Coast sandstone reservoir trials. The Drive Index is simply a measure of the contribution of reservoir-drive mechanisms for a given reservoir. The relationship depicted suggests that an operator should avoid higher pressure water-drive reservoirs, or in the case of CVU and SSU--waterfloods. Unfortunately, as with the case at CVU and SSU, major oil reserves available to Permian Basin operators are associated with maturing waterfloods--therefore, the need for experimentation and these demonstrations.

After further review of Fig. 6, it was hypothesized that CO_2 Huff-n-Puff recovery efficiencies might be improved in the waterflooded environment by utilizing immiscible injection steps and miscible, or near-

miscible production steps. The near-wellbore vicinity of producing wells is the pressure sink in the system. Further, it might be possible to gain an advantage in certain reservoir environments by temporarily ceasing offset water injection--creating somewhat of a pressure depletion environment. If an operator could inject in an inefficient manner, manipulating pressures and rates, such that a limited amount of oil was mobilized and/or fingering of the injectant occurred, then a two- or three-fold improvement in recovery efficiencies might be obtained. Once a given volume of CO_2 was injected, the offset injection could be restarted. The pressure in the near-wellbore vicinity could increase to, or exceed, MMP conditions during the soak due to the active waterflood. Under these conditions, a more significant swelling of the oil would be experienced in the near-wellbore producing area than in a pressure-depleted reservoir. The no-flow pressure boundary of the waterflood pattern would also serve to confine the CO_2, reducing leak-off concerns. When the well is returned to production, the mobilized oil would be swept to the wellbore by the waterflood. Energy introduced to the typical pressure depleted reservoir normally would dissipate away from the subject wellbore, further reducing efficiency. A study was therefore initiated to investigate the possibilities of this technology in a SSC reservoir.

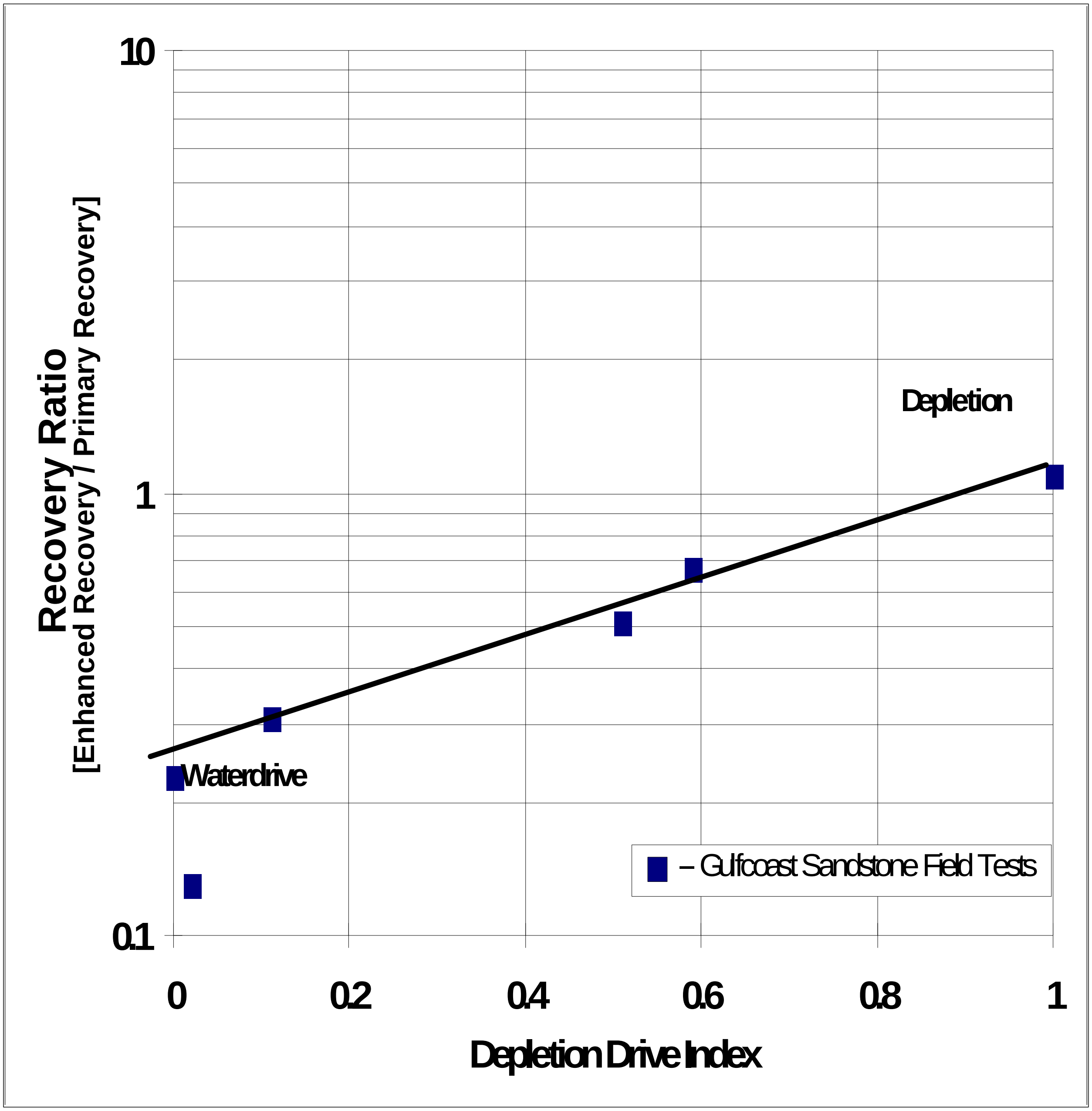

Fig. 7 Relation between Drive Index and Recovery Efficiency of the CO_2 Huff-n-Puff process. Developed from Gulf-Coast sandstone reservoir field trials.

DISCUSSION

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Original plans were to select eight demonstration sites at CVU representing a wide range of reservoir characterization. Parametric simulations found that due to the nature of the near-wellbore environment/conditions, reservoir heterogeneity had little effect on the resulting recovery efficiency. Near-wellbore saturations of oil and water and the CO_2 injection volume was found to be the more dominate factors in recovery. Therefore, it was determined that no more than four demonstration sites, instead of eight, would accomplish the goals of the project. Furthermore, these same findings suggest that the demonstration site could be moved to the SSU without the need to perform the detailed reservoir characterizations performed for CVU. The 1997 Annual Report will provide results from tests at this second demonstration site, including a discussion of costs and economic considerations, relevant conclusions to date, and future activities.

