

# Reservoir Management of the Fullerton Clearfork Unit

R.K. Bane,\* R.A. Parker,\* W.G. Storbeck,\* and R.L. Sunde, Exxon Co. USA

\*SPE Members

#### Copyright 1994, Society of Petroleum Engineers, Inc.

This paper was prepared for presentation at the 1994 SPE Permian Basin Oil and Gas Recovery Conference held in Midland, Texas, 16-18 March 1994.

This paper was selected for presentation by an SPE Program Committee following review of information contained in an abstract submitted by the author(s). Contents of the paper, as presented, have not been reviewed by the Society of Petroleum Engineers and are subject to correction by the author(s). The material, as presented, does not necessarily reflect any position of the Society of Petroleum Engineers, its officers, or members. Papers presented at SPE meetings are subject to publication review by Editorial Committees of the Society of Petroleum Engineers. Permission to copy is restricted to an abstract of not more than 300 words. Illustrations may not be copied. The abstract should contain conspicuous acknowledgment of where and by whom the paper is presented. Write Librarian, SPE, P.O. Box 833836, Richardson, TX 75083-3836, U.S.A. Telex, 163245 SPEUT.

#### ABSTRACT

The Fullerton Clearfork field, Andrews County, Texas, was discovered in 1942 and waterflooding was initiated in 1956. Field development continues through infill drilling, injection conversions, and add-pay workovers. Recent reservoir management efforts in the Fullerton Clearfork Unit have concentrated on improving workover and drill well economics, and optimizing waterflood performance. This paper discusses techniques that have been developed to identify potential thief zones, improve perforation selection in workovers and drill wells, balance waterflood patterns, and optimize location selection for new drill wells. The flood balancing techniques described in this paper have been implemented in a test area and results from this test will be discussed. Results from recent workovers, conversions, and drill well programs will also be discussed.

#### INTRODUCTION

The Fullerton Clearfork Unit (FCU) is located in Andrews County, Texas, about 50 miles northwest of Midland, Texas as shown in Figure 1. Unit production and injection history is shown in Figure 2. The Fullerton Clearfork field was discovered in 1942 and was originally developed on 40-acre spacing. Peak production occurred in April 1948, at 44,000 BOPD. In 1954 the field was unitized and gas injection was initiated. A pilot waterflood was installed in 1956. Field scale waterflooding was initiated in 1961 with a north-south oriented 3-1 line drive pattern in the North Dome. Infill drilling to 20-acre spacing began in 1973. The line drive pattern was converted to a five-spot pattern beginning in 1973. A pilot 10 acre infill drilling program was initiated in 1986. Current development is occurring on 10 acre spacing in the developed areas of the field in addition to the drilling of selected 20 and 40 acre locations in less developed areas of the field. The unit is approximately 13 miles long and 6 1/2 miles wide and covers 29,542 acres. A total of over 1300 wells have been drilled in the unit. There are currently 529 active producers and 432 active injectors in the unit. The unitized interval is approximately 2000 ft. thick and includes the San Angelo.

Upper Clearfork, Lower Clearfork and Wichita formations. Production is primarily from a 600 ft. section in the Lower Clearfork and Wichita formations that averages approximately 150 ft. of pay. Unit data and reservoir properties are summarized in Table 1.

Unit production has been maintained between 11,000 and 16,000 BOPD since 1974. During that time the water production has increased from 20,000 BWPD to 120,000 BWPD. Oil production has been maintained through continuing efforts to optimize waterflood and reservoir performance. Stiles' reported on efforts to optimize waterflood recovery through pattern modification and infill drilling. George and Stiles' developed techniques to determine the relationship between floodable volume and injection pattern. Barber, George, Stiles and Thompson discussed the results and impact of infill drilling at FCU. FCU benefited from these optimization efforts many years prior to development of the current concept of reservoir management as described in industry literature.

While this field has proven very profitable, there is additional recovery to be realized through improved management of the reservoir. This process is controlled by a multi-disciplinary multi-functional team consisting of operations personnel, reservoir engineers, a subsurface engineer and technician, a reservoir geologist, an artificial-lift technician, and a facilities engineer. This team meets regularly with the goals of minimizing operating costs, maximizing field profitability, and improving both waterflood recovery and reservoir management.

