Operation and Performance Review of the Goldsmith-Cummins (San Andres) Unit Water Flood

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INTRODUCTION

This paper is a review of the operation and performance of the Goldsmith-Cummins (San Andres) Unit. The Unit is located in northwest Ector County, Texas. It produces from the San Andres dolomite at approximately 4200 ft. The general Goldsmith Field structure is an anticline with two large domes connected by a productive saddle. Gas caps are present in portions of the field. First field production began in 1934.[1]

The Unit is operated by Atlantic Richfield Company. It is composed of 191 wells; most wells were drilled and completed prior to 1940. The general completion procedure was to drill to 3900-4100 ft, set casing, deepen to total depth and treat acid and/or short with nitroglycerin. A few of the wells were fracture treated during the 1950's and 1960's to increase production rates.

The Unit became effective in July 1963 and water injection began in June 1964. Cumulative production for the Unit area to Jan. 1, 1964 was approximately 18,000,000 bbl of oil. Reservoir pressure had declined from 1727 psia initial to approximately 500 psia. The average gas-oil ratio had increased from 700-800 SCF/STB solution ratio to 10,000 SCF/STB. Portions of the Unit are overlain with a gas cap which has contributed to the high producing ratio.

A number of studies have been made of the Goldsmith Field to determine the best secondary recovery method and anticipated reserves. These studies indicated secondary recovery by waterflood should nearly equal the predicted ultimate primary recovery: i.e. approximately 100,000 bbl of oil per well in the Goldsmith-Cummins (San Andres) Unit area. A peripheral waterflood presented the most favorable economics for this United based on the limited reservoir data available.[2]

The Unit Engineering Subcommittee developed the basic plan of operation. This plan called for the east peripheral area to be flooded initially and the west area added in about six months

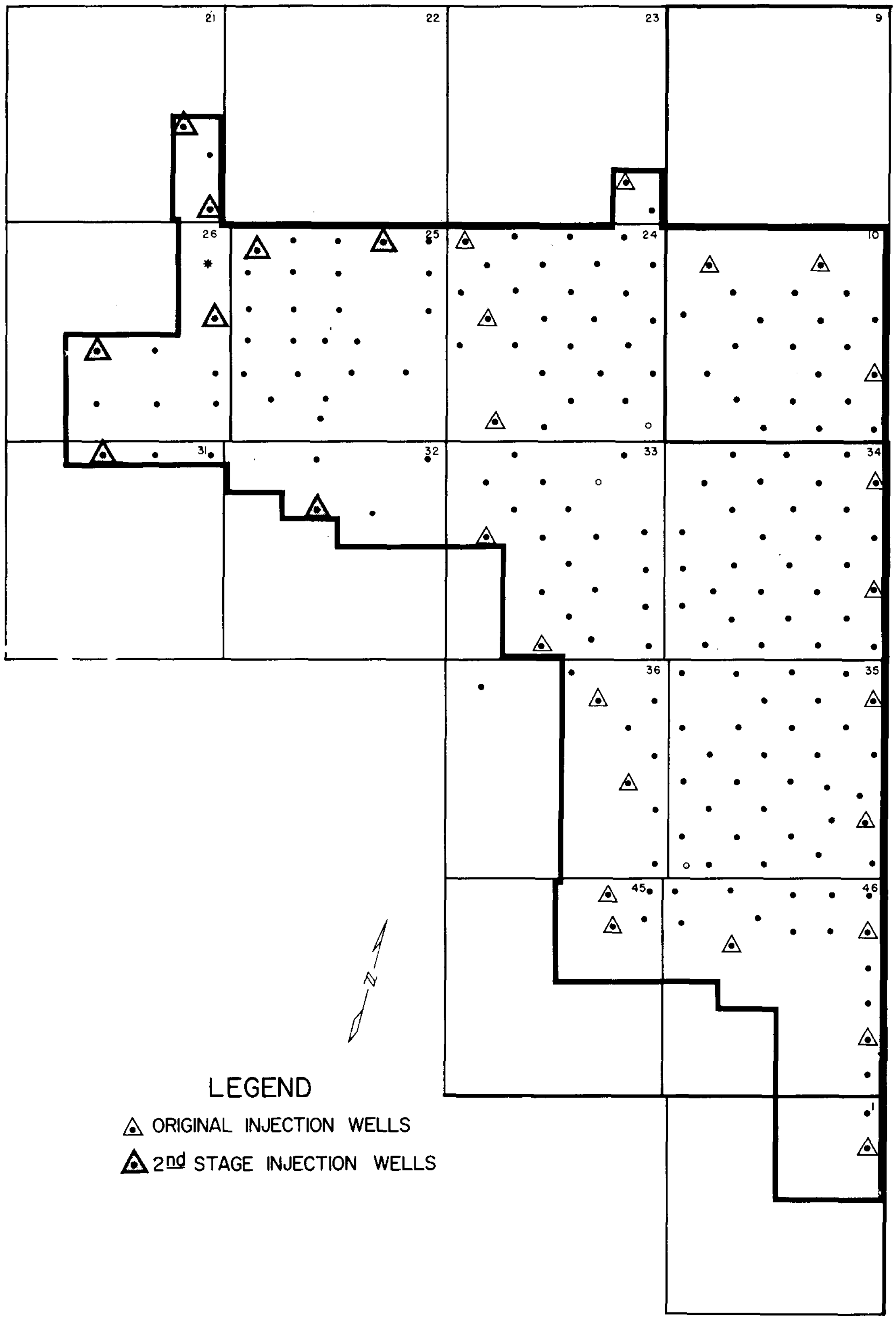
Figure 1 shows the location of proposed injection wells. Water was to be injected at an average rate of 1500 bbl of water per day per well. Fill-up of the free gas space in the first row area was estimated at 0.8 year. It was assumed top allowable production would occur by that time. Injection was to continue at the same rate until the entire Unit area was repressured to approximately 1100 psia bottomhole pressure. Injection would then be reduced to meet production and loss requirements. Fill-up of the entire Unit area was estimated at 3.7 year.

