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

Final Report
February 10, 1994 to December 31, 1997

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February, 1999

Work Performed Under Contract No. DE-FC22-94BC14986

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Midland Texas

National Petroleum Technology Office
U. S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

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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 be mostly confined 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 covered the actual field demonstration of the proposed technology. Technology transfer spans the entire course of the project.

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 was in the form of a cost sharing Cooperative Agreement (Project). The goal of this joint Project was to demonstrate the Carbon Dioxide (CO_2) Huff-n-Puff 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 expansion and acceleration of such capital-intensive projects in many similar reservoirs. This is a common finding throughout the Permian Basin SSC reservoirs. In theory, it was 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 have resulted in near-term production, or revenue, to help offset cash outlays of the capital-intensive miscible CO_2 project. The DOE partnership provided 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 have been replicated within industry many fold, resulting in additional domestic reserves. However, the process appears to have limited opportunities within a waterflooded environement based on this study's results.

The principal objective of the CVU and SSU CO_2 Huff-n-Puff projects was 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 was 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. The tasks associated with this objective were completed in a timely manner.

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. If successful, the proposed technology promised a number of economical advantages. Profitability of marginal properties could be maintained until such time as pricing justified 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 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. However, the economics and operational limitations in most fields are not favorable for application of this technology.

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 a 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 produced water may have dissolved the newly developed 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 in the Vacuum Field, 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 encouraging enough to consider expanding 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 experienced 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.

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. The work at SSU also resulted in sub-economic performance, although recoveries were notably higher than at CVU.

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. However, this hypothesis is beyond the nature of this demonstration project.

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 continued to experience reduced electrical costs due to reduced water production. Although similar in response, the demonstration at SSU did not experience the lifting cost margin improvement levels as that of the CVU demonstration site.

INTRODUCTION

CVU Development History

The Vacuum Field was discovered in May 1929 by the Socony-Vacuum Oil Company, a predecessor of Mobil. The discovery well was the New Mexico "Bridges" State Well No. 1 (drilled on the section line of Sec's 13 & 14, T16S R34E). The well was shut-in until 1937 when pipeline facilities became available to the area. The field is located 22 miles west of Hobbs in Lea County, New Mexico (**Fig. 1**). Field development began on 40-acre well spacing. By 1947 the field limits were defined. The CVU was infill drilled on 20-acre spacing during 1978-1979. Further reservoir development began in the late 1980's with sporadic infill drilling on 10-acre spacing, which continues. Enhanced recovery operations by waterflooding are in progress across the entire Vacuum field. Water injection at CVU was initiated in 1978. A polymer-augmented waterflood was initiated and completed during the mid-1980's. The CVU has performed well under waterflooding with ultimate recoveries (primary + secondary) forecast at 44.8% of original oil-in-place (OOIP). A plot of the CVU production and injection history is found in **Fig. 2**. The flood is quite mature in some areas, yet would be considered an adolescent in others due to varying reservoir qualities. Miscible CO_2 Flooding was initiated in 1985 by Phillips in the southeastern portion of the field, immediately east of the CVU, and to the west of CVU in 1996 at the State 35 Unit (Mable-Hale). **Figure 3** identifies the Unitized operations of the Vacuum field. In addition to the San Andres/Grayburg producing horizons, there are 12 other formations that are, or have been productive in the Vacuum field. These mostly deeper horizons were developed predominantly during the 1960's.

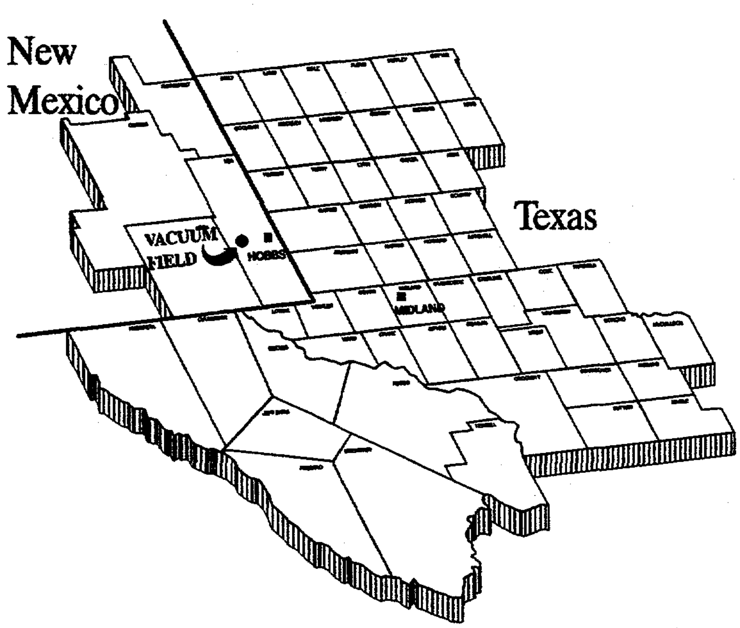

Fig. 1: Regional location of Central Vacuum Unit.

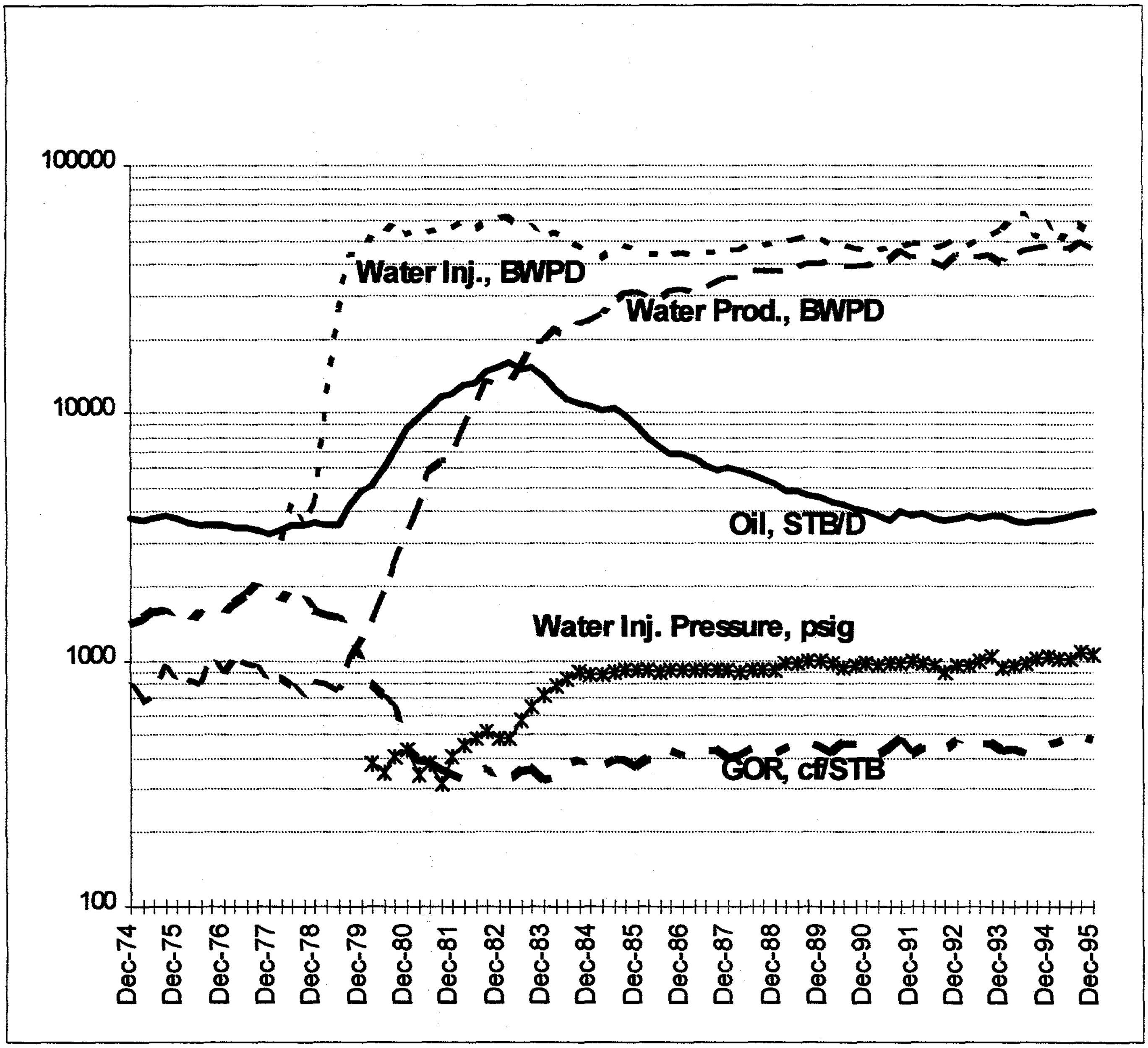

Fig. 2: Central Vacuum Unit production and injection history. Textbook waterflooding character.

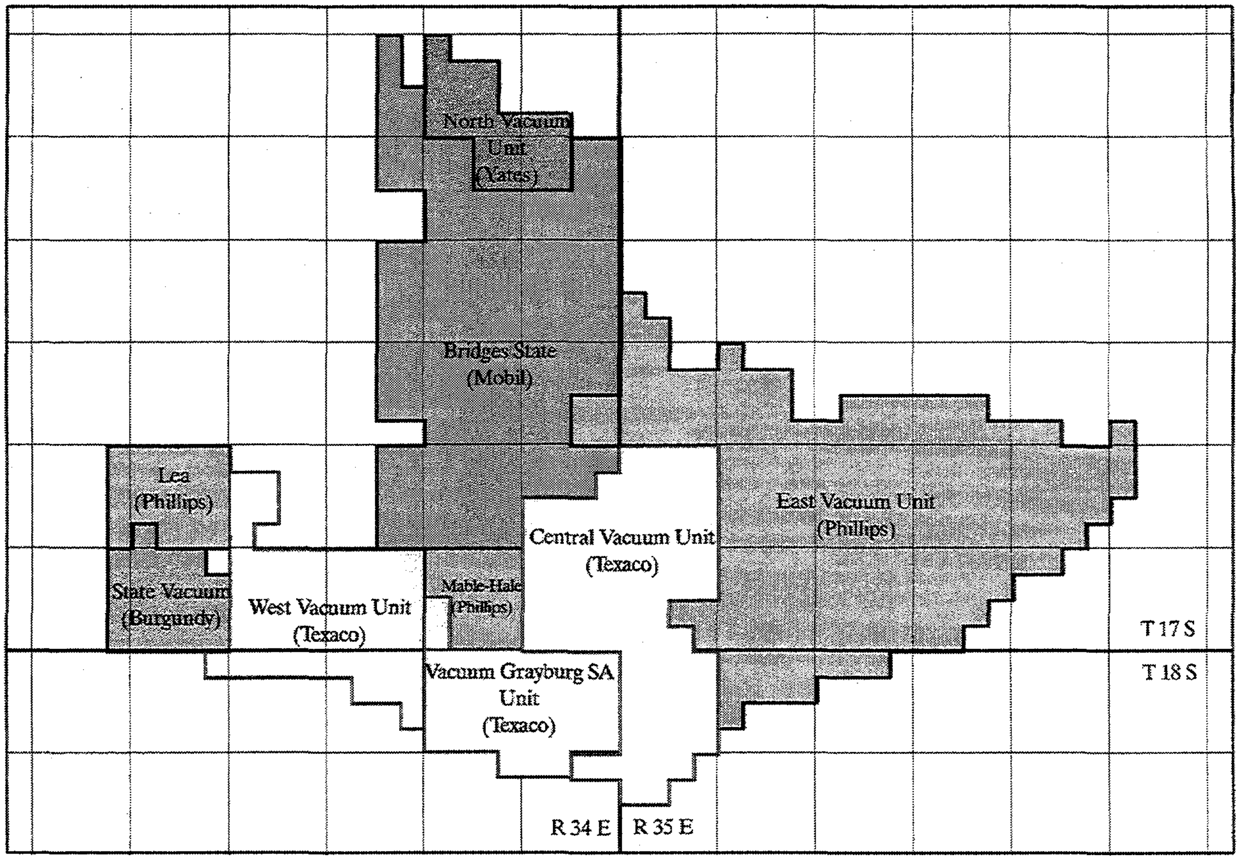

Fig 3: Unitized Acreage of Vacuum Field, Lea Co., New Mexico.

CVU Geology

The Vacuum field lies on the margin between the Northwest Shelf and Delaware Basin (**Fig. 4**). Production is primarily from the Permian Guadalupian age San Andres formation. Less than 15% of the Unit's OOIP is located in the overlying Grayburg formation. The San Andres is composed of cyclical evaporites and carbonates recording the many "rises" (transgressing) and "falls" (regressing) of sea level occurring around 260 million years ago in a climate very similar to the present day Persian Gulf. The San Andres pay zone is divided by the Lovington sand member. The Grayburg formation is composed of cyclical carbonates and sands. The oil has been trapped in porous dolomites and sands that developed on a structural high. The productive intervals are sealed by overlying evaporites. Stratigraphically to the north, the porous dolomites pinch out into non-porous evaporites and evaporite filled dolomites. The porous zones are thinning and dip below the free oil-water contact (~4,700 ft.) in the southerly, basinward direction. A structural map is provided in **Fig. 5**.

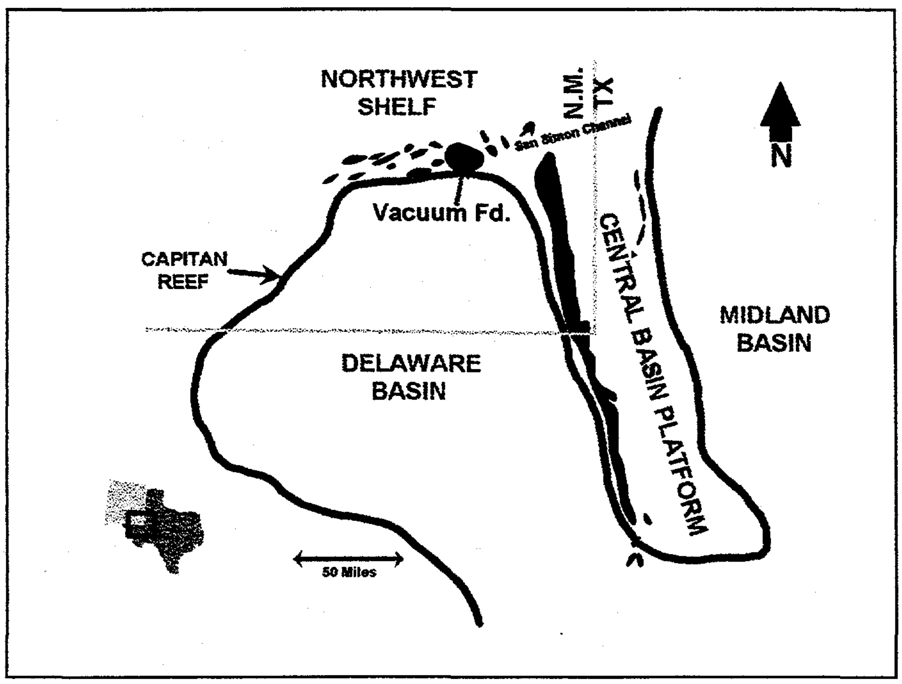

Fig. 4: Permian Basin and relative position of Vacuum field.

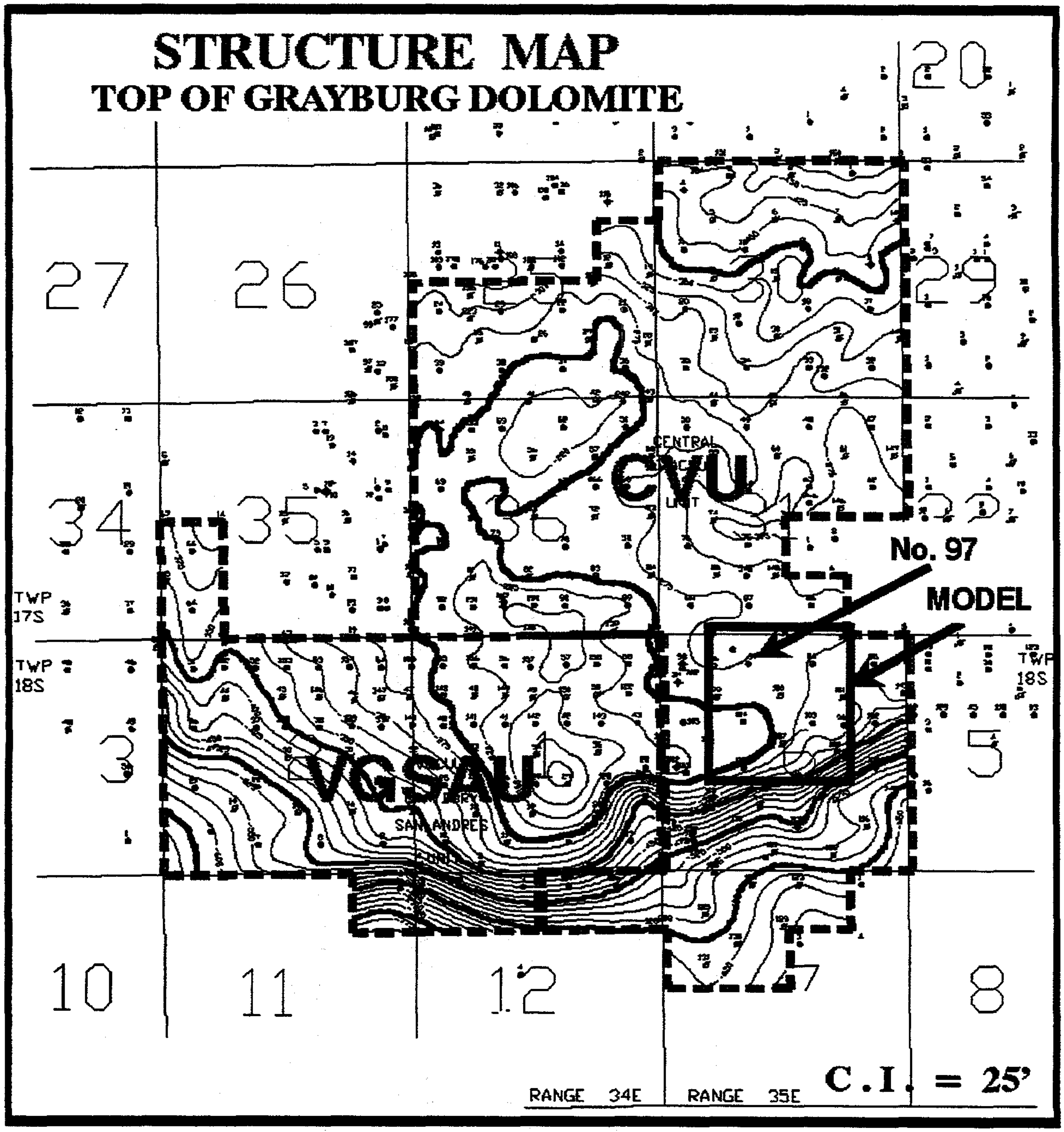

Fig. 5: Limits of Central Vacuum Unit with structural contours on Grayburg Dolomite. Shelf-Basin margin

Lithologically, the Grayburg formation consists of relatively dense dolomite with some anhydrite. It contains interbedded dolomitic sand stringers. The San Andres formation consists of dense medium crystalline and oolitic dolomite with some anhydrite. The pay is a fine to medium crystalline oolitic dolomite with slight fracturing and some solution cavities. Productive intervals consist of a series of permeable beds separated by relatively impermeable strata. The impermeable strata extend over large areas of the field and are believed to serve as effective barriers to prevent cross-flow between the permeable beds. The gross pay would be characterized as heterogeneous.

The Grayburg/San Andres formations produce 38.0° API oil from an average depth of 4,550' within the CVU. The original water-free oil column reaches as much as 600' in height. Porosity and permeability in the pay interval can reach a maximum of 23.7%, and 530 md, respectively. The porosity and permeability over the gross pay interval averaged 6.8% and 9.7 md, respectively. Based on core studies, the net productive pay averages 11.6% porosity and 22.3 md. Although current saturations in the near wellbore vicinity have not been directly measured, core studies suggest typical residual oil saturations to waterflooding in swept zones to be in the range of 30-35%. Oil saturations in poorly swept zones, created by the heterogeneous architecture of the reservoir, could approach initial conditions. Hypothetically, this leaves a significant volume of uncontacted and immobile oil in the near wellbore vicinity of producing wells, which is the target of this CO_2 Huff-n-Puff process.

SSU Development History[12]

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 6)**. 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 as the field was developed on 35-acre spacing. The wells were produced via solution gas drive. In 1959, waterflooding operations began.

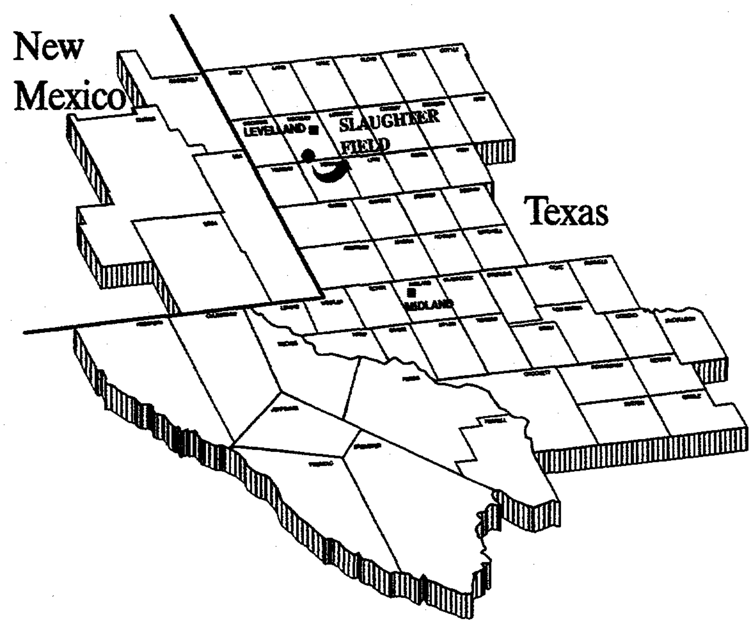

Fig. 6: Regional location of Sundown Slaughter Unit.

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 into the SSU, and in January 1994 miscible CO_2 flooding operations began in it's eastern portion. 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 36.0% 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. 7)**.

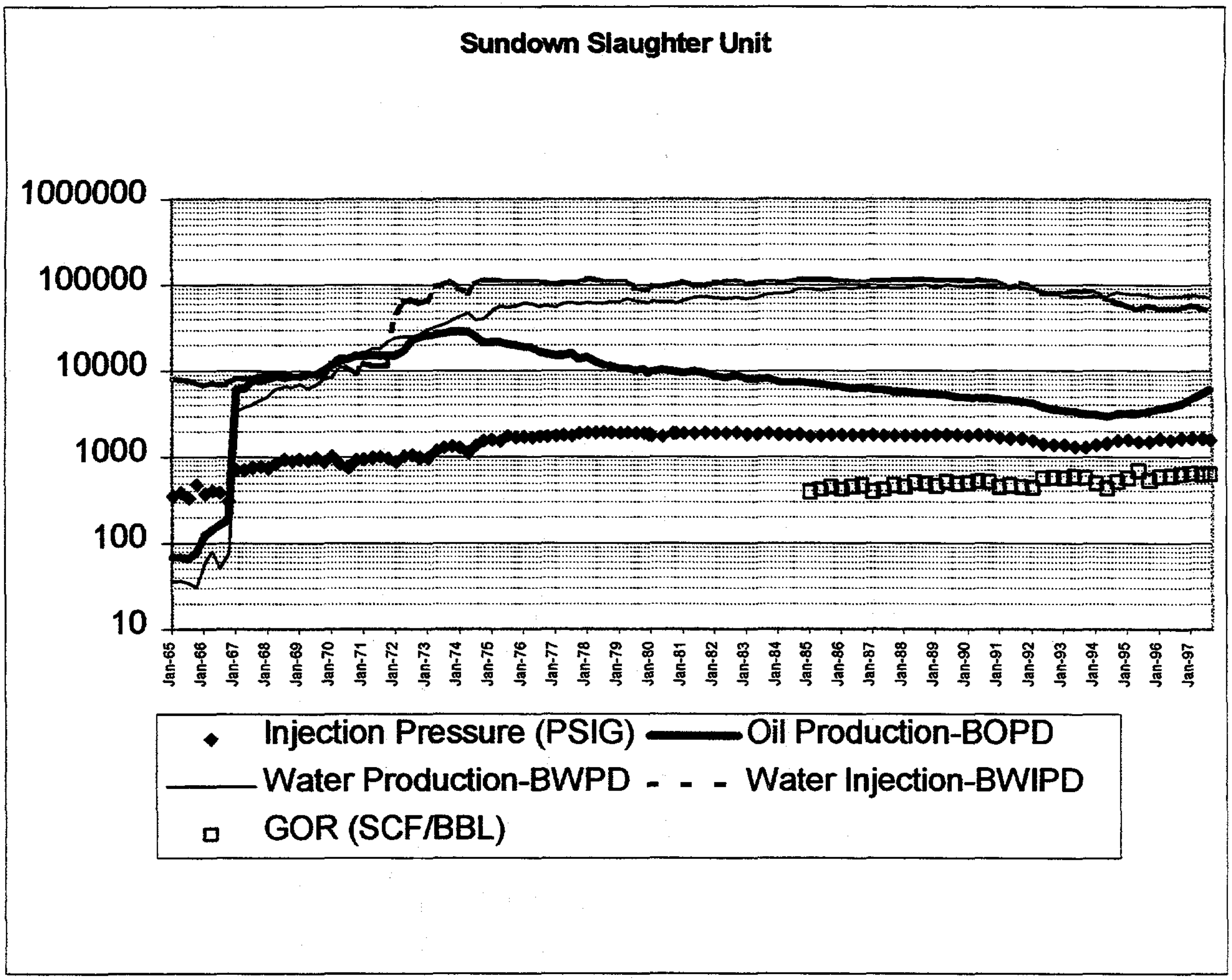

Fig. 7: Sundown Slaughter Unit production and injection history.

There are currently eight active CO_2 floods in Slaughter Field, including the SSU. Four of these projects are adjacent to SSU (**Fig. 8**). 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.

