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COALINGA POLYMER DEMONSTRATION PROJECT

MASTER

Second Annual Report, July 1976—July 1977

July 1977

Work Performed Under Contract No. EF-77-C-03-1556

**Shell Oil Company
Ventura, California**

U. S. DEPARTMENT OF ENERGY

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COALINGA POLYMER DEMONSTRATION PROJECT
SECOND ANNUAL REPORT
JULY, 1976 - JULY, 1977

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ACKNOWLEDGEMENTS

The authors wish to express their appreciation to all who helped in the preparation of this report or contributed to the information contained herein. Special appreciation is given to the operating personnel who have meticulously gathered the data necessary to evaluate the performance of the project.

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SUMMARY

The Coalinga Polymer Demonstration Project is a jointly funded venture between the Shell Oil Company and the United States Energy Research and Development Administration (ERDA) that was initiated to test polymer flooding as an enhanced oil recovery method in the East Coalinga field of California. Under the terms of the ERDA cost-sharing contract (number E(04-5)-1004), ERDA funded 29 percent of the originally estimated cost of the project, while Shell is providing the remaining costs.

Water injection started for the project June 28, 1976, in a program to determine if the added expense of a polymer flood over a conventional waterflood is justified in the Temblor Zone II reservoir of the East Coalinga field, California. Polymer flooding is an enhanced waterflooding method used to improve oil recovery by water displacement mobility control. More information on polymer flooding as an enhanced recovery technique for the East Coalinga field and the details of the project site selection, installation, and testing are included in the Coalinga Polymer Demonstration Project, First Annual Report, July 1975 - July 1976 (ERDA Report No. San/1004-76-1, published December 1976).

The 132-acre project area consists of four 22-acre inverted five-spot injection patterns plus a 44-acre up-dip area (with no injection wells) that will be monitored as part of the evaluation procedure. The Temblor Zone II reservoir being flooded consists of about 125 feet of net pay divided among ten sands with a 350-foot gross interval. In addition to the production and injection wells making up the five-spots, there are four observation wells located within the injection patterns to sample liquids.

from individual sands and one logging observation well used to determine changes in liquid saturation. Additional oil recovery from the demonstration project is expected to amount to 2,600,000 barrels which includes 600,000 barrels from polymer injection.

The Coalinga Demonstration Project has been divided into five operational phases which are the (1) Evaluation Phase, (2) Development Phase, (3) Water Injection Phase, (4) Polymer Injection Phase, and (5) Production Monitoring Phase. The Evaluation Phase consisted of field testing and site selection while the Development Phase consisted of project installation.

The Water Injection Phase has been underway for about one year. The lack of a clearcut waterflood response has prolonged this phase. The overall production performance of the waterflood differs significantly from the performance predicted in a 1973 reservoir simulation study. As the 1973 study was preliminary in nature, a detailed simulation study is being undertaken to re-evaluate the current waterflood response. This study should benefit from an improved reservoir description and a history match calibration. Injection well performance shows a fairly good balance of injection into the individual sands. A stimulation treatment program is being conducted to determine if wellbore impairment in the pattern producers is responsible for the slow response. The results of the treatments are currently being evaluated.

The water plant operation has gone well with only minor problems associated with the need to change the screen size on the diatomaceous earth (DE) filters and the problem of fluctuating suspended solids content in the source water. A series of polymer and water injection tests were

carried out in a polymer test well outside the injection patterns. The results of the tests were inconclusive and future polymer injection tests are probable.

The Polymer Injection Phase is expected to start in January, 1978, and continue for approximately 1.5 years, or until it is possible to evaluate the polymer flood performance. After a Production Monitoring Phase of one year, during which a reliable comparison of the performance of Polymer flooding and waterflooding will be determined, a proposal would be considered for a full-scale expansion of the optimum supplemental recovery process. Potential oil recovery from Shell's Temblor Zone II reservoir in the East Coalinga field is 35,000,000 barrels which includes 8,000,000 from polymer injection.

I - RESERVOIR DESCRIPTION

A - GEOLOGICAL MODEL*

BY J. C. SWARBRICK

The Coalinga field is located on the northern end of the San Joaquin Valley in Central California, as shown on Figure I-1, the index map. The Temblor formation, of Middle Miocene age, is the main producing formation. The Section 27 Area of the field or main project area, is located on a southeasterly plunging asymmetrical anticline as shown on Figure I-2, the geological structure map of the East Coalinga field. Most of the Section 27 area of interest is located near the crest of the structure, refer to Figure I-3, a structural cross-section through the East Coalinga field. The top of Temblor Zone II, designated as the Black Shale, occurs in the pilot area at depths ranging from 1,900 to 2,400 feet. The dip of the strata is 13 to 14 degrees to the southeast.

The geologic section of the Section 27 area from the surface to the base of Temblor Zone II is as follows (refer to Figure I-4, the type log of the East Coalinga Field):

*Figures and Tables found in Appendix I.