The injection interval was from 980 to 1070 ft sub-sea (gas-oil to oil-water contacts). Figure 2 shows the injection interval and the quality of pay anticipated.

The Unit produced 28,213 bbl of oil, 3240 bbl of water and 336,942 Mcf gas in July 1963 when the Unit was formed. December 1966 production was 41,352 bbl of oil, 56,401 bbl of water and 174,558 Mcf gas. Engineering studies prior to unitization predicted substantially better response at this time. The reasons for this difference, methods used to determine the problems and additions to the operations are discussed in the following sections.

OPERATIONS

Beginning with the east area, 16 wells were converted to water injection. Four of these were dual gas-cap and oil-column injectors. The average initial injection rate was 1800 BWPD per well. Three additional oil column injectors were added in May 1965. Initial injection rate was 500 BWPD per well. The waterflood has not been expanded to the west area. This expansion is related to formation of a waterflood unit in the West Goldsmith Field, which will be operated by Cities Service Oil Company. They anticipate starting water injection by early 1968.



GOLDSMITH CUMMINS (SAN ANDRES) UNIT

Fig. No.1

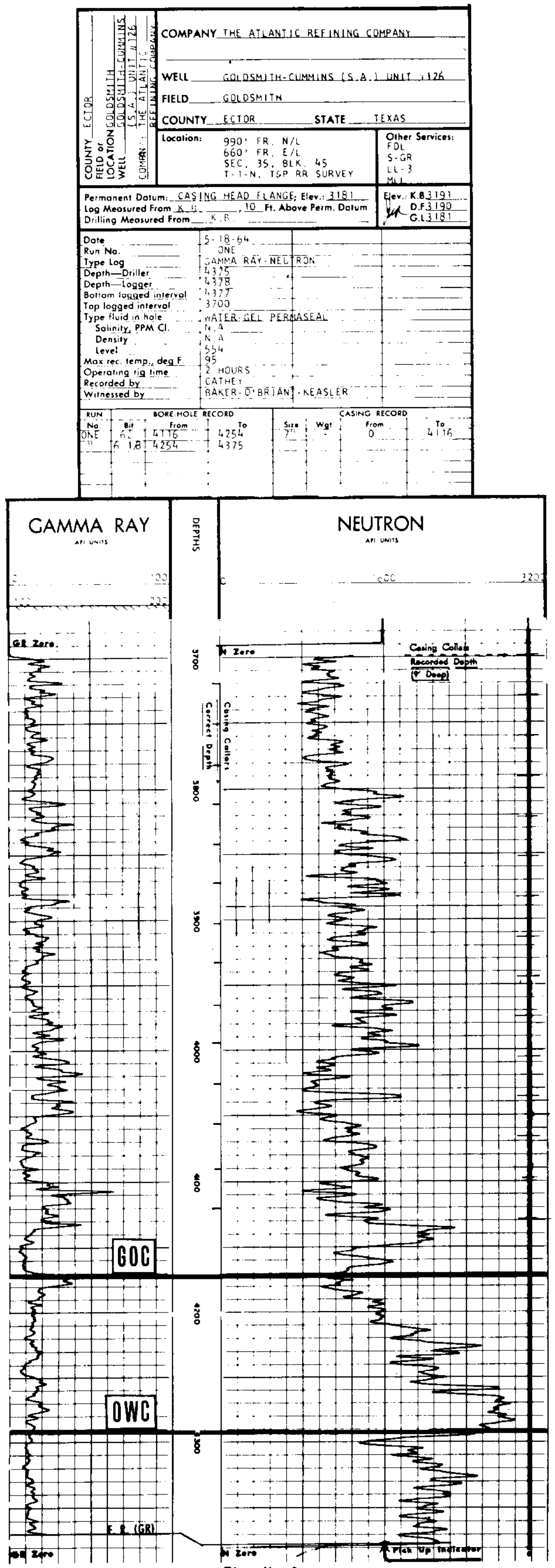

COMPANY THE ATLANTIC REFINING COMPANY
WELL GOLDSMITH-CUMMINS (S.A.) UNIT #126
FIELD GOLDSMITH
COUNTY ECTOR STATE TEXAS
Location: 990' FR. N/L 660' FR. E/L SEC. 35, BLK. 45 T-1-N, T&P RR SURVEY
Other Services: FDL S-GR LL-3
Permanent Datum: CASING HEAD FLANGE; Elev.: 3181
Log Measured From K.B. 10 Ft. Above Perm. Datum
Drilling Measured From K.B.
Elev.: K.B. 3191 D.F. 3190 G.L. 3181
Date 5-18-64
Run No. ONE
Type Log GAMMA RAY-NEUTRON
Depth—Driller 4375
Depth—Logger 4378
Bottom logged interval 4377
Top logged interval 3700
Type fluid in hole WATER-GEL PERMASEAL
Salinity, PPM Cl. N.A