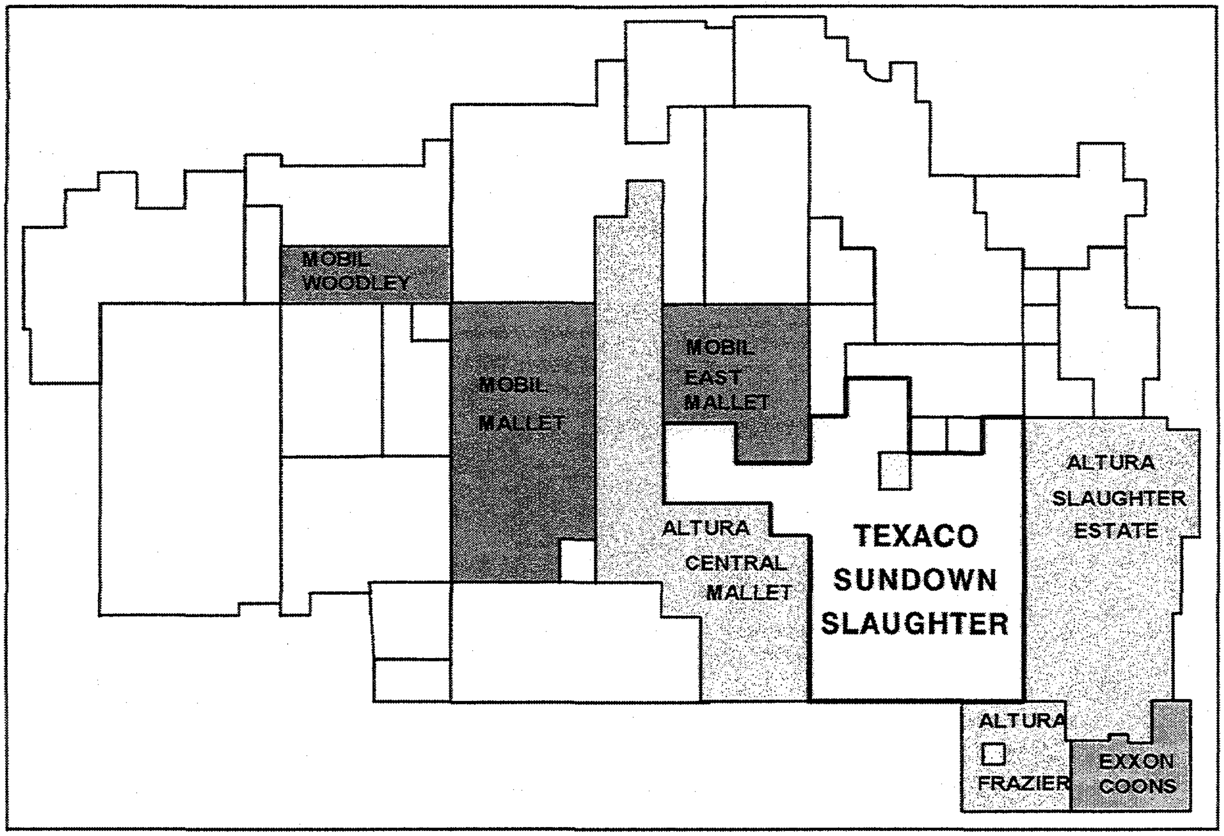

Fig 8: Unitized Acreage of Slaughter Field, Hockley Co., Texas.

SSU Geology[12,13]

The Slaughter Field lies on the Northwest shelf of the Midland Basin (**Fig. 9**). 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. 10**) 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 33.0° API oil. Porosity and permeability average 12.0% and 5.0 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 23.0%. It is estimated that waterflood residual oil saturation is greater than 50.0% of the original oil-in-place (OOIP) which would leave a large target for tertiary 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.

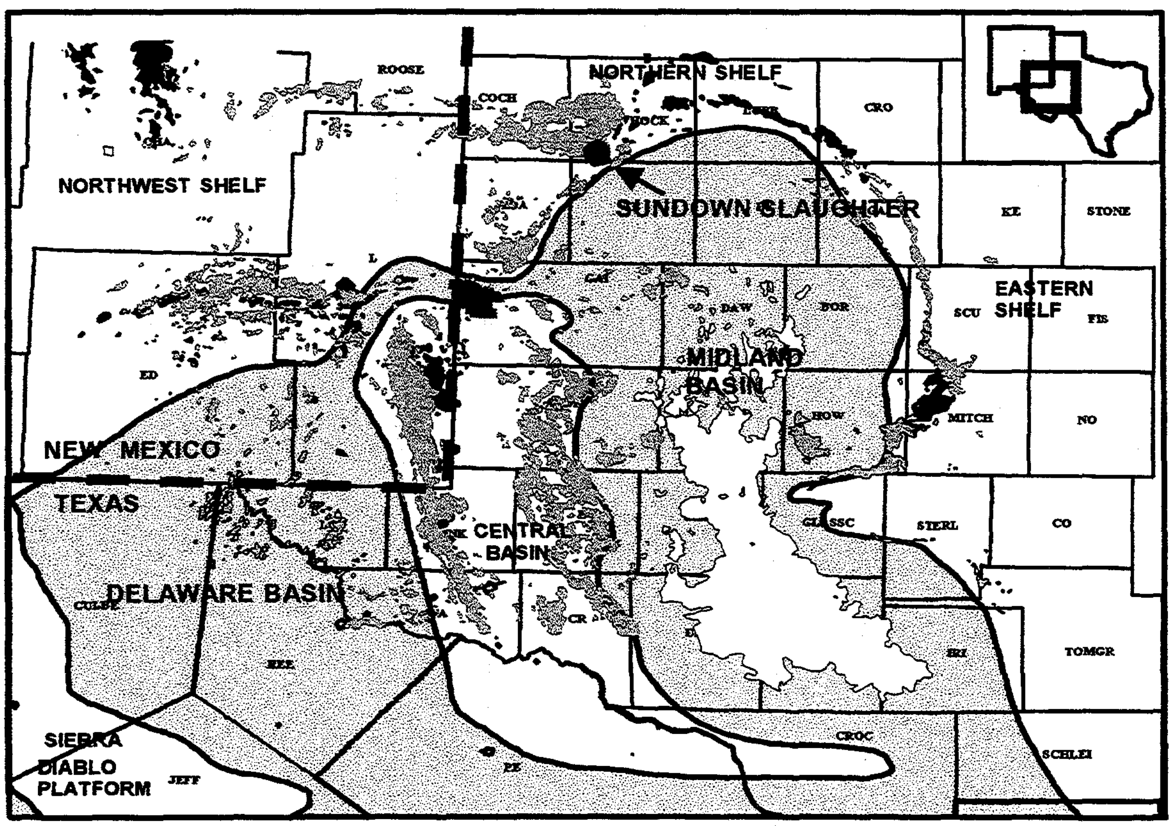

Fig. 9: Permian Basin and relative position of Slaughter field.

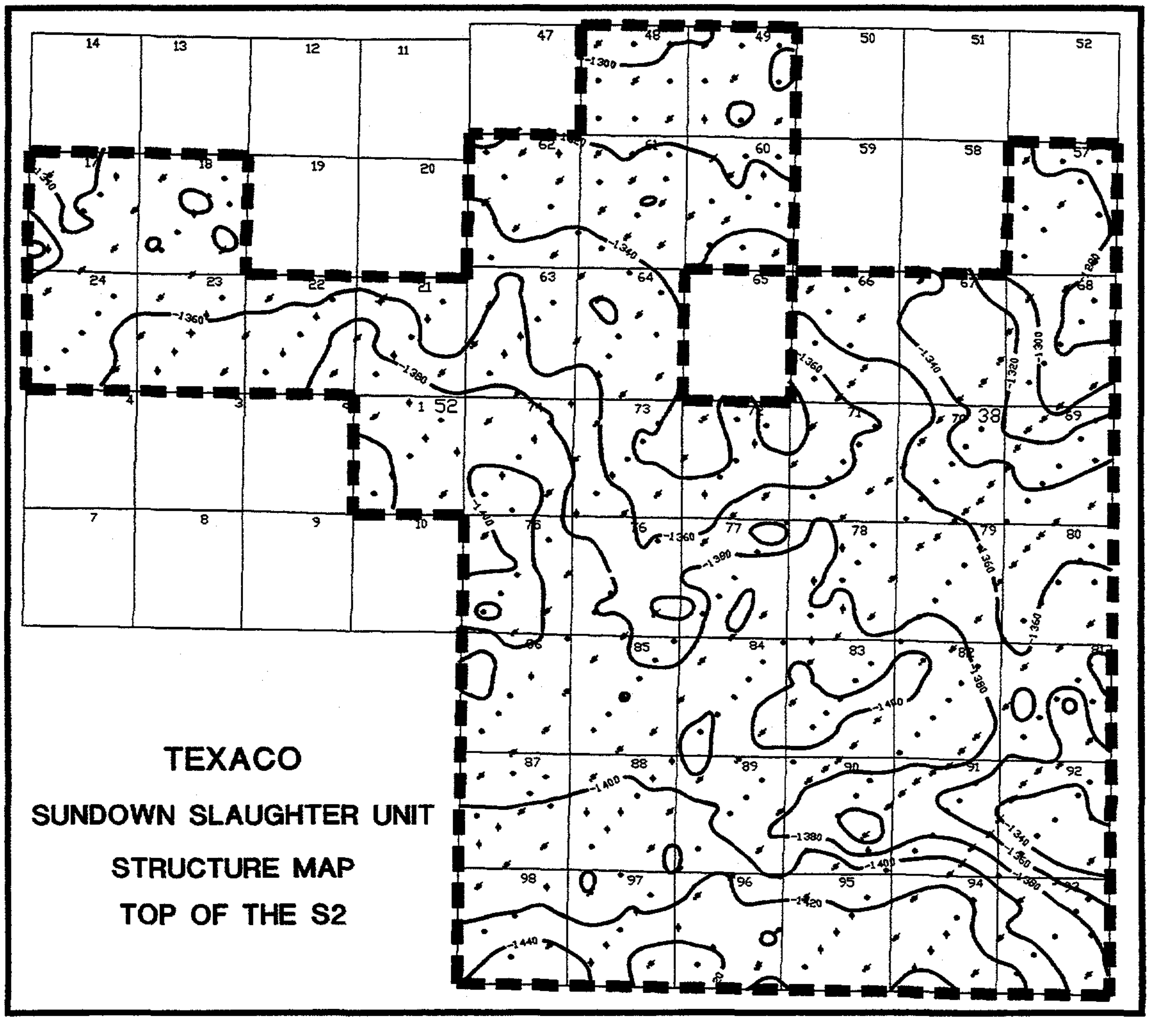

Fig. 10: Limits of Sundown Slaughter Unit with Structural Contours on San Andres S2 (Subsea, ft).

Brief of Project & Technology Description

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 at CVU. The second, and final budget period incorporated 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.

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 Objectives. 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 hydrocarbon system. As depicted in **Fig. 11**, recovery efficiencies are notably less under immiscible conditions.

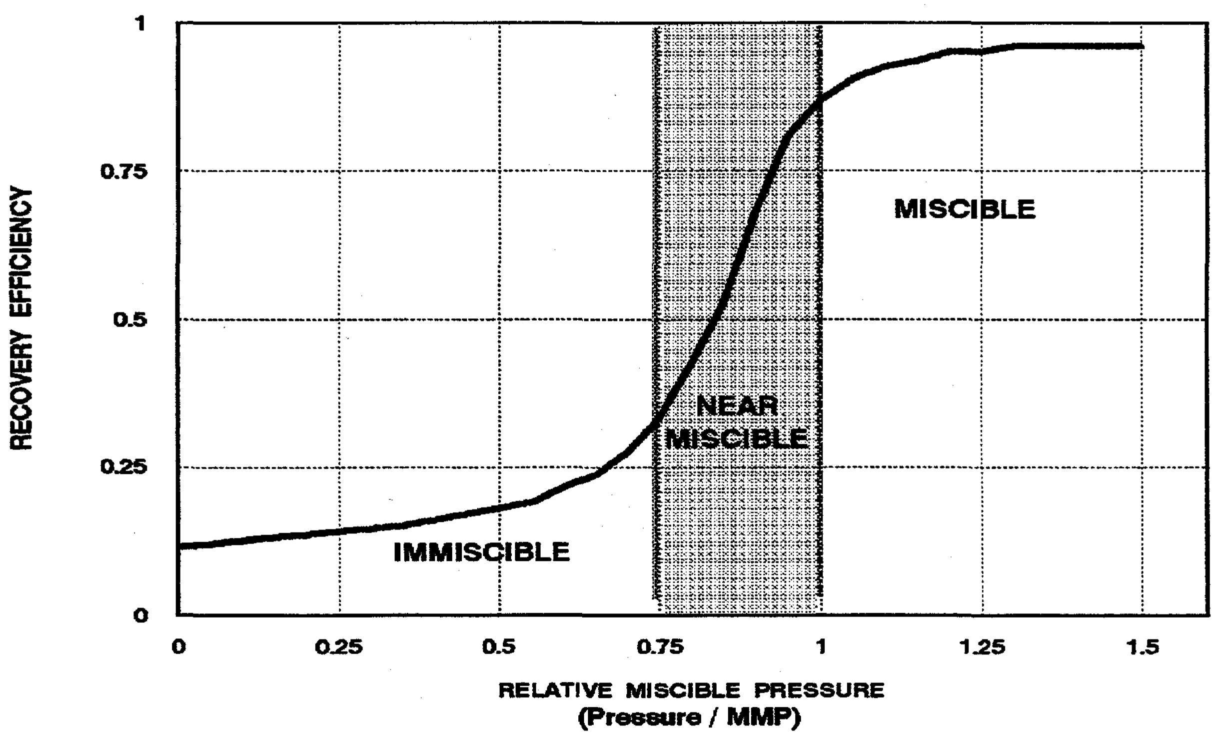

Fig. 11: Generalized Recovery Efficiency vs. Relative Minimum Miscibility Pressure.

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 is then absorbed 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. **Figure 12** visually illustrates the CO_2 Huff-n-Puff process.

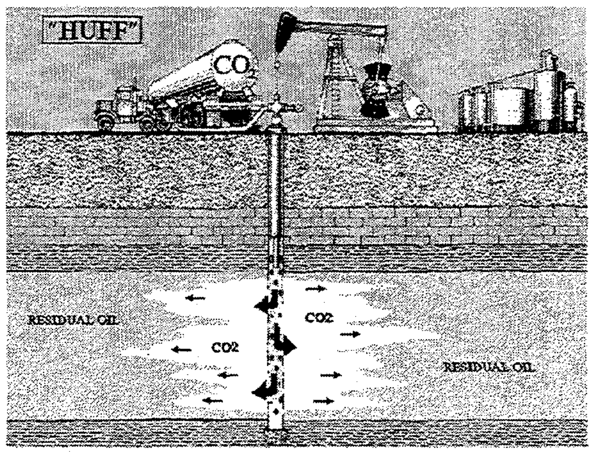

Fig. 12a: Injection, or "Huff" phase of Project.

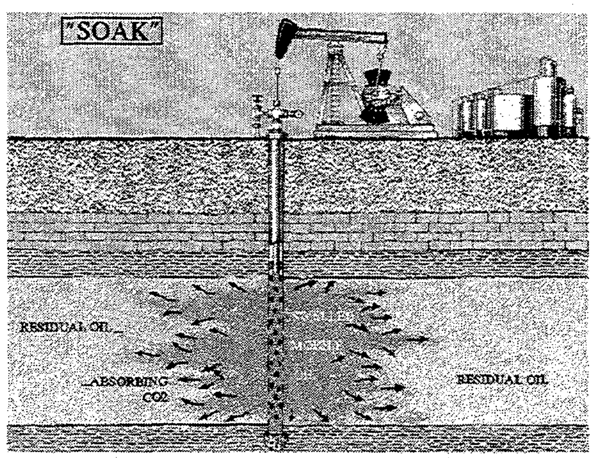

Fig. 12b: The "Soak" phase of the Project.

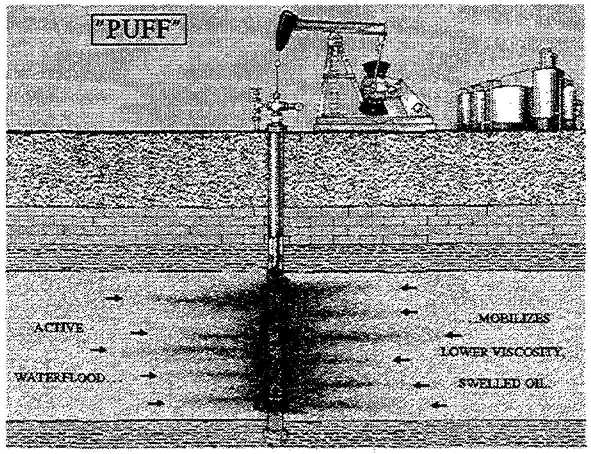

Fig. 12c: The production, or "Puff" phase of the Project.

The vast majority of field trials have been conducted in low-pressure environments. Trials in moderate water-drive reservoirs have met with limited success. **Figure 13** 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. 11**, 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 waterflooded SSC reservoirs.

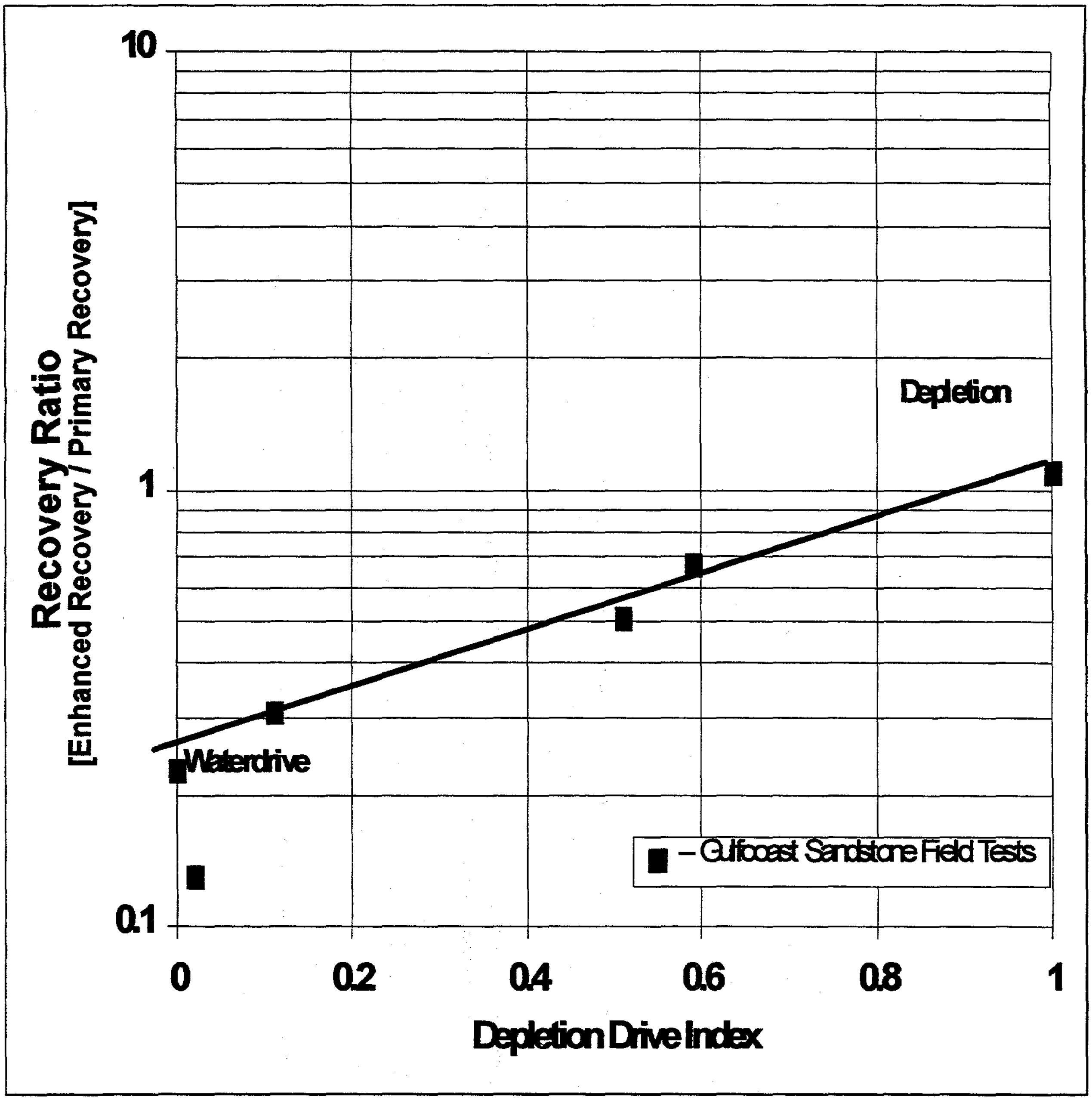

Fig. 13: Relation between Drive Index and Recovery Efficiency of the CO_2 Huff-n-Puff process. Developed from Gulf-Coast sandstone reservoir field trials.

DISCUSSION

Work encompassing the initial budget period of the reservoir characterization and simulation was undertaken in 1994 and completed in 1995. Macro zonation exists throughout the study area and cross-sections are available. The Oil-Water contact was defined and laboratory capillary pressure data was used to define the initial water saturations within the pay horizon. An understanding of the reservoir's porosity distribution was enhanced with the assistance of geostatistical software. Three-Dimensional kriging created the spacial distributions of porosity at inter-well locations. Artificial intelligence software was utilized to relate core permeability to core porosity, which in turn was applied to the 3-D geostatistical porosity gridding. An Equation-of-State was developed and refined for compositional simulation exercises and a waterflood review was performed to identify the site for modeling and field demonstration of the project. Parametric simulations. site-specific simulation, history match and forecast were performed.

Work began on the second budget period field demonstrations in 1996 and concluded in 1997. 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 were found to be the more dominant 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.

Macro Zonation & Cross Sections

A total of 455 wellbores penetrate the Grayburg and San Andres formation within the CVU project study area. Cross-sections through all wells within the producing horizons on Texaco operated acreage within the project study area were completed. An index map of the CVU cross sections is provided in **Fig 14**. These cross sections were stratigraphically hung on the Grayburg Marker. Formation tops shown on the cross sections include (where identified/present) the Grayburg Dolomite, Grayburg Sandstone (non-pay), San Andres Sandstone (non-pay), Upper San Andres, Lovington Sandstone (non-pay), and the Lower San Andres. These tops represent the macro zonation based on a deterministic approach. The cross sections were developed using the commercial software, GeoGraphix Evaluation System. An example cross-section is shown in **Fig. 15**. Completion histories are included on the cross-sections. The cross sections assist in the understanding of the reservoir architecture, providing a quick review of correlative zones while reviewing waterflood histories.

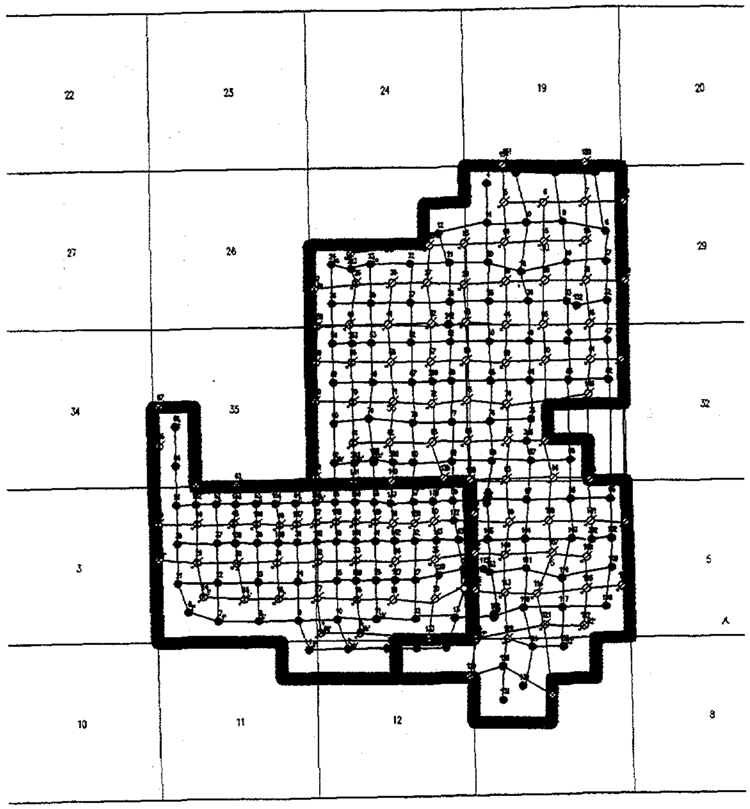

Fig. 14: Index map of available cross sections.

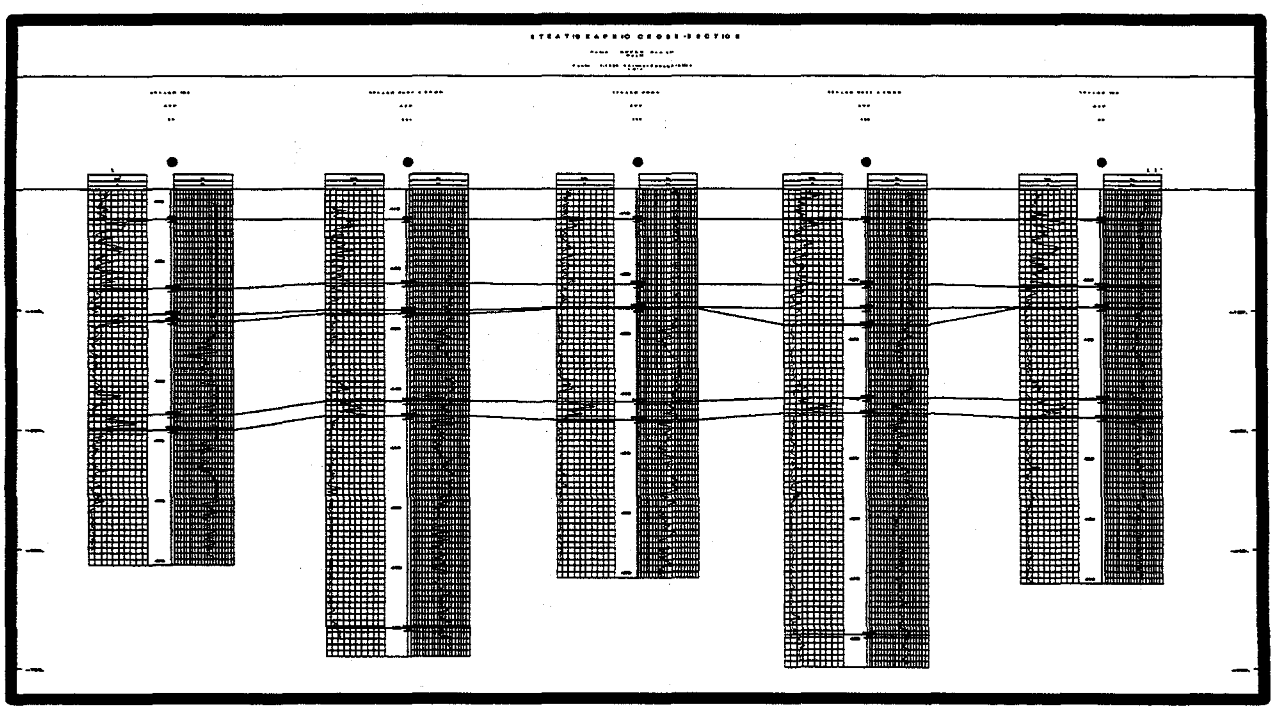

Fig. 15: Example cross section within project study area.

