DESIGNING A CO_2 FLOOD FOR A SMALL WATERFLOOD DEPLETED UNIT

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Abstract

The South Cowden (San Andres) Unit is the site selected for one of three mid-term projects to be conducted under the DOE Class II Oil Program for Shallow Shelf Carbonate Reservoirs. The proposed $21 million dollar project is designed to demonstrate the technical and economic viability of an innovative CO2 flood project development approach. The new approach employs cost-effective advanced reservoir characterization technology as an integral part of a focused development plan utilizing horizontal CO2 injection wells and centralization of production/injection facilities to optimize CO2 project economics. If proven successful, this new approach will help improve the economic viability of CO2 flooding for many older, smaller fields which are or soon will be facing abandonment.

Part 1: DOE Class II Oil Program Proposal

The South Cowden Field

The South Cowden Unit is located in Ector County, Texas and produces primarily from the Grayburg and San Andres Formations of Permian age. These formations were deposited in shallow carbonate shelf environments along the eastern margin of the Central Basin Platform. The primary target for CO2 flood development under the proposed project is a 150-200 foot gross interval within the San Andres located at an average depth of approximately 4550 feet. The original oil-in-place for the South Cowden Unit is estimated to be less than 180 million barrels. The field was discovered in 1940 and unitized for secondary recovery waterflood operations beginning in 1965. The Unit is currently nearing its economic limit, producing about 450 BOPD at a watercut in excess of 95% from 39 active producers and 11 active water injectors. Ultimate primary plus secondary recovery is expected to be about 35 million STB or approximately 20 percent of the original oil-in-place.

Introduction

CO2 miscible flooding has been demonstrated to be a technically viable tertiary enhanced oil recovery process which can extend the producing life and add significantly to the ultimate recovery of the remaining oil resource in Shallow Shelf Carbonate reservoirs in the Permian Basin. Most of the incremental tertiary oil production from CO2 projects implemented to date has come from a few, large scale projects where the sizable economies of scale inherent in this type of development improve project economics. In 1992, Moritis reported that the five largest CO_2 projects accounted for over one-half of the total incremental oil production attributable to CO_2 miscible flooding in the United States.[1]

Lang, et. al. estimate that between 250 and 575 million barrels of incremental oil could be produced from new CO_2 miscible flood projects in the Permian Basin over the next 25 years if oil prices stabilize in the $16 to $20 per barrel range[2]. Much of this remaining CO_2 flood target oil in the Permian Basin is found in the large number of small to medium sized fields where the economies of scale inherent in larger projects are not available to improve project economics. Many of these smaller fields are at risk for premature abandonment unless innovative reservoir management and CO_2 flood project development technologies can be implemented and shown to be economically viable. Flanders, et. al. investigated the economic viability of implementing CO_2 flood projects in these small to medium sized fields.[3] These authors concluded that CO_2 flooding can profitably recover oil from many of these smaller fields, however cost-effective design, implementation, and surveillance strategies are critical to economic viability.

Conventional CO2 Feasibility Evaluations

CO_2 flood potential at South Cowden was first evaluated in 1982. This study concluded that the South Cowden reservoir was an excellent technical candidate for CO_2 flooding. Plans were made in the early 1980's to implement a CO_2 miscible WAG project using a conventional 40-acre fivespot pattern development. These plans were put on hold following the oil price collapse in the mid-1980's. A second full feasibility study was conducted in 1991. This study again indicated excellent incremental CO_2 oil recovery potential, however the project did not meet minimum economic guidelines.

The project failed to meet economic guidelines for three major reasons; 1) the large initial investment required to implement a conventional CO_2 flood was compounded with the need to drill all new injection wells; 2) the higher marginal cost of producing tertiary oil; and 3) the stabilization of crude oil price projections for the next 10 years. Of these three effects, the only variable that Phillips Petroleum could control was the initial investment cost of the flood. The other two variables were market driven (oil price and CO_2 price). A study was then implemented to determine how the initial investment could be reduced through innovative technologies without compromising reservoir performance.