Density N.A
Level 554
Max rec. temp., deg F. 95
Operating rig time 2 HOURS
Recorded by CATHEY
Witnessed by BAKER-O'BRIANT-KEASLER
BORE HOLE RECORD
CASING RECORD
GAMMA RAY
API UNITS
DEPTHS
NEUTRON
API UNITS
GR Zero
N Zero
Casing Collars Recorded Depth
Casing Collars Correct Depth
3700
3800
3900
4000
4100
4200
4300
GOC
OWC
Pick Up Indicator

Fig. No. 2

UNIT PERFORMANCE

Oil production has not increased as predicted although some wells have responded favorably. Figure 3 compares actual production and injection with predicted rates modified for the actual operating plan.

Response was noted in 16 producing wells four months after water injection began. Wells Nos. 74, 97, 129, 131, 141, 163, 174 and 176 exhibited favorable oil response. In Wells Nos. 74, 129 and 141 the response was short-lived and soon turned to water production. Wells Nos. 26, 29, 30, 86, 168, 169 and 172 began to produce appreciable quantities of water. About this same time, Wells Nos. 48, 51, 69 and 98 ceased to flow and loaded with water. Water samples were taken from the wells' production and analyzed. The results did not agree generally with either San Andres or injected water. Wells Nos. 48, 51, 69, 86, 98 and 172 were subsequently worked over to repair casing leaks, run and cement liners through the open-hole sections and/or deepen the wells to penetrate the entire productive interval.[3] The work on Wells Nos. 48, 69 and 172 was very successful; water production was eliminated and wells have responded favorably to the waterflood. In Wells Nos. 86 and 98 the work was only a partial success; water production was deceased but the wells have not responded. Well No. 51 was a complete failure; there was no decrease in water production and the well has not responded. Work on these wells and the results obtained are summarized in Appendix A.