Initial Water Saturation Distribution & Oil-Water Contact

One of the major milestones associated with the reservoir characterization component of the project is determination of Original Oil-in-Place (OOIP). Therefore, an evaluation of fluid saturation was warranted. Initial water saturation (S_{wi}) distribution in a given reservoir is a function of capillary pressure[14-16] and the height of a zero capillary pressure point. Laboratory derived capillary pressure data, corrected for reservoir conditions, can be used to define initial saturations above an Oil-Water Contact (OWC), or zero capillary pressure level (S_w=100 %). This study defined the OWC to be at -1,000' from sea level datum based on wireline resistivity measurements. The average S_{wi} of the main pay zone was established at 20.0 % using the wireline log and capillary pressure data.

It was first necessary to establish the OWC in order to apply the capillary pressure data. Historically, operators within the field have used various "OWC's" ranging from -700' to -775' from sea level[17-21]. This datum was probably established by drillers during the early development of the field as the deepest point for a water-free completion. This depth however is not the OWC, but is an average representation of the end point on the relative permeability curve corresponding to the irreducible water saturation, S_{wirr}. This depth will be referred to as the top of a transition zone (TZ). A review of original depths for wells within the CVU & VGSAU found the average well depth to be at -700' from sea level. Very few wells had produced any measurable water above this depth by 1945[17] and few would make any water prior to waterflooding operations in the 1970's. The majority of water encountered above the TZ in current operations has therefore been introduced by waterflooding operations. All known/documented tests within the TZ were included in this OWC study.

The task of establishing the true OWC, or bottom of the TZ, was accomplished by standard electric wireline log (E-log) evaluation techniques. Until recently, the unavailability of useable E-logs prohibited an accurate estimate of the OWC. Most of the E-logs that previously existed did not penetrate the TZ. Up until 1990, only 26 of the existing 85 E-logs penetrated enough of the formation to evaluate any part of the TZ, and only five of these were logged prior to waterflood influence. The few E-logs that did penetrate the TZ were found to be of questionable quality due to their vintage. Deeper drilling locations also yielded a few useable E-logs. Since 1990, an additional 68 E-logs (penetrating the TZ) have been obtained within, or in near proximity to, the CVU & VGSAU boundaries. A 10-acre infill drilling program within the San Andres formation, beginning in 1990, provided an additional 23 E-logs. A large-scale infill drilling program to the deeper Glorieta formation, beginning in 1991 provided an opportunity to gather another 45 E-logs across the TZ of the San Andres formation. As expected, the waterflood influence on these more recent logs caused a distortion of the shallower data, making log analysis difficult. However, in spite of the alteration from initial conditions in some zones, many of these new logs were found to be adequate due in part to compartmentalization and discontinuities within the reservoir. A "ghost" or "shadow" of the original saturation profile can be identified due to these heterogeneities. Some 10-Acre infill locations even exhibited a classic, uninfluenced saturation profile.

A thorough study of all available data suggests that the OWC be defined at approximately -1,000' from sea level datum. A review of the geological structure within the region containing the Vacuum field suggests that there is field closure to the north, east and south at approximately -800' from sea level. Hydrodynamic forces should be acting from the updip, northwesterly direction. However, the field is sealed by stratigraphic facies changes to the West, and a lack of water influx coupled with the obvious hydrocarbon saturations well below this level on E-logs suggest that the field is not in contact with any hydraulic pressure. Therefore, the OWC has been represented at a constant horizon of -1,000' from sea level datum.

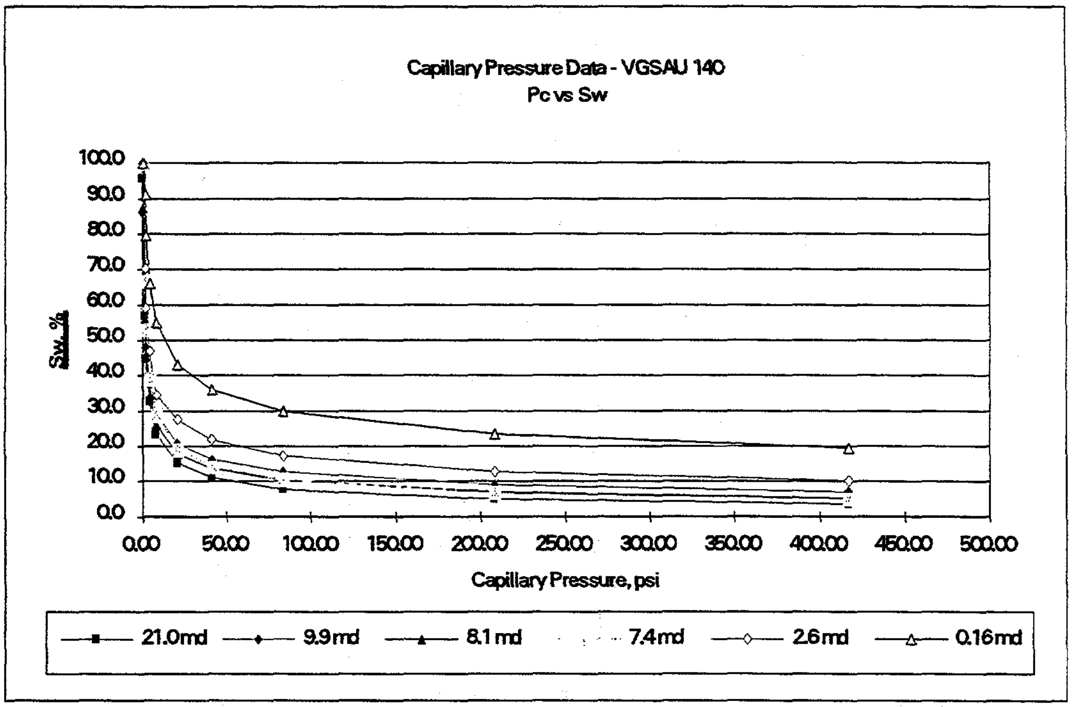

Fig. 16: Capillary pressure related to water saturations, S_w. VGSAU Well No. 140.

Capillary pressure data is available for VGSAU Wells 140 and 157. VGSAU Well No. 140 had the only core centrifuge derived capillary data (air-water) available. Mercury injection derived capillary pressure data from VGSAU No. 157 was found to be of questionable value for these calculations. The mercury capillary pressure data was inconsistent from sample-to-sample. Capillary pressure data from VGSAU Well No. 140 is plotted in **Fig. 16**. The laboratory data was then related to the height above zero capillary pressure (the OWC) by the following formula,

$$P_c = (\rho_o - \rho_w)h/144$$

where,	P_c	=	Capillary pressure, psia
	ρ_o	=	Oil density, lbs/ft^3
	ρ_w	=	Water density, lbs/ft^3
	h	=	Height above P_c= 0, ft

The data was converted to reservoir conditions by applying the following scaling factor:

$$f = (\sigma\cos\theta)_{air\text{-}water}/(\sigma\cos\theta)_{oil\text{-}water}$$

where,	f	=	Scaling factor, dimensionless
	σ	=	Interfacial tension between respective fluids, dynes/cm
	θ	=	Contact angle between respective fluids, degrees

[The products of the interfacial tension and cosine of the contact angle for the laboratory fluids (air-water) and the reservoir fluids (oil-water) were taken from Core Laboratory's Fundamentals of Core Analysis[22], as 72 and 26, respectively. The resulting scaling factor is 2.77]

This capillary pressure data was used to determine the S_{wi} profile of the reservoir calculated at the geometric mean permeability. The geometric mean permeability of the VGSAU Well No. 140 core was found to be 2.7 md, which compared favorably with the geometric mean average for the entire Vacuum Core Database. The average S_{wi} determined by this approach was then estimated at 19.5 % for the main pay zone. The capillary pressure approach is considered to be within the limits of accuracy and is historically supported by log derived values of 20.0 % as the average S_{wi} within the pay.

The capillary pressure data was then reduced to a Leverett "J" Function, J(Sw) with the following formula:

$$J(Sw) = h(\rho_o - \rho_w)(k/\phi)^{.5}/144(\sigma\cos\theta)_{oil\text{-}water}$$

where,	$J(Sw)$	=	Leverett "J" Function, dimensionless
	ρ_o	=	Oil density, lbs/ft^3
	ρ_w	=	Water density, lbs/ft^3
	h	=	Height above $P_c = 0$, ft
	σ	=	Interfacial tension between respective fluids, dynes/cm
	θ	=	Contact angle between respective fluids, degrees
	k	=	Permeability, md
	ϕ	=	Porosity, decimal

The capillary pressure derived $J(S_w)$ data points for VGSAU Well No. 140 are shown in **Fig. 17** along with the data points derived from the well's logging suite. For the wireline-derived data, the porosity value was taken from wireline measurements, normalized to core porosity. The permeability was determined by neural network relationships derived from core porosity and core permeabilities discussed in detail elsewhere within this same report. A curve was fit to match this data, and is also provided in the same exhibit.

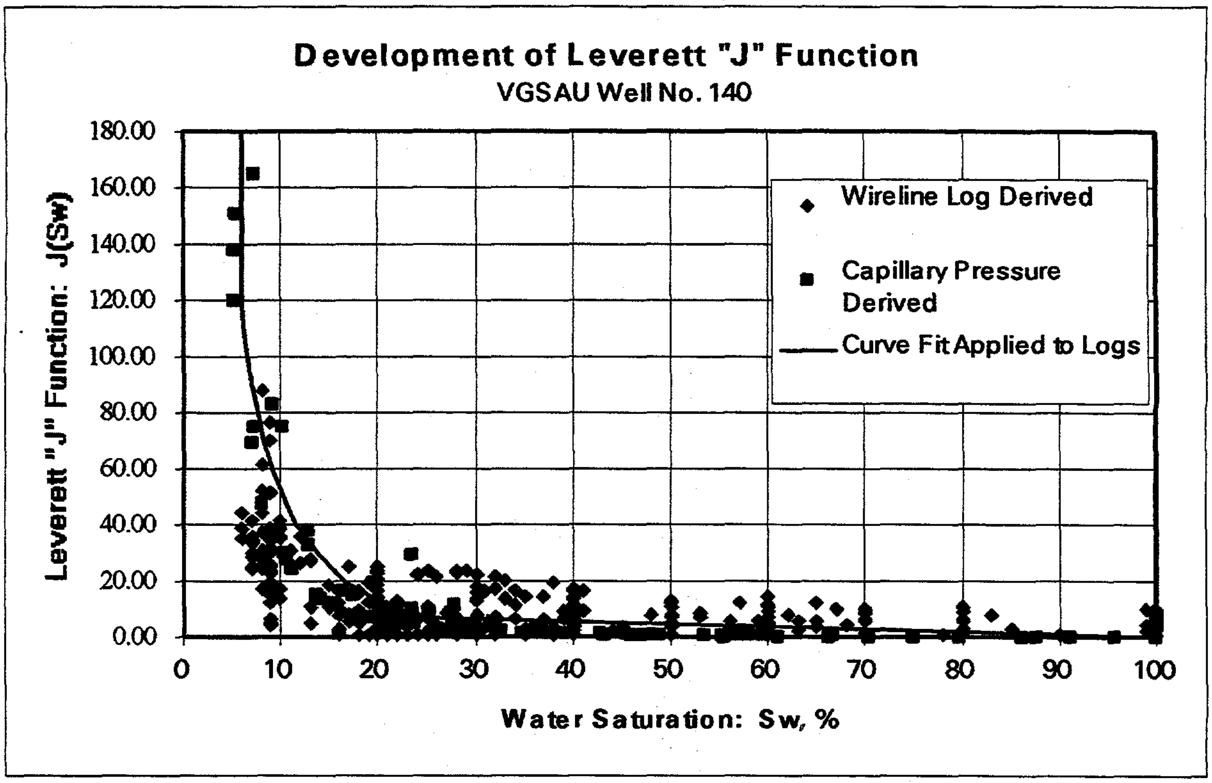

Fig. 17: Comparison of wireline derived saturations and capillary pressure derived $J(S_w)$ data. VGSAU Well No. 140.

This curve-fit relationship is then applied to all wells within the study area to define the Swi profile for the reservoir. The average water saturation, S_{wi}, for the pay zone in this same well using $J(S_w)$ results in a value of 20.9 %, further supporting previous findings. The $J(S_w)$ derived calculation is compared to the E-log values in **Fig. 18** for VGSAU No. 140.

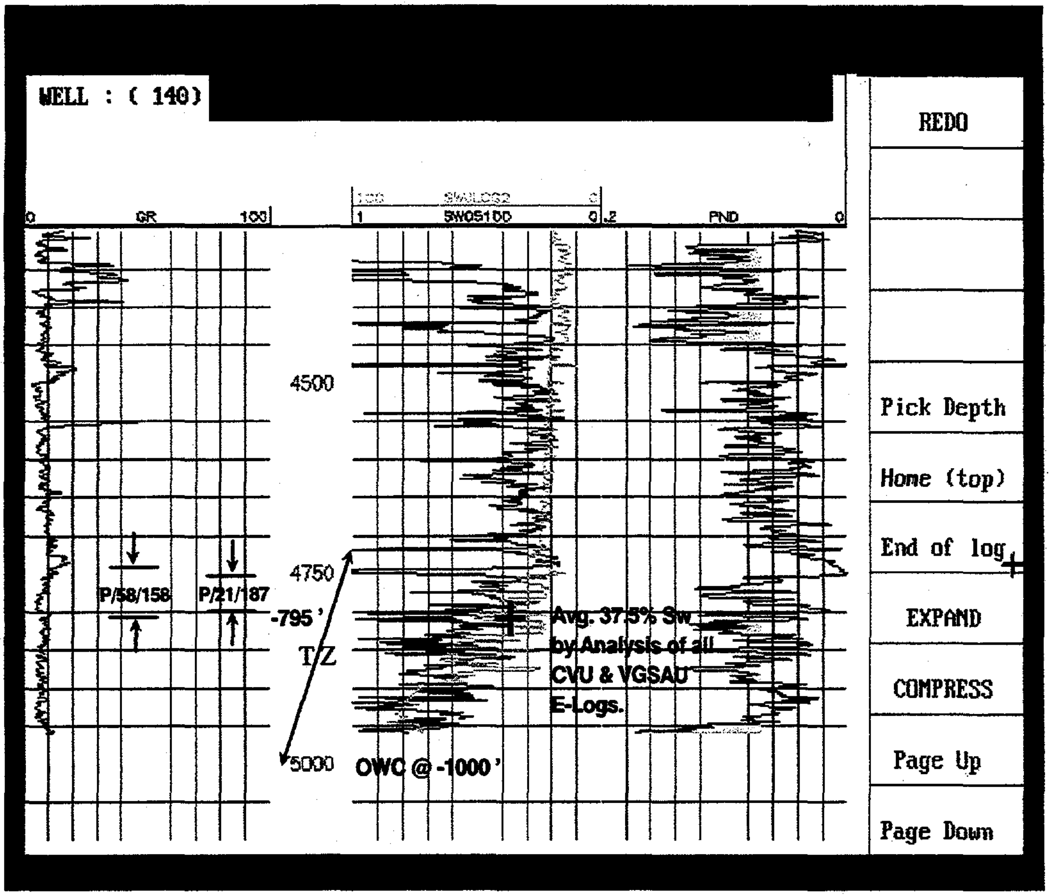

Fig. 18: Leverett "J" Function developed S_{wi} profile compared to wireline data. VGSAU Well No. 140. Production tests tend to support definition of transition zone (however waterflooding has been active for 12 years). Evaluation of all electric logs available suggests that the Avg. 37.5% S_{wi} (50% water per fractional flow curve) is at -795' from sea level.

Application of this $J(S_w)$ also honors the fractional flow curve. Field production tests prior to waterflooding suggested that appreciable water production would not occur above -700' from sea level. Recent testing of individual deeper zones further suggests that 100.0 % water production should be expected below -800' from sea level. The fractional flow curve suggests 100.0 % oil flow below approximately 25.0 % S_w and 100.0 % water flow above approximately 60.0 % S_w. These two end points on the fractional flow curve are honored by application of the $J(S_w)$ derived above to log data.

A review of resistivity logs run before the introduction of foreign fluids to the reservoir suggests an S_{wi} as low as 15.0 % in some of the shallower, higher quality pay zones. This range is supported by the capillary pressure study. More recent resistivity measurements indicate S_{wi} as low as 6.0-10.0 % in some of these same correlative zones. This is likely a resultant of the introduction of fresh water to the system in the early years of waterflooding, along with continued fresh water make-up volumes added to the produced water prior to reinjection. In addition, a polymer-augmented waterflood performed in the mid-1980's could have also adsorbed onto the matrix rock adding to the complexity of modern resistivity log interpretation.

The culmination of this exercise was the selection of a "pseudo-OWC" surface, or an "economically attractive OWC" within the TZ, which would be used in the calculation of OOIP. However, with much consideration and review of data, it was felt that it was more important for this project that the OOIP be calculated to represent the hydrocarbon section available for application of the proposed technology. Therefore a detailed study of past and current completions identified a fairly constant surface at -700' subsea to be the average bottom of the current producing horizon. This artificial horizon will be used in subsequent evaluations of OOIP. The $J(S_w)$ relationship will be applied to the massive database described in the geostatistics section of this report for initial simulation model conditions. Material balance will allow estimation of current average saturations by injection pattern for waterflood efficiency review.

Net Pay Determination

The rock might have hydrocarbon saturation, but can it be produced? Not all reservoir rock is economically productive. It is important to know what reservoir pay is contributing to the production stream. Disregarding sweep efficiency, a 98.0% water-cut is reached just before 98% of the reservoir flow capacity is depleted. Therefore, as a rule-of-thumb, the 98.0% flow-capacity has been used in considering the permeability cutoff. By sorting the database on permeability, the permeability necessary to provide 98.0% flow capacity (k*h) can be determined. Noting the corresponding storage capacity (Phi*h), the database is resorted on porosity, Phi. The porosity cutoff corresponds to the same value of storage capacity found in the previous sorting. Use of either the porosity or permeability cutoff should yield approximately the same value for net pay.

A total of 18 whole-core analyses (10 CVU & 8 VGSAU) provided 4,312 porosity and permeability samples, representing 4,979' of reservoir material for study. The data was digitized for database manipulation. Fracture dominated footage was culled, along with any "plug" analyses. Evaluation of the database finds on average a 1.7 md permeability cutoff within the oil column to be equivalent to the 98.0% flow capacity, which corresponds to approximately a 7.0% porosity cutoff. Each of the zones identified within the reservoir was evaluated independently. The findings are included in **Table 1**.

Table 1: RESULTS OF POROSITY & PERMEABILITY CUTOFF STUDY

ZONE	FOOTAGE AVAILABLE, ft	PERMEABILITY CUTOFF, md	POROSITY CUTOFF, %	Avg. POROSITY Above CUTOFF, %
Grayburg Dolomite	320	0.8	7.3	10.2
Grayburg Sandstone	256	0.4	7.3	11.4
Upper San Andres	1,823	2.7	7.9	12.0
Lovington Sandstone	211	0.1	5.0	7.1
Lower San Andres	2,368	1.5	7.3	11.3
TOTAL	4,979	1.7	7.7	11.6

The sandstone intervals are considered to be non-pay. Where sandstone porosity is developed, the permeability is inferior to the carbonates of the Grayburg and San Andres dolomite. The Grayburg Sandstone is believed to contain a considerable amount of samples interbedded with carbonate material, which inflates the findings. The Grayburg Sandstone is similar to the Lovington Sandstone. The sandstones do not likely effect the overall flow capacity of the producing horizon. However, no capillary pressure data has been gathered to confirm this assumption. No known production tests of the sandstone interval have been found.

A cutoff value for porosity in the 7.0% range seemed high. As a confidence check, an entire set of East - West row injection well profiles within the study area was reviewed. No single zone below 7.0% porosity was accepting water based on the velocity and tracer surveys available. One of the injection wells also had a production profile log dated prior to its conversion. It did not indicate any production from zones below 7.0% porosity (but we should keep in mind that production profiles are typically run because production anomalies exist).

A study of vertical permeability was conducted. Only two wells included any measurements of vertical permeabilities. The ratio of vertical-to-horizontal permeability was found to be 0.30:1.00 and 0.27:1.00 for the VGSAU Well No. 140 & 157, respectively. The sandstone intervals were excluded from the analysis. Although these ratios seem fairly conductive, it is suspected that the effective vertical transmissibility between facies in a heterogeneous carbonate reservoir is negligible.

Permeability Relationships

A more descriptive characterization of a reservoir would include a variance in permeability rather than the application of an average value. Permeability relationships provide a method of distributing saturations and evaluating flow capacity; an integral need for reservoir simulation. Past work has involved the use of linear regressions to represent a scattering of core measured porosity vs. permeability data.

This portion of the reservoir characterization applies artificial intelligence to determine porosity/permeability relationships and then derive values of permeability for all well traces in the study. The use of a neural network to derive permeability from wellbore measurements is a patented Texaco process (Patent number 5,251,286, October 5, 1993, "Method for Estimating Formation Permeability from Wireline Logs using Neural Networks"). Further information concerning the patent can be obtained from Jack Wiener c/o Texaco E & P Inc., P. O. Box 2100, Denver, CO 80201-2100 (DD: 303-793-4079).

Artificial intelligence is a name applied to several types of computer programs that attempt to simulate the decision-making processes of a human. The particular type of artificial intelligence applied to develop the porosity/permeability relationship for this project is called a neural network. A neural network is made up of a number of highly interconnected individual processing units much like a mammalian brain is made up of a very large number of highly interconnected neurons. Neural networks consist of input nodes, where data is supplied to the network, and output nodes, where resulting values are generated. Between these two sets of nodes are one or more "hidden" layers of nodes. Every input node is connected to every hidden node. Every hidden node is connected to every output node. Every one of these connections has an independently associated weight factor.

The artificial intelligence of neural networks are found in two places. The first is the knowledge of the relationship between inputs and outputs and is represented by the values taken on by the weight factors. It is these values and how they are interconnected that shows why this branch of artificial intelligence is called neural networks. The second is how the neural network acquires its knowledge of the relationship between inputs and outputs. With typical computer programming, the relationship is coded directly into the computer program by a human. With a neural network there is no *a priori* knowledge of this relationship. The neural network must create its own coded program, which captures the relationship between inputs and outputs. This is done by having the neural network learn the relationship by repeatedly comparing examples of inputs with their associated outputs and self-adjusting the connection weights until it has developed a relationship that works. After the neural network has learned the relationship between inputs and outputs it is ready for use. This phase of the operation is to present the input nodes with data in which the values of the outputs are unknown, and let the network solve/generate, based on the results of the learning phase, for the unknown values. Commercial software is available for designing and applying neural networks. For this study, NeuroShell, a product of Ward Systems Group, Inc., and NeuralWorks, a product of NeuralWare, Inc. were used.

The data set supplied to the network during the learning phase included porosity and permeability values derived from core measurements obtained from eighteen wells (aerial distribution) within the project area. This core data were reviewed for evidence of fracturing, and suspect data were culled from the data set. This left slightly over 4,000 data points to be used in training the network. Additional data from the core included its physical location, latitude and longitude, and macro-zone identification.

The general methodology used for this study consists of four steps;

1. Decide what data to use to train the network and assemble it in the proper format.

2. Present the data to the network and allow "learning" to occur.

3. Apply the network to a test data set held in reserve for this purpose.

4. Evaluate the effectiveness of the network.

After the above steps are complete, a decision is made as to what changes to the network architecture or the training data set would most likely improve the performance of the network, and the methodology is repeated until the resultant network gives satisfactory performance.

More than fifty repetitions of the above process were completed before a network was finalized to apply to the wellbore data. Several findings are of note in the case of this study:

1. Any input data used to train the network, must also be available for all data points to be analyzed (for instance, if sonic travel time is used to train the network, then sonic data will be required to apply the network).

2. A major hurdle to the application of neural networks in mature fields such as Vacuum is the lack of consistent usable data from well to well. The "lowest common denominator" of data for this project was normalized wireline porosity, location of the well in latitude and longitude, and macro-zonation of the reservoir. Better results could certainly have been achieved if, for example, sonic logs and resistivity logs had been available for all wells, or pore-type descriptions.

3. In spite of the limitations in data cited above, the final neural network achieved a mean absolute deviation (error) of 7.28 millidarcies vs. 10.96 millidarcies for the standard linear regression analyses. In this case, the application of standard linear regression analysis would have resulted in data 50% less accurate than that obtained from the neural network.

Figure 19 is a scatter-plot of porosity vs. permeability on a semi-log plot for a representative test set of the core data and the neural network solution. Although not perfect, it exceeds the historical option of linear regression considerably. Permeability not only varies with porosity, it also varies spacially over the study area within given zones due to the nature of the geology of the area as represented in the training set.