#### RESERVOIR GEOLOGY

FCU is located on the Central Basin Platform of the Permian Basin in Andrews County, Texas, Figure 1. Unit production is primarily from the Permian Lower Clearfork and Wichita formations with minor production from the Upper Clearfork formation. Non-unit production in the Fullerton field occurs from the Ordovician Ellenburger formation, the Devonian formation (actually Silurian in age),

Ex. 49

SPE-27640-

the Permian Wolfcamp formation, and the Permian San Andres formation.

Volumetrically, dolomite is the most important reservoir lithology within the unit, although limestones are locally significant reservoirs. Average porosity is 7%, and average permeability is 3 md. Reservoir heterogeneity is high, with a Dyskra-Parsons coefficient of 0.94. Reservoir rock results from the preservation of primary porosity or secondary porosity enhancement. Secondary porosity types include moldic, intercrystalline, intergranular, vugular, and fenestral. Wichita formation deposition occurred in a shallow water carbonate platform environment. Wichita reservoir rocks were deposited as thinly bedded lime muds and local grainstones interstratified with thin, shallow-water shales. The Lower Clearfork was also deposited in a shallow-water carbonate platform environment as lime muds and grainstones. Bedding is thicker, and shales are less common. Producing intervals within the unitized interval have been subdivided into a series of zones as shown on the type log in Figure 3. Zone 1 and zone 2 are the most important producing zones. However, other zones can be significant as the stratigraphic distribution of reservoir character varies across the field.

The Fullerton field is a large anticlinal structure which is subdivided into a northern structural closure and a much smaller southern closure referred to as the North Dome and the South Dome in Figure 4. Maximum structural relief is 300 to 400 ft. Mississippian to Pennsylvanian structuring resulted in a depositional drape of Permian sediments over pre-Permian faulted and folded rocks. Faulting does not propagate up to the Wichita or Lower Clearfork formations. Hydrocarbon traps within the Wichita Lower Clearfork and formations are pre-dominantly structural. Several oil-water contacts have been defined within the field. These oil-water contacts increase in depth with increasing stratigraphic age. There are additional local hydrocarbon accumulations which may be combination structural and stratigraphic traps as well as small, subtle structural closures.

#### THEF ZONE IDENTIFICATION

As the FCU waterflood matured, high reservoir heterogeneity contributed to the development of "thief zones". Thief zones are defined as laterally continuous stratigraphic units of relatively high permeability which have approached residual oil saturation. An injection well completed in a thief zone typically accepts a relatively higher volume of injected water at a relatively lower pressure than an injector without a thief zone. Injection profiles commonly indicate a relatively high percentage of injected water going into a relatively thin zone. A producing well completed in a thief zone typically produces higher than average total fluid with a higher than average water-cut. Water cut may be average or lower than average in a producing well that has received limited injection support even though a potential thief zone is present. With increasing offset injection, the highest permeability zone(s) will be preferentially swept by injected water, and oil saturation will decrease to the point where production from the thief zone will primarily be water. Pressure differences between zones may increase or decrease the effects due to permeability variation.

Several years ago, a map of thief zones was prepared by analyzing injection profiles and production logs in an attempt to identify and map their areal extent. This map was used to identify areas and zones to be avoided when adding perforations in existing wells or completing new drill wells. Accuracy of this map was dependent on the density of injection profiles and production logs, the elapsed time since logging, and the cumulative injected water volume at the time the wells were logged.

Another method of mapping thief zones at FCU has been developed which uses porosity and gamma ray logs and injection volumes. The accuracy of this method is dependent upon log coverage and quality, accuracy of porosity to permeability transforms, and the validity of assumptions that relate water movement to permeability.

#### FLOOD MATURITY MAPPING

Maps depicting the progress of the waterflood through time at FCU have been developed. A map of current calculated average flood-front extent for water injected into the Lower Clearfork and Wichita formations is shown in Figure 5. The ellipses depict calculated average areal sweep of the injection flood-fronts. The shaded squares depict the watercut and total fluid rate of the producing wells. An individual zone may have a smaller or larger ellipse than the average for that well depending upon the porosity and permeability of the zone, relative to the total average porosity and permeability of the well. This type of map has been created for selected time intervals beginning with initiation of waterflooding in the unit.