Most of the early response and problem wells are located on the east-west trend with water injection wells. Early response and breakthrough are common to most dolomite-limestone waterfloods in West Texas. It is generally believed to be due to the opening and extension of natural or induced fractures. Pressure build-down tests were run on injection wells. The calculated permeability capacity to water from these tests ranged from 500 to 2000 md-ft. These values were higher than expected, but reasonable, considering well stimulation. Injection profiles and channel checks which were run approximately one month after injection began revealed some minor vertical communication.

Formation logging programs designed to determine the true porosity and composition of the reservoir rock were run in four wells in the east area.[4] These indicated the pay quality was quite different from that assumed by the Engineering Subcommittee. The logs indicated a large part of the porosity measured by the prior neutron logs was due to anhydrite and gypsum content of the rock. A study of these logs indicated the waterflood would have to extend over 80 to 100 ft of 5 to 8 per cent porosity rock rather than 30 to 50 ft of 8 to 15 per cent.

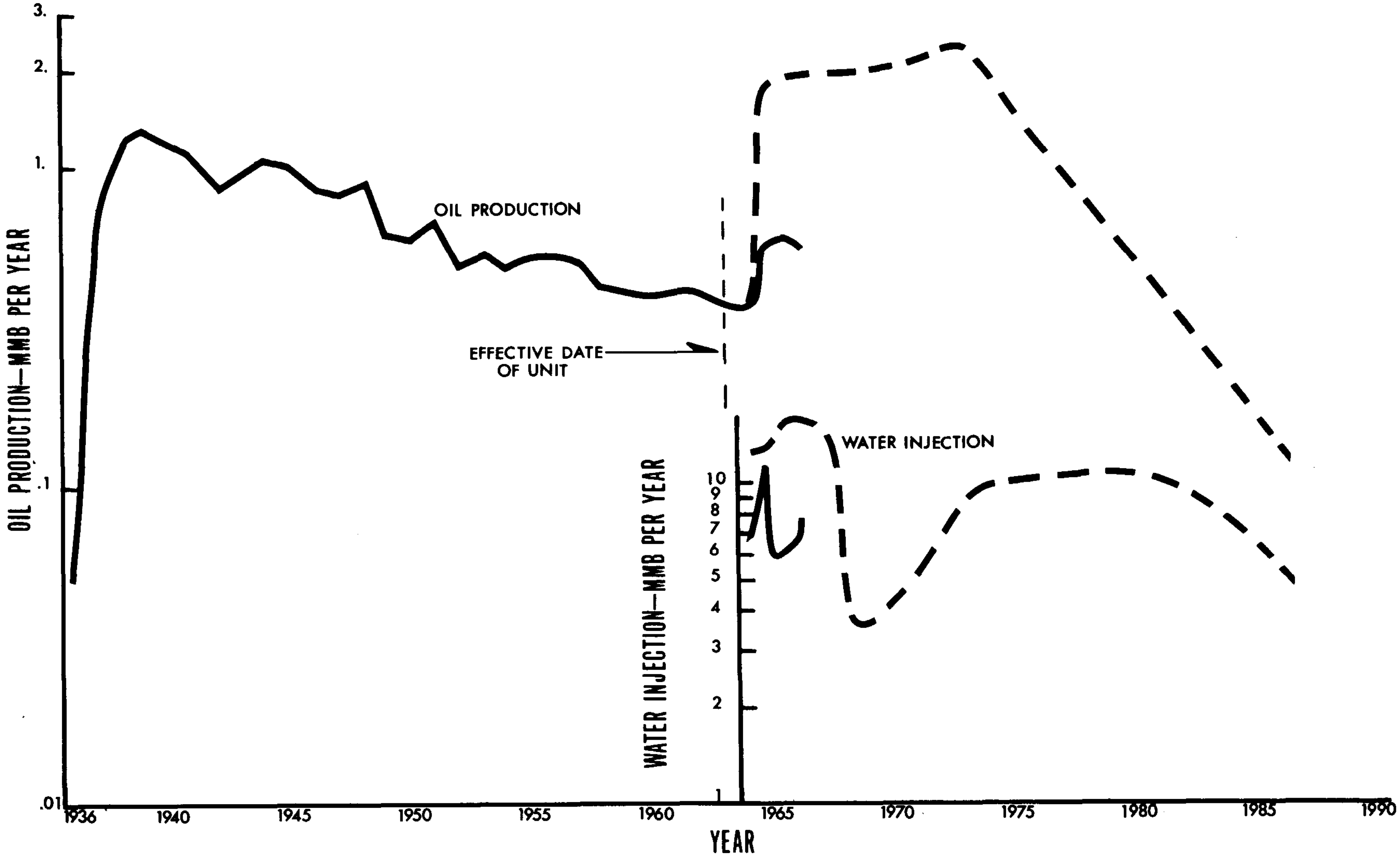
By early 1965, several wells had responded with rates and extrapolated reserves in line with predicted values. Cumulative injection into the first row area, 7,440,778 bbl to April 1, 1965, was near the estimated fill-up volume, 6,872,000 bbl of water. It was decided to wait for further developments and run special tests to accurately determine the true formation permeability to water. These tests indicated injections wells' capacity should range from 150 md-ft in the north to 500 md-ft in the south. Build-down tests of the injection wells at this time were indicating from 150 to 4000+md-ft. This provided some insight into the nature of the problems: fracture extension or vertical communication with zone above the desired injection interval.