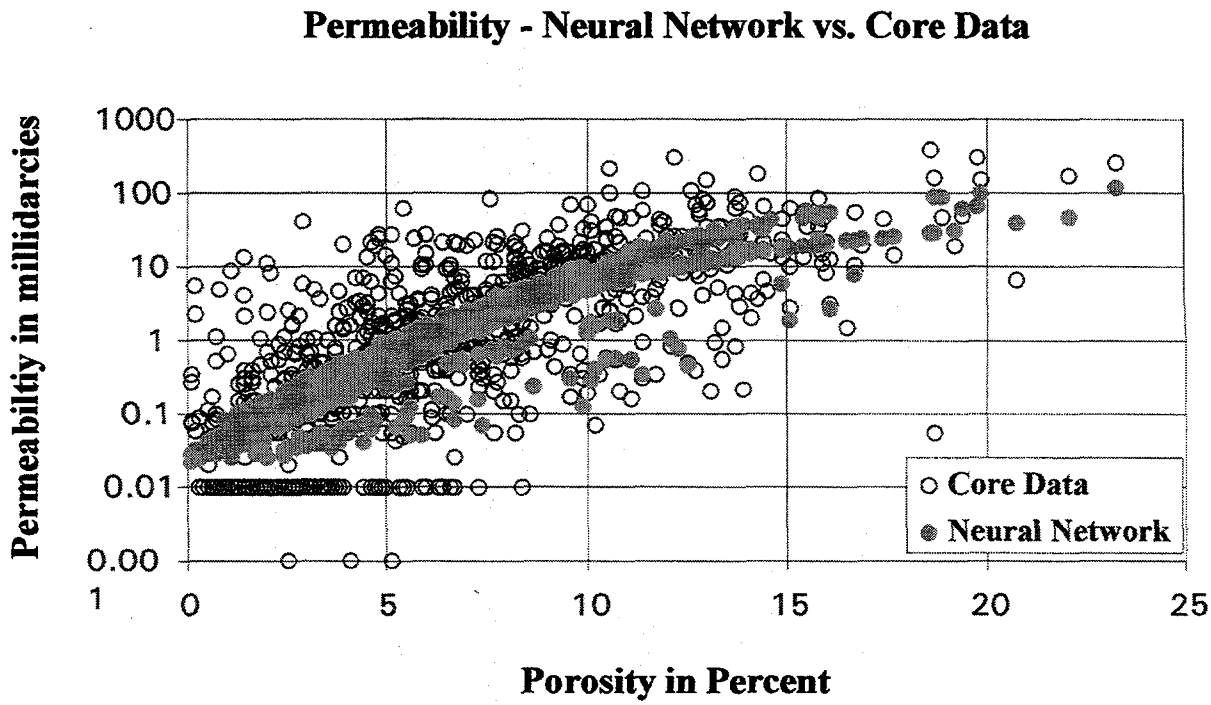

Fig. 19: Neural Network Solution of permeability relationship to porosity. Example for well (test set) VGSAU No. 140.

Geostatistical Realizations

Once a permeability relationship is obtained through the use of neural networks, another problem is interpolating the data between well locations. Core data shows that porosity and permeability can vary by orders of magnitude over a small interval. If this is any indication of the variability or heterogeneity that exists between wells, then methods are needed to incorporate this in reservoir models. Geostatistics was used in this study to distribute wellbore data to interwell locations (cells). This exercise is believed to have provided a more realistic spacial distribution of the data than the typical algorithm used in mapping software. Normalized porosity and neural network derived permeability data from 455 wells in the project area were available for use. Markers within the pay were taken from the CVU project database.

The first step involved screening data. All sonic logs were removed from the population. It was felt that the sonic logs were introducing statistical variation. This effect was the result of differences in the ability to recognize secondary porosity. The neutron-derived logs would see the secondary porosity. The normalization techniques used on these different logging suites resulted in a poor sonic-core porosity relationship, which will be addressed at a later time. The reduced well count used for the variograms and gridding was 322.

Initial porosity variograms appear reasonable. The Grayburg Dolomite has its greatest correlation trend in a north-northeast to south-southwest direction. The Grayburg Sandstone and the San Andres have their greatest correlation trend in an East to West direction. Not surprisingly, these trends follow the general strike of the basin margin.

At 752,400 cells, the geostatistical exercises are handling a rather large volume of data for the study. The 3-D gridding consists of 150 layers within the San Andres formation, with an aerial distribution of 76 rows, by 66 columns. The layers are 4.00 ft thick. Each cell is 250 ft X 250 ft on a side. This work was performed on a personal computer with a geostatistical software package developed by Texaco, called GRIDSTAT. Preliminary 3-D porosity grids were created using a kriging gridding algorithm. In the case of this project, the model area had to be broken into sections due to its size. After working with several grid generations, it became obvious that the software was not properly using the data from wells in adjacent sections, resulting in "banding." The software coding was subsequently refined and the banding problems eliminated. An acceptable porosity grid for the project area has now been defined for the San Andres and Grayburg formations.

Originally, it was anticipated that the variograms developed from the porosity data would be used in construction of the permeability grids. This approach was abandoned in favor of directly applying the neural network permeability relationships corresponding to the geostatistically distributed porosity. The original approach left concern regarding the redistribution of permeability data, which was partially defined based on its 3-D spacial distribution in the reservoir. Therefore, efforts were undertaken to apply the neural network to this massive porosity grid. **Figure 20** visually depicts the process of dealing with this large mass of data. The porosity values are first downloaded from Stratamodel or GRIDSTAT, to an ASCII file format, and imported into an Access database. Cell location (latitude & longitude) not available in the original databases, are added to the Access database. The previously trained Neural Network is then applied to calculate "virtual" permeabilities for each of the cells. The data can then be uploaded to Stratamodel for visual inspection.

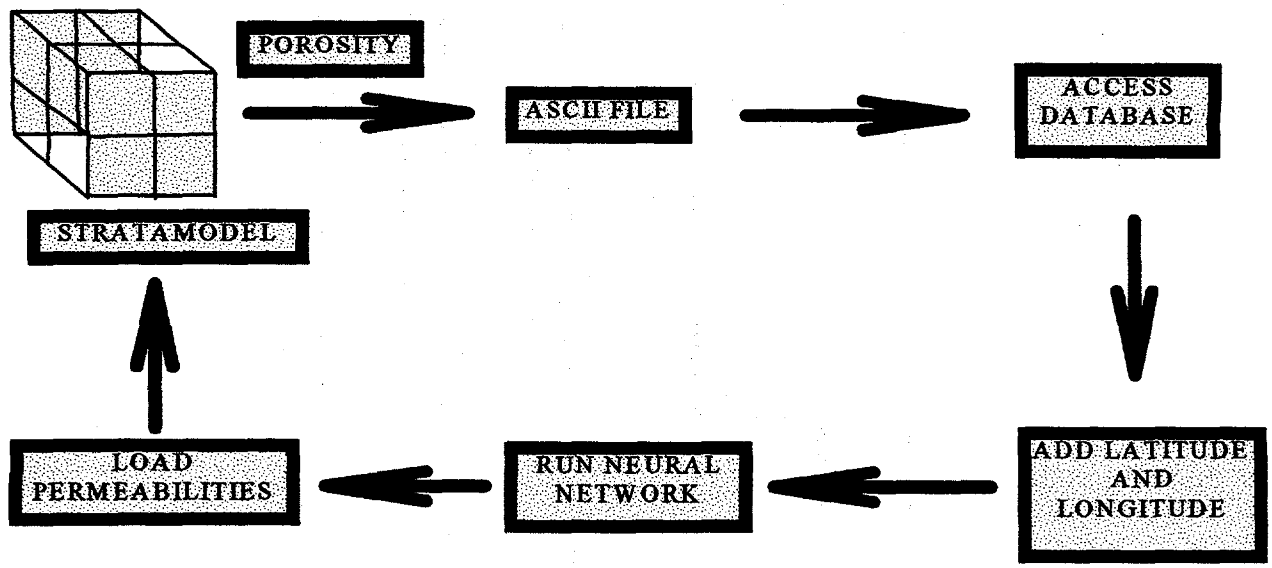

Fig. 20: Visual depiction of data management associated with assignment of permeability to porosity grid cells.

The 250' X 250' aerial grids were used to determine saturations throughout the entire field study area. Capillary pressure data, as previously discussed, was combined and used in calculating the OOIP. Initial geostatistical results proved too conservative relative to current and forecast recoveries. However, continued investigation into the impact of various inputs resulted in relatively similar results. As it turned out, the difference between the geostatistics and other approaches stemmed from a mis-formatted data file. The following table (**Table 2**) compares the three methods of porosity distribution and the resulting OOIP. The previously accepted OOIP determination suggested 225.0 MMBO. The distribution of the original hydrocarbon accumulation, as determined by the three approaches is provided in **Fig. 21**.

Table 2: Comparison of Geostatistical approaches relative to OOIP calculations.

MODEL TYPE	OOIP CENTRAL VACUUM UNIT
STRATAMODEL DETERMINISTIC (POWER FACTOR = 2)	209.6 MMBO
STRATAMODEL STATISTICAL (POWER FACTOR = 5)	201.4 MMBO
GRIDSTATS (Texaco Geostatistics Software)	211.1 MMBO

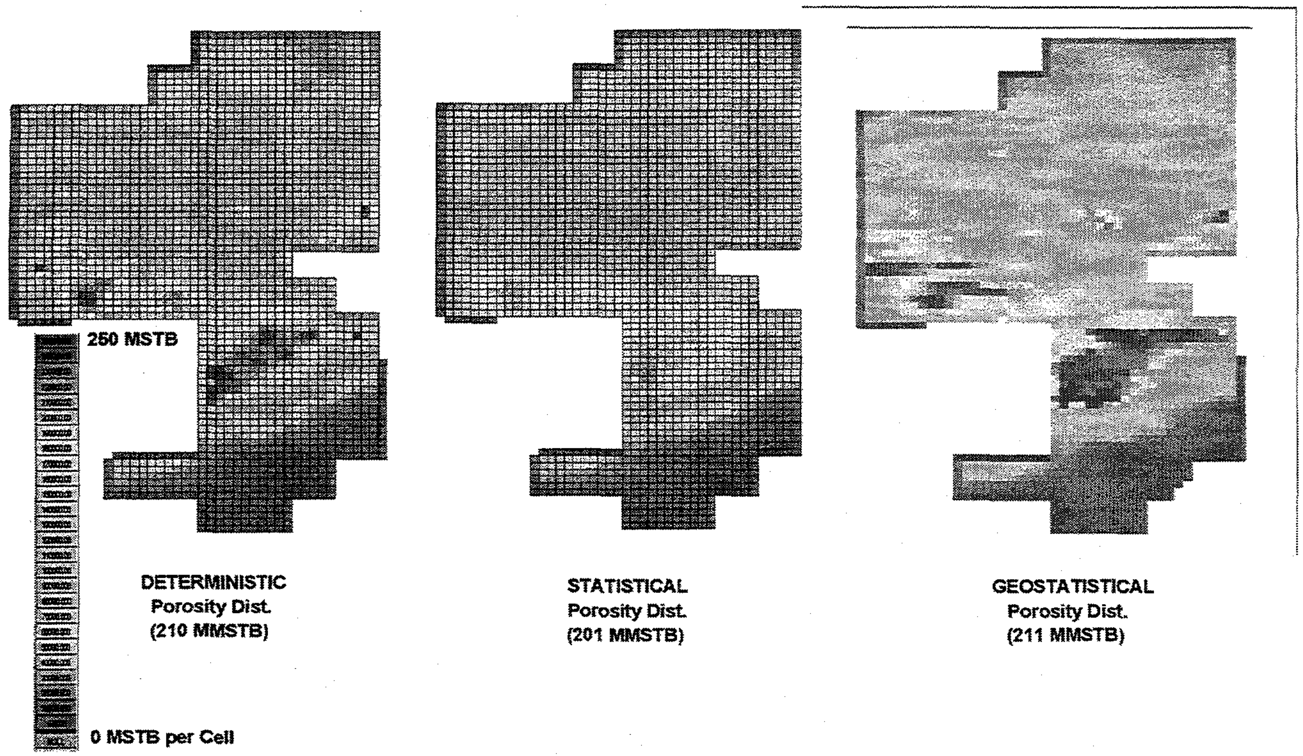

Fig. 21: Comparison of OOIP distribution based on three investigations.

Resulting OOIP calculated from the geostatistical (Texaco's GridStats program) derived porosity compares favorably to that using the distributions (deterministic and statistical) within the StrataModel program. The lower value for the StrataModel Statistical (Power Factor=5) model was to be expected. The porosity values of actual wireline measurements are not maintained at wellbore cells with this particular approach. The resulting calculations tend to represent the reservoir flow units as a more continuous architecture, with lower porosity in any given zone of comparison (i.e. the data is heavily averaged). The StrataModel Deterministic and GridStats (geostatistics) approaches were quite similar in OOIP calculations. But, it is only the geostatistical approach that does not rely heavily on any user-defined input (power factor for scaling). Had the investigators chosen different scaling factors in StrataModel, the results could have been quite variable, or the StrataModel Statistical approach could have even had a similar result to the other two. Both the Geostatistical and StrataModel Deterministic approaches match fairly well with the estimated ultimate recovery forecast trends from injection pattern to pattern. Since no flow simulation was planned for the large Project study area, no conditional simulation was done. All grids were made using kriging.

Attention in the first half of 1995 refocused on a smaller study area, which encompassed the site-specific simulation area and impending initial field demonstrations. The geostatistical exercise was repeated in this area for added modeling detail. A total of twenty stratigraphic porosity grids were made for this smaller study area. Five zones were identified for kriging exercises. The five gridded zones are a 13 layer grid for the Grayburg Dolomite, a 7 layer grid for the

Grayburg Sandstone, a 30 layer grid for the Upper San Andres, a 15 layer grid for the Lovington Sandstone, and a 90 layer grid for the Lower San Andres. Each cell is 132' X 132' on a side. The layers are approximately 4' thick. This model covers the same vertical component of gross pay as the larger study, after excluding some non-pay footage from the bottom of the model. These five zones were then used in three successive conditional simulations and the site-specific model for compositional simulation was extracted from this work.

Waterflood Review

A proper review of past operations is not complete without a comparison to the initial hydrocarbons in the formation. The procedures for calculating Original Oil-In-Place (OOIP) within StrataModel software were developed and tested. OOIP was calculated for each cell in the model. Calculating OOIP in this manner required porosity, permeability, and initial water saturation, S_{wi}, values for each cell in the model. Porosity was derived from the distribution of porosity data from each well location. Permeability was determined for each cell using the Neural Network described previously. Initial water saturation was calculated for each cell using the Leverett "J" function. Polygons for unit boundaries and waterflood patterns were added to the model. These polygons allowed summation of OOIP for specific areas and individual waterflood pattern review. Summation by stratigraphic sequence was also possible, allowing each of the five sequences to be summed individually. Many parameters, such as net pay, hydrocarbon pore volume, efficiency's, etc. were investigated and mapped. These parameters were mapped and previously included in Appendix "A" of the 1995 Annual Report[23] in both Tabular and Visual formats.

Current observations are that overall, either, 1) the property is experiencing ultimate recovery efficiencies above normal, at approximately 44.8% OOIP, 2) the OOIP is too low, or that 3) two independent approaches to estimating ultimate recoveries, although equivalent in findings, resulted in erroneous forecasts. Investigations continued during the later half of 1995. The site-specific modeling helped address this issue during the history-matching phase. The history matching went very smoothly. This is believed to be due to the detail provided in the geologic model, coupled with the initialization parameters developed within this study. The simulation suggests that the calculation and distribution of hydrocarbons is good. Overall, volumes and efficiencies fit with structural and geologic trends. Therefore, it is inferred that the ultimate recovery efficiency at CVU is above normal when compared to other San Andres waterfloods.

A review of waterflood efficiencies was conducted. It was anticipated that this detailed review would allow proper selection of the field demonstration site(s) for the proposed technology. The results of the parametric simulation studies were to be coupled with the waterflood review information. The intent was to be able to select a sufficient variation in reservoir conditions/character to support the parametric studies findings. In turn, this information would ultimately assist in developing guidelines to assist operators in selecting candidate sites based on this information and actual field trials. The waterflood review was performed parallel to the parametric simulation exercises which eventually concluded that reservoir characterization has relatively limited impact on this near-wellbore process as it relates to the CO_2 Huff-n-Puff (see discussion under Parametric Simulation topic). Following the actual demonstration, this data may still prove beneficial to the analysis.

Based on review of the available data, a site-specific model area was selected. It is located in the northern area of Section 6, T18S - R35E, Lea County, New Mexico (Fig. 5). This model area represents average reservoir conditions known to exist within the CVU Project study area. It includes four (4) of the original 40-acre 5-spot injection patterns. This model area was drilled on a 10-acre well spacing, providing modern logging suites in early 1995. The size of the model allows for the potential to analyze results from more than one field demonstration. This configuration was selected as a safety precaution, should the initial site fail mechanically. The data helped refine the model and provides a future measure to the geostatistical efforts. The drilling was not part of the cost-share DOE project.

Development of an Equation-Of-State

Western Atlas' DESKTOP-PVT program has been used to develop an Equation-of-State (EOS) which will be incorporated in the compositional simulations for the CVU Huff-n-Puff process.

Constant composition expansion experiments had previously been run in 1989 on samples of CVU crude oil (CVU Well No. 162) with increasing concentrations of CO_2[24]. Concentrations of 0, 20, 41, and 55 mole-% CO_2 resulted in bubble point fluids. Liquid phase viscosities were determined for the 0, 41, and 55 mole-% CO_2 samples. Concentrations of 70, 75, and 85 mole-% CO_2 did not result in dew point fluids. No single phase was formed below 6,000 psia (equipment limitation) for any of these last three mixtures. Phases included a CO_2 rich vapor (V), a hydrocarbon rich dark liquid (L1), and a CO_2 rich clear liquid (L2). Below 1,158 psia, V and L1 are present and above 1,316 psia, L1 and L2 are observed. Between these two pressures all three phases are present. Since compositional simulators are limited to two-phase equations of state, approximations were required to deal with the three-phase behavior observed in the laboratory experimentation.

The CO_2 rich liquid phase, L2, present above 55 mole-% CO_2 and 1,158 psia was treated as part of the vapor phase. Above 55 mole-% CO_2, saturation pressures could not be determined and were estimated. Given the error inherent in these estimates, the relative volume (sample volume at given pressure divided by volume at saturation pressure) was not used as data to be matched. The heavy liquid phase (L1) fraction was the only data matched above 55 mole-% CO_2.

Prior to matching the experimental data, the C_{7+} fraction of the crude analysis (molecular weight of 202) was split into three pseudocomponents. In order to reduce the number of components and thus the run-time of the compositional simulation, the small amount of nitrogen was combined with the methane, C_1, and the C_5 and C_6 components were combined. The system, shown in **Table 3** was thus represented with nine pseudocomponents including CO_2.

Table 3: PSEUDOCOMPONENT SYSTEM

Original Components	Pseudocomponent	Mole-%
CO_2	CO_2	2.03
CH_4, N_2	C1N2	14.19
C_2H_6	C2	9.83
C_3H_8	C3	9.80
nC_4H_{10}, iC_4H_{10}	C4	8.38
nC_5H_{12}, iC_5H_{12}, C_6H_{14}	C5C6	9.04
C_7+	HVY1 (MW=133)	27.21
C_7+	HVY1 (MW=251)	15.29
C_7+	HVY1 (MW=467)	4.23

A three parameter Peng-Robinson EOS was initially used to match this data and to provide CO_2 - Oil phase behavior descriptions for use in the compositional simulation model. The Omega A and Omega B EOS parameters for the three heaviest pseudocomponents and the binary interaction parameters between these pseudocomponents and CO_2 were adjusted to fit the experimental phase behavior data. To insure proper CO_2 densities over the range of pressures anticipated in the CVU project, the CO_2 volume shift parameter was adjusted. A completely satisfactory match of the liquid volume fraction at high mole-% CO_2 mixtures could not be found with the Peng-Robinson EOS. Matching efforts were then shifted to the Zudkevitch-Joffe-Redlich-Kwong (ZJRK) EOS. The same EOS parameters were adjusted. Much better matches of the liquid volume fraction at high mole-% CO_2 mixtures were found with the ZJRK equation than with the Peng-Robinson equation. Typically the most difficult type of data to match is the liquid volume fraction for the high mole-% CO_2 mixtures. Viscosities were matched by adjusting the critical z-factor of the three heavy components in the Lohrenz-Bray-Clark viscosity correlation.

Table 4: CO_2 - OIL MIXTURE SATURATION PRESSURES

Mole-% Added CO_2	Experimental Saturation Pressure, psia	Calculated Saturation Pressure, Psia
0	790 BP	810 BP
20	1,045 BP	1012 BP
41	1,273 BP	1,241 BP
55	1,378 BP	1,405 BP
70	>6,000	3,263
75	>6,000	4,559
85	>6,000	10,042

A reasonable match of the bubble points for the 0, 20, 41, and 55 mole-% CO_2 mixtures resulted, as shown in **Table 4**. An excellent match was obtained for the relative volume as a function of pressure, the easiest property to match. Very good matches of the liquid volume fraction at, and below 55 mole-% CO_2 mixtures were found. Good matches were found for the volume fraction of the high mole-% CO_2 mixtures (i.e., 70, 80, and 85 mole-% CO_2 mixtures). Satisfactory matches were also found for the viscosities. In addition, a reasonable match of pure CO_2 densities over the range of pressures likely for the project was found.

The match of CO_2 density is not standard and required a special procedure. The special procedure involved simultaneously matching pure CO_2 densities along with the laboratory CO_2 - oil phase behavior data. This was done because it was found that an EOS does not typically predict pure CO_2 density sufficiently well when it is matched only to the laboratory CO_2 - oil phase behavior data. When pure CO_2 density was also included in the matching process, the prediction of pure CO_2 density was much improved without significantly degrading the liquid volume fraction matches. Proper matching of CO_2 density is important for determining the amount of CO_2 used in a process. The EOS matches to the laboratory data are presented in **Figures 22** through **36**.

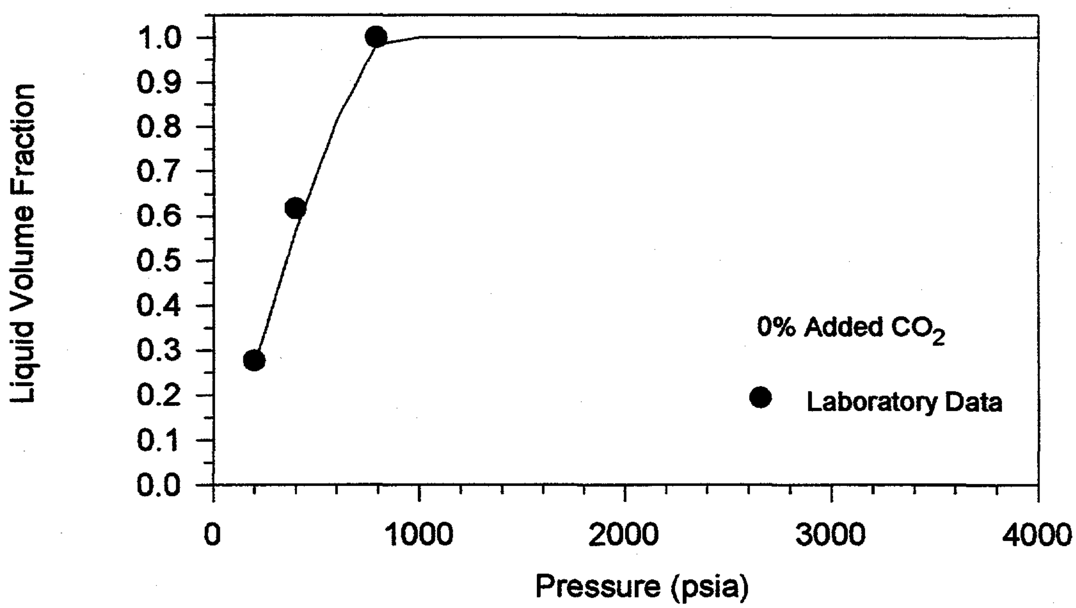

Fig. 22: Comparison of laboratory data and EOS prediction of liquid volume fraction as a function of pressure for no added CO_2. (Solid line is EOS prediction)

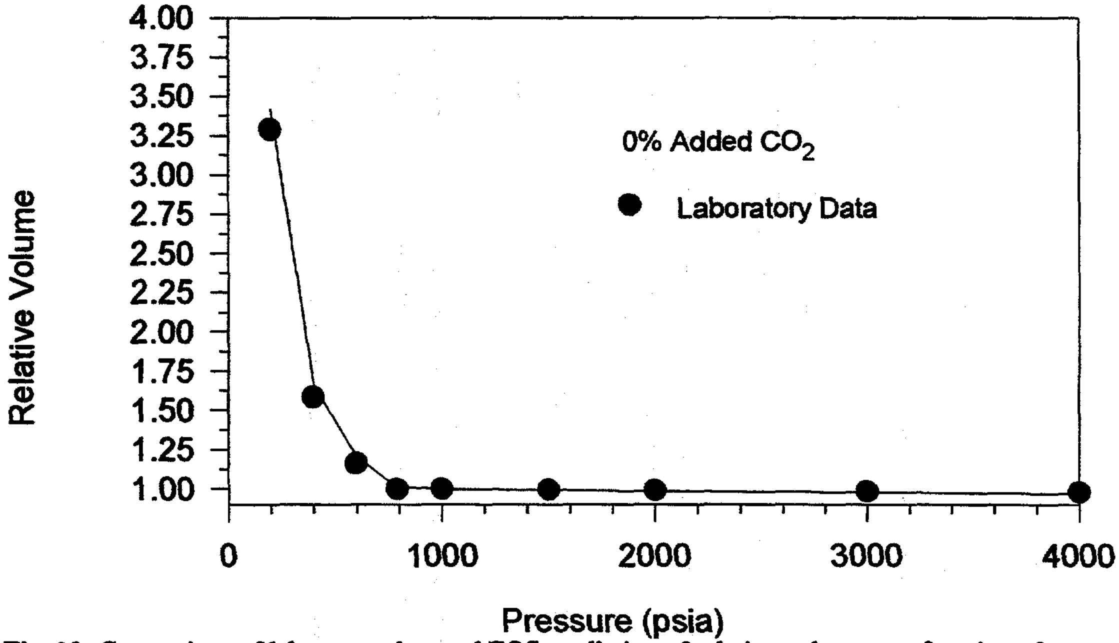

Fig. 23: Comparison of laboratory data and EOS prediction of relative volume as a function of pressure for no added CO_2. (Solid line is EOS prediction)