Innovative Approaches

One of the primary problems with developing a CO_2 flood project at South Cowden using a conventional approach is that the majority of existing wells are not suited mechanically for conversion to CO_2 WAG injection service. The 1991 project development plan premised that all CO_2 injection wells would have to utilize new wellbores. To achieve the planned pattern flood of the 1000-acre CO_2 flood project area premised in the development plan, it would be necessary to drill and equip 27 new injection wells and 4 new producing wells at an estimated investment of 9.5 million dollars. The effect of this large front-end capital cost on project economics was devastating. Figure 1 shows a map of South Cowden and a comparison between the conventional development and the potential horizontal approach.

One solution to reduce the necessity of multiple redrills of injection wells was to use horizontal wells. If an extended horizontal well could replace up to three 20 acre infill injection locations, not only would drilling cost be reduced by also surface equipment costs could be reduced as well.

The technology of drilling horizontal wells has advanced significantly over the past 10 years. The capability of drilling multiple laterals from a single wellbore and reentering old wellbores and drilling a lateral is now done on a routine basis in the Permian Basin. The majority of this type drilling has thus far been used in production wells. Known applications of horizontal laterals has included two primary objectives, attempting to increase the productivity of a low permeability layer, and attempting to avoid gas or water coning. The success of horizontal laterals has depended on the objective and has been met with mixed success.

The application for horizontal laterals in South Cowden would allow reduced development cost from reduced overall drilling and CO_2 distribution costs. Replacement of multiple vertical wells with extended reach horizontal wells has the potential to reduce development costs from 1) reduced completion equipment; 2) less overall drilling; and 3) reduced CO_2 distribution cost by eliminating extensive high pressure distribution lines.

Improved Recovery And Accelerated Performance

The feasibility of horizontal injection wells has been studied by Lim, et. al.[4]. In their study of multiple-contact CO_2 miscible flood simulations of actual West Texas carbonate reservoirs, they concluded that "the use of horizontal injectors with vertical producers in a tertiary CO_2 WAG flood generally resulted in oil recovery that was as good or better than using both a horizontal injector and producer and always higher than using all vertical wells". These authors also conclude that under the West Texas conditions investigated in their simulation work, "the application of CO_2 flooding using horizontal wells significantly shortens project life, thus substantially improving project economics". This study also highlights the critical role that reservoir characterization plays in determining optimum horizontal well location(s) and completion design, and in selecting the optimum overall project design and operational strategy for a CO2 miscible WAG injection project in these types of reservoirs.

The potential for areal sweep efficiency improvement, relative to a conventional CO_2 flood pattern development using vertical injection wells, is also possible. A recent article discussing some of the more innovative alternative horizontal well applications describes the potential economic and operational benefits of using horizontal injection wells in CO2 flood enhanced oil recovery projects [5]. These potential advantages take the form of 1) improvement in areal sweep efficiency delaying early breakthrough problems; 2) the use of larger initial slugs of CO2 and smaller overall WAG ratio resulting in faster processing of the reservoir; and 3) increased injection rates, several fold over the injection rates achievable with vertical wells with no appreciable increase in fracture extension pressure;

The Role of Reservoir Characterization

The key to success of horizontal lateral injection has to be the degree of understanding of the particular reservoir architecture. The use of horizontal wells requires that a small selected interval relative to the total interval be selected for completion. This selection has to take into account the overall vertical permeability of the interval as well as any known areal variations. This requires a critical level of understanding of the vertical hetrogenity as well as areal variations that exists to ensure optimum well performance.