The success of workovers on producing wells designed to eliminate vertical communication seemed to indicate a large part of the water breakthrough problems were due to vertical communication. This was further substantiated by produced water analyses and reservoir calculations. A reasonable approximation of actual performance was calculated by correcting injection volumes for vertical losses. This was done by assuming the net injection in the productive interval for any given well was equal to the volume of water injected multiplied by the formation capacity divided by the indicated well capacity from build-down tests. Several increments of volume were used, the number depending upon the frequency of pressure tests. A summary of these calculations and first row production data are included in Appendix B.

There was some hope the problem of vertical communication would correct itself. By the fall of 1965 injection well pressures and oil production rates were increasing again. It was thought the zones accepting the water were pressuring to the extent that losses were reduced. Again, it was decided to wait and see. Final plans were also being formulated to correct the problem if necessary. Lower formation capacity required that additional wells be converted to injection,

Fig. No. 3

PREDICTED AND ACTUAL OIL PRODUCTION AND WATER INJECTION
GOLDSMITH—CUMMINS (SAN ANDRES) UNIT



regardless of the success or failure in correcting problems in the present wells.

Oil production began to decline again in 1966. It appeared the zones were still accepting much of the water injected. The first approach to regain producing capacity was to attempt to reduce vertical communication. Wells No. 50, 52. 87, 110, 126 and 175 were worked over. The nature and results of these workovers are included in Appendix C.

FUTURE PLANS

Seventeen additional injection wells are scheduled to be added in early 1967. Figure 4 shows the location of these wells. The maximum distance from injection to producing wells was based on the average formation permeability to water in a given area. The pattern will have nine more injection wells located around the west periphery. These will be added when the West Goldsmith (San Andres) Unit waterflood becomes effective.

Lines of injection wells are generally oriented east-west. This should minimize further breakthrough problems where it is impossible to obtain complete containment of the injected water to the desired interval.

The pattern may be further modified by converting inside wells. This may be required if the formation capacity is found to be still lower than the present estimated values.

CONCLUSIONS

Following are the conclusions drawn from the first 3-1/2 years operation of the Goldsmith-Cummins (San Andres) Unit waterflood.

(1) Vertical communication between the desired injection interval and non-productive zones has contributed to the early water breakthrough problems.

(2) Once communication between zones is established, complete correction is difficult to obtain.