Field Demonstration

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In the test at SSU our goal, ideally, would be to conduct the Huff-n-Puff on the best well in the field, rather than one that could be considered average or representative of the field in general.

Well No. 1341 was chosen as the best overall candidate in SSU. It was drilled in 1984 and cased with five and one-half inch casing to TD at 5032'. The San Andres Formation was perforated over a fifty-three foot interval in the S2 horizon with 2 jet-shots per foot. The well was produced as a waterflood well with initial production of 95 BOPD and 450 BWPD. By mid 1997 production had dropped to 2 BOPD and 400 BWPD. Cumulative production reached 110,500 barrels of oil, 2,400,000 barrels of water and 36,500 Mscf of gas. The well would have been shut-in as uneconomic if not for the demonstration test. **Figure 8** shows well production by month since the well was drilled in 1984 and includes Huff-n-Puff results. A more detailed curve showing daily production and injection data since the inception of the Huff-n-Puff demonstration test is provided later in this report as **Figure 9**.

The primary criteria in choosing a demonstration candidate at SSU included several items. First, reservoir quality as indicated by porosity-feet of pay and offset well performance was reviewed. Porosity averages 10.9 % through the 70 feet of gross pay putting it at the upper end of wells available for Huff-n-Puff operations. Offset well performance in terms of cumulative oil production also indicates that the area around well 1341 would be a good choice for the demonstration. Wells 1040 and 1023, two older wells offsetting 1341, had cumulative oil production that compares favorably with wells in any other part of the field. A strong consideration was also given to the casing condition. Many wells at SSU have had casing leaks, particularly the older wells; in fact, before deciding on 1341 as the Huff-n-Puff candidate, one older well was unsuccessfully tested for casing integrity. At that point, it was decided to focus on newer wells with good primary cement jobs. This eliminated the majority of potential candidates.