Shallow shelf carbonate reservoirs like South Cowden were deposited in various sea level conditions and therefore are suspectable to large variations in reservoir quality over small vertical increments. The San Andres Formation in South Cowden is up to 200 feet thick in a gross sense. The actual zones which contribute effective production are believed to be 60-80 feet. Conventional logging techniques cannot discern the effective layers from the non-productive layers without more detailed reservoir characterization and calibration. These techniques include:

1. Detailed core description and thin section petrography. Particular rock types are identified by their pore shapes, sizes, and aspect ratio.

2. Developing porosity-permeability correlations for each rock type. When rock types are identified, conventional core permeabilities and core porosity are plotted for correlation.

3. Relating core description results to log signatures. Once particular rock types are identified, the appropriate log response is related to that type.

4. Determining consistent correlation markers between wells. Identifying key marks which carry from well to well and thus identify the layer distributions.

Areal Distribution of Reservoir Quality

The areal distribution of reservoir quality is also important to understand. Conventional mapping techniques of net pay often times do not reconcile cumulative oil production maps. South Cowden has been producing since the late 1940s allowing an excellent opportunity to calibrate geological mapping with actual production results. Specifically, initial well potential, first three year average production, waterflood response, and total cumulative oil production will be compared with hydrocarbon pore volume maps for the main pay zone. Outlines of the "sweet spots" and "dead spots" will be used to calibrate the geologic model.

In summary, reservoir characterization will be used to define the exact areal and vertical locations of any remaining moveable oil and the best areas for obtaining residual oil recovery from the CO2 miscible process. Advanced technologies including horizontal drilling will then be used to lower initial investment costs to improve project economics.

PART 2: SUMMARY OF TECHNICAL PROGRESS

In June of 1994, Phillips Petroleum and the Department of Energy, (DOE), signed a contract for the development of the South Cowden CO2 flood. The DOE would provide funds for the detailed reservoir characterization of South Cowden and if approved would participate in the actual demonstration of the project. In return, Phillips Petroleum would make public any technology gained from the project and would make strong efforts to publish results. Technology transfer would be an integral part of the project.

The Phillips-DOE project is broken into two distinct phases. Phase 1 is the reservoir characterization and project design phase while Phase 2 is the project demonstration phase. Phase 1 was commenced in June of 1994 and Table 1 lists the individual tasks to be completed. Results to date are highlighted as follows:

Geological Characterization

Prior to the DOE project, three wells had been cored in South Cowden. The detailed core description and petrography analysis of these three cores was commenced in June 1994. Well 8-19 had the most extensive core coverage of the interval and was chosen as the base description well for rock classification.

The following criteria was used for the various classifications:

1. The rock framework, weather grainstone, packstone, or wackestone.

2. The amount of quartz sand present.

3. The presence of peloids, ooids, or fusilinids (all increase intergrainular space).

4. The mottled or chaotic appearance (due to hydrocarbon staining)

From the these classifications, nine rock types were identified which are listed in Table 2.

Description of the "Chaotic" Zone

The primary productive interval in the South Cowden Unit consists of Rock Type 7. The rock is dolomitized packstone (i.e. grain supported with some mud in the intergrainular spaces) that had peloids as the original grain type. Dolomitization has extensively altered the original grain framework and the calcareous mud to the point that dolomite crystals dominate the rock. Only a small percentage of the original rock matrix can be seen in thin section.

The dolopackstones in the reservoir interval can be further subdivided into two rock "subtypes" from detailed core description. Subtype 1 is a tight dolopackstone which has very low porosity (5 percent) and very low permeability (less than 0.2 md). This subtype appears gray in slabbed core. Subtype 2 is a very porous dolopackstone which has well developed porosity and permeability and appears tan in the core due to oil staining. Subtype 2 is well interconnected throughout the core. In well 8-19, over 60% of the reservoir rock is subtype 2. Both subtypes are intermixed on a scale of several inches throughout the reservoir in a random and "chaotic" manner, thus, the descriptive term "chaotic" is used to describe the interval.