Ellipses have been chosen to depict the injection flood-fronts based on observed initial breakthrough of injection water and an oriented core study. Injection water breakthrough tended to occur first in producers east or west of an injector rather than to the north or south. Currently, producers to the north or south of an injector tend to have a lower watercut than equally distant producers to the east or west. Additionally, a previous study analyzed a small number of oriented core samples for maximum expansion direction. This study determined that an orientation of approximately north 70° east was the most likely orientation of the maximum expansion direction. Measurements of horizontal permeability and horizontal permeability at 90° to

the orientation of the first measurement in non-oriented conventional core from FCU typically vary by a factor of 1.5. Neither orientation is likely to measure the maximum or minimum horizontal permeability in non-oriented core, so the actual ratio of maximum horizontal permeability to horizontal permeability at 90° would be somewhat greater than 1.5:1. A ratio of 2:1 has been used for flood-front maps at FCU with an orientation of maximum permeability of north 70° east. This ratio describes the relationship between the calculated flood-front positions and the observed watercut in offset producers. This orientation is sub-parallel to one common fault trace trend and approximately perpendicular to the fault trace trend of the largest displacement faults at FCU.

The calculation of the area that has been swept uses a variation of the oil in place equation:

	$W_{i} = 7758 \phi Ah (1-S_{orw})(1)$
Where	W <sub>i</sub> = cumulative injected water
	φ =porosity, fraction
	h= thickness, feet
	S <sub>orw</sub> = residual oil saturation to water flood

#### solving for area: $A \approx W_i / 7758 \phi h (1-S_{orw}) \dots (2)$

This technique is not intended to be used in an absolutely quantitative manner. There are many other factors that control the movement of injected water within the reservoir, such as continuity, completion efficiency, reservoir pressure, and production and injection well pressures.

The map created using these assumptions is useful for obtaining an overall picture of flood maturity throughout the unit, but is not useful for identifying individual thief zones. This problem has been addressed by creating flood-front maps by zone. Permeability was calculated from porosity logs using a core derived porosity-permeability transform for each of the zones. A kh (md-ft) value was calculated or interpolated where logs were not available. The injected water was then allocated to each zone based on the kh of that zone relative to the kh of the total well. These kh values only include intervals open for production or injection. These calculations were done at two year time intervals to account for changes in completed intervals. A map of zone 2, shown in Figure 6, illustrates a zone that has better than average permeability over the eastern half of the North Dome. This thief zone has caused early water breakthrough in many producing wells. This flood-front map of zone 2 depicts the calculated average areal extent of injected water in a small area of the North Dome. The size of the squares is proportional to the total fluid rate and the kh of zone 2 relative to the total kh for the well. These maps were useful in identifying thief zones and correlated with

the earlier map of thief zones based upon injection profiles and production logs. These flood-front maps are also used to evaluate add-pay candidates and to screen drill well locations by identifying potential thief zone(s).

The individual zone flood-front maps enhanced the identification of thief zones. However, the averaging of reservoir character over an entire zone still de-emphasized thin thief zones. To further emphasize the heterogeneity of the reservoir and the movement of injected water from injector to producer another tool was developed. This tool is a flood-front profile and is a depth plot of the producer and four closest offset injectors as shown in Figure 7. The four tracks to the right illustrate the calculated extent of the injected water in solid black. This calculation technique is similar to the individual zone flood-front maps, but instead of using the zone kh and oh (porosity-ft.), the profile shows the flood-front extent on a foot by foot basis. This total does not take into account the porosity and permeability of the injectors but assumes porosity and permeability of the producer is constant throughout the producer centered pattern. This obviously is not the case. However, the log suites for injectors in the unit are generally older and the porosity logs are difficult to interpret quantitatively. This tool, in conjunction with conventional logs analysis, can be used to pick additional perforations or to identify the likely source of water in high water-cut wells. Although there are many assumptions involved with this tool, production logs and injection profiles confirm that this tool can be used to identify thief zones. A production log is shown on Figure 7 in the track entitled "% Flow".

#### INFILL DRILLING RESULTS

Fifty-eight 10-acre producers were drilled in 1986-88. The wells were drilled in a group of clusters as shown in Figure 8. There were two reasons for drilling these clusters. First, this strategy would provide data on the effect of directional permeability. Previous work had indicated that there was evidence of an east-west directional permeability in the North Dome. Secondly, the location of clusters would provide data on areas of the field which could be economically visble to develop on 10 acre spacing.