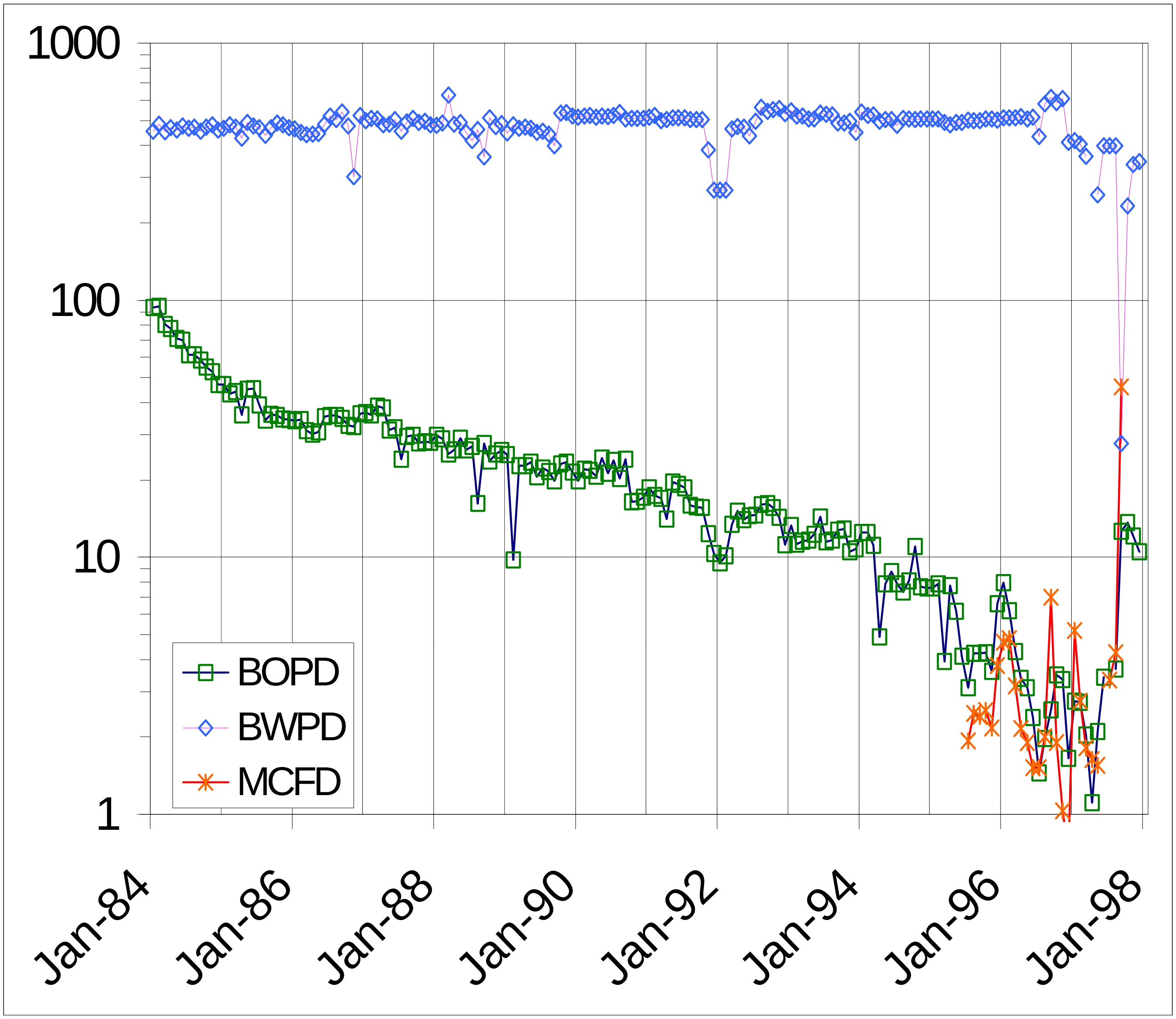

Fig. 8. SSU 1341 Production Plot - life of well

Well 1341, drilled in 1984, had cement circulated to surface during the primary casing cement job, which made for an excellent candidate. As expected, when the casing was pressure tested it was found to be in excellent condition. A third consideration was the well's proximity to an existing pipeline source of CO_2. When the CO_2 transmission lines were installed in SSU, lines were installed to serve both Phase I, the eastern part of the field, and Phase II, the western part of the field--even though it was not known for sure when Phase II would be placed in service. This well's location allowed the use of pipeline CO_2 from a source within 800 feet of well 1341, simply by laying a short lateral and opening a few valves. Only 800 feet of a small lateral line was needed to get the CO_2 to the wellsite. Texaco did not want to sink a large amount of money into a CO_2 line that may or may not have been used again in the future. Well 1341 was an excellent candidate with respect to a source of CO_2. The fourth consideration was current production rate. It was felt that a high total fluid rate indicated good permeability. A low oil cut was desirable since any incremental oil produced could be considered tertiary oil, making it easier to evaluate the success of the project. Additionally, the parametric simulations suggested better response from higher water-cut wells than high oil-cut wells. The gross fluid rate of 400 barrels per day in well 1341 also puts it at the upper end of the spectrum in SSU. Since the well was going to be shut in as uneconomic, any production over 2 BOPD can be considered incremental oil and not just accelerated production. If a well had been producing at economic rates, it could be argued that any additional oil recovered as a result of the Huff-n-Puff project was simply accelerated production and not incremental production. In this respect, well 1341 was an ideal candidate. A fifth consideration was the well's proximity to existing horizontal wells and CO_2 injectors. This situation was to be avoided. Texaco did not want any abnormal influences affecting the results of the test. Since the field is under miscible flood in the eastern part of the field, we were limited to the western part of SSU. As mentioned, we also felt we had to stay some distance away from existing horizontal wells to avoid interference. Well 1341 is far enough away from any "abnormal" field operations that it could be assured that, whatever results were obtained in the demonstration well, there would not be any question as to whether other field operations affected those results. SSU Well 1341 was the best overall candidate when all the screening criteria were taken into account.

Field Demonstration Results.

SSU

CO_2 injection commenced on June 16, 1997 and was completed on August 6, 1997. Originally it was planned to inject a total volume of 50 MMscf of CO_2 which would have affected approximately a 100 foot radius around the wellbore. Injectivity was expected to be about 1.0 MMscf/D based on other wells in SSU that were on permanent miscible flood. Actual injectivity was around 600 Mscf/D. CO_2 injection continued through August 6, 1997 with a total of 34 MMscf being injected at the demonstration site. Injection was discontinued before the target of 50 MMscf was reached because of the lower than expected injection rates encountered. Texaco wanted to get the test completed in a timely manner while still getting a valid test of the Huff-n-Puff process. The radius of CO_2 penetration was calculated to be about 80 feet with 34 MMscf injected which is considered adequate to get a good test. On July 10, about half way into the injection, an injection profile was run to determine which zones were taking CO_2. Well 1341 was perforated in 1984 with 2 jet-shots each at 4950, 4954, 4966, 4974, 4981, 4987, 4990, 4996, 5000, 5003, 5008, 5012, and 5016 feet. The perforations at 4950 and 4966 feet apparently did not take any fluid. Twenty-five percent of the injected fluid went into the perforations at 4996, 5000, and 5003 feet. Notably, 27% of the fluid apparently exited the casing below all of the perforations, i.e. through the casing shoe. The rest of the injection was distributed amongst the remaining perforations. Texaco considered performing a workover to eliminate the injection of CO_2 through the casing shoe but that would have been too costly, time consuming, risky, and of questionable benefit so injection continued until August 6, 1997. Experience in miscible floods also show that this injection situation does not necessarily result in lost injectant, as the process works well in the transition zone too.

The well was then shut in for a three-week soak period. The well was placed on production on August 26, 1997 but froze up at the choke due to the pressure drop. Initial production was 100 % CO_2. A line heater was installed and the well was returned to production on August 29, still making 100% gas (97% CO_2). The first oil appeared on September 4, 1997 when the well flowed 5 BOPD and 16 BWPD. Pressure upstream of the choke had decreased from 1500 psig to 1100 psig during this time while flowing on an 8/64" choke. Oil production fluctuated between 0 BOPD and 23 BOPD while water production ranged from 0 BWPD to 26 BWPD on 8/64", 9/64", and 10/64" chokes until September 20. On September 21, the choke was opened up to 16/64" with a flowing tubing pressure of 850 psig. Production jumped to 53 BOPD and 87 BWPD. The well was choked back the next day to 12/64" due to freezing problems in the choke. On September 26 a production profile log was run to determine which zones were contributing fluid. Consistent with the injection profile the perforations at 4996 and 5000 feet did not produce any fluid. The perforation at 5016 feet also did not produce fluid. Forty-two percent of the oil and gas came from the perforation at 4974 feet. The remaining oil and gas was distributed amongst the rest of the perforations below 4974 feet. No oil and gas was produced from below the perforations. Water production was distributed amongst the perforations below 4980 feet. Four percent of the water apparently was produced through the casing shoe. On September 28, the choke was opened up permanently to 45/64", which is wide open, and production for the next three days was 334, 196, and 128 BOPD, respectively, before dropping back to 22 BOPD on the fourth day. It should be noted here that the high tests of 334, 196, and 128 BOPD are somewhat questionable based on findings later on in the test period--which is discussed in further detail later in the report. Production then fluctuated between 0 BOPD and 23 BOPD until October 25, when a pumping unit was installed. Flowing tubing pressure had decreased to 50 psig by that time. The first two tests after the pumping unit installation were 90 and 263 BOPD, respectively. At this time it was discovered that there was a problem with the test facilities. Testing of the well was through a test separator in the battery, the same test separator that Texaco tests all other wells through in that part of the field. Texaco felt confident that accurate tests were being made, however it was discovered that the micromotion sensor may have been interpreting gas laden fluid (oil + water + gas) as a high oil cut fluid, hence the high oil production reported. It is suspected, but not proven, that the same situation may have happened on/about September 28 when there were three days of extraordinarily high tests. Unfortunately there is no way to quantify the degree of error in the tests—if any. Based on simulation results from CVU, increased liquid rates are to be expected when higher gas rates occur so the well probably did get some increase in oil and total fluid production. It is believed that when the back pressure on the formation was decreased drastically, there may have been an extraordinary influx of gas which adversely affected the test facilities. On September 28 the choke was opened from 13/64" to

30/64” and then to 45/64” in a matter of two days. Previous choke size increases were only 1/64 or 2/64”. This sudden increase in choke size resulted in a decrease in flowing tubing pressure from 725 psig to 100 psig. Likewise, when Texaco installed the pumping unit, much of the hydrostatic head on the formation was removed, allowing for another influx of gas resulting in another two days of very high tests. By the end of December, production had returned to pre-demonstration levels of about 2 BOPD. Cumulative reported production as of December 31, 1997 was 1786 STB of Oil. Even though some of the tests are suspect, for lack of better information, we will assume the best case scenario for economic purposes. It is obvious that we did get some incremental production from this well. Had the well not been Huff-n-Puffed, production from June 16 through December 31, 1997 (199 days) would have been about 398 STB of Oil. On the high side, it appears that we recovered about 1388 barrels of incremental oil.