Stratigraphic Framework

The stratigraphy of the San Andres has been divided into 8 layers. These layers were chosen based on the gamma ray (GR) log for the SCU 8-19 well. The top of each layer is represented by a "kick" on the GR log that appears to be correlatable across the South Cowden, Emmons, and Moss Units. These "kicks" appear to be induced by changes in lithology. Based on what was seen in the 8-19 core, the GR log is deflected when there is an increase in quartz sand. These thin sandy beds may be chromostratigraphic markers, but this is not certain. These layers differ somewhat from the rock types since the rock types are based on foot by foot core descriptions. The core revealed minor changes in the rock that cannot be detected by the log or at least are not consistent from log to log. In order to define the stratigraphy of the South Cowden Field, consistent GR log picks are absolutely necessary. Some comments on the key layers are given below:

Layer D: The lower two thirds of the layer are tight and separate the layer from underlying porous rocks.

Layer E: This is the main reservoir interval and the rock type is "chaotic".

Layer F: The top of the layer marks the top of the "chaotic" zone.Porosity improves with depth.

Layer G: The layer is a tight interval that provides the seal for the reservoir.

Layer H: The base of this layer, know as the Cowden Sand, marks the top of the productive interval.

Petrophysical Work

Digital data for 57 wells with modern logs and 90 wells with older neutron or sonic logs from the South Cowden, Emmons, and Moss Units were loaded on a UNIX computer for log interpretation. Normalization of the modern neutron and photoelectric logs were completed. SCU Wells 8-19, 8-11, 7-10, 6-21, and 6-23, which have core porosity data, were used to establish the log interpretation parameters for the porosity calculation. A lithology model of dolomite, anhydrite and quartz was used for the porosity calculation from the density, compensated neutron, photoelectric and sonic logs. The lithology parameters from these five wells were used to complete the porosity calculation for all 57 wells with modern log data.

Normalization of the old gamma-neutron logs has been completed. Porosity will be computed for the 92 old well logs using regression equations for the neutron and sonic curves correlated to core porosity data.

Seismic Interpretation

The South Cowden 3D seismic survey was processed internally by Phillips Petroleum. The digital data was sent to Phillips Odessa office and was loaded onto an interpretation workstation. Several sonic logs were also loaded onto the workstation so that synthetic seismograms could be generated. The synthetics were used to tie the well log tops with the seismic data. Based on the synthetic ties, four seismic horizons that correspond to major formation tops were interpreted: Yates, Queen, Grayburg, and San Andres. Seismic time structure maps were generated for each horizon and were compared to the geologic contour maps (based on the well tops for all available wells under the 3D data). In each case, agreement between the geophysical and geologic maps was quite good.

Seismic trace data culled from the 3D survey was plotted at normal well log scale and displayed next to a gamma log to five a measure of seismic resolution. Although this was a high resolution seismic survey, the resolution at the San Andres level is on the order of 150 to 200 feet. However, seismic modeling and geostatistics should provide much improved resolution.

Reservoir Characterization Wells

Phase I of the DOE project called for the drilling, testing, and coring of two reservoir characterization wells to fill out additional characterization data needs. Wells 6-23 and 6-21 were drilled in July of 1994 in 20 acre offset locations. The locations were also selected in part based upon the core distribution and available drilling sites. The main results from these wells is listed below:

1. Core recovery of 237 feet was obtained from well 6-23 and 102 feet from 6-21. Conventional core analysis was performed which indicated average geometric permeabilities through the chaotic interval of 10.5 md and 6.7 md respectively.

2. Pressures obtained from a formation test tool and subsequent pressure transient analysis indicated average reservoir pressure between 2000-2200 psig. Transient analysis indicated a flow capacity of 62 md-ft for the 6-23 well with no indication of formation damage.

3. A microfrac was conducted in each well prior to completion. A fracture was initiated with 2363-2430 psig bottomhole pressure indicating a fracture gradient of 0.55 psig/foot. The well was then logged with Atlas CBIL tool. Results of this test indicated a strong tendency for fracture growth to occur out of the main chaotic interval into lower intervals. The fracture asimith indicated a direction of north 70 east.