Analysis of the 10 acre infill drilling program began with an analysis of the production performance and completion strategy for each well. Most of the wells were completed by perforating and acidizing all calculated pay. However, in a few wells, potential thief zones were not perforated. This was done to limit water production. Three of the 58 wells produced such high water volumes that they were not economic. Thirty-four of the remaining 55 wells were oriented north-south of existing 40-acre injectors. The EUR (Estimated Ultimate Recovery) for these wells averages 72,000 STB. The EUR for the 21 east-west wells averages 50,000 STB. While these results support an

261

SPE 27640

east-west directional permeability, there were several anomalies. For example, one of the best 10 acre wells was an east-west well that has an EUR of over 180,000 STB.

The techniques described above for thief zone identification and mapping had not been developed when these wells were drilled. Flood-front maps were also used in a post drilling analysis to evaluate the potential for improving drill well location selection. A flood-front map was generated using injection data through the end of 1985. The fifty-eight 10-acre producers were then spotted on this map and ranked based on proximity to injection flood-fronts. The results of this ranking are shown in Table 2. Wells farther from existing flood fronts, typically, have a higher EUR. However, as with the directional orientation, there were anomalies. For example, three wells with high EURs were in the "good" category. All three wells were selectively completed to limit water production by leaving the potential thief zone(s) unperforated. A total of four wells in the good category had been selectively completed. These four wells in the good category along with the five wells in the "excellent" category have an average EUR of 125,000 STB. The last two drilling packages were developed using similar ranking criteria.

#### ADD PAY WORKOVER PROCESS

The add-pay workover program at FCU has historically been important to maintaining field production. The process and tools used to identify and screen add-pay workover candidates have changed as the waterflood has matured and as reservoir management objectives have changed.

A multi-functional team was formed in 1989 to identify the remaining add-pay workover opportunities at FCU. This was the first systematic attempt to identify and prioritize the remaining add-pay workover opportunities for the entire field. The team was comprised of geologists, engineers, and operations personnel. They evaluated the remaining Lower Clearfork and Wichita add-pay potential in both producers and injectors, the reserve potential of the Upper Clearfork and the West Flank, and pay below the traditional oil-water contacts. The study resulted in a prioritized list of over 800 work items that included add-pay workovers and artificial-lift optimizations in a multi-year implementation plan.

The prioritized candidate list was worked by reviewing complete patterns instead of individual wells. As each successive candidate was worked, the entire pattern was reviewed for optimization. All wells in the pattern were evaluated for add-pay workovers and artificial-lift optimization. All remaining pay which exceeded the porosity cutoff was to be added during the workover. This would maximize sweep efficiency and prepare the wells for a future carbon dioxide tertiary project. Add-Pay workovers frequently added high permeability zones with low oil saturations. These zones hold significant reserve potential for a tertiary project, but are difficult to manage as part of a mature multi-layer waterflood because they are capable of cycling large volumes of water.

Early workover results prompted the need to revisit the operational strategy which called for the addition of all calculated pay. A number of the early producer workovers added 300 to 1600 BWPD and increased producing fluid levels to the surface. These "Perf-N-Surf" workovers required installation of electric submersible pumps or fiberglass rodstrings to decrease producing fluid levels. Additionally, early in the implementation of the plan, the anticipated date for initiation of the tertiary project was delayed due to economic factors. The operational strategy was changed accordingly. The field would be managed as a mature waterflood instead of a mature waterflood in anticipation of carbon dioxide flooding.

Identifying thief zones before they were perforated was necessary to minimize operating costs and reduce water cycling. This would reduce water production and improve vertical distribution of injected water. Zone selection became the most important part of each workover. The techniques for thief zone identification and mapping had not been developed when the 1989 study was completed. A new process was developed to incorporate these techniques in future workovers.