At this point it appears that the test met with limited success but was an economic failure. Approximately 4300 barrels of incremental oil, i.e. oil over and above what would have been produced under normal operations, would be required to pay out the project. Actual incremental recovery was about 32%, or 1388 barrels of oil.

Actual Performance

SSU

Detailed reservoir characterization and simulations were not performed at SSU. Instead, lessons learned at CVU, the first demonstration site, were applied to the second demonstration site at SSU. Miscible injection operations in this field have verified the reduced injectivity with CO_2 WAG operations--suggesting an ability for gas trapping. SSU has experienced very pronounced injection hysteresis effects, suggesting the ability for CO_2 to form a near-wellbore gas saturation. Gas trapping was experienced in the test at SSU well number 1341 and some incremental oil was produced. Although the reservoir at SSU was amenable to gas trapping, whereas CVU was not, the test at SSU was rate limited (similar to CVU) due to pressure limitations of the test equipment. Ideally, a well would be flowed at maximum flow rates to achieve the best recovery, however the facilities in-place precluded that option. This was also the case at CVU. Texaco considered flowing the well into a tank, which would have allowed maximum flow, but the gas would then have been vented to the atmosphere so Texaco eliminated that option due to safety and environmental considerations. Such being the case, the well was flowed to one of the test facilities at one of the satellite stations at SSU. The maximum pressure downstream of the choke that Texaco felt safe was about 100 psig. The limiting equipment was the test separator with a working pressure rating of 125 psig. In addition to that, the flowline from the well to the test station was fiberglass with a working pressure rating of 300 psig. Like CVU, gas production (and total fluid production) was limited at SSU. Because of this, maximum incremental production probably was not possible. The maximum gas production rate obtained during the test was 719 Mscf/D (that was for only one day). Gas rates ranged from 90 Mscf/D to 125 Mscf/D during the first week of testing. The second week of testing resulting in a range of 193 Mscf/D to 350 Mscf/D. For the next three weeks, gas production averaged 173 Mscf/D. Gas rates gradually decreased through the remainder of the test period to eventually stabilize at around 45 Mscf/D. The decreasing gas rates were accompanied by increasing water rates and decreasing oil cuts. By the 95th test day, liquid production had returned to pre test levels of about 2 BOPD, 400 BWPD. At 45 Mscf/D, gas production remains well above the pre test level of about 2 Mscf/D. **Figure 9** depicts the results of the Huff-n-Puff test with daily production and injection parameters plotted (the data is included as an Appendix to this report). CO_2 production will continue at a slow rate as the residual saturation is reduced in the near wellbore vicinity. Initially, an improvement in oil cut was seen. Pre-test oil cuts were 5 %. During the first three weeks of testing, the oil cut averaged 30%. After that, the oil cut dropped to 0-5% for the remainder of the test period. As of December 31, 1997, approximately 1388 barrels of incremental oil had been recovered which would result in a recovery efficiency of 24.5 Mscf/STB (34,000 Mscf/1388 bbls). It will be seen below that a recovery efficiency of eight is necessary to simply recover the field costs. It is obvious that this project is far from economic.