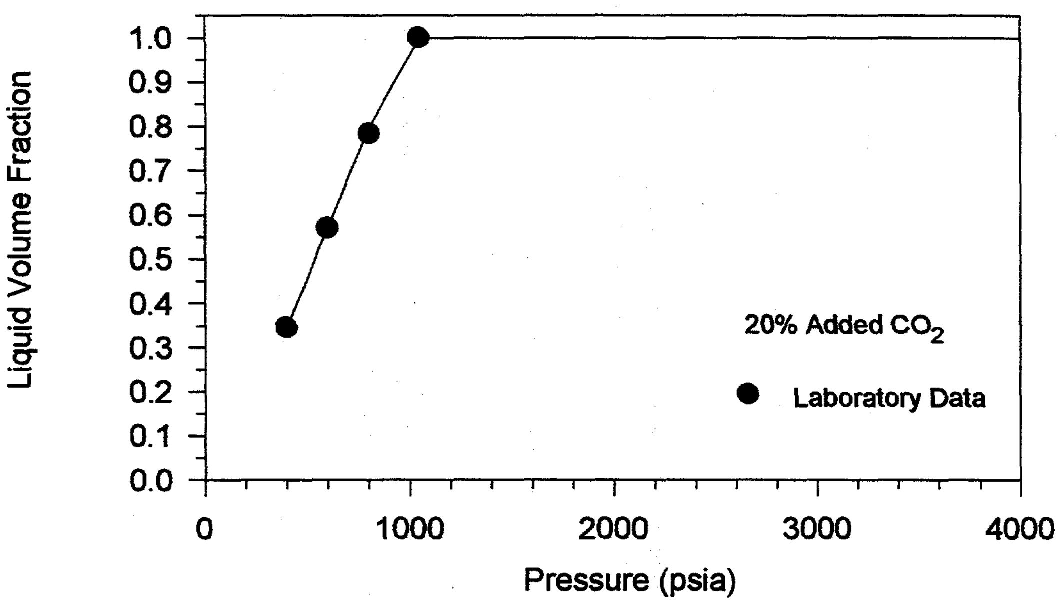

Fig. 24: Comparison of laboratory data and EOS prediction of liquid volume fraction as a function of pressure for 20 mole-% added CO_2. (Solid line is EOS prediction)

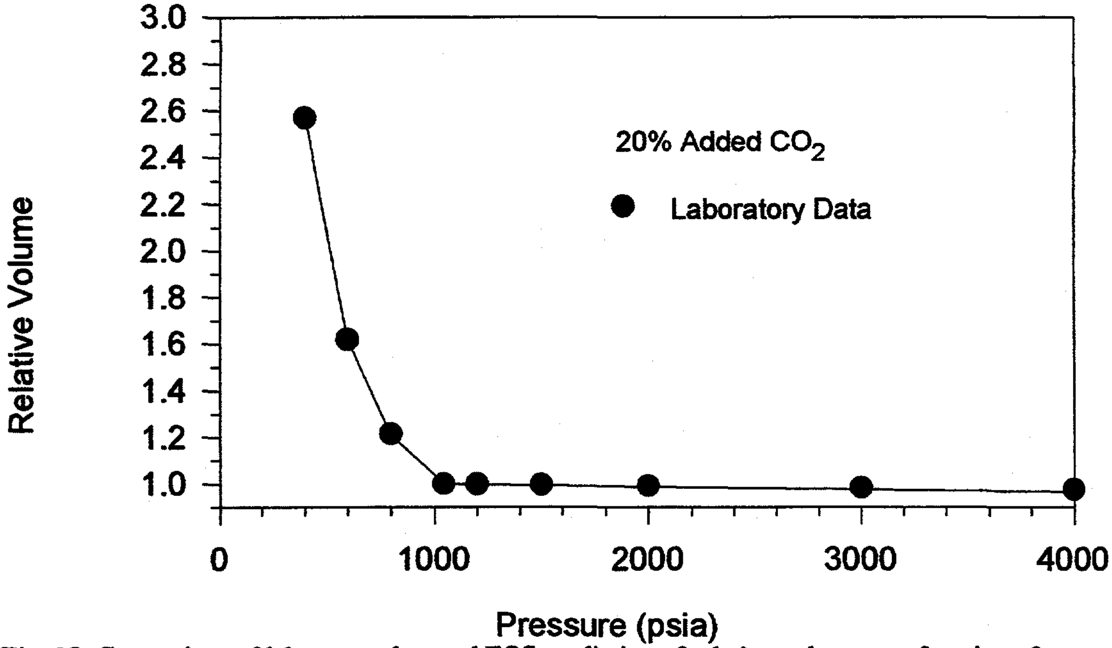

Fig. 25: Comparison of laboratory data and EOS prediction of relative volume as a function of pressure for 20 mole-% added CO_2. (Solid line is EOS prediction)

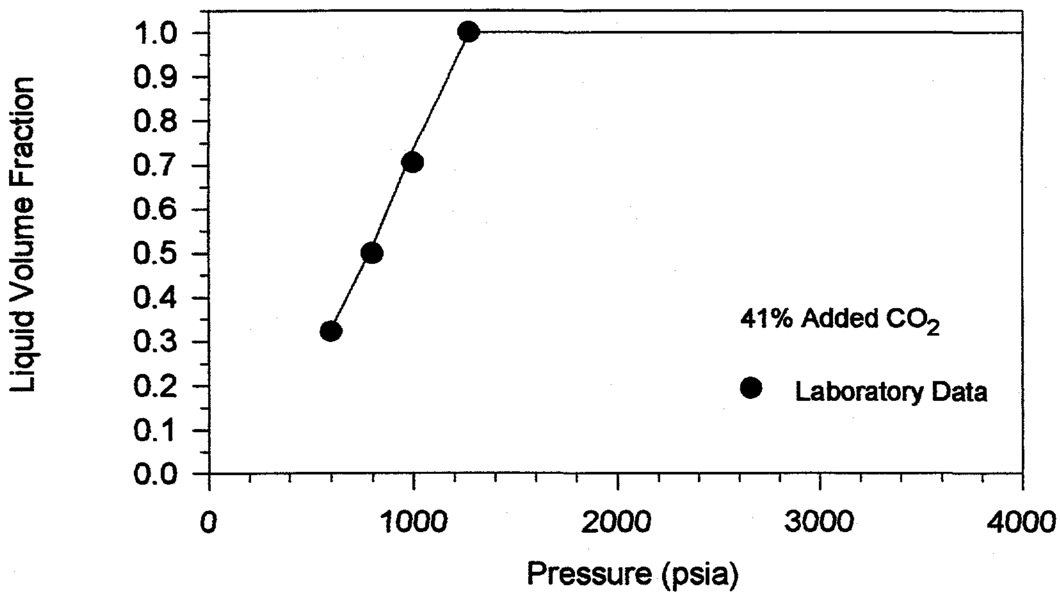

Fig. 26: Comparison of laboratory data and EOS prediction of liquid volume fraction as a function of pressure for 41 mole-% added CO_2. (Solid line is EOS prediction)

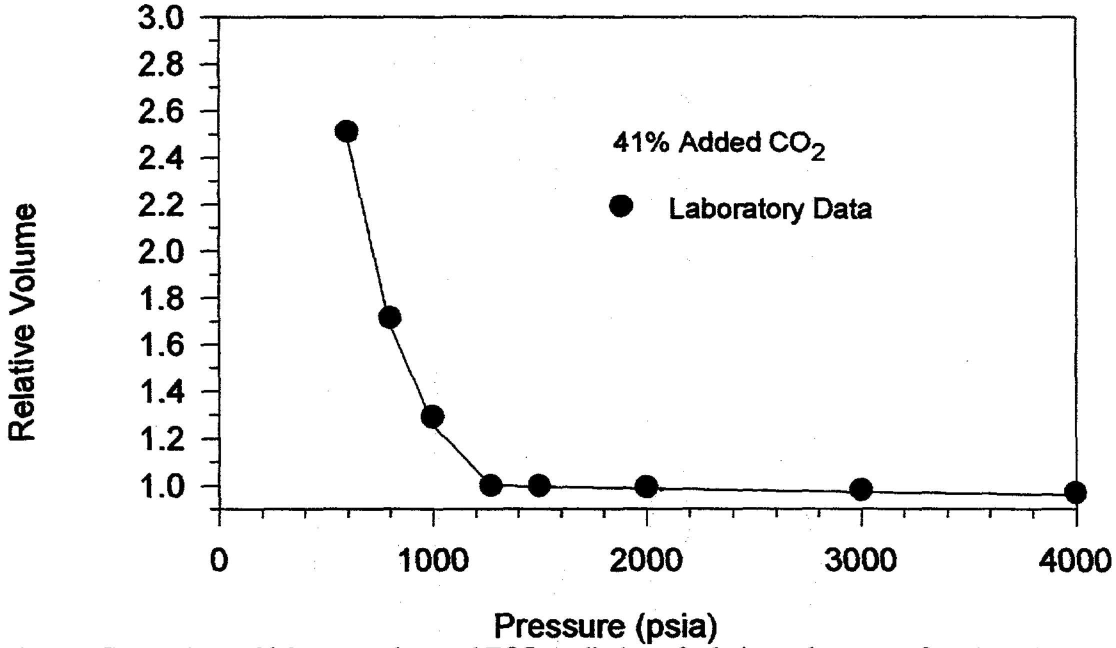

Fig. 27: Comparison of laboratory data and EOS prediction of relative volume as a function of pressure for 41 mole-% added CO_2. (Solid line is EOS prediction)

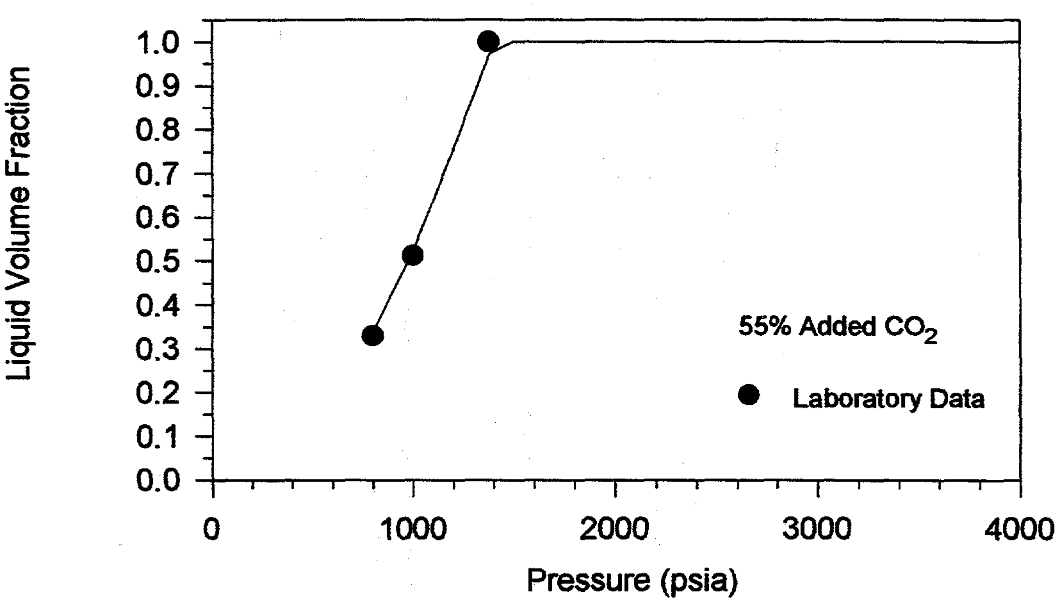

Fig. 28: Comparison of laboratory data and EOS prediction of liquid volume fraction as a function of pressure for 55 mole-% added CO_2. (Solid line is EOS prediction)

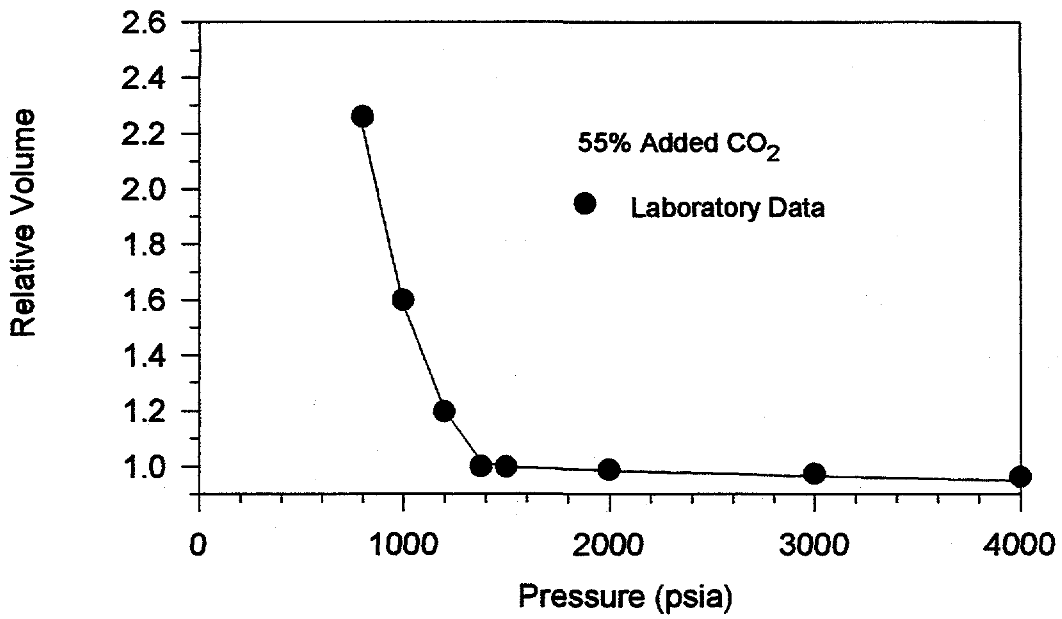

Fig. 29: Comparison of laboratory data and EOS prediction of relative volume as a function of pressure for 55 mole-% added CO_2. (Solid line is EOS prediction)

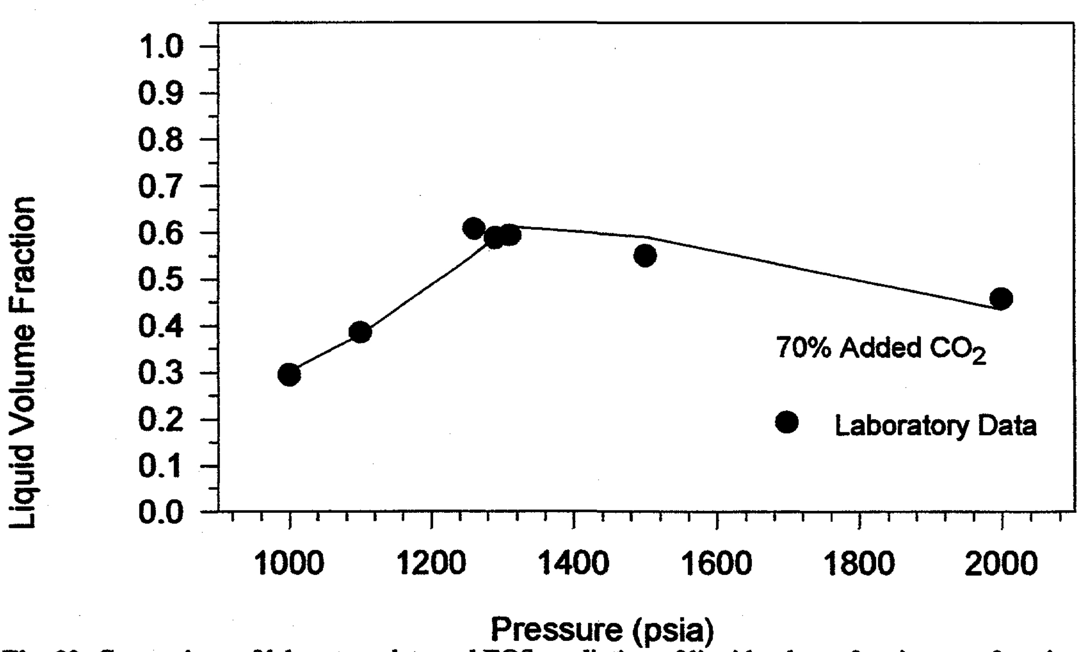

Fig. 30: Comparison of laboratory data and EOS prediction of liquid volume fraction as a function of pressure for 70 mole-% added CO_2. (Solid line is EOS prediction)

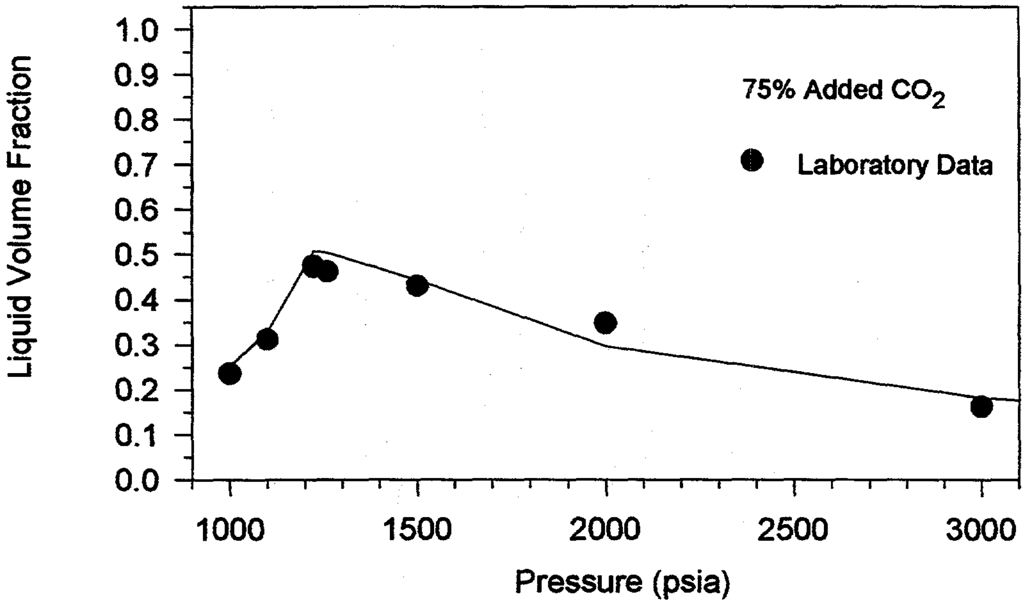

Fig. 31: Comparison of laboratory data and EOS prediction of liquid volume fraction as a function of pressure for 75 mole-% added CO_2. (Solid line is EOS prediction)

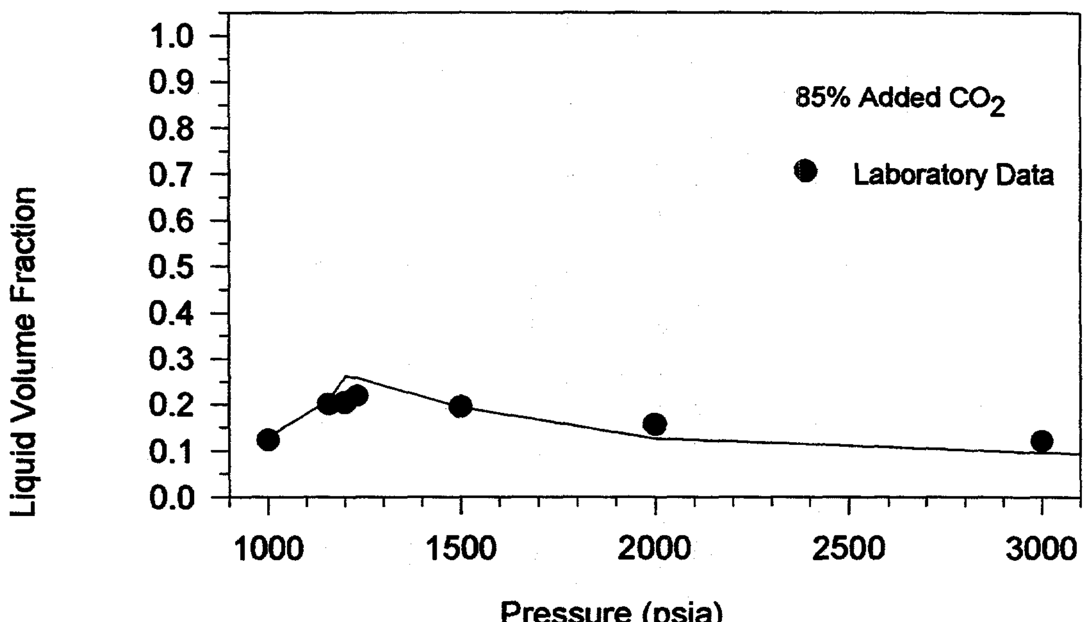

Fig. 32: Comparison of laboratory data and EOS prediction of liquid volume fraction as a function of pressure for 85 mole-% added CO_2. (Solid line is EOS prediction)

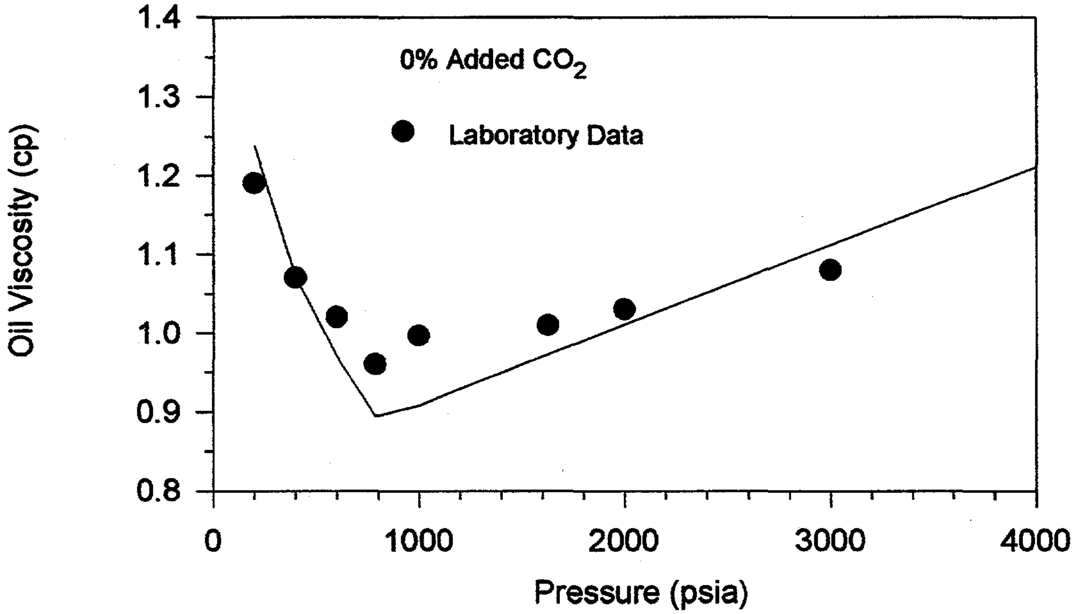

Fig. 33: Comparison of laboratory data and EOS prediction of liquid viscosity as a function of pressure for no added CO_2. (Solid line is EOS prediction)

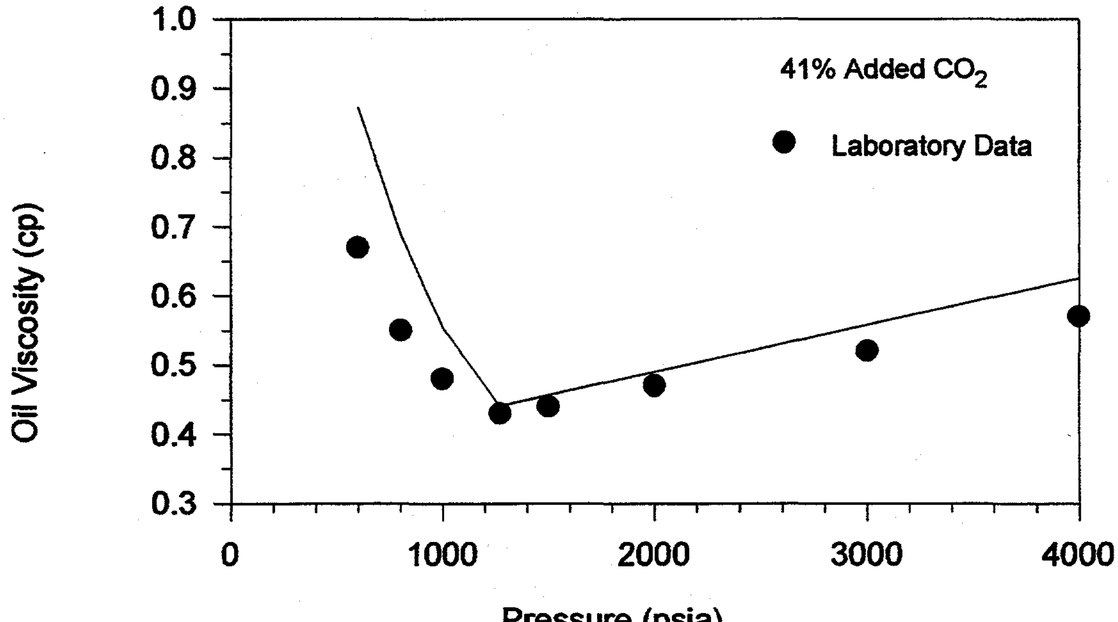

Fig. 34: Comparison of laboratory data and EOS prediction of liquid viscosity as a function of pressure for 41 mole-% added CO_2. (Solid line is EOS prediction)

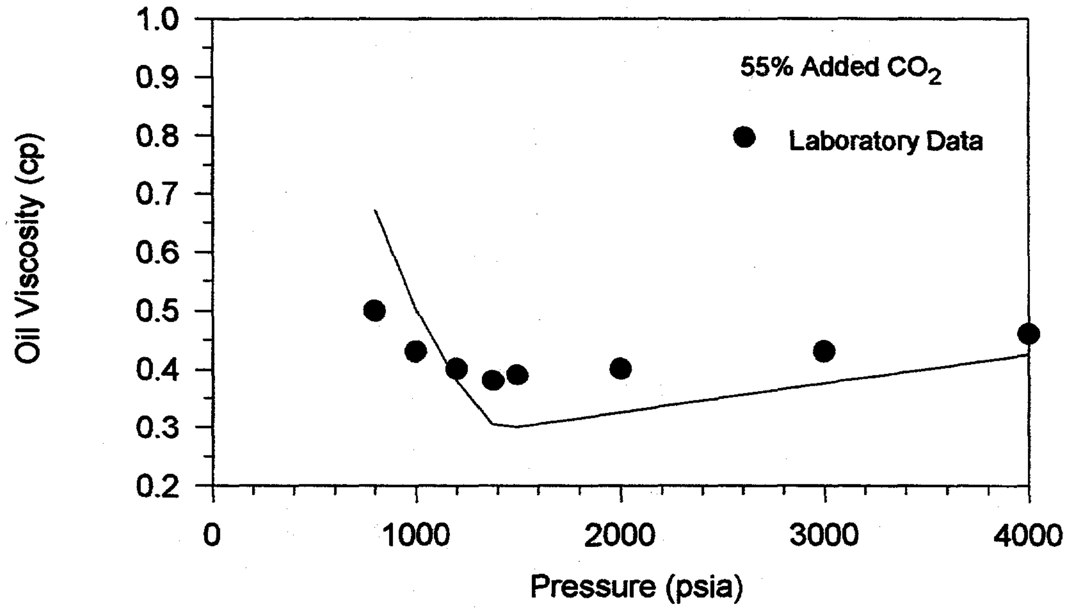

Fig. 35: Comparison of laboratory data and EOS prediction of liquid viscosity as a function of pressure for 55 mole-% added CO_2. (Solid line is EOS prediction)

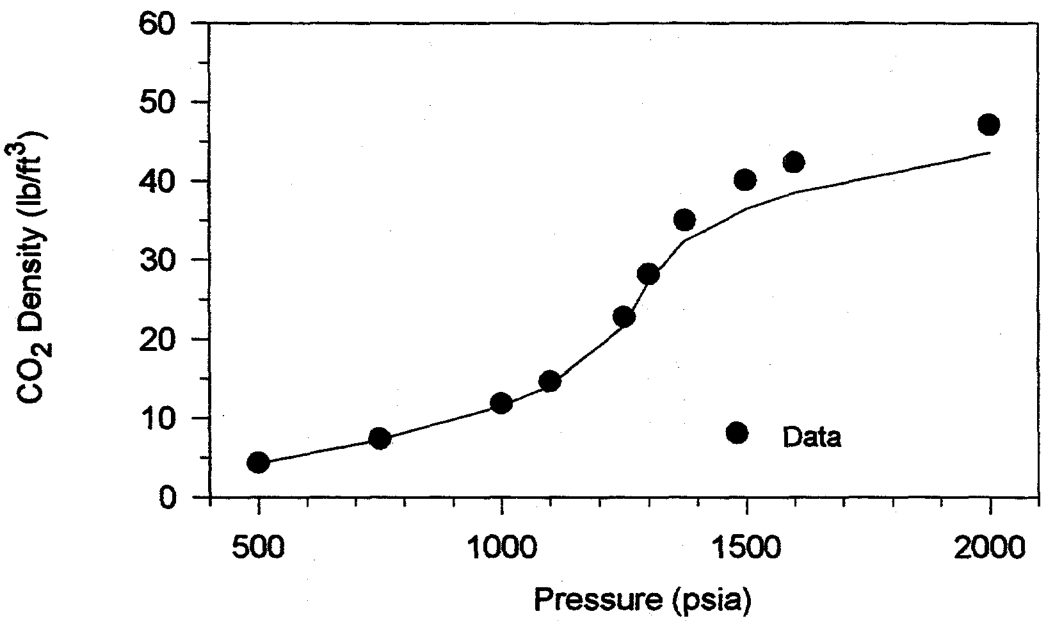

Fig. 36: Comparison of established data and EOS prediction of pure CO_2 density as a function of pressure. (Solid line is EOS prediction)

Slimtube experiments were performed in 1989[25]. The tests were conducted at a temperature of 105° F and from 1,100 through 3,000 psia to determine the CVU crude system's minimum miscibility pressure (MMP). The MMP was found to be approximately 1,250 psia. Considering the complexities of dealing with the three-phase system, simulations of these laboratory experiments were necessary for the development of a realistic fit of the live oil - CO_2 phase behavior data. The slimtube experiments were successfully simulated with the ZJRK EOS. Highly representative gas-oil relative permeability curves were used. The ability to match the slimtube tests with representative relative permeability curves gives added credibility to the EOS. Good matches were obtained for the oil recovery as a function of the volume of CO_2 injected for several pressures. Shown in **Fig. 37** are results for a pressure below the MMP (1,100 psia), a pressure near the MMP (1,212 psia), and a pressure above the MMP (3,000 psia). The simulated pressure for the 1,212 psia slimtube test was about 1,235 psia. Experimentally, at the 1,100 psia pressure, the injected CO_2 did not displace an equal volume of oil from the slimtube even at the start of the test; rather, a substantial portion of the CO_2 dissolved in the oil. The equation of state was able to match this behavior. The ability of the EOS to predict proper behavior below the MMP is important because the Huff-n-Puff tests will initially be operating below the MMP in the near-wellbore vicinity.