(3) There is a definite east-west orientation to water breakthrough problems.

(4) Frequent and careful use of pressure build-down tests on injection operations. It must, however, be coupled with periodic downhole surveys to insure injection into the proper interval.

REFERENCES

1. Akins, G. Thane and Frost, Harold T., "Atlantic Uses New Ideas in Waterflood Automation", **World Oil,** Vol. 159, No. 6, Nov. 1964, pp. 88-92.
2. Engineering Subcommittee Report, Goldsmith-Cummins (San Andres) Unit, Ector County, Texas (June 1962) unpublished.
3. O'Briant, J.F. Jr. and Mills, M.L., "Planning and Execution of Workovers for a Peripheral Waterflood", presented at the Spring Meeting of the Southwestern District, Division of Production, American Petroleum Institute, March 1965.
4. Sayre, Wayland C. and Burke, Jack A., "Determination of True Porosity and Mineral Composition in Complex Lithologies with the Use of the Sonic, Neutron and Density Surveys", **Transactions of the Society of Professional Well Log Analysts 4th Annual Logging Symposium,** May 23 and 24, 1963, pp. XI-1 through XI-35.

ACKNOWLEDGMENT

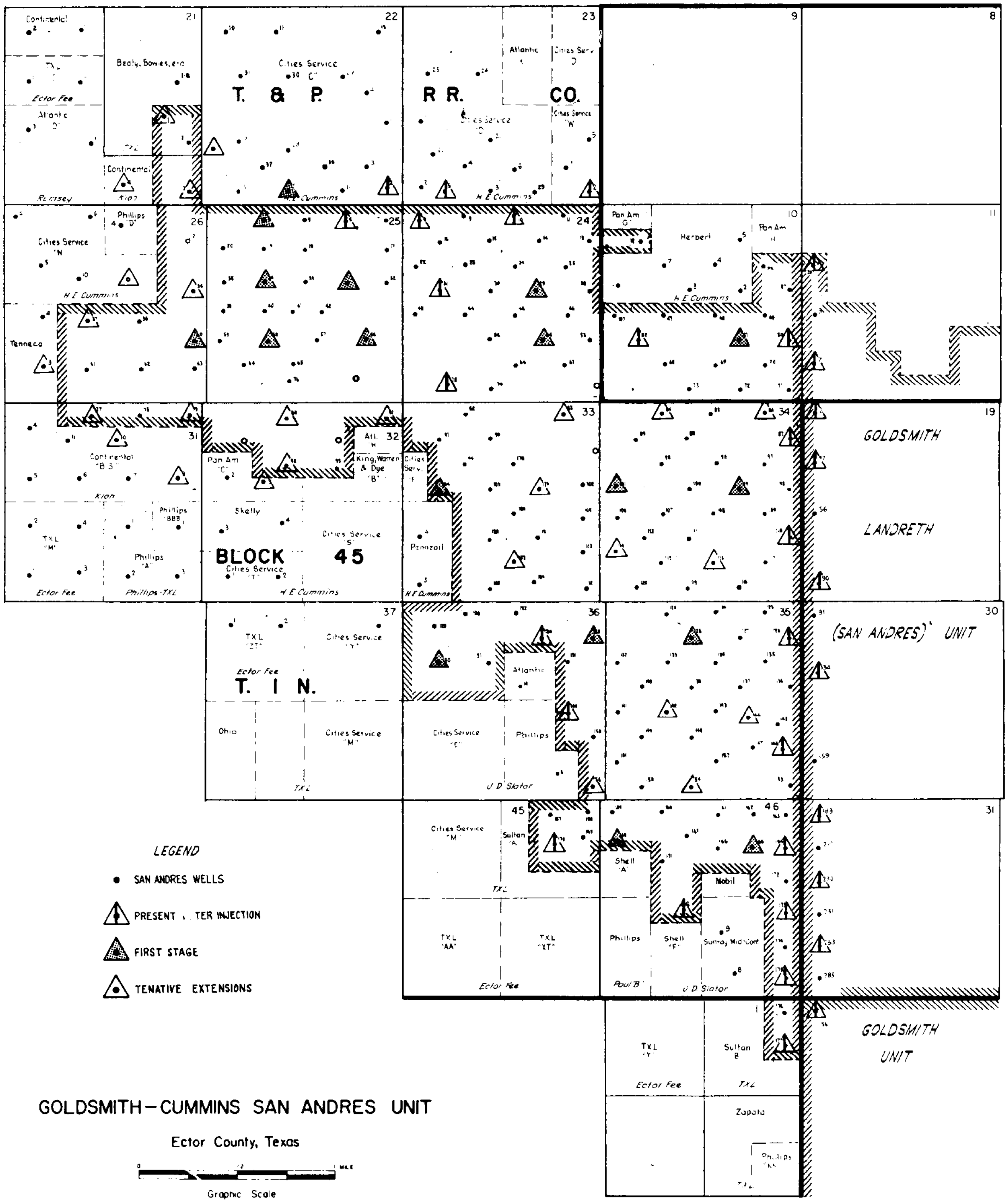
I wish to thank Atlantic Richfield Company for permission to prepare this paper. This does not imply nor deny agreement with the thoughts and conclusions expressed herein.