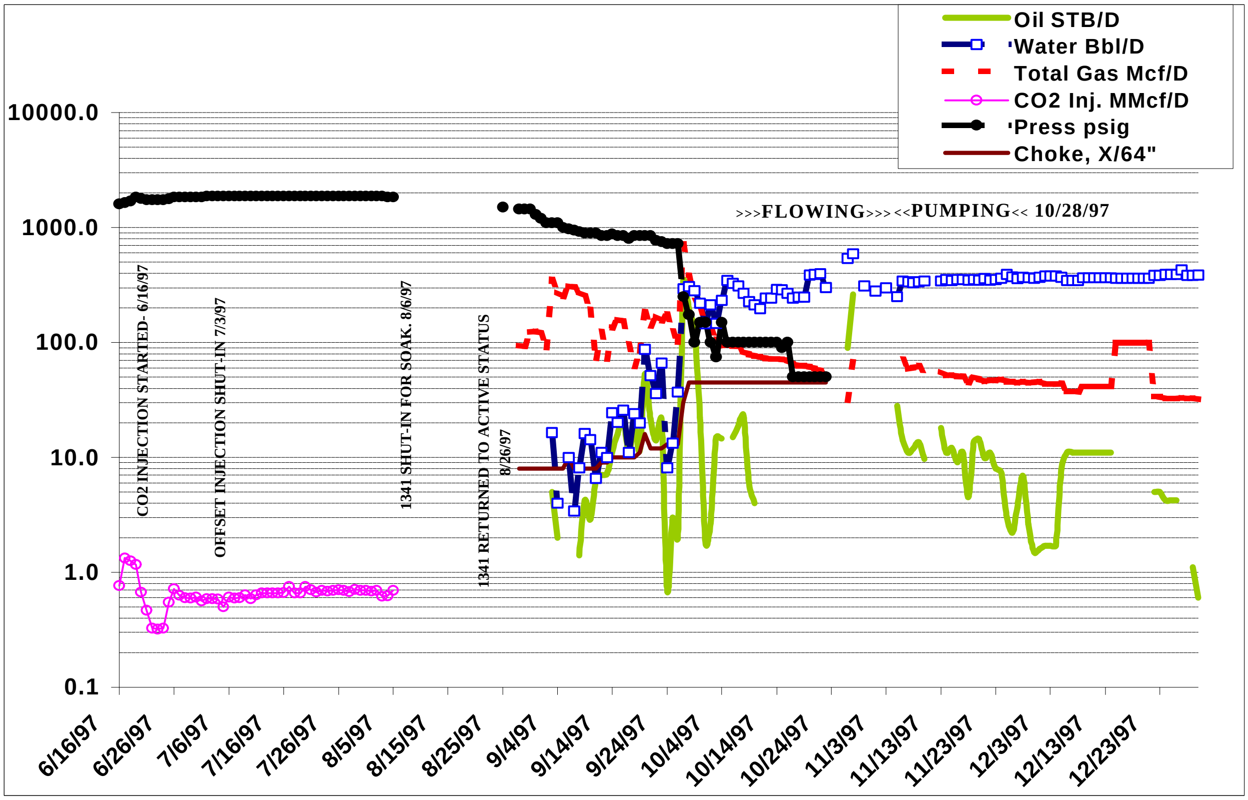

Fig. 9. SSU 1341 Huff-n-Puff results

Summary. In addition to requirements for the trapped gas saturation, there also appears to be a "rate" requirement for a successful Huff-n-Puff which cannot be tolerated due to disposal limitations at SSU. The same problem was experienced at CVU during the first demonstration. If the total liquid production rate during the Huff-n-Puff cannot be maintained at the same level (or at least a high fraction) of the pre-Huff-n-Puff level, then the Huff-n-Puff will not be successful because the oil rate will be too small (even though the oil cut might be improved). If the CVU and SSU wells are typical, a successful Huff-n-Puff may not be possible for a well that must be converted from pumping status to flowing status and back again. The liquid production rate during the flowing period would be too low/slow. This work suggests that improved rates may be possible if higher gas volume production equipment can be utilized. However, it is doubtful from these demonstrations that the efforts would be economical. The pressure requirements would be more than the vast majority of in-place, Permian Basin waterflood facilities. Additional consideration requires a disposal option for the produced CO_2 gas, which has a high content of hydrocarbons. It would not be environmentally sound to vent such a gas to the atmosphere. Unfortunately, if nearby CO_2 separation facilities were available, it would be more economic to implement a miscible CO_2 project rather than the less efficient immiscible CO_2 Huff-n-Puff technology. It appears that the demonstrated technology has little opportunity due to facility, environmental, and efficiency issues.

COST & ECONOMIC CONSIDERATIONS

The actual costs associated with the field demonstration components of the project at SSU are included in **Table 1**.

Table 1: Field Demonstration Costs

($M)

DEMONSTRATION	Direct Cost (M$)
Materials-Line Pipe, valves, fittings	6
Labor-Install flowline & Misc Surface Cost	6.1
Trucking-Pump & Transport	8.5
CO2 Commodity	23
Wireline	3.5
Service Unit & Misc Downhole	13.7
In-Line Heater & Propane	3.5
Downhole pump & Parts	6.6
Misc.	6
TOTAL:	76.9
DOE Share (45%)	34.6
CVU Share (55%)	42.3

Table 2 shows some simple relationships depicting the basic economics of the Huff-n-Puff demonstration at SSU. Assuming an $18.00/STB sales price for crude oil, the necessary volume of recovery to reach a pseudo-breakeven point is calculated to be 4272 STB of Oil. This results in a breakeven CO_2 utilization efficiency of 8.0 Mscf of CO_2 injected per barrel of oil recovery as compared to CVU which had a breakeven efficiency of 3.2 Mscf/bbl. The higher breakeven point at SSU is the result of lower costs, particularly regarding the cost of CO_2. The CO_2 at CVU

was trucked in and pumped down the wellbore at a cost of $2.85/Mscf. The availability of pipeline CO_2 at SSU resulted in substantial cost savings since the CO_2 costs only $0.679/Mscf.

Table 2: Field Demonstration Economics

DEMONSTRATION	CVU ACTUAL	SSU ACTUAL
CO2 Vol., MMscf	50	34
CO2 Cost, $/Mscf	2.85	0.679
Deferred Production, STB	2924	398
TOTAL Cost, $M	284.1	76.9
Equiv. Bbl's @ $18/STB	15800	4272
Breakeven Utilization, Mcf/STB	3.2	8

Additional benefits that are not accounted for in this simplistic review include reduced electrical requirements during the injection, soak and flow period and reduced water handling requirements for an extended period of time—most notably at CVU.

TECHNOLOGY TRANSFER

Technology transfer activities during the 1997 period consisted of updates of project progress and findings through newsletters, publications/presentations, and Joint Project Advisory Team Meetings. The Petroleum Recovery Research Center continues to provide updates on the project in its quarterly newsletter. In addition, the Petroleum Technology Transfer Counsel, a joint venture between the Independent Producers Association of America (IPAA) and DOE is providing complete Quarterly and Annual Technical Reports on an Industry Bulletin Board called GO-TECH. This provides a timely dissemination of information to interested parties.

CONCLUSIONS

A successful demonstration of the CO_2 Huff-n-Puff process could have had wide application. The proposed technology promised several advantages. It was hoped that the CO_2 Huff-n-Puff process might bridge near-term needs of maintaining the large domestic resource base of the Permian Basin until the mid-term economic conditions supported the implementation of more efficient, and prolific, full-scale miscible CO_2 projects. Although it still has promise for pressure depleted reservoirs, the Huff-n-Puff process does not appear to be viable at CVU or at SSU—waterflooded shallow shelf carbonates.

By far the most important finding to date is that the field demonstrations at CVU and SSU have not performed as expected. Hydrocarbon recoveries appear to be equivalent to, or slightly above the deferred production of the injection and soak period. In addition, it is apparent that 100% of the injected CO_2 will be recovered, although much slower at SSU. These results indicate that a large trapped gas saturation did not exist, and, as previously stated, a large trapped gas saturation is necessary for a successful Huff-n-Puff based on the assumptions imposed on the parametric simulations. It is theorized either that the water production was able to rapidly dissolve the trapped gas saturation or that the reservoir is not amenable to gas trapping. Gas trapping may not occur in this specific reservoir due to pore throat size, porosity-type, lithological characteristics, or a combination of these factors that are not currently understood. The poor performance could also be directly related to the higher pressure waterflooding processes.

The second field demonstration at SSU did exhibit a larger trapped gas saturation. As of December 31, 1997 only 30 % of the injected gas had been recovered. The well is currently producing about 30 Mscf/D, which includes 26 Mscf/D of CO_2. The gas rate has been declining throughout the test period and is trending toward its' pre test gas rate of 2 Mscf/D. It is obvious that a large amount of CO_2 will remain trapped in the formation for an extended period of time relative to CVU. Unlike CVU, incremental oil was recovered in the test at SSU. Unfortunately, incremental recovery was not sufficient to pay for the costs of the test. As previously speculated, recovery performance is probably a function of pore size, pore throat configuration, fluid saturations and composition and perhaps some other unknown phenomena relating to the waterflooding processes.