4. Completion of both wells in the chaotic zone resulted in very high watercuts, (+98%), indicating that both areas had been swept effectively by the waterflood.

Conclusions

1. Application of horizontal well technology for CO2 injection service has the potential to reduce CO2 development costs significantly. In the case of the South Cowden Field, a centralized horizontal injection well development has the potential to reduce the required oil price by $2 to $3 per barrel and still achieve comparable return on investment versus a conventional 40-acre fivespot development.

2. The South Cowden Unit was a technically viable candidate for conventional CO2 flooding. Current economic conditions however, make the project non attractive from an investment point of view. Advanced reservoir characterization analysis is underway to

determine if the horizontal approach to CO_2 development is appropriate, and if appropriate, if project economics can be improved sufficiently for investment.

3. Initial core description has identified nine separate rock types which contain varying degrees of dolopackstones, dolograinstones, dolowackestones, and fusilinids. Rock Type 7, a mottled, peloid dolopackstone, makes up the main pay zone within the South Cowden Field.

4. The producing interval in South Cowden has also been described as a chaotic facies of two rock subtypes within the general classification of Rock Type 7. Subtype one is a tight dolopackstone which has low porosity and appears grey in slabbed core and Subtype 2, a porous dolopackstone which has well developed porosity. The porous dolopackstone appears tan in the core due to oil staining and appears to be well interconnected.

Acknowledgements

The authors wish to thank Phillips Petroleum Company for permission to publish this paper.

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Table 1 - Listings of Tasks for Reservoir Characterization Phase of the SCU Doe Project

RESERVOIR CHARACTERIZATION PHASE

Task I: Reservoir Analysis & Characterization

I.1 Process and interpret 3-D Seismic data.
I.2 Update injection well condition database.
I.3 Drill, test, and complete first reservoir characterization Well RC-1.
I.4 Drill, test, and complete second reservoir characterization Well RC-2.
I.5 Evaluate unit production history and waterflood response.
I.6 Core description and petrographic studies.
I.7 Geological-petrophysical interpretation of stratigraphic framework.
I.8 Conduct/conceptual simulation studies for reservoir characterization.
I.9 Integrate geological, petrophysical, and seismic data into a 3-D geologic reservoir description.

Task II: Advanced Technology Definition

II.1 Conduct special laboratory studies.
II.2 Conduct advanced geostatistical studies.
II.3 Conduct reservoir simulation studies needed for project design and performance forecasting.
II.4 Design horizontal well scheme and finalize project development plan.
II.5 Design upgrades and additions to the producing well equipment, production gathering system, and production facilities.
II.6 Design upgrades and additions to injection well equipment, water and CO_2 distribution systems, and CO_2 recycle and reinjection facilities.
II.7 Finalize AFE-quality cost estimates and forecast operating expenses.

Task III: Technology Transfer, Reporting, and Project Management Activities

III.1 Prepare and submit technical papers for presentation and publication.
III.2 Quarterly newsletter to select target audience.
III.3 Host a forum or symposium on the project.
III.4 Host a core workshop.
III.5 Press releases or summary articles submitted to a variety of industry periodicals.
III.6 Project management, reporting, and activities required for project continuation.

Table 2 - Description of Nine Major Rock Types
Which Make Up South Cowden San Andres

A dolomite sandstone (more than 50% quartz) or sandy dolomite (more than 20% quartz).

A sandy, peloid dolopackstone.

A peloid dolopackstone.

A sandy, peloid dolopackstone with some ooids or fusilinids.

A fusilinid, peloid dolopackstone or dolowackestone (many fusilinids).

A mottled, fusilinid, peloid dolpackstone or dolowackestone.

A mottled, peloid dolopackstone (the main pay zone).

A dolopackstone to dolograinstone.