APPENDIX A

Producing Well Workovers

No. 48: Original total depth (TD) 4205 ft (1020 sub-sea) with 5-1/2 in. casing set at 4175 ft (990 sub-sea). Casing inspection log revealed holes in the casing. These were squeeze-cemented, the well cleaned out and deepened tc 4287 ft (1102 ss) in March 1965. The cement at the casing shoe failed during the workover; it was squeeze-cemented and the well restored to producing status. Perforations were added at 4172 and 4181 ft to give an over-all completion interval of 4172 to 4287 ft (987 to 1102 ss). The well responded in July 1965 and has produced 54,077 bbl of oil and 8.8 Mbbl water July 1, 1963 to September 1, 1966.

No. 51: Original TD 4200 ft (1015 ss) with 5-1/2 in. casing set at 4161 ft (976 ss). Casing inspection log revealed holes in the casing. The



GOLDSMITH–CUMMINS SAN ANDRES UNIT
Ector County, Texas
Graphic Scale
LEGEND
SAN ANDRES WELLS
PRESENT WATER INJECTION
FIRST STAGE
TENATIVE EXTENSIONS
T. & P. R R. CO.
BLOCK 45
T. I N.
GOLDSMITH
LANDRETH
(SAN ANDRES) UNIT
GOLDSMITH
UNIT
Continental
Ector Fee
Atlantic
Cities Service
H E Cummins
Tenneco
Phillips
Pan Am
Herbert
Skelly
Pennzoil
TXL
Ohio
U D Slator
Sulton
Shell
Mobil
Sunray Mid-Cont
Zapata

Fig. No. 4

well was cleaned out, deepened to 4320 ft (1135 ss) and 4-1/2 in. casing set at TD and cemented in place. Perforations were from 4172 ft (987 ss) to 4275 ft (1090 ss). The workover was completed in October 1965. Well flowed water on test. Analysis indicated injection water. Perforation at 4172 ft was squeeze-cemented; no change was noted in producing characteristics.

No. 69: Original TD 4200 ft (1027 ss) with 4-1/2 in. casing set at 4057 ft (884 ss). Casing inspection log indicated several holes in the pipe above 1500 ft. Casing was cut, pulled and new pipe tied into the old at 1500 ft. Well was cleaned out, deepened to 4265 ft (1092 ss) and restored to production in December 1964. Response was noted in March 1965. Well has produced 27,882 bbl of oil and 2.1 Mbbl water from July 1, 1963 to September 1, 1966.

No. 86: Original TD 4249 ft (1061 ss) with 7-in. casing set at 4047 ft (859 ss). Well was cleaned out, deepened to 4304 ft (1116 ss) and a liner set through the open-hole section. Perforations were from 4180 ft (992 ss) to 4285 ft (1097 ss). Well was restored to production in September 1964. Test following workover was 110 BWPD. Perforations were squeeze-cemented and well reperforated from 4217 ft (1029 ss) to 4285 ft (1097 ss). Test following this workover was 54 BWPD. No oil response has occurred.