This process is outlined below:

- 1. Select candidate from prioritized list.
- 2. Review the well history and wellbore sketch.
- 3. Plot production and perform decline analysis.
- 4. Post offset production and injection on a map.
- 5. Generate cross-section including log and profile data for the subject well, all other wells in the pattern, and other offsets of interest.
- 6. Review flood-front maps.
- 7. Review flood-front profile.
- 8. Review pressure and core data if available.
- 9. Identify potential thief zone(s).
- 10. Decide if potential thief zone(s) should be included in workover.
- 11. Perform workover.
- 12. Document results back to the well file for future reference.
- 13. Initiate remedial work or artificial-lift optimization as required.

Table 3 summarizes the results of the add-pay workover program from 1987 through 1992. Reserves were calculated by three different methods. Only the rate versus time analysis has been included in the table. The rate

versus time analysis was found to be the most pessimistic reserve assessment while the WOR versus cumulative production analysis was the most optimistic. The rate versus cumulative production analysis agreed well with the reserves calculated by the rate versus time analysis.

Flowstreams were analyzed based on the aggregate production of the workovers performed in each calendar year. Buildups do not always reflect pumped off conditions. Inflow performance analysis would need to be run on each workover, taking fluid levels into account, to determine the buildups associated with wells that are not pumped down.

Average oil buildups and reserves are decreasing with time, while associated water buildups are increasing with time. This performance is consistent with the operation of a mature waterflood. However, the process described above was initiated in early 1992. Average WOR associated with these workovers dropped with initiation of this process. While it is still too early to determine the impact this process will have on reserves, operating costs have been reduced as a result of the reduction in water production associated with oil build-ups.

#### INJECTION WELL CONVERSIONS

The pace of injection well conversions at FCU has slowed over the last few years as the number of 40-acre conversion candidates has decreased. Three 40-acre producing wells have been proposed for conversion in late 1993 or early 1994.

Conversions are an important aspect of reservoir management for a number of reasons. Conversions improve areal sweep efficiency. The reserves associated with improved areal sweep efficiencies are greater than the short term loss of production due to conversion. Offset production typically experiences both an oil build-up and an improvement in the decline rate. Additionally, conversions maintain reservoir pressure and provide injection support for pattern flooding. Finally, artificial-lift equipment becomes available to meet other unit needs as a result of converting producers to injection.

Before this latest group of conversions was proposed, all conversions from 1987 to 1991 were reviewed. The study included four conversion packages with a total of 53 wells. Forty-nine of the 53 wells were actually converted to injection. Three wells were plugged for mechanical reasons, and another well was deepened and then returned to production. Results for each package are shown in Table 4. The reserve impact of past conversions was determined by the following process.

1. Review past production and injection for offset 20-acre patterns including all 10-acre wells.

- 2. Review completion dates for all wells in the patterns of interest.
- Review offset injection history to identify possible interference. Where offset injection interference was noted, reserves were discounted by a factor that reflected the degree of interference.
- Calculate an initial EUR for each producer using production versus rate decline analysis before the conversion.
- Calculate the current EUR for each producer after conversion. EUR's for wells exhibiting flat or increasing production were calculated by declining the well at a rate that approximated the field's average decline rate.
- 6. Review production histories and adjust the EUR to eliminate the effects of add-pay workovers and artificial-lift optimizations.
- Subtract the initial EUR from the current EUR to determine the net conversion gain for each producer.
- 8. Sum the producer reserves to yield net conversion reserves.

Total flowstreams were determined by aggregating the production of all wells which offset the conversions in each package. The yearly buildups and decline rate differences were determined directly from the decline curve. The average annual decline rate improvement for wells offsetting conversions at FCU is eight percent. Yearly conversion buildups per offset for the first five years are 2.5, 4.6, 4.1, 2.8 and 0.7 BOPD.

Probability plots were used to confirm the estimated reserves for the recent conversion proposal. The probability plot for injection wells with six offsets is shown in Figure 9. The average EUR for conversions on this plot is 224,000 BO, or 37,300 BO per offset. This method agrees with the volumes shown in Table 4 for 1987. The EUR associated with conversions is decreasing with time as shown in Table 4. This is to be expected as the waterflood matures, however conversions remain attractive at FCU.

#### WATERFLOOD BALANCING

Optimizing waterflood profitability with existing facilities and wellbores is a primary focus of FCU reservoir management. The highly stringerized and discontinuous nature of the reservoir<sup>1,2</sup> and multiple thief zones make waterflood optimization difficult. Low pressure pay does not contribute to production if the bottom hole pressure is high due to a high producing fluid level. A possible solution is to increase the artificial-lift capacity in wells with high fluid levels. Since this option involves significant additional investment and increased operating costs, an alternate option was investigated. A plan was developed to evaluate the feasibility of optimizing the waterflood with existing equipment, through "balancing" of the waterflood.