It is interesting to note that near-wellbore gas trapping of CO_2 has been cited as one possible cause of reduced injectivity following Water-Alternating-Gas (WAG) injection methods employed in many miscible CO_2 floods. The offset to CVU, the East Vacuum Grayburg San Andres Unit miscible CO_2 flood, operated by Phillips, is one of the few Permian Basin CO_2 floods that has not experienced any appreciable reduction in injectivity during 12 years of WAG operations. Many of the other shallow shelf carbonate reservoirs experience 30 to 50 percent reductions in water injectivity following the introduction of CO_2 to the reservoirs. If it can be inferred that reduced injectivity in WAG operations is related to gas trapping, then Vacuum field was not a good candidate for further testing of the Huff-n-Puff technology. Oxy had been experimenting with Huff-n-Puff technology in the Welch field of West Texas. Oxy's Huff-n-Puff results have been favorable enough to at least consider expanding their program. An offset miscible CO_2 flood within the Welch field showed reduced injectivity in WAG operations. This further suggested that the technology should be applied to another reservoir that has documented WAG injectivity reductions to validate the hypothesis. Therefore a second demonstration was selected at the SSU site. Although SSU did exhibit gas trapping, incremental recovery was so low that further tests at SSU are not warranted. After the first demonstration at CVU, it was hoped that the Huff-n-Puff technology might become a valuable indicator of potential injection rates when designing a miscible CO_2 flood. Injectivity is one of the main parameters affecting the economics of these large-scale projects. The failure of a Huff-n-Puff might indicate favorable expectations of injection, whereas a positive response may suggest injectivity reductions--thus the need for the parallel implementation of the Huff-n-Puff technology. To an extent, this hypothesis was realized. The CVU site injected at rates well above expectation and the SSU site was sub-par in injectivity. This topic might be of further interest to investigators concerned with the injectivity topic.

In addition to requirements for the trapped gas saturation, there appears to be a "rate" requirement for a successful Huff-n-Puff, which may not be possible due to disposal limitations at CVU and SSU—or most other Permian Basin waterflooding operations. The downsteam line pressure at SSU was controlled at about 50 psig, which resulted in gas production rates of less than 400 Mscf/D. As the flowing tubing pressure decreased, the choke was gradually opened but the gas rate was continuously and artificially restricted by the choke. As a result, the maximum flow rates that would yield the greatest recovery could not be realized. The total liquid production from the well also decreased during the period when the gas production was reduced. Modifications of the CVU history match as well as previous parametric simulations indicate that increasing the gas production rate will also increase the total liquid production rate, which, in turn, will increase the incremental oil. If the total liquid production rate during the Huff-n-Puff cannot be maintained at the same level (or least a high fraction) of the pre-Huff-n-Puff level, then the Huff-n-Puff will not be as successful because the oil rate will be too small/slow (even though the oil cut might be improved). In the case of SSU, pre-test total liquid rates were about 400 BFPD. During the first month of testing, rates varied from 0 to about 50 BFPD. On September 27 the choke was opened up to its' fullest potential but back pressure remained on the formation and by this time flowing tubing pressure had declined substantially. Even with a wide-open choke, flow rates remained below pre-test levels. If the demonstrations at CVU and SSU are typical, a successful Huff-n-Puff may not be possible for a well that must be converted from pumping status to flowing status and back again. The liquid production rate during the flowing period would be too low. This work suggests that improved oil production rates may be possible if higher gas volume production equipment can be utilized.

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APPENDIX

DOE/SSU CO2 Huff-n-Puff Test

Pre-demo/Injection/Soak/Production Testing Data.

Date	Day	Oil STB/D	H2O Bbl/D	Avg. Total Gas Mcf/D	H2O Cut %	Cum. Oil STB	Cum. CO2 Mcf	CO2 Inj. MMcf/D	Tbg. Press. psig	Choke Size x/64”	CO2 in Gas %
6/16/97	0										
6/17/97	1						760	0.76	1600		
6/18/97	2						2090	1.32	1650		
6/19/97	3						3350	1.26	1700		
6/20/97	4						4510	1.16	1850		
6/21/97	5						5180	0.67	1800		
6/22/97	6						5650	0.46	1750		
6/23/97	7						5980	0.32	1750		
6/24/97	8						6300	0.31	1750		
6/25/97	9						6620	0.32	1750		
6/26/97	10						7170	0.54	1775		
6/27/97	11						7890	0.71	1850		
6/28/97	12						8520	0.63	1850		
6/29/97	13						9120	0.59	1850		
6/30/97	14						9710	0.59	1850		
7/1/97	15						10320	0.60	1850		
7/2/97	16						10880	0.56	1850		
7/3/97	17						11470	0.58	1875		
7/4/97	18						12060	0.58	1875		
7/5/97	19						12640	0.58	1875		
7/6/97	20						13140	0.49	1875		
7/7/97	21						13750	0.60	1875		
7/8/97	22						14340	0.59	1875		
7/9/97	23						14940	0.59	1875		
7/10/97	24						15580	0.63	1875		
7/11/97	25						16170	0.59	1875		
7/12/97	26						16800	0.63	1875		
7/13/97	27						17460	0.65	1875		
7/14/97	28						18120	0.65	1875		
7/15/97	29						18770	0.65	1875		
7/16/97	30						19430	0.65	1875		
7/17/97	31						20090	0.66	1875		
7/18/97	32						20840	0.74	1875		
7/19/97	33						21500	0.65	1875		
7/20/97	34						22150	0.65	1875		
7/21/97	35						22900	0.74	1875		
7/22/97	36						23610	0.70	1875		
7/23/97	37						24270	0.66	1875		
7/24/97	38						24970	0.69	1875		
7/25/97	39						25650	0.68	1875		
7/26/97	40						26350	0.69	1875		
7/27/97	41						27060	0.70	1875		