No. 98: Original TD 4250 ft (1051 ss) with 5-1/2 in. casing set at 4056 ft (857 ss). Well was cleaned out, deepened to 4311 ft (1112 ss), liner set through the open-hole section and perforated from 4192 ft (993 ss) to 4270 ft (1071 ss). Test following workover was 3 BOPD and 64 BWPD. Several months later upper perforations were squeeze-cemented with a Diesel oil cement. Tests following the workover were 5 to 7 BOPD and 73 to 94 BWPD. No response has been noted.

No. 172: Original TD 4285 ft (1069 ss) with 7-in. casing set at 4086 ft (870 ss). Casing parted in October 1964. The well was cleaned out, deepened to 4320 ft (1104 ss), inner casing run and well perforated from 4217 ft (1001 ss) to 4297 ft (1081 ss). It was restored to production and has produced 41,519 bbl of oil and 13.4 Mbbl of water from July 1, 1963 to September 1, 1966.

APPENDIX B

Calculation of first row fill-up as of June 1, 1966:

Estimated fill-up volume:	6,872,000 bbl
Estimated cumulative oil and water production from first row wells from start of flood to 6-1-66:	1,531,000 bbl
Total fill-up volume + production to June 1, 1966	8,403,000 bbl
Total net injection from GC(SA)U and offset injection wells after vertical losses and areal factors:	4,176,000 bbl
Estimated remaining fill-up volume from June 1, 1966	4,227,000 bbl

Tabulation of first row production:

Year - Mo.	Oil Barrels	Gas Mcf	Water Barrels
1964 - 6	10,939	142,382	1,099
12	19,419	63,291	19,896
1965 - 6	24,879	46,666	25,761
- 9	30,430	38,217	39,306
- 12	32,625	28,814	51,556
1966 - 3	29,761	23,837	53,835
- 5	28,251	19,883	59,378
Cumulative to June 1, 1966	748,201	———	782,900

APPENDIX C

Injection Well Workovers

No. 50: Originally dual gas-cap oil column. Pressure build-down test (PBDT) indicated communication between the gas cap and oil column; i.e. $k_w h = 4000+$md-ft. The gas cap perforations were squeeze-cemented. Calculated capacity from PBDT after workover was 1230 md-ft.

No. 52: Originally oil column. PBDT indicated excessive permeability to water: i.e. $k_w h = 4000+$md-ft. The first attempt to reduce communication was to pump 1000 gal. of permanent gel through the existing perforations, overflush with 5 bbls and allow approximately 24 hr for gel to set. Follow PBDT did not indicate appreciable change. The well has been squeezed several times with cement, both through and above the perforations, without any appreciable change in the calculated capacity.

No. 87: Originally dual gas cap and oil column. PBDT of the oil column injection revealed communication with the gas cap. The PBDT test indicated $k_w h = 4000+$md-ft. The gas cap perforations were squeeze-cemented. Capacity calculated from PBDT after the workover was 769 md-ft. Estimated formation $k_w h$ is 350 md-ft in this area.

No. 110: Originally dual gas cap and oil column. PBDT on oil column indicated communication was gas cap; i.e. $k_W h = 818$ md-ft compared to oil column $k_W h = 350$ md-ft. Gas cap perforations were squeeze-cemented. PBDT after the workover indicated the channel was plugged.

No. 126: Originally gas cap and oil column. PBDT of oil column injection indicated communication with the gas cap; i.e. $k_W h = 1013$ md-ft compared to oil column $k_W h = 350$ md-ft. Gas cap perforations were squeeze-cemented with tagged cement. Follow-up gamma ray log indicated the cement was confined to the gas cap interval.

No. 175: Oil column. PBDT indicated excessive permeability to water; i.e. $k \ h = 2206$ md-ft compared to estimated formation capacity of 500 md-ft. Communication with upper zones was further confirmed by water production from offset wells with casing set 300 to 600 ft above the productive interval. The casing was perforated approximately 50 ft above the desired injection interval and squeeze-cemented. PBDT following workover indicated a reduction in communication. Calculated $k \ h$ was 1468 md-ft.