Typically, waterflood balancing refers to a process where injection is controlled in an effort to have all flood-fronts in a pattern reach the producer at approximately the same time. Balancing, in mature waterfloods, can also refer to the process of maintaining reservoir pressure by adjusting injection to match production. Waterflood balancing at FCU manages water injection to minimize fluid levels in offset producers while providing adequate injection support to all producers.

-6

A field wide balancing model was developed to manage water injection and control fluid levels. A total of 1239 wellbores were used to describe a total of 605 blocks. The blocks typically consist of a regular 20-acre five-spot pattern. The water injection for each well is "allocated" to adjacent blocks in proportion to offset production, Figure 10. For example, if each of the four offset producing wells produced exactly the same volume in a given time period then each of the four blocks would be allocated 25% of the wells injection.

Although the entire field was described in the model, it was realized that balancing a field the size of FCU would be difficult. A team was formed to select a test area and develop a process to balance the waterflood. The team consisted of two reservoir engineers, a field superintendent and a lease operator. The team selected a 16 pattern area near the center of the North Dome. The test area, Figure 11, included 26 producers and 26 injectors. The area was selected based on the following criteria: (1) nearly all wells were currently active; (2) proximity to the waterflood facility permitted maximum flexibility for adjusting injection rates and pressures; (3) high density of modern well logs; (4) wide variability in production and injection rates; (5) surface facilities with capacity to handle anticipated volume changes; and (6) the area contained a representative sample of the artificial-lift equipment being used at FCU.

The objectives of the team were to pump off all wells in the test area without overloading the pumping equipment, to evaluate the results of pumping off all wells, and to set target injection rates that would provide adequate support for all producers. Not all pumping equipment in the test area had been previously designed to operate in a pumped off condition. Four possible processes were considered to accomplish these goals. These processes are shown in Figure 12. The team selected process option three which involved unloading the wells prior to implementing target rates. This process was selected to minimize pumping equipment failures and downtime. The process was initiated with a wellbore review that resulted in the identification of 27 potential work items. They included injector cleanouts, acid stimulations, add-pay workovers, artificial-lift changes, and profile modifications. Seven pumping units were slowed to prevent overloading at pumped-off conditions. Workovers

to add-pay or upgrade artificial-lift equipment were delayed until the results of the initial balancing effort were analyzed.

Injection rate changes were necessary to balance the test area. Some wells requiring rate increases were already at the maximum available injection pressure. All injectors in the test area were checked with wireline to determine the amount of fill in each wellbore. The amount of fill and the need for increased injection was used to prioritize the wells for cleanout jobs. Coiled tubing cleanouts were performed on seven wells. Four of the coiled tubing workovers were successful and increased injectivity between 50 and 150%. On the other three wells, the coiled tubing workovers were unsuccessful in removing fill and conventional cleanouts were required. Target rates were implemented for each injector in the test area, based on offset artificial-lift capacity. The artificial-lift capacity at pumped off conditions was estimated for each well and input into the balancing model. Current injection tests were used to calculate an actual injection to withdrawal ratio (I/W) for each block. The injection rate necessary to achieve the desired target I/W for a block, was calculated using the balancing model. The initial target I/W for all blocks in the test area was 1.0. The target I/W ratio was reduced to .75 for blocks with high producing fluid levels. Blocks with submersible pumps were maintained at a 1.0 I/W to avoid equipment damage.

Performance was monitored using a number of tools. Control charts were used to identify producers that responded to balancing. A control chart for one well that responded to the drop in producing fluid level caused by reduced offset injection is shown in Figure 13. The producing fluid level in this well was reduced 2000 ft. This resulted in an increase of 15 BOPD and a decrease of 40 BWPD. Additionally, a test area surveillance map was used to manage the volume of data associated with the 52 wells. This map displayed the last three producing fluid levels and well tests for each producer. Target and permitted rates are displayed for each injector along with the last three injection rates and pressures. Producing fluid levels were mapped using dot maps to indicate both the magnitude and direction of fluid level changes. Fluid level changes observed through the first six months of the test are shown on Figure 14. Open dots indicate producing fluid levels that have increased and solid dots indicate producing fluid levels that have decreased.