Date	Day	Oil STB/D	H2O Bbl/D	Avg. Total Gas Mcf/D	H2O Cut %	Cum. Oil STB	Cum. CO2 Mcf	CO2 Inj. MMcf/D	Tbg. Press. psig	Choke Size x/64”	CO2 in Gas %
7/28/97	42						27750	0.69	1875		
7/29/97	43						28430	0.67	1875		
7/30/97	44						29140	0.70	1875		
7/31/97	45						29830	0.69	1875		
8/1/97	46						30530	0.69	1875		
8/2/97	47						31210	0.68	1875		
8/3/97	48						31910	0.69	1875		
8/4/97	49						32530	0.61	1875		
8/5/97	50						33150	0.62	1850		
8/6/97	51						33850	0.69	1850		
8/7/97								SOAK			
8/8/97								SOAK			
8/9/97								SOAK			
8/10/97								SOAK			
8/11/97								SOAK			
8/12/97								SOAK			
8/13/97								SOAK			
8/14/97								SOAK			
8/15/97								SOAK			
8/16/97								SOAK			
8/17/97								SOAK			
8/18/97								SOAK			
8/19/97								SOAK			
8/20/97								SOAK			
8/21/97								SOAK			
8/22/97								SOAK			
8/23/97								SOAK			
8/24/97								SOAK			
8/25/97								SOAK			
8/26/97		0.0	0.0	0.1					1500	3	
8/27/97											
8/28/97	0	0.0									
8/29/97	1	0.0	0.0	94.5			64		1450	8	67.4%
8/30/97	2	0.0	0.0	92.2			154		1450	8	97.3%
8/31/97	3	0.0	0.0	123.0			273		1450	8	97.3%
9/1/97	4	0.0	0.0	125.7			396		1300	8	97.2%
9/2/97	5	0.0	0.0	121.2			513		1200	8	97.1%
9/3/97	6	0.0	0.0	90.1		0	600		1100	8	96.8%
9/4/97	7	5.0	16.4	352.2	77%	5	943		1100	8	97.1%
9/5/97	8	2.0	4.0	275.4	67%	7	1210		1100	8	97.0%
9/6/97	9	0.0	0.0	249.8		7	1452		1000	8	97.0%
9/7/97	10	0.0	10.0	309.1	100%	7	1752		975	10	97.2%
9/8/97	11	0.0	3.4	301.0	100%	7	2044		950	8	96.9%
9/9/97	12	1.4	8.1	274.7	85%	8	2310		925	8	96.8%
9/10/97	13	4.2	16.1	253.7	79%	13	2555		900	8	96.6%
9/11/97	14	2.9	14.3	192.6	83%	16	2741		900	8	96.6%
9/12/97	15	6.2	6.6	72.5	52%	22	2811		900	8	96.6%
9/13/97	16	7.0	11.0	124.0	61%	29	2931		850	9	96.6%
9/14/97	17	7.2	10.0	71.0	58%	36	2999		850	9	96.6%
9/15/97	18	11.1	24.4	135.5	69%	47	3130		880	10	96.6%

Date	Day	Oil STB/D	H2O Bbl/D	Avg. Total Gas Mcf/D	H2O Cut %	Cum. Oil STB	Cum. CO2 Mcf	CO2 Inj. MMcf/D	Tbg. Press. psig	Choke Size x/64”	CO2 in Gas %
9/16/97	19	16.0	20.1	157.9	56%	63	3283		850	10	96.6%
9/17/97	20	23.1	25.9	153.0	53%	86	3430		850	10	96.6%
9/18/97	21	10.9	11.0	96.8	50%	97	3524		800	10	96.6%
9/19/97	22	18.3	24.0	61.4	57%	115	3583		850	10	96.0%
9/20/97	23	11.6	20.0	84.4	63%	127	3664		850	11	96.4%
9/21/97	24	53.2	87.3	184.0	62%	180	3842		850	16	96.4%
9/22/97	25	21.6	51.8	138.5	71%	202	3975		850	12	96.3%
9/23/97	26	14.0	36.0	169.8	72%	216	4138		775	12	95.8%
9/24/97	27	21.3	66.0	155.3	76%	237	4286		750	12	95.7%
9/25/97	28	0.7	8.1	176.7	92%	238	4456		725	13	95.9%
9/26/97	29	3.0	13.3	125.8	82%	241	4577		725	13	95.9%
9/27/97	30	2.0	37.0	100.5	95%	243	4673		725	13	95.9%
9/28/97	31	334.0	293.0	718.6	47%	577	5362		250	30	95.9%
9/29/97	32	196.0	307.0	383.0	61%	773	5724		175	45	94.4%
9/30/97	33	127.8	282.3	229.4	69%	901	5940		100	45	94.4%
10/1/97	34	22.3	220.7	199.1	91%	923	6128		150	45	94.4%
10/2/97	35	1.8	145.1	152.6	99%	925	6271		150	45	93.3%
10/3/97	36	2.7	211.3	133.3	99%	927	6395		100	45	93.3%
10/4/97	37	14.9	146.1	105.2	91%	942	6493		75	45	93.3%
10/5/97	38	14.5	232.8	93.1	94%	957	6580		150	45	93.3%
10/6/97	39	0.0	345.7	96.2	100%	957	6668		100	45	91.8%
10/7/97	40	15.0	328.0	93.1	96%	972	6754		100	45	91.8%
10/8/97	41	19.0	310.0	92.3	94%	991	6838		100	45	91.8%
10/9/97	42	23.0	267.0	83.7	92%	1014	6915		100	45	91.8%
10/10/97	43	6.0	226.0	79.3	97%	1020	6988		100	45	91.8%
10/11/97	44	4.0	213.0	75.9	98%	1024	7058		100	45	91.8%
10/12/97	45	0.0	197.0	75.3	100%	1024	7127		100	45	91.8%
10/13/97	46	0.0	243.0	72.4	100%	1024	7193		100	45	91.1%
10/14/97	47	0.0	244.0	72.3	100%	1024	7259		100	45	91.1%
10/15/97	48	0.0	290.0	71.7	100%	1024	7324		100	45	91.1%
10/16/97	49	0.0	288.0	71.4	100%	1024	7389		90	45	90.9%
10/17/97	50	0.0	268.0	70.3	100%	1024	7453		100	45	90.9%
10/18/97	51	0.0	243.0	65.1	100%	1024	7512		50	45	90.9%
10/19/97	52	0.0	247.3	62.7	100%	1024	7569		50	45	90.9%
10/20/97	53	0.0	247.3	62.7	100%	1024	7626		50	45	91.0%
10/21/97	54	0.0	385.8	61.7	100%	1024	7682		50	45	91.0%
10/22/97	55	0.0	389.4	59.2	100%	1024	7736		50	45	91.0%
10/23/97	56	0.0	398.3	56.5	100%	1024	7788		50	45	91.2%
10/24/97	57	18.6	301.8	50.4	94%	1042	7834		50	45	91.2%
10/25/97	58	0.0	0.0	0.0		1042	7834		0	0	91.2%
10/26/97	59	0.0	0.0	0.0		1042	7834		0	0	91.2%
10/27/97	60	0.0	0.0	0.0		1042	7834				84.1%
10/28/97	61	89.7	537.0	31.3	86%	1132	7860				84.1%
10/29/97	62	262.6	589.9	67.6	69%	1395	7917				84.1%
10/30/97	63	0.0	0.0	0.0		1395	7917				90.5%
10/31/97	64	11.0	311.0	0.0	97%	1406	7917				90.5%
11/1/97	65	0.0	0.0	0.0		1406	7917				90.5%
11/2/97	66	2.0	281.0	0.0	99%	1408	7917				90.5%
11/3/97	67	0.0	0.0	0.0		1408	7917				90.5%
11/4/97	68	2.0	300.0	0.0	99%	1410	7917				90.5%