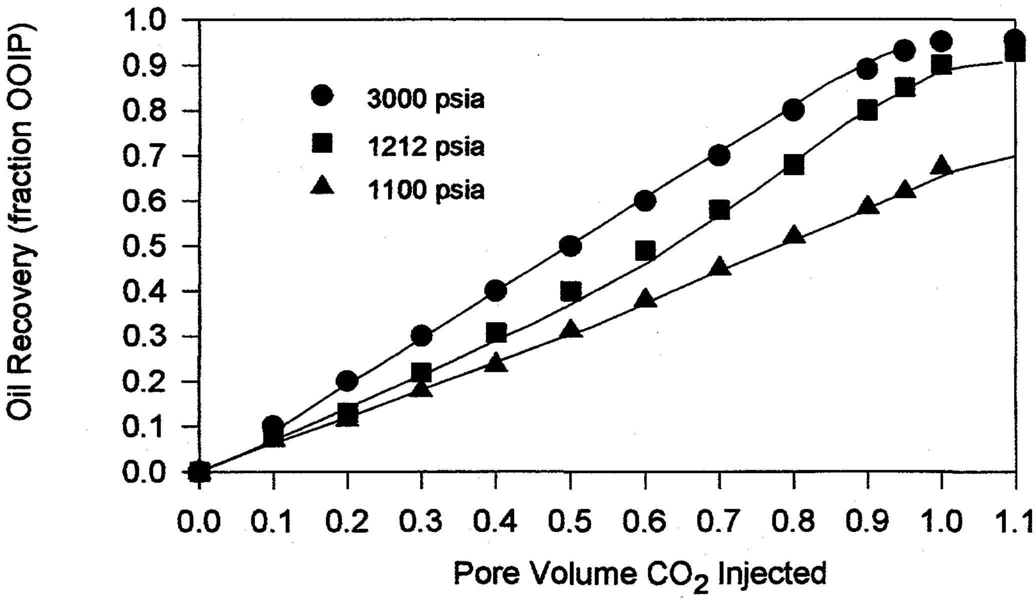

Fig. 37: Comparison of laboratory slimtube data and simulations of oil recovery as a function of injected CO_2 volume for selected pressures. (Solid lines are simulations)

Compositional Simulation Study

The reservoir characterization work was incorporated into models for computer simulation. Western Atlas' VIP-COMP Simulation software was utilized. An equation-of-state (EOS) with nine pseudocomponents was developed using the Zudkevitch-Joffe-Redlich-Kwong approach to represent interactions between CO_2 and oil. Extra efforts were made at this stage to assure an adequate match of phase properties, including CO_2 densities over an anticipated wide pressure range. The EOS was able to match the behavior of slim-tube tests[25] at, above, and below the

MMP of 1,250 psia. This added credibility to the EOS and was important since the CO_2 would be in contact with hydrocarbons over a wide pressure range. A detailed discussion has previously been proivded above.

A parametric simulation study of the CO_2 Huff-n-Puff process was employed to identify reservoir parameters that might be favorable or unfavorable to the process and to provide insight into the best operational procedures. The results from the parametric study were incorporated into a site-specific simulation which was used for history matching the waterflood and to forecast recoveries. The site-specific simulation was later used to history match the CO_2 Huff-n-Puff demonstration.

Parametric Simulations. A 25 layer radial model was used. The model employed geometrical spacing between the grids but included local grid refinement for better definition near the wellbore. An injector was placed in the outside radial grid so waterflooding could be simulated and pressure in the model could be maintained. Porosities, saturations, and net pay were representative of the site selected for the field demonstration. Relative permeability curves obtained from laboratory measurements were used.

In several previous Huff-n-Puff's in a waterflooded environment, the total liquid production rate increased[6]. This increase represented the majority of incremental Huff-n-Puff oil. However, there is no mechanism in a simulator to cause an increase in total liquid production over an extended period of time. In this study, an attempt was made to keep the total liquid production rate steady before and after the Huff-n-Puff. This made it necessary to operate the simulator sometimes with a well rate constraint rather than a bottom-hole pressure constraint.

The reservoir parameters investigated in the study were the degree of reservoir heterogeneity and the magnitude of the watercut at the start of the Huff-n-Puff. The sensitivity to the number of layers in the model was also investigated as part of the study of the effects of reservoir heterogeneity. The operational parameters investigated were the CO_2 slug size, the CO_2 injection pressure (and rate) during the huff, the soak time, the gas production rate during the puff, and the number of Huff-n-Puff cycles. For consistency, most of the study was done using a slug size of 25,000 Mcf CO_2. A slug size of 25,000 Mcf CO_2 provides about 80 Mcf CO_2 per foot of net pay for the cases studied here.

Commercial reservoir simulators normally do not directly incorporate a number of the mechanisms that have been identified or suggested as being present in the CO_2 Huff-n-Puff process. As part of the parametric study, methods were identified which could be used to indirectly compensate for the absence of potentially important flow mechanisms in the simulator. These included primarily increases in the gas-oil capillary pressure to very large levels to approximate diffusion during the soak period and increases in the oil relative permeability curve (and even reductions in the residual oil saturation) during the puff to approximate suggested oil relative permeability hysteresis. The VIP-COMP simulator can also include directional relative permeability so that a decrease in the gas relative permeability can be approximated, if desired. Diffusion, which is approximated by an increase in the gas-oil capillary pressure, tends to bring oil back toward the well during the soak period, and an increase in the oil relative permeability increases oil production. Recovery efficiency, or CO_2 utilization, in this parametric study could have been improved if these options had been incorporated in the predictions. However, they were not invoked during the parametric study, but left to be used as needed for the history matching of the demonstration.

Typical Huff-n-Puff performance for a 25,000 Mcf CO_2 injection is shown in **Fig. 38**. Following a soak period, a typical case showed a large increase in the oil rate beginning about 10 to 15 days after the well was placed back on production. The peak oil rate was typically 2 to 5 times the base rate. Prior to the peak response time, the production was primarily gas (mostly CO_2) with little water or oil. A large percentage of the CO_2 that had been injected was produced back before the oil peak. After the peak, the oil rate diminished rapidly with time, returning to the base rate within 40 to 80 days. The incremental oil recoveries were typically between 1.5 to 3.0 MSTB. Good CO_2 utilizations were in the 10 Mcf/STB range, which are similar to the factors for standard CO_2 floods and are much greater than the factors of about 1 Mcf/STB previously reported in the literature for Huff-n-Puff processes. However, as noted earlier, including additional flow mechanisms could improve the utility. The objective of the parametric study was to compare the relative effects of selected parameters rather than predict the actual performance.

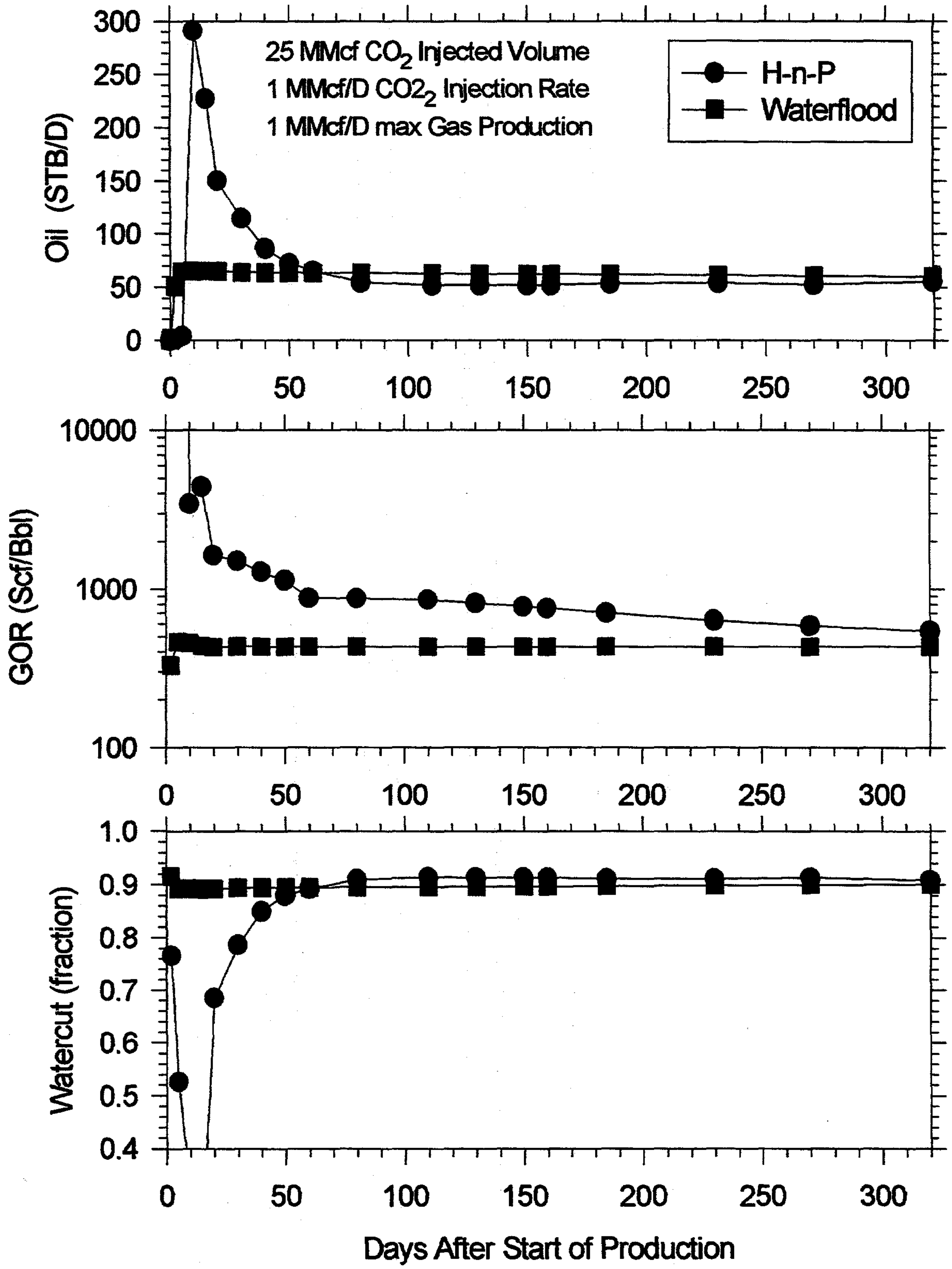

Fig. 38: Typical Simulated CO_2 H-n-P Performance.

Most of the CO_2 that was injected was produced back before or during the peak oil production. In the model, the CO_2 that was injected, except for the trapped volume, was ultimately produced back. The gas-oil ratio (GOR) was predicted to remain high for several months after the well was put back on production.

The water-oil ratio (WOR) returned to its base level soon after the oil production peaked. The WOR was not reduced for an extended period of time. Although a long-term reduction in the WOR would be desirable, such a change can not be expected. A previous study showed that the WOR is determined by the fractional flow of oil and water coming to the well from the larger part of the reservoir outside of the zone contacted by a process such as a Huff-n-Puff.[26]

Parametric Study Results. The effects of key parameters are shown in **Table 5**. Incremental recovery is defined as increased production over that of the waterflood after the well is put back on production.

Table 5
Effect of Important Parameters on Oil Production

	Incremental Oil (MSTB)	Utility (Mcf/STB)
CO_2 Volume Injected, MMcf		
78	5.1	15.3
50	3.7	13.5
25	2.3	10.9
10	0.9	11.1
Watercut, Fraction [25 MMcf Case]		
0.85	1.4	17.9
0.90	2.3	10.9
0.97	3.1	8.1

The effect of **reservoir heterogeneity** was investigated by changing the base reservoir description. The layer permeabilities were altered. An initially very surprising result was that the Huff-n-Puff process was not found to be very sensitive to reservoir heterogeneity. This is directly opposite to standard CO_2 floods, which are very sensitive to reservoir heterogeneity. It can be explained by considering the differences between the standard CO_2 flood and the Huff-n-Puff. In a standard flood, high reservoir heterogeneity degrades performance because CO_2 inefficiently keeps channeling through zones in which the oil has already been recovered. In a Huff-n-Puff this does not happen. Rather, all the CO_2 that is injected, except for the trapped volume, is ultimately produced back from all the layers, even from the thief zones. All the zones are just processed one time. A thief zone does not degrade a Huff-n-Puff process unless the CO_2 permanently channels away from the pressure sink.

Reservoir heterogeneity does not appear to degrade the Huff-n-Puff process substantially unless there are very high permeability zones without vertical permeability. The presence of vertical permeability largely prevents high permeability streaks from degrading the process. A large amount of vertical permeability is not needed and values as little as 0.1 to 0.2 md are effective. The vertical permeability makes a layered system with heterogeneity more effective than a completely homogeneous system. If vertical permeability is present, the CO_2 enters the high permeability streaks but can move vertically into other layers. If there is no vertical permeability, zones of very high permeability will degrade the process since the CO_2 is confined primarily to the high permeability layers.

An additional finding, which also indicates that reservoir heterogeneity is not critical for the Huff-n-Puff process, is that predicted Huff-n-Puff performance was not found to depend significantly on the **number of layers** used in the simulation model. Similar results were found with 1, 2, 5, and 12 layer models. Even though a one-layer model is completely homogeneous, the results from a one-layer model were typically within 20% of the results from multi-layer models. The results shown in Fig. 38 are from a one-layer model. Previous investigators have also suggested that one-layer models are sufficient for modeling Huff-n-Puff processes.[8, 27]

Another surprising result was that the Huff-n-Puff process in waterflooded (water drive) environments appeared to work better for wells with a **higher water-cut**. These wells have an oil saturation close to the residual oil saturation to waterflood. The incremental oil recovery was somewhat higher (better) and the CO_2 utilization was somewhat lower (better) for a high water-cut case. The peak Huff-n-Puff oil rate was not found to be a strong function of the prior watercut. Consequently, a well with a high water-cut showed a large relative increase in oil rate.

The original idea of the CVU Huff-n-Puff process was to try to inject the CO_2 below the MMP of 1,250 psia, and then let the pressure build during the soak period. However, the simulation model suggested that an operator could not inject the CO_2 below the MMP. For the CVU cases, the average reservoir is above the MMP. Near-wellbore average pressure reached the MMP rather rapidly after beginning injection in this simple model. Furthermore, the pressure rapidly reached the MMP even when the well was shut-in without injection and when offset injection was stopped 15 days in advance. Oil recoveries in the CO_2 Huff-n-Puff process simulated here were not found to depend strongly on the injection pressure or rate. **Injection pressures** from the MMP to 3000 psia were investigated, and it was found that the process was not degraded significantly at successively higher pressures when above the MMP.

Limiting the **gas production rate** between 500 and 3,000 Mcf/D affected the incremental oil production, but not to a very large extent. It was found that slightly higher incremental recoveries occurred with the higher gas production rates.

The volume of incremental oil was found to depend on the volume of CO_2 injected. As the **volume of CO_2** was increased, the incremental oil recovery was increased, but also the start of oil production during the "puff" was delayed. The associated deferred oil volume also increased accordingly.

In agreement with previous simulation studies, soak times longer than a few days did not produce different results[8,26]. Current commercial simulation models may not adequately handle the soak period.

Multiple Huff-n-Puff cycles were not found to be very effective. The reason was that the main recovery mechanism was gas trapping, and the majority of trapping occurred in the first cycle. The repetitive application of the process was seen as unwarranted in the waterflooded environment.

Dominant Mechanism. Entrapment of CO_2 by gas hysteresis was theorized to be the dominant recovery mechanism. This study supports the conclusion of Denoyelle and Lemonnier that a trapped gas saturation is the main cause of incremental oil for a Huff-n-Puff in a light-oil, waterdrive reservoir[28]. The mechanisms of oil swelling and viscosity reduction are important in the production of the initial oil peak, but they do not result in permanent incremental oil. In the present study, if a trapped gas saturation generated by gas relative permeability hysteresis was not used in the Huff-n-Puff simulation, virtually no incremental oil was predicted. The trapped CO_2 in the Huff-n-Puff zone prevents the Huff-n-Puff zone from being resaturated with oil that is flowing toward the well from further out in the reservoir. What happens without a trapped gas saturation is this. Although the Huff-n-Puff initially produces oil from the affected region by reducing the oil saturation to very low levels, oil from further out in the reservoir enters the affected zone as it flows toward the well and re-establishes an oil saturation similar to the saturation before the Huff-n-Puff. In other words, without a trapped gas saturation, the oil and water flowing into the Huff-n-Puff zone return the oil and water saturations to the values that would have existed without a Huff-n-Puff. A trapped gas saturation prevents resaturation by oil.

In the simulator, a trapped gas saturation has a tendency to reduce the total liquid production rate. This effect was not used in the parametric studies or the site-specific forecast. For both these cases, an attempt was made to keep the total liquid production rate steady before and after the Huff-n-Puff by operating the simulator with a well-rate constraint rather than a bottom-hole pressure constraint.

Summary of Parametric Study. Reservoir description was found not to be as important a parameter in a Huff-n-Puff as in a standard CO_2 flood. This indicates that most wells could be Huff-n-Puff candidates unless they have problems that would cause the CO_2 to channel permanently away. Huff-n-Puff operations can be flexible because Huff-n-Puff predicted performance was found to be similar over a range of injection pressures and gas production limits. Injection volume is an issue because recoveries were found to be related to the total CO_2 volume injected, similar to typical miscible floods.

Site-Specific Study. The model site covers 160 acres (four original 40-acre five-spot patterns) in the north half of Section 6 (outlined in Fig. 5). The model covers an area that was developed on 10-Acre spacing in early 1995. The site spans varying reservoir quality. The northwest pattern is more contiguous, and has exhibited textbook waterflood characteristics. The southeast quarter is more heterogeneous and has had a much poorer waterflood history. The model site covers the margin between the Northwest Shelf and the Delaware Basin. Producers are located on the periphery of the model. Four interior producers are considered candidates within the model area; however, CVU Well No. 97 was chosen as the most representative of the reservoir and is the only injection pattern comprehensively evaluated to date in this study.

The 160-acre model was finely gridded with 26 rows and 22 columns (132 ft. × 132 ft.). Twelve layers were incorporated to model flow units identified by earlier geostatistics work. A cross-section through the model is provided in **Fig. 39**. Additional local grid refinement was imposed at the cell encompassing the producing wellbore in an effort to more accurately mimic the process.

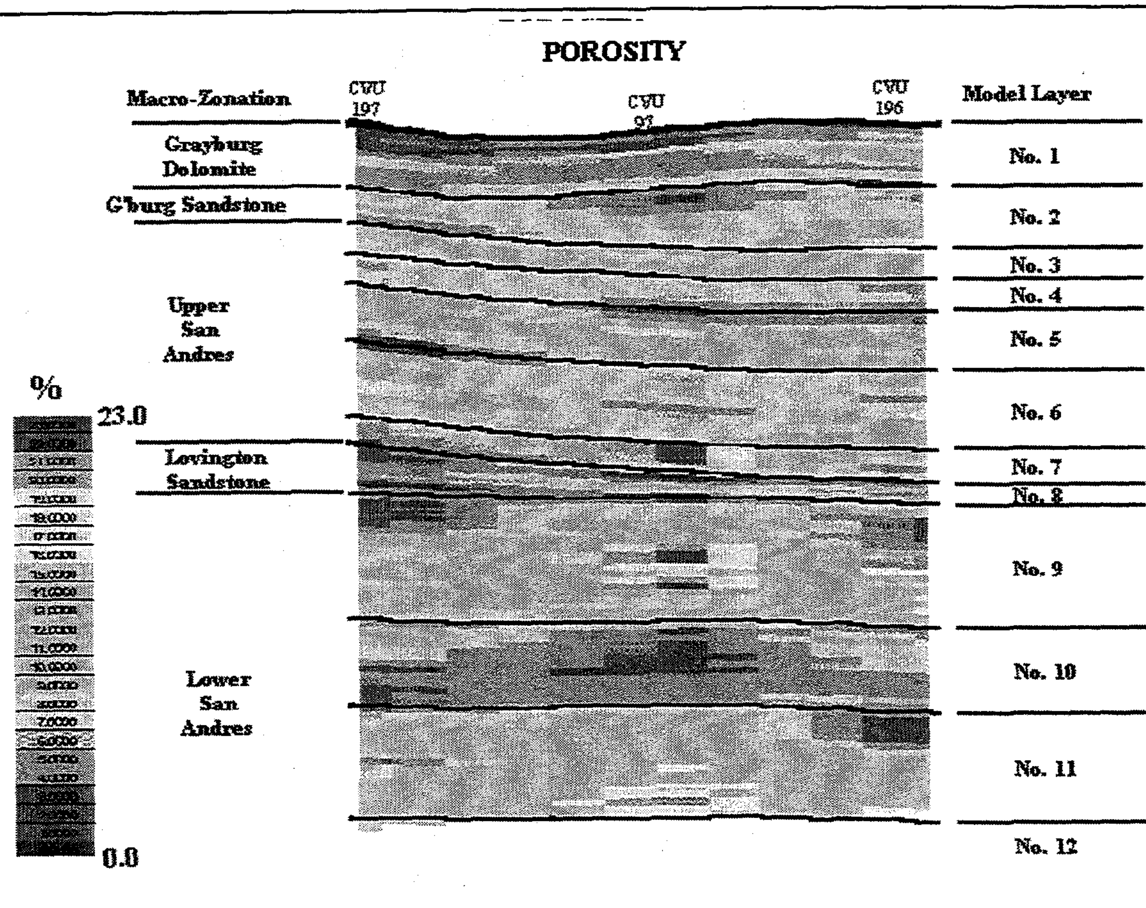

Fig. 39: East-West cross-section through Porosity model. Macro-zonation and model layer numbers identified.

The full model contained 6,924 cells (6,864 cells, exclusive of local grid refinement). History matching the waterflooded period of 1978 (start of waterflood) through 1995 was performed. The historical oil rates were used as input to the simulator, and the water production rates were history matched primarily by adjustments in the oil relative permeability curve. Although the primary production is available, it cannot be accurately history matched with the current equation-of-state since it was developed from Pressure, Volume, and Temperature (PVT) studies on the waterflooded oil properties. No PVT data is available prior to waterflooding. The relative permeability adjustments were kept within the range of laboratory data. A forecast of the process was developed for a demonstration at CVU No. 97, and is provided in **Fig. 40**. A moderately large gas-oil capillary pressure and trapped gas hysteresis were the only special relative permeability features used in developing the forecast. In addition, the total liquid production rate was kept steady/constant before and after the Huff-n-Puff by operating the simulator with a well-rate constraint rather than a bottom-hole pressure constraint.