Production and injection for the balancing test area, beginning in January 1992, is shown on Figure 15. The balancing team was formed in September 1992. Unloading of the artificial-lift equipment was completed on January 14, 1993 and target rate implementation began on February 20, 1993. This delay in target rate implementation caused the drop in production seen in February. Three factors caused the drop in production: (1) the three week period between

slowing pumping units and the reduction of offset injection caused the average producing fluid level to increase and oil cut to decrease; (2) pump-off controllers on the producers began shutting down units on a low load alarm; and (3) an injection well workover in February caused cross flow into the pay interval which, in effect, increased injection in the south central portion of the test area.

Production tests in association with producing fluid levels demonstrate the effect that producing fluid level changes have on production. Ten wells exhibited producing fluid level increases or decreases of more than 400 feet that could be correlated with production tests. Production changes in these wells ranged from 0.7 to 2.1 BOPD per 100 feet change in fluid level.

The GOR in the test area has remained constant at about 650 SCF/STB and reservoir pressure remains well above the bubble point pressure. Seven wells in the test area have responded favorably to reduced injection. Oil production has increased in these wells by 80 BOPD and water production has decreased 270 BWPD. Total oil production for the test area increased 30 BOPD above the initial production level, exclusive of the test area's historic decline. Water injection has been reduced 1000 BWIPD, and water production decreased by 300 BWPD. Additional production data is needed to determine what effect this process will have on production decline in the test area. This performance improvement was not realized for approximately eight months.

#### **PROFILE MODIFICATION**

A producer completed in a thief zone typically will produce large fluid volumes at high watercut. Fluid levels in these wells are generally near the surface and high capacity artificial-lift equipment is often needed to reduce the fluid levels. Cement squeeze treatments and cast iron bridge plugs have been used to isolate thief zones and reduce water production and operating expenses. The results of these workovers are shown in Table 5. These workovers have been successful in reducing water production 59% of the time.

Most FCU injectors were originally completed as open hole producers and later converted to water injection. These open hole completions prevent the use of most mechanical water-shut off treatments. Cement and sand have been used to shutoff injection in a few wells where thief zones were identified at the bottom of the open hole interval.

A majority of the wells at FCU are completed in at least one thief zone and a method of treating these wells is being studied. A team was formed to investigate products and techniques available for treating thief zones under conditions present in FCU. This team reviewed products and techniques ranging from diesel oil cement to cross-linked polymer. A cross-linked polymer has been selected for use in a seven well test. The seven wells include four injectors in a single five-spot pattern and three producers located elsewhere in the field. These workovers have not yet been completed and no results are available to report.

#### CONCLUSIONS:

- 1. Reservoir management of the Fullerton Clearfork Unit has evolved in response to increasing waterflood maturity and changing operational strategy.
- Thief zones can be identified at FCU through use of flood-front mapping and flood-front profiles. Production logs and injection profiles have confirmed these flood-front mapping techniques.
- Selective infill drilling is attractive at FCU and can be optimized with flood-front mapping and thief zone identification.
- 4. Add-pay workover performance has been optimized with thief zone identification.
- Although there are a limited number of remaining candidates, conversion of producing wells to injection continues to be attractive at FCU.
- The flood balancing techniques described in this paper have improved waterflood performance in a test area at.FCU.

#### \_

#### NOMENCLATURE:

8

¢	=	Porosity, fraction
A	=	Area, acres
Ь	=	Thickness, feet
k	=	Permeability, md
I/W	=	Injection to Withdrawal Ratio
W.	=	Cumulative water injections, barrels
EÙR	z	Estimated Ultimate Recovery
STB	=	Stock Tank Barrel
BFPI	)=	Barrels fluid per day
BOPI	D≂	Barrels oil per day
BWP	D =	Barrels water per day
BWI	PD =	Barrels water injection per day
Sorw	=	Residual oil saturation to water floodin
-		fraction

#### ACKNOWLEDGMENTS

The authors wish to thank Exxon Company, U.S.A. and the Fullerton Clearfork Unit working interest owners for their cooperation in presenting this paper. We also want to thank the past and present Fullerton Clearfork Unit team members for their assistance in the work described in this paper.