Date	Day	Oil STB/D	H2O Bbl/D	Avg. Total Gas Mcf/D	H2O Cut %	Cum. Oil STB	Cum. CO2 Mcf	CO2 Inj. MMcf/D	Tbg. Press. psig	Choke Size x/64”	CO2 in Gas %
11/5/97	69	0.0	0.0	0.0		1410	7917				90.5%
11/6/97	70	28.0	250.0	0.0	90%	1438	7917				87.4%
11/7/97	71	14.2	344.3	70.6	96%	1452	7978				87.4%
11/8/97	72	11.0	338.0	58.5	97%	1463	8030				87.4%
11/9/97	73	11.9	330.2	60.1	97%	1475	8082				87.4%
11/10/97	74	13.5	337.9	61.9	96%	1488	8139				91.6%
11/11/97	75	9.7	341.6	54.0	97%	1498	8188				91.6%
11/12/97	76	0.0	0.0	0.0		1498	8188				91.6%
11/13/97	77	0.0	0.0	0.0		1498	8188				86.3%
11/14/97	78	18.0	342.0	55.9	95%	1516	8237				86.3%
11/15/97	79	11.0	353.0	51.5	97%	1527	8281				86.3%
11/16/97	80	12.1	346.1	52.0	97%	1539	8326				86.3%
11/17/97	81	9.1	351.5	50.6	97%	1548	8370				86.3%
11/18/97	82	11.0	354.1	50.3	97%	1559	8413				86.3%
11/19/97	83	4.5	350.3	45.0	99%	1564	8452				86.3%
11/20/97	84	13.8	351.1	50.0	96%	1577	8495				86.3%
11/21/97	85	14.4	350.1	47.7	96%	1592	8536				86.3%
11/22/97	86	9.9	360.7	45.8	97%	1602	8576				86.3%
11/23/97	87	11.0	350.0	47.2	97%	1613	8617				86.3%
11/24/97	88	8.0	353.8	46.6	98%	1621	8657				86.3%
11/25/97	89	7.4	363.1	48.0	98%	1628	8698				86.3%
11/26/97	90	3.0	389.4	45.8	99%	1631	8738				86.3%
11/27/97	91	2.2	371.6	45.9	99%	1633	8777				86.3%
11/28/97	92	3.7	358.5	44.5	99%	1637	8818				90.7%
11/29/97	93	6.9	369.5	45.9	98%	1644	8859				90.7%
11/30/97	94	2.6	367.2	44.5	99%	1647	8900				90.7%
12/1/97	95	1.5	363.1	45.0	100%	1648	8940				90.1%
12/2/97	96	1.6	370.7	45.6	100%	1650	8981				90.1%
12/3/97	97	1.7	378.6	43.3	100%	1651	9020				90.1%
12/4/97	98	1.7	378.6	43.3	100%	1653	9059				88.4%
12/5/97	99	1.7	378.6	43.3	100%	1655	9097				88.4%
12/6/97	100	7.8	369.0	43.6	98%	1663	9136				88.4%
12/7/97	101	11.0	345.8	37.4	97%	1674	9169				88.4%
12/8/97	102	11.0	345.8	37.4	97%	1685	9202				88.4%
12/9/97	103	11.0	345.8	37.4	97%	1696	9235				88.4%
12/10/97	104	11.0	366.0	41.5	97%	1707	9272				88.4%
12/11/97	105	11.0	366.0	41.5	97%	1718	9308				88.4%
12/12/97	106	11.0	366.0	41.5	97%	1729	9345				88.4%
12/13/97	107	11.0	366.0	41.5	97%	1740	9382				88.4%
12/14/97	108	11.0	366.0	41.5	97%	1751	9418				88.4%
12/15/97	109	11.0	366.0	41.5	97%	1762	9455				88.4%
12/16/97	110	0.0	361.0	99.8	100%	1762	9543				88.4%
12/17/97	111	0.0	361.0	99.8	100%	1762	9632				88.4%
12/18/97	112	0.0	361.0	99.8	100%	1762	9720				88.4%
12/19/97	113	0.0	361.0	99.8	100%	1762	9808				88.4%
12/20/97	114	0.0	361.0	99.8	100%	1762	9896				88.4%
12/21/97	115	0.0	361.0	99.8	100%	1762	9985				88.4%
12/22/97	116	0.0	361.0	99.8	100%	1762	10073				88.4%
12/23/97	117	5.0	383.0	33.7	99%	1767	10103				88.4%
12/24/97	118	5.0	383.0	33.7	99%	1772	10133				88.4%

Date	Day	Oil STB/D	H_2O Bbl/D	Avg. Total Gas Mcf/D	H_2O Cut %	Cum. Oil STB	Cum. CO_2 Mcf	CO_2 Inj. MMcf/D	Tbg. Press. psig	Choke Size x/64"	CO_2 in Gas %
12/25/97	119	4.2	390.0	32.4	99%	1776	10161				88.4%
12/26/97	120	4.2	390.0	32.4	99%	1780	10190				88.4%
12/27/97	121	4.2	390.0	32.4	99%	1784	10219				88.4%
12/28/97	122	0.0	429.9	33.2	100%	1784	10248				88.4%
12/29/97	123	0.0	383.5	32.5	100%	1784	10275				83.5%
12/30/97	124	1.1	384.2	32.9	100%	1785	10302				83.5%
12/31/97	125	0.6	387.1	31.9	100%	1786	10329				83.5%