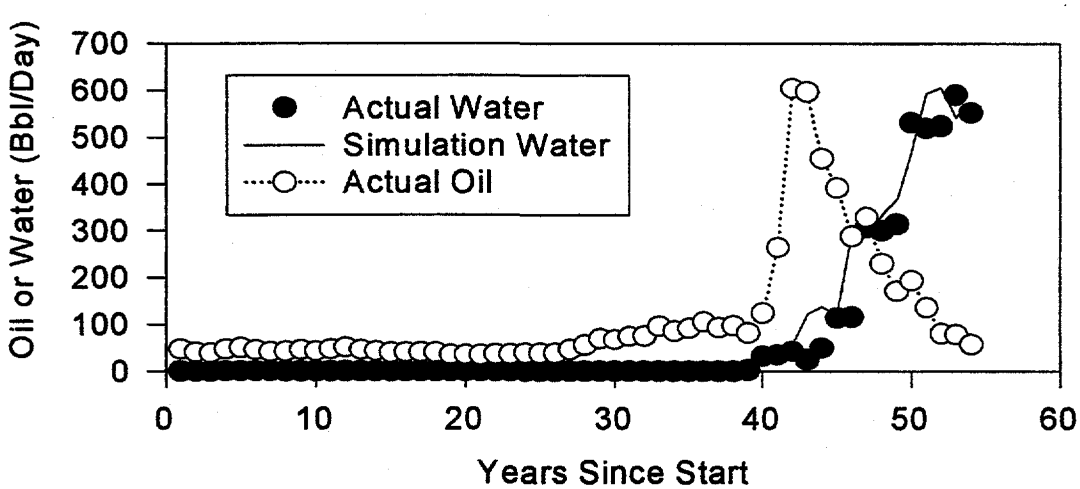

Fig. 40a: Demonstration Site History Match (primary + secondary) And CO_2 H-n-P Prediction for CVU No. 97.

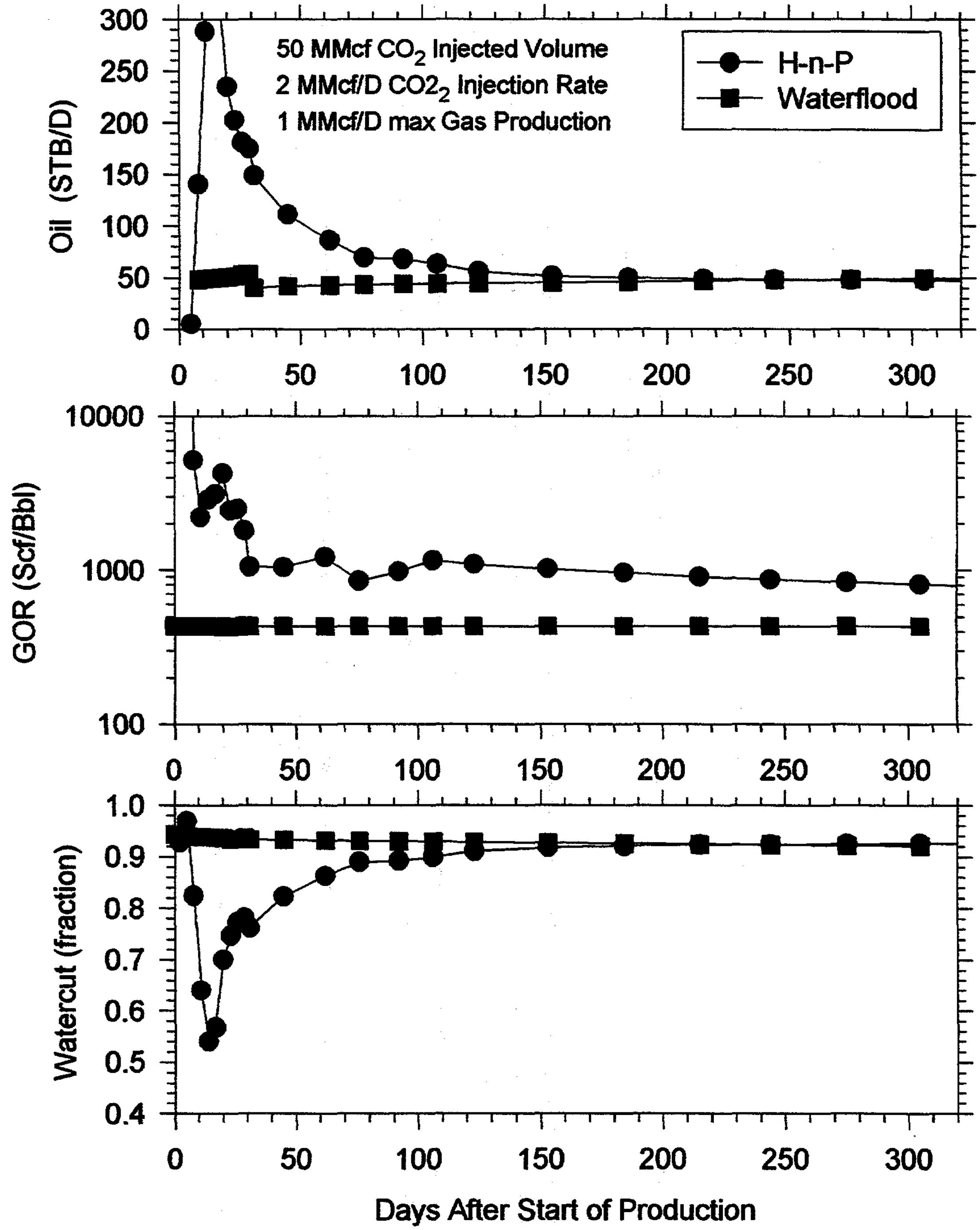

Fig. 40b: Demonstration Site History Match (primary + secondary) And CO_2 H-n-P Prediction for CVU No. 97.

History Match of Field Demonstration. The need for model refinement was demonstrated by the differences between the site-specific predictions and field demonstration results (injection rates, pressures, & production). Sufficient data was gathered for a meaningful attempt at history matching. The mechanisms investigated during the parametric simulation were incorporated as warranted. The history matching of the Field Demonstration was completed during the third quarter of 1996. The pursuit of a second demonstration site was weighed with findings developed during the history matching.

Although the predicted and actual Huff-n-Puff performance appears to be very different, a reasonably close history match was obtained with only two changes, a limitation on the gas production rate and a removal of gas hysteresis. First, the gas production during the first 65 days of production was limited to the actual gas production rate experienced in the demonstration test. Second, gas hysteresis (i.e., the gas trapping mechanism) was also eliminated. **Figure 41** shows the history match with the limitations on the initial gas rate (and without gas trapping).

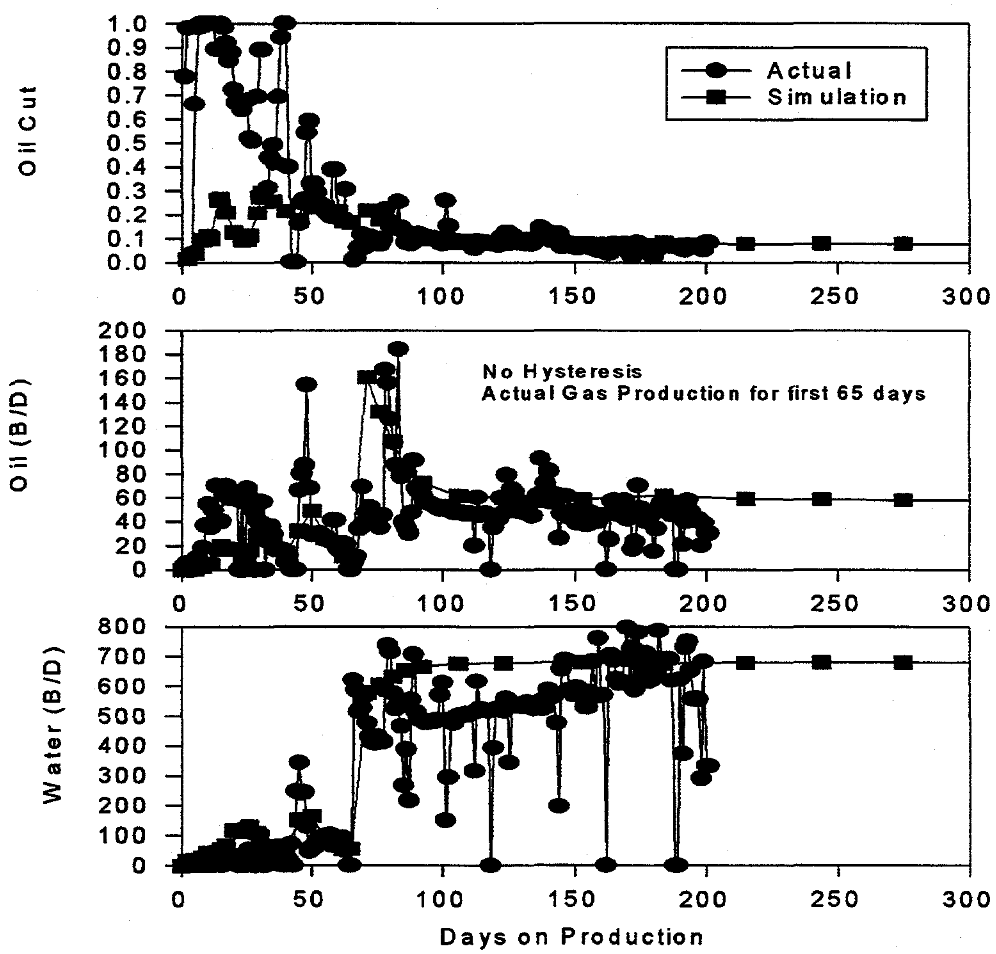

Fig. 41: History Match of CO_2 H-n-P Field Demonstration.

Comparison of Actual Performance and the Site-Specific Prediction. The two main differences between the predicted performance and the actual performance of the Huff-n-Puff were an apparent absence of gas trapping and lower than predicted production rates. The most obvious difference between the actual and predicted performance was that the total liquid (oil + water) production rates were much lower for the actual test during the period in which the well was flowing. The low production rates, which were actually less than the rates prior to the demonstration, needed to be matched in the simulation. The liquid production rates in the simulation were reduced indirectly by placing a limitation on the gas production. For the original site-specific prediction, the well was controlled in the simulation model to maintain the same liquid (oil + water) production rate after the Huff-n-Puff as before, and the gas production was not allowed to exceed 1,000 Mscf/D. There was anticipated to be an actual field limitation of 1,000 Mscf/D on gas production (the limitation on gas production in the early production period was due to disposal issues). However, in the actual field test, both the initial total liquid production rates and the gas production rates were much less than in the prediction. The gas production was initially around 1,000 Mscf/D, but it rapidly declined and became less than 100 Mscf/D before the pump was put back in the well. This was the result of flowing the well, which ultimately loaded up with liquids. The lower early liquid production rates were matched in the simulation model by limiting the simulated gas production rates to the actual gas production rates for the first 65 days the well was placed back on production.

The history match case was modified to permit the well to produce at a maximum gas rate of 1000 Mscf/D. Permitting the well to produce at a gas rate of 1,000 Mscf/D (drawing down the wellbore fluid level), increased the oil recovered during the simulated Huff-n-Puff. About 3,000 STB of incremental oil was recovered during the production period under the 1000 Mscf/D limitation scenario compared to no incremental oil when the gas production rate was reduced to match actual gas production in the demonstration site. However, the incremental oil under the 1,000 Mscf/D limitation is still only enough to compensate for deferred production during the CO_2 injection and soak phases. This modified history match case, which indicates that a high gas rate during production increases oil recovery, is consistent with previous parametric simulations that indicated incremental oil during the production phase was increased when the gas production limitation was removed. However, the rate dependency in the modified history match case was somewhat larger than in the previous parametric simulation cases. Permitting the well to produce at higher gas rates should increase the oil recovered during the Huff-n-Puff, but it is not expected to compensate for more than the oil deferred during the CO_2 injection and soak phases unless a trapped gas saturation is anticipated/developed. **Figure 42** shows the difference between the history match simulation with the actual gas production rates and the history match case when the well was permitted to produce at a gas rate of up to 1,000 Mscf/D during the first 65 days. When the gas limitation was removed, the oil response was improved. This suggests not limiting gas production during a Huff-n-Puff.

If the well had been drawn down, higher total liquid rates would have likely been achieved. In addition, if the total liquid production rates in the actual test had been close to those in the prediction, there would probably have been a larger oil spike in production. After the pump was put back in, the liquid rate in the demonstration site did increase to pre-Huff-n-Puff levels, and the oil rate did spike up for a number of days. The oil-cut stayed above the pre-Huff-n-Puff level for a period of time after the pump was put back in.

In many Huff-n-Puffs that have been described as successful in the literature, the total liquid production rate increased although the steady oil-cut did not increase. These previous reports of increased total liquid may simply reflect a cleanup of perforations or the wellbore, whereas this demonstration utilized a wellbore that had been cleaned out several months earlier, eliminating the unknown variable.

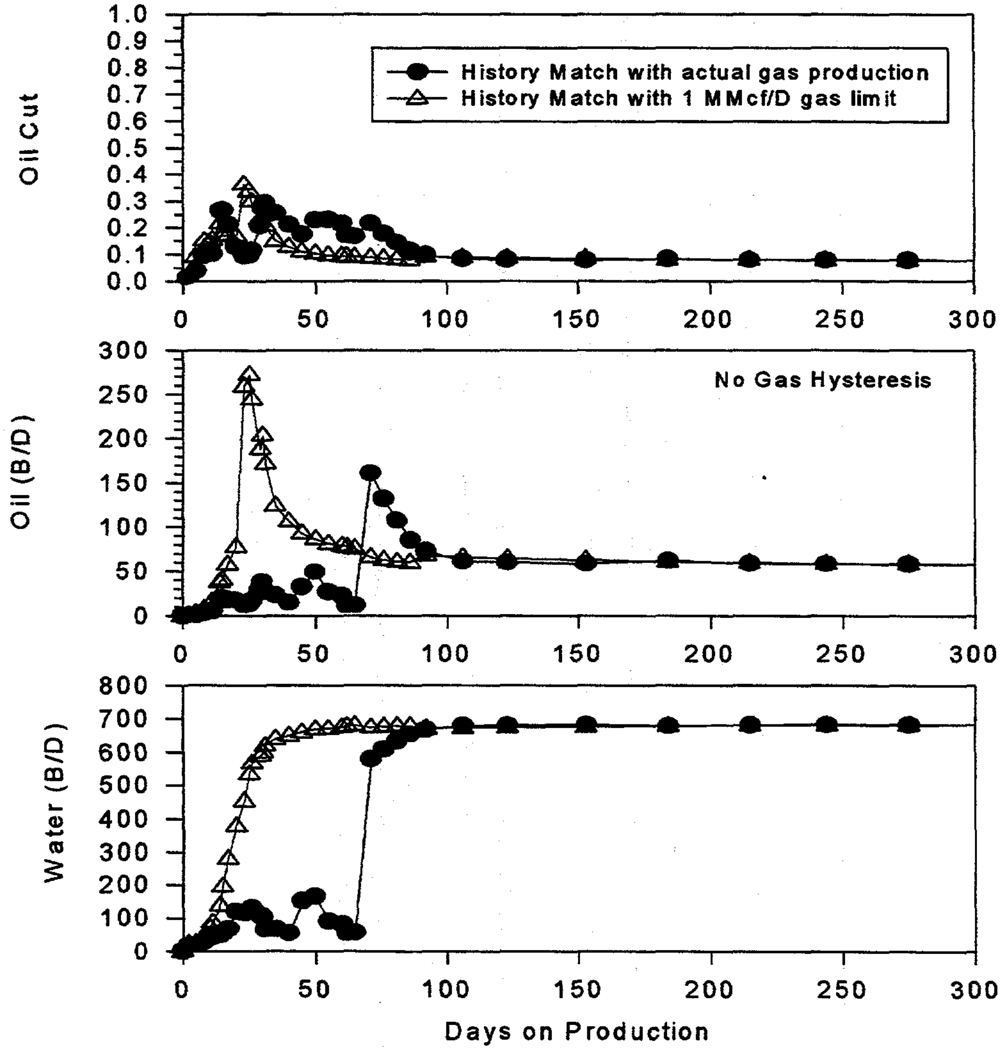

Fig. 42: Comparison of Field Demonstration History Matches while varying gas production rates.

If gas trapping occurred during the demonstration it was short-lived since nearly 100% of the injected CO_2 volume was produced. Gas trapping was the main mechanism required in theory to provide the improved oil recovery profile developed in the parametric and site specific simulations. It is theorized that either the water production was able to dissolve the trapped gas saturation or the reservoir is not amenable to gas trapping. The simulation predictions (and history matching) do not include dissolved gas in the water fraction. Although this is known to occur on a limited basis, it could not be adequately simulated with the software which was used due to computational instabilities. (A new version of the software may have overcome these instabilities.) Additionally, it is possible that gas trapping cannot 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.

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 most 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 during 11 years of WAG operations, even though 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 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 consider expanding their program. An offset miscible CO_2 flood within the Welch field experienced reduced injectivity in WAG operations. This further suggests that the technology should be applied to another reservoir that has documented WAG injectivity reductions. This option was pursued and a second demonstration site was chosen in the Slaughter Field of West Texas (discussed later). 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.

The oil-cut in the actual Huff-n-Puff was very high, better than 0.90 for a period of time. The predicted oil-cut did not reach such high levels. In addition, the high oil-cut could not be achieved in the history match efforts. Although the oil-cut was very high, the actual oil rate was quite small in this period, as was water production. The capability of accurately measuring these small volumes may have an influence on the calculated oil-cut in the initial production period. It is also possible that water relative permeability curve hysteresis may be required to limit the water production in the simulation. This option is not available in the commercial simulator used. If the total liquid production rate in the actual test during the flowing period had been close to that in the prediction, there would have been a large oil spike in production. After the pump was put back in, the liquid rate in the demonstration site did increase to pre-Huff-n-Puff levels, and the oil rate did spike up for a few days. The oil-cut stayed above the pre-Huff-n-Puff level for a period of time after the pump was put back in.

The simulation also suggests that an error in the measured gas production rate may have occurred shortly after the pump was put back in. The metered volumes plateaued after the 100th day rather than continuing to decline. Metered gas volumes from the demonstration site also suggest recovery was 40-50% higher than the volume injected. **Figure 43** compares the measured and simulated gas production for the history match.

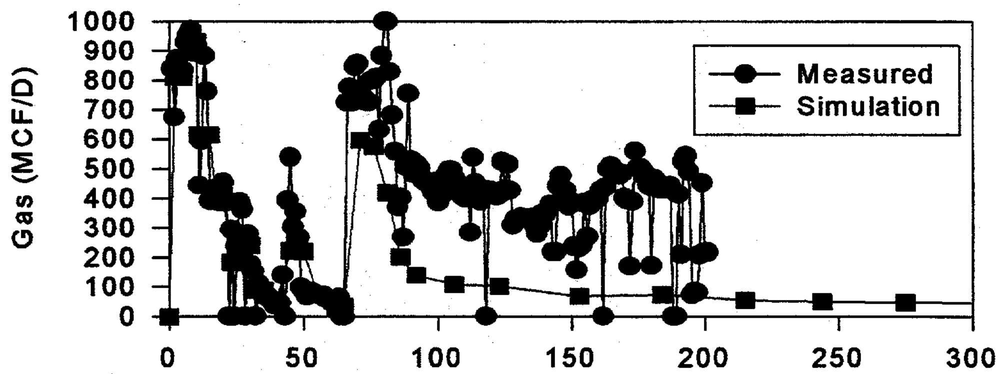

Fig. 43: Actual vs. Simulated Gas Production from Field Demonstration.

Figure 44 compares the site-specific prediction with the history match case in which the gas production rate was permitted to reach 1000 Mcf/D. The site-specific forecast also had a 1000 Mcf/D gas production limitation. The main difference between these two cases is that the forecast had gas trapping (i.e., gas hysteresis) while the history match case did not. The absence of the residual gas saturation delays and reduces the predicted oil production.

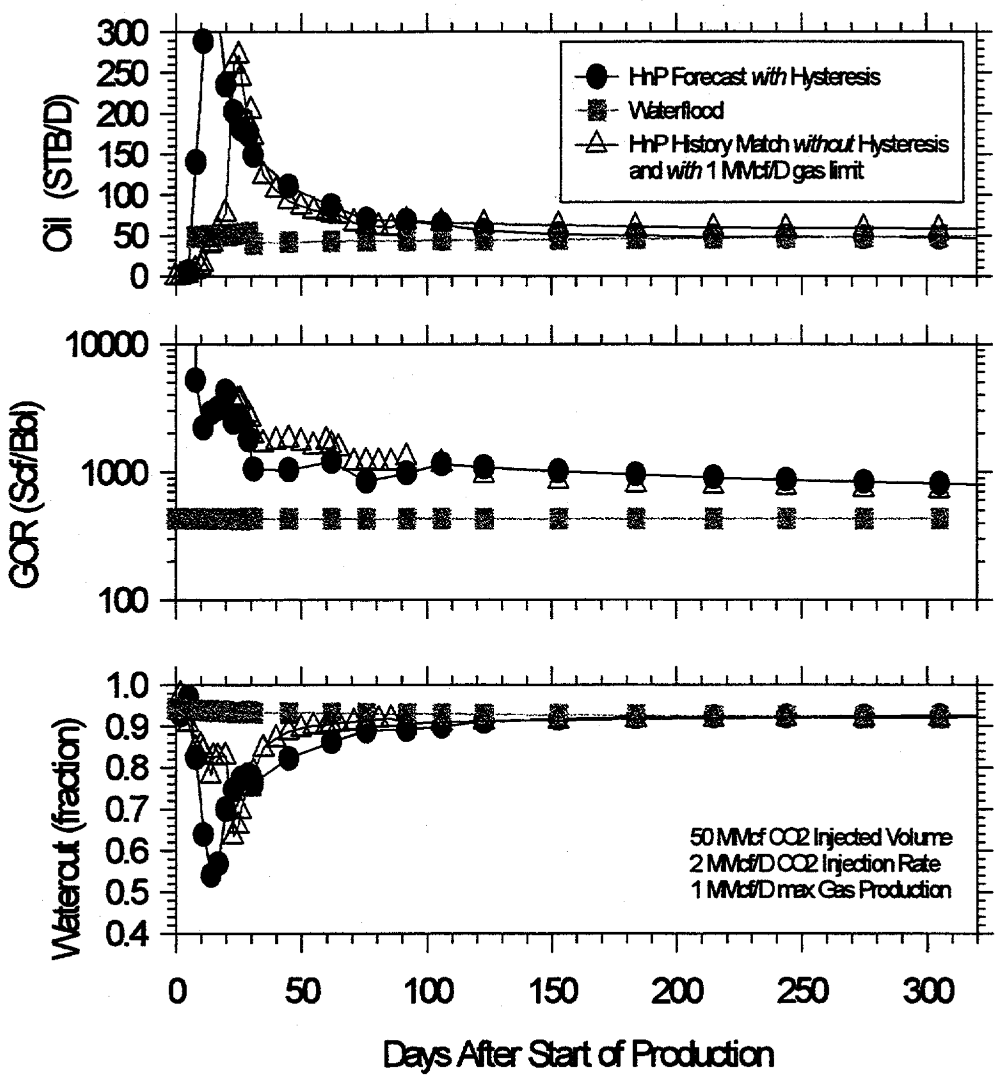

Fig. 44: Comparison of Site-specific forecast and Field Demonstration History Match after removing the gas rate restrictions.

Summary. The history matching efforts validated the decision to not attempt any more Huff-n-Puffs at CVU. In addition to requirements for a 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 CVU. 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 successful because the oil rate will be too small (even though the oil-cut might be improved). If this CVU well is typical, a successful Huff-n-Puff may not be possible for a well which 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 rates may be possible if higher gas volume production equipment can be utilized. Gas lift might be an option.

The simulation input and output data sets were provided in Appendix "B" of the 1995 Annual Report[23].

Field Demonstration 1 - CVU

Even though parametric simulation exercises suggested reservoir heterogeneity would not play a large role, a well with average reservoir characteristics of the CVU was desired. Additionally, the parametric study showed that a higher water-cut production stream would have a better CO_2 utilization ratio. CVU No. 97 was selected in part based on these guidelines. The well has several distinct, relatively thin, higher permeability flow units which are common within CVU. The remainder of the net pay is of average reservoir quality. The well was drilled in 1938 and completed open hole. A volume of 50,000 Mcf CO_2 was trucked to the field site. The volume was determined to be sufficient for the storage volume available in the near wellbore vicinity, yet small enough to reduce concerns of any loss of CO_2 beyond the interwell distance if the higher flow-capacity zones took all the injectant. Based on average reservoir parameters, this volume would expose the reservoir to less than a 100 ft. average radius of CO_2.

The production equipment was removed from the wellbore. Since the well had been acidized in recent months no further remedial action was performed. An on-off tool and injection packer trimmed for CO_2 service was set above the open-hole section.

The theory of ceasing offset water injection was not strongly supported by simulation. However, recognizing that simplistic models may not have the capability to quantify this case, the offset injection was shut-in 17 days before CO_2 injection commenced at CVU No. 97.

Frequent and detailed testing was conducted for the duration of the project. A dedicated horizontal, three-phase test separator was set at the well site. Data gathering was automated. Flowing tubing pressure, casing pressure, and temperature were monitored continuously. Liquid volumes were measured daily. Gas production rates and volumes were also measured. Automated gas sampling provided a daily sample for gas chromatography. Liquid samples were initially gathered daily for visual inspection, API gravity determination, and occasional compositional analysis. The test separator dumped liquids to the existing production satellite. Polyethylene pipe was used exclusively to tie the well and separator together, and separator into existing assets.

Air quality regulations would not permit venting the hydrocarbon enriched CO_2 produced gas stream to the atmosphere. The produced gas was delivered via an existing pipeline (1000 Mscf/D capacity limitation) to a nearby CO_2 processing facility.

Field Demonstration 1 – CVU: Results. Injection was initiated November 13 and completed on December 7, 1995. Based on the offset miscible CO_2 flood injection rates and pressures, an average rate of 1,500 Mscf/D CO_2 was expected in the demonstration. Actual injection averaged 2,210 Mscf/D CO_2 over 23 days net injection. Injection line temperature fluctuated between -14°F and 20°F, averaging 3.4 °F. Wellhead injection pressure averaged 644 psig and did not exceed 817 psig.