#### REFERENCES

- Stiles, L.H.: "Optimizing Waterflood Recovery in a Mature Waterflood, The Fullerton Clearfork Unit", paper SPE 6198 presented at the SPE-AIME 51st Annual Fall Technical Conference and Exhibition, New Orleans, Oct. 3-6, 1976.
- George, C.J. and Stiles, L.H.: "Improved Techniques for Evaluating Carbonate Waterfloods in West Texas", JPT, (November 1978) pp 1547 - 1554.
- Barber, A.H. Jr., George, C.J., Stiles, L.H. and Thompson, B.B.: "Infill Drilling to Increase Reserves-Actual Experience in Nine Fields in Texas, Oklahoma and Illinois", paper SPE 11023 presented at the SPE-AIME 57th Annual Fall Technical Conference and Exhibition, New Orleans, Sept. 26 -29, 1982.
- Satter, A., Varnon, J.E. and Hoang, M.T. 'Reservoir Management: Technical Perspective", paper SPE 22350 presented at the SPE International Meeting held in Beijing, China, March 24 - 27, 1992.

TABLE 1
FULLERTON CLEARFORK UNIT DATA
OCTOBER 1993

Discovery Date	1942
Unit Area, acres	29,542
Average Porosity, %	7
Average Permeability, md	8
Average Pay, ft	151
Oil Gravity, °API	42
Hydrogen Sulfide, %	0.1
Original Reservoir Pressure, psig	2940
Original Water Saturation, %	24
Bubble Point Pressure, psig	2370
Original FVF, RB/STB	1.635
Original GOR, SCF/STB	1250
Cumulative Oil Production, MMBO	258
Oil Production, BOPD	11,837
Water Production, BWPD	105,732
Active Producers	529
Active Injectors	482

## R.K. BANE, R.A. PARKER, W.G. STORBECK AND R.L. SUNDE

LYNN GARZA TERRY YOAKUM NORTHWESTERN SHELF LEA GAINES BORDEN DAWSON MIDLAND BAS MARTIN Andrew LANDRE S FULLERTON HOWARD CENTRAL BL LOVING DELAN BASHARE Midland ECTOR MIDLAND GLASSCOCK WINKLER BASIN WARD CRANE UPTON REAGAN

LOCATOR MAP

FIGURE 1





**FIGURE 2** 

# FULLERTON CLEARFORK UNIT PRODUCTION/INJECTION HISTORY

267

SPE 27640



FULLERTON CLEARFORK UNIT TYPE LOG FCU #5927

FIGURE 3



# LOWER CLEARFORK STRUCTURE MAP

FIGURE 4



SPE-27640

.



FCU #2145

FIGURE 7



	Table 2		
1986-	88 10 Acre W	ells	
	Average	Number of	
Flood-Front Ranking*	EUR	Wells	
	(STB)		
Poor	39,800	14	_
Fair	55,800	13	
Good	73,100	. 23	
Excellent	110,600	5	

## 1986-88 10-ACRE DRILL WELLS

		Table Add-Pay Workover F (1987-19	3 Program Results 192)		
Year	Number of Workovers	Average Reserves Per Workover (STB)	Average Pay Added Per W/O (Ft.)	Production Increase (BOPD)	Buildup WOR
1987	33	72.1	150	18.6	11.1
1988	52	69.2	149	15.2	9.4
1989	46	48.2	162	22.5	11.1
1990	38	39	162	13.4	10.4
1991	33	• .	136	13.6	29.2
1992	15	•	147	15.1	4.1

• Not enough production history available to estimate reserve impact

Table 4 Conversion Program Results (1987–1991)				
Year	Number of Conversions	Average Reserves per Conversion (STB)	Average Number of Offset Producers	Reserves per . Offset Producer (STB)
1987 (1)	12	243,100	5.8	41.7
1987 (2)	10	198,400	5.8	34.2
1988	22	86,900	3.6	24.2
1991	5	73,600	5.0	14.7



R.K. BANE, R.A. PARKER, W.G. STORBECK AND R.L. SUNDE



SPE 27640

FIGURE 15

--- BWIPD

ŧ

BWPD - BOPD

Left Right **BALANCING TEST RESULTS**