A ooid dolograinstone (many ooids)

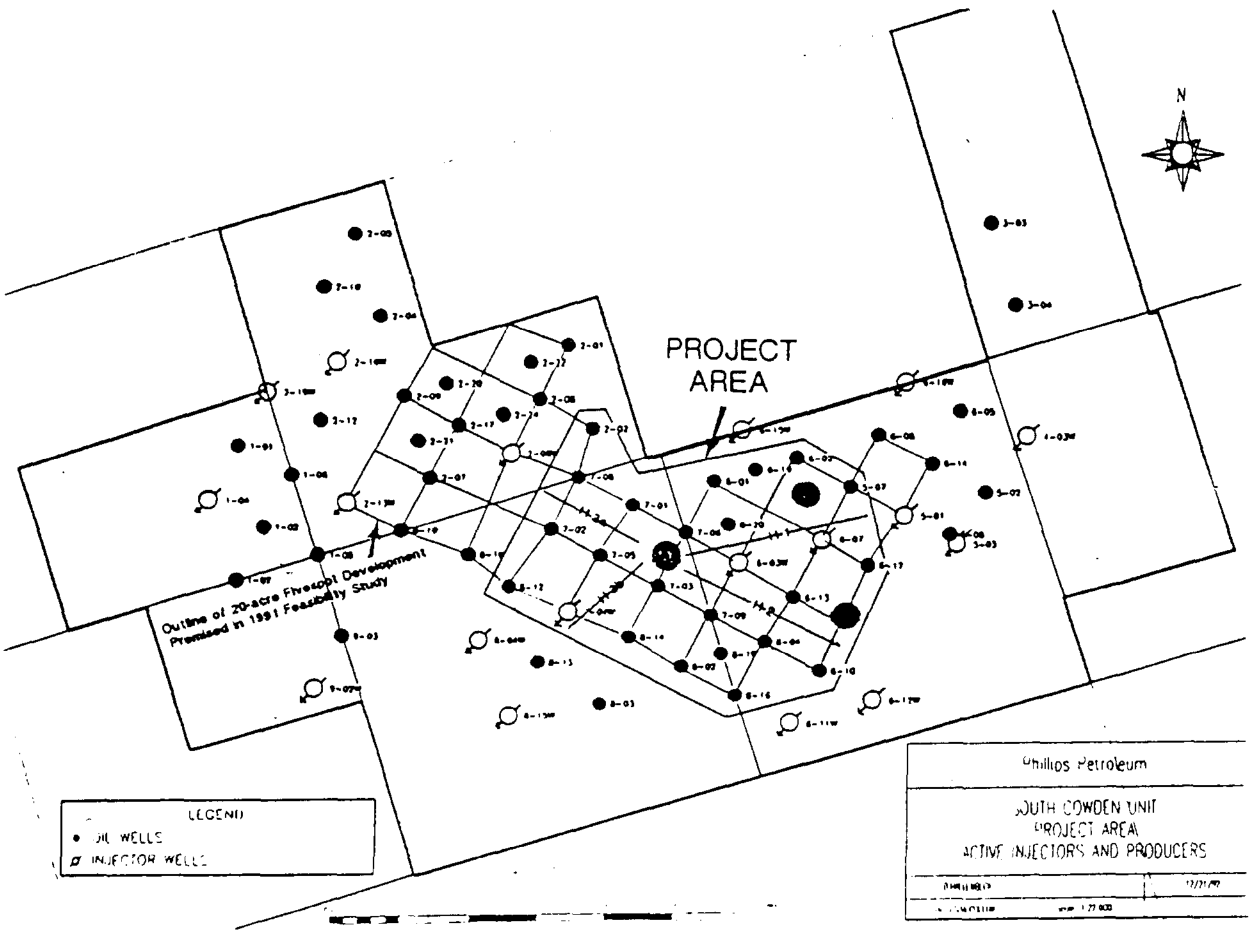

Figure 1