Concern over the open-hole section, lower injection pressures and higher injection rates than expected prompted an injection profile survey once half the target volume was injected. The CO_2 was found to be distributed within both the Grayburg and San Andres formations. Although the injectant was confined to the pay zone, the distribution was somewhat weighted toward the Lower San Andres. The injectant was at the reservoir temperature of 101°F by the time it reached the bottom injection interval. The estimated average bottomhole injection pressure of 2,175 psig never approached the parting pressure of the formation (3,200 psig). It is doubtful that any part of the near-wellbore vicinity was able to maintain a pressure below the MMP of 1,250 psig as originally desired for the injection phase. This supported the simulation findings.

Once the CO_2 was in place offset water injectors were returned to active service. CVU No. 97 was then shut-in for a 20-day soak period. Wellhead pressure averaged 630 psig during the last week of injection and increased steadily to 889 psig during the soak period. Although common in the CVU water injectors, it is unknown if any cross-flow from higher permeability to lower quality zones occurred in the producing wellbore during the soak period. It is believed that this phenomenon would be beneficial to the demonstration rather than detrimental.

CVU No. 97 was returned to active status under flowing conditions on December 27, 1995. Early flowing tubing pressure averaged 631 psig with choke settings between 13/64 in. and 18/64 in. Liquid hydrocarbon production was initially too small to measure and began increasing on the third day. Samples were collected and retained. The fluid was initially a transparent straw color (41°API) suggesting that lighter hydrocarbons were being effected (or paraffins & asphaltenes were being left behind). The well returned to producing the field normal 38°API crude in rather short order. The well had achieved a 70 BOPD rate by the tenth net day of flow-back (average pre-demonstration was 68 BOPD). Production was quite volatile. The well initially flowed on various choke settings, but eventually loaded up. An Electrical Submersible Pump was run into the wellbore in early March 1996. Following some minor operational problems, the well peaked at 184 BOPD. However, production declined rather sharply following this peak. Previous simulation exercises suggested that the peak oil response would not occur until 60% of the CO_2 had been produced back. The peak actually occurred at about 55% CO_2 recovery. The well has continued on a relatively shallow steady decline and is producing approximately 55 BOPD as of the date of this report.

Initially, gas production averaged 901 Mscf/Day. Gas production was not allowed to exceed 1,000 Mscf/D due to disposal limitations. Compositional analyses of the gas stream shows that early gas rates were above 90 mole-% CO_2. The CO_2 production steadily fell to 68 mole-% CO_2 by July, 1996. The daily monitoring of the demonstration ended in July, 1996 because it was apparent the well's production streams had stabilized near the pre-demonstration rates. A random sampling of gas from the well one year after return to production still indicates an elevated CO_2 concentration at the well (i.e., over 40%).

The magnitude of the gas production volumes is in question. Even after an attempt at accounting for in-situ CO_2, material balance suggests that a volume equal to 140% of the injected CO_2 volume had been produced by July, 1996 and 150% by the end of the year. The well continues to produce relatively high gas volumes compared to its offsets. However, the earlier gas rate itself is likely in error. The gas rate stopped declining around April 1996. When the well was placed through the field facilities, the rate, although higher than offsets, was much lower than those measured in the test facility through July 1996. The volume probably dropped below the measuring range for the meter utilized on the test separator around April 1996. It is probably safe to say that the well will recover 100% of the injected CO_2.

The accuracy of either the gas test rates/volumes, sampling procedures, laboratory analysis, or a combination of each remain suspect. However, the laboratory analysis seems to be an unlikely cause due to the level of accuracy obtained from consistent standard industry practices. Although sampling procedures are questionable, the resulting error would likely be a lower CO_2 percentage measured, not higher. All the Huff-n-Puff simulations, including all the parametric and site specific cases, indicated that increased CO_2 production could last for well over a year. Consequently, the continued production of a high concentration of CO_2 (i.e., as much as 40%) is consistent with the simulation results. The error seems to be with the measured gas rates. If some assumptions are made in decline behavior of the gas rate from April, 1996 to the monthly rates measured in the field facilities during the last half of the year, the figures are more realistic, but still 20% high. The frequency of measurements could account for much of this discrepancy.

It is interesting to observe that although predicted oil response from the site-specific simulations are substantially different, the predicted GOR for all cases are very similar after about 150 days. The GOR for the simulated base waterflood remained at about 430 Scf/STB, whereas the GOR for the Huff-n-Puff cases remained substantially higher and was above 700 Scf/STB even after a year. The simulations were done only out to about a year, but the GOR appears to be declining only very gradually and would be expected to remain high well into the second year, as has been seen in the field demonstration.

The concentrations of the produced gas streams were not reported in the simulation outputs. However, the concentration of CO_2 can be approximated because the increased GOR above the base of 430 Scf/STB is due primarily to the presence of CO_2. Using this approximation, which is fairly good, the fraction of CO_2 for a given GOR can be estimated with the following formula:

$$CO_2 \text{ fraction} = ((0.05 * 430) + (GOR - 430)) / GOR$$

Using this formula, the anticipated fraction of CO_2 in the produced gas can be expected to be above 0.40 even a year after the start of production as indicated in **Table 6** for the two history match cases discussed later in this report.

Table 6: Comparison of Estimated CO_2 Fraction based on Simulations.

Simulation Case	Days after Start of Production	GOR	**Estimated CO_2 Fraction**
Actual Initial Gas Rates	336	724	**0.43**
1000 Mscf/D Gas Limit	336	705	**0.42**

Offset producers were monitored on a regular basis for CO_2 breakthrough. Levels remained in the normal 4-5% background range. A check one year after injection shows somewhat elevated CO_2 levels in the two immediate offset wells. The offsets show 31-39 mole-% CO_2. However, these elevated findings may represent the influence of spent acid due to recent workover activity.

It is noteworthy to point out that although hydrocarbon production expectations have not been achieved at this specific test site, there was a period that experienced a favorable reduction in operating expenses. During the injection, soak and flowing periods there were no electrical costs. Electrical load was also significantly reduced during the early pumping period when water rates were 100% to 33% below pre-demonstration levels. No appreciable water production was seen initially. As expected, the water production slowly increased over a six-month period and approached the pre-demonstration rates. The water remained on average 17% short of the original rate after one year of production. Although there are a few signs of paraffin buildup and scaling (inspection of downhole equipment), the lower than forecast oil production result is felt to be due to a lack of gas trapping in the matrix since nearly 100% of the injected CO_2 volume is expected to be recovered. The reduced water rate may be impacted by the remaining CO_2 saturation. More discussion of this conclusion is found in the history match discussion of this report.

Figure 45 provides the field demonstration history through mid-July, 1996. Supporting data was previously provided in Appendix "A" of the 1995 Annual Report[23].

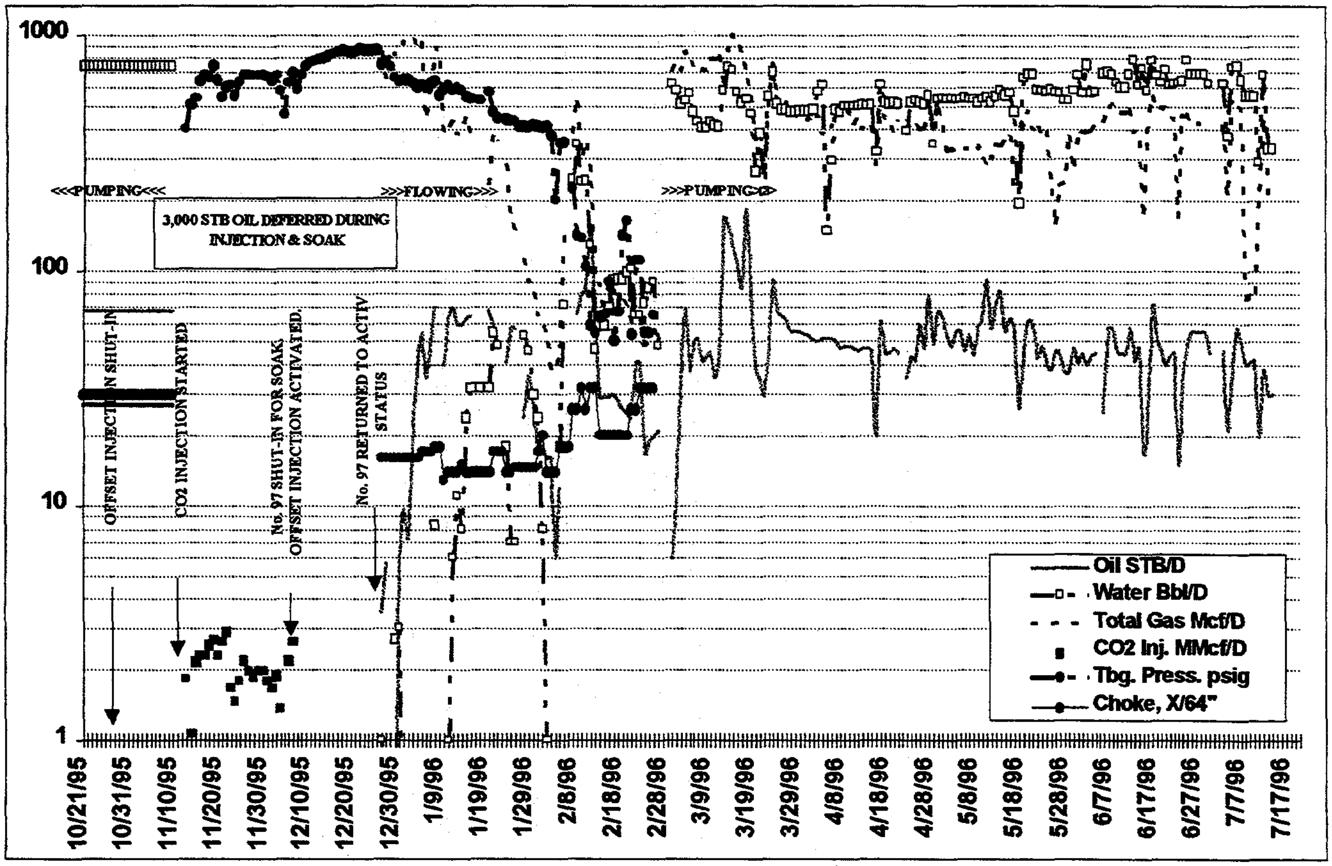

Fig. 45: CVU CO_2 H-n-P Demonstration History.

Field Demonstration 2 – SSU: Results

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 46** 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 47**.

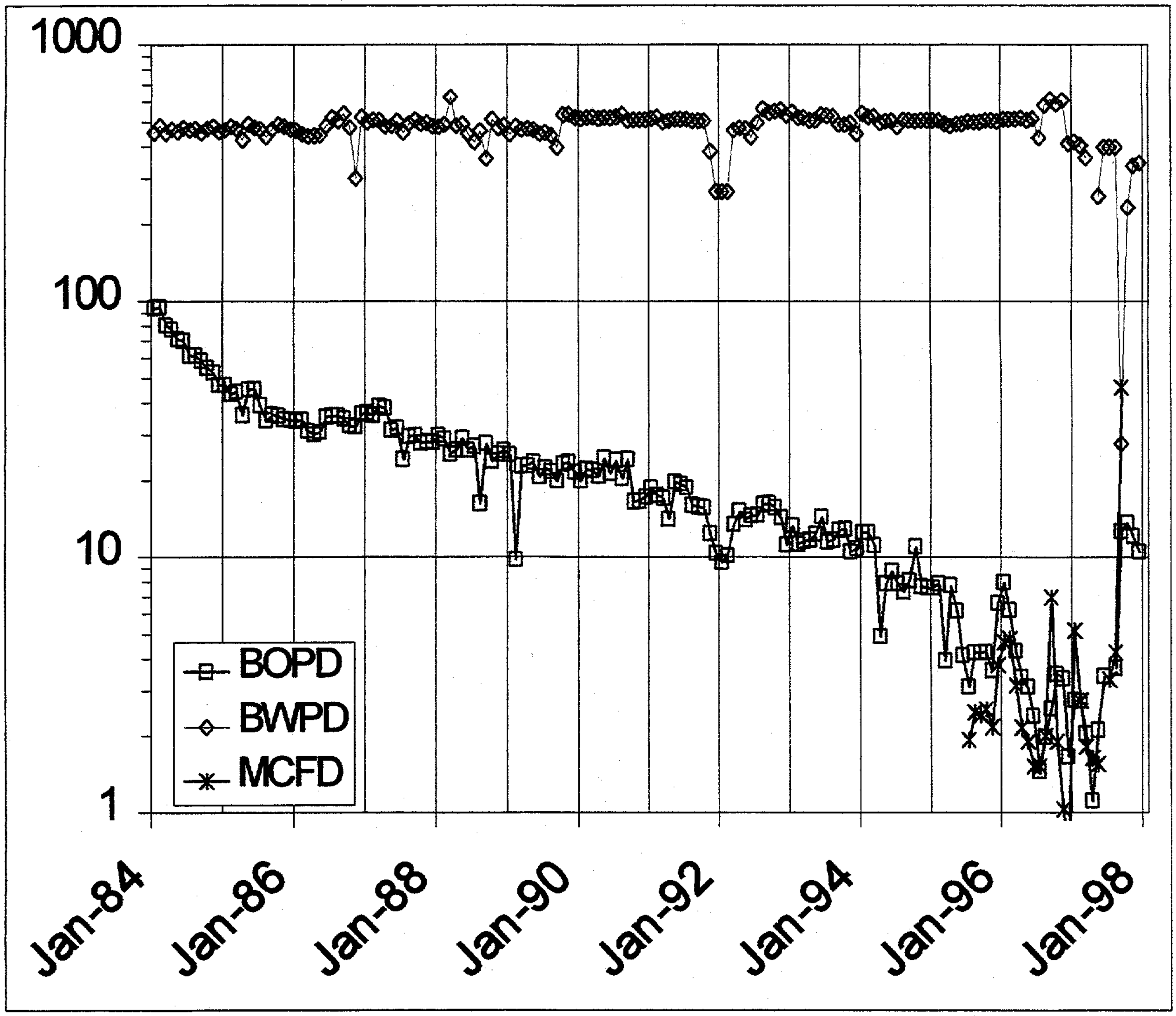

Fig. 46: SSU 1341 Production Plot - life of well

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 candidate 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 many potential candidates. Well 1341, drilled in 1984, had cement circulated to surface during the primary casing cement job, which made it 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 well site. Texaco did not want to spend a large amount of money on 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 CO_2 flood in the eastern part of the field, the demonstration site candidates were limited to the western part of SSU. As mentioned, there was also a desire 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 50.0 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 only 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 50.0 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 through September 20.

On September 21, the choke was opened 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 at the tank battery, the same test separator that Texaco tests all other wells through in that vicinity of the field. Texaco felt confident that accurate tests were being made, however it was discovered that the micro-motion 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 occurred on or 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, therefore the well probably did experience 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% of that requirement, 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 the ability for gas trapping exists. 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.

This being the case, the well was flowed to one of the test facilities at one of the satellite production 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 and 400 BWPD. The gas production, currently at 45 Mscf/D, remains well above the pre-test level of about 2 Mscf/D.

Figure 47 depicts the results of the Huff-n-Puff test with daily production and injection parameters plotted (this data was included as an appendix to the 1997 Annual Report[29]). 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 5.0 %. During the first three weeks of testing, the oil-cut averaged 30.0%. After that, the oil-cut dropped to less than 5.0% 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.

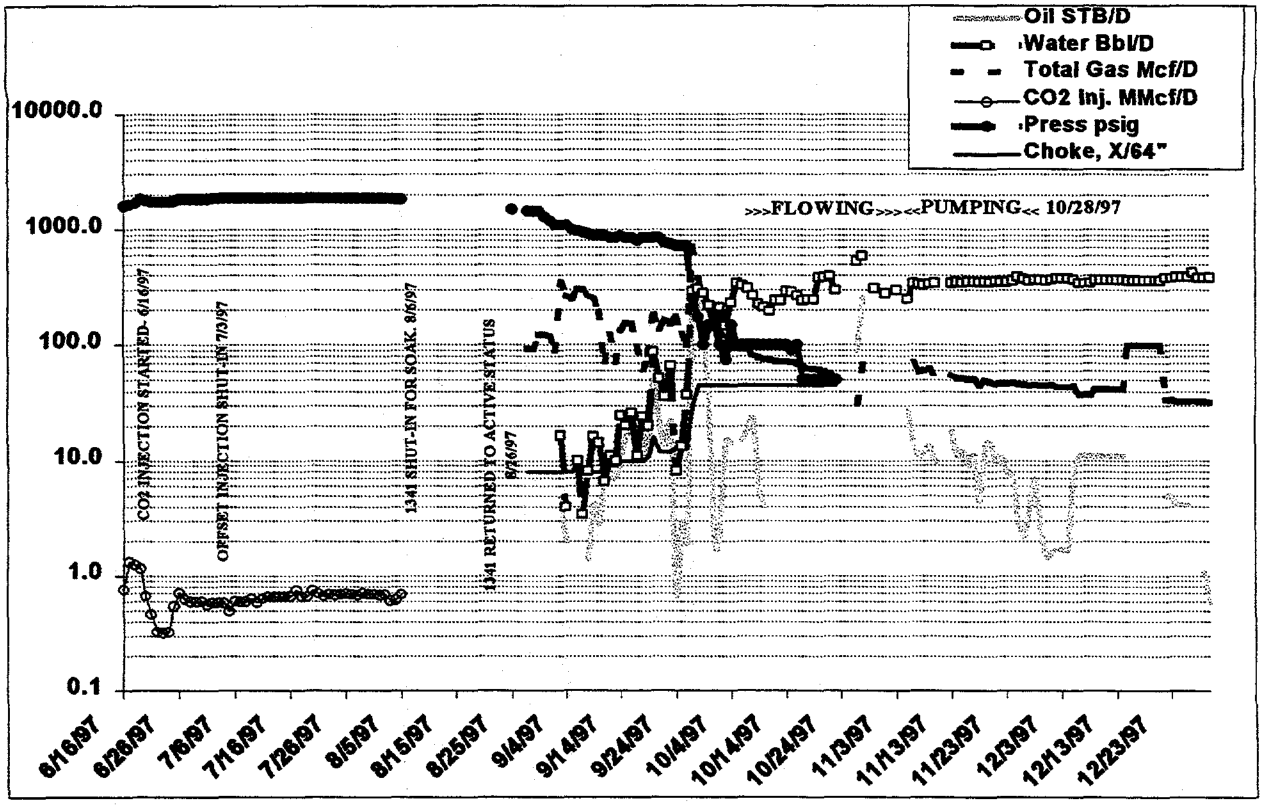

Fig. 47. SSU 1341 Huff-n-Puff results

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 could handle. 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

CVU

The actual costs associated with the field demonstration components of the project are included in **Table 7** under the heading, *No. 1 (Pumped)*. There were a number of non-recurring charges identified that would not be included if a second site were chosen at CVU for another demonstration. Additionally, the volume of CO_2 would not be as large; reducing pump time. The soak period would also be scaled back somewhat. This second option is depicted in **Table 7** as *No. 2 (Pumped)*. The cost of a second site at CVU would be about half the cost of the first site. As originally hypothesized, the largest benefit of this technology would come from coupling it to a miscible CO_2 flood, which would have pipeline CO_2 available as the project was implemented and expanded. This last scenario is included in **Table 7** as *No. 2 (Piped)*. The availability of pipeline CO_2 makes a significant impact on the cost of the demonstration. The piped CO_2 scenario would cost about one-quarter of the first demonstration.

Table 7: Field Demonstration Costs, M$.

DEMONSTRATION	No. 1 (Pumped)	No. 2 (Pumped)	No. 2 (Piped)
Deferred Production, Days	43	20	20
Test Separator	34.2	0	0
CO_2 Commodity/ Transport/ Pump	142.3	79	19
Wireline	5.9	6	6
Downhole*	19.5	15	15
Surface**	42.8	20	20
New Tbg.	15.6	0	0
In-Line Heater	6	0	0
Misc.	17.8	10	10
TOTAL:	284.1	130	70
DOE Share (45%)	127.8	58.5	31.5
CVU Share (55%)	156.2	71.5	38.5

* Pulling Unit, Etc.

** Contract labor, welding, transport, etc.

Table 8 shows some simple relationships depicting the basic economics of the Huff-n-Puff demonstration along with the two options previously discussed. The same naming convention is applied. In addition to some non-recurring items the field demonstration costs were heavily influenced by the cost of delivering and pumping the CO_2. As can be seen in Table 8, the planned CO_2 volume would not likely be as large for a second demonstration. This directly impacts the amount of deferred production.

The project becomes more attractive if pipeline CO_2 is available. Assuming an \$18.00/STB sales price for crude oil, the necessary volume of recovery to reach a pseudo-breakeven point is calculated. The cost reductions available for the *No. 2 (Piped)* case begin to look encouraging. The CO_2 utilization in this later case looks reasonable at 6.4 Mscf/STB, similar to miscible CO_2 flooding cases. The recovery for the *No. 2 (Piped)* case are similar to expectations derived from the compositional simulations when a trapped gas saturation develops in the near wellbore vicinity.

Table 8: Field Demonstration Economics.

DEMONSTRATION	No. 1 (Pumped)	No. 2 (Pumped)	No. 2 (Piped)
CO_2 Vol., MMscf	50	25	25
CO_2 Cost, \$/Mscf	2.85	3.16	.76
Deferred Production, STB	2924	1360	1360
TOTAL Cost, M\$	284.1	130	70
Equiv. Bbl's @ \$18/STB	15800	7200	3900
Breakeven Utilization, MCF/STB	3.2	3.5	6.4

Additional benefits that are not accounted for in this simplistic review were noted earlier. First, even though recoveries in this demonstration accounted for only the deferred production, there were reduced electrical requirements during the injection, soak and flow period. Secondly, there were reduced water handling requirements for an extended period of time. These benefits, coupled with the potential to recover additional oil suggest further investigation was warranted if the technology is applied to a reservoir amenable to gas trapping.

SSU

The actual costs associated with the second field demonstration components of the project at SSU are included in **Table 9**.

Table 9: Field Demonstration Costs, M$.

DEMONSTRATION	Direct Cost (M$)
Materials – Line Pipe, valves, fittings	6
Labor – Install flowline & Misc. Surface Costs	6.1
Trucking – Pump & Transport	8.5
CO_2 Commodity	23
Wireline	3.5
Service Unit & Misc. Downhole	13.7
In-Line Heater & Propane	3.5
Downhole pump and Parts	6.6
Misc.	6
TOTAL:	76.9
DOE Share (45%)	34.6
CVU Share (55%)	42.3

Table 10 shows some simple relationships depicting the basic economics of the Huff-n-Puff demonstration at SSU and a comparison to CVU. 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 10: Field Demonstration Economics.		
DEMONSTRATION	**CVU Actual**	**SSU Actual**
CO_2 Vol., MMscf	**50**	**34**
CO_2 Cost, $/Mscf	**2.85**	**.679**
Deferred Production, STB	**2924**	**398**
TOTAL Cost, M$	**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—more notable at CVU.

MISCELLANEOUS

An industry Consortium led by the Colorado School of Mines selected the Central Vacuum Unit as a site to conduct 4-Dimensional, 3-Component (compressional & shear) seismic studies. The project is attempting to monitor dynamic reservoir conditions associated with the introduction of CO_2 into the reservoir along with stress field changes. A base survey was made prior to the introduction of CO_2. A follow-up survey was then obtained immediately prior to the end of the CO_2 soak period. The information gained through this seismic demonstration complements the subject project. As yet, the seismic information has not provided the necessary data for any refinements to the reservoir model (layering, flow capacity, fracture orientation, etc.) and fluid characterization (saturations, fluid flow; etc.). Their work continues. Their consideration of the CVU as a demonstration site was made possible by the fact that the accumulation of data from this CO_2 Huff-n-Puff project is available in the public domain; obligated by the use of DOE funding. The 4D, 3C Seismic project is being conducted in parallel, at no cost to the DOE. The Consortium is expected to complete their initial phase of study during 1997 as miscible CO_2 operations are initiated and continue monitoring through early 1999.

TECHNOLOGY TRANSFER

Technology transfer activities during the CO_2 Huff-n-Puff project consisted of updates of project progress and findings through newsletters, publications and presentations, Joint Project Advisory Team Meetings, and information posted on an Internet site.

The New Mexico Petroleum Recovery Research Center continued to provide updates on the project in its quarterly newsletter during the duration of the project. In addition, the Petroleum Technology Transfer Counsel, a joint venture between the Independent Producers Association of America (IPAA) and DOE provides complete Quarterly and Annual Technical Reports on an Industry Internet Bulletin Board called GO-TECH. This provides a timely dissemination of information to interested parties.

Abstracts were accepted and manuscripts presented at the Society of Petroleum Engineers' (SPE) Permian Basin Oil and Gas Recovery Conference (March 1996). The technical paper was published in the conference's proceedings (SPE No. 35223 - CO_2 Huff-n-Puff: Initial Results From a Waterflooded SSC Reservoir, S. C. Wehner, Texaco E&P Inc., J. Prieditis, Texaco E&P Technology Div., 03/27-29/96).

The Joint Project Advisory Team (JPAT) was composed of the 21 partners holding ownership in the Central Vacuum Unit, TEPI principal investigators, the New Mexico Petroleum Recovery Institute and the DOE. The JPAT representatives were brought up-to-date on the field demonstration and discussed related issues.

Two industry presentations were conducted. The first presentation was in Roswell, New Mexico on August 22-23, 1996. This first presentation was a workshop called Integration of Advanced Geoscience & Engineering Techniques of Class II DOE projects. The second presentation was at the New Mexico Petroleum Recovery Research Center in Socorro, New Mexico on October 23-24, 1996. This second presentation was part of a CO_2 Oil Recovery Forum co-sponsored by the Petroleum Technology Transfer Counsel.

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.

Simulation of the Huff-n-Puff process was found to be useful, and it was found that most aspects of the CO_2 Huff-n-Puff process could be adequately simulated with existing commercial software. The simulation efforts involved in history matching the CVU Huff-n-Puff support the conclusion to not attempt any additional Huff-n-Puffs at CVU. All the simulation efforts to date, including the initial parametric studies as well as the history matches, supported a theory that a high trapped gas saturation was required for a successful Huff-n-Puff. Actual performance of the Huff-n-Puff suggests an absence of a large trapped gas saturation.

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 than CVU. 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, conducted 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 was then 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 site was selected at the SSU. Although SSU did exhibit gas trapping, incremental recovery was too low to warrant further tests at SSU. 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 downstream 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. Gas plunger lift may be a potential production method for this process

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