<u>Unit</u>	<u>Thickness</u> <u>Section 27 Area</u>	<u>Nature and Depositional Environment</u>
Etchegoin (Pliocene)	1,000+'	Clay, sands and conglomerates; both marine and non-marine.
Santa Margarita (Upper Miocene)	300+'	Sand; marine
Temblor (Middle Miocene)		
a) Big Blue	225+'	Claystone with a few sands and gravel; channels-marginal marine to continental
b) Zone I	300+'	Fine grained sands and shales; marine to marginal marine
c) Zone II	350+'	Conglomerate to fine sands and shales; alluvio-marine (deltaic) to marginal marine

The top of Temblor Zone II, the Black Shale, is a dense marine shale easily correlated over the entire Coalinga field. The geological structure map for the East Coalinga field is contoured on top of the Black Shale, see Figure I-5. The base of Zone II is the unconformable surface of the Kreyenhagen (Eocene/Oligocene) formation, a diatomaceous shale which underlies the Miocene section in this area.

The detailed type log (Figure I-6) defines ten separate sands in the Zone II reservoir. This reservoir is divided into two distinct depositional environments, marine and non-marine. The "E" and "F" sands, which make up the marine portion of Zone II, can be locally well developed (such as in the pilot area), but they are usually poorly developed, fine grained, silty sands and interbedded shales; as such, they are expected to play a minor role in the overall project. The non-marine portion of Zone II, from the "G" marker to the top of the Kreyenhagen shale, is 260+ feet thick and has been subdivided into eight sand packages, or subzones. These subzones are sometimes comprised of several small sand units or sand stringers.

The geologic control does not permit mapping individual sand stringers, but the sand packages appear correlative, and are considered as separate units. It is recognized that sand continuity in the direction across the depositional stream flow or channels can be seriously disrupted by clay and shale deposits in some sands because the channels appear to accrete in a northeasterly direction. Sand continuity along channel trends appears to be good. Figures I-7 through I-14 are a series of structural contour maps on top of the eight individual sand packages. Figures I-15 through I-23 are a series of isopach maps which have been constructed showing the net permeable sand distribution of these eight major correlative sand packages in the pilot area.

A detailed discussion of the geologic history and sedimentary genesis of the Temblor Zone II of the Coalinga Field is contained in the First Annual Report¹. Also covered in the report was the outcrop study, coring procedure and core processing methods which were used to obtain and process the core materials from the unconsolidated oil sand reservoirs.

Previous work in the Coalinga Field has disclosed several pronounced fluid saturation changes within the Temblor Zone I and Zone II. Three possible explanations exist for the discontinuities: (1) impermeable barriers of sedimentary origin, (2) barriers resulting from cementation of vertical fractures, and (3) the hydraulic injection of overpressured and unconsolidated sediment into incipient tension fractures or fault planes during the early phases of sedimentation.

In the northern portion of the project area an impermeable barrier exists as is evidenced by a difference in fluid content. This barrier, which is referred to as Barrier "C" in Figure I-15 through I-23, provides

a lateral closure for the oil accumulation in this area of the Coalinga field. The edge water parallels the barrier zone at approximately right angles to the strike at the structural contours, which represents an apparent water level difference of 2,500 feet (refer to Figure I-2).

Barrier "C" is believed to be caused by cemented fractures. Such fractures have been observed in cores and in the Temblor outcrop along the general trend of this barrier zone. This barrier is believed to be completely sealing, even with the high percentage of sand present in Zone II on both sides of the barrier. The presence of desaturated sands in the Temblor Zone II section is evidence that the pilot area is not being charged with water from the water bearing sands to the north of Barrier "C".

References

- (1) Shell oil Company: "Coalinga Polymer Demonstration Project, First Annual Report, July, 1975 - July, 1976", ERDA Report SAQ/1004-76-1, December, 1976.

I - RESERVOIR DESCRIPTION

B - PETROPHYSICAL DATA

BY D. R. MONTAGUE

Introduction

Data for refining the petrophysical description of the Temblor Zone II reservoir and for monitoring and evaluating the performance of the polymer flood demonstration project is continually being obtained. During the period covered by this Second Annual Report, the petrophysical data collection effort focused on five areas as follows:

- (1) Core Analysis - Laboratory analyses of core material obtained from Well 16-6-27, the logging observation well, have been made and additional work continues.
- (2) Cased hole neutron logs - Eight wells were logged with calibrated gamma ray-neutron logs prior to abandonment.
- (3) Induction monitor log program - The logging observation Well 16-6-27 is completed with a non-conductive fiberglass liner cemented across the Temblor Zone II reservoir interval. This wellbore was logged 42 times during the period July, 1976 to July, 1977 with a conventional Dual Induction log.
- (4) Sampling observation wells - Four wells in the pilot area are each completed in three separate Zone II sands. Well tests from these isolated zones provide production and water salinity data.
- (5) Production logs - Various types of production logs are continually being obtained and evaluated.

- (6) Water salinity data - An active sampling program has collected over 3,000 water samples during the period July, 1976 to June, 1977. Salinity was measured on all samples and 250 samples have had laboratory water analyses made.

Several of the above items will be discussed only briefly in this petrophysical section but will be further developed in subsequent sections of this report.

Core Analysis - Well 16-6-27

The logging (or petrophysical) observation Well 16-6-27 was continuously cored through the Temblor Zone II reservoir interval when drilled in 1975.¹ The cores were taken to provide additional information on reservoir geology, formation shaliness and other petrophysical parameters for the reservoir description, and as a control for the flood monitoring logs which are being continually run in this well.

Most of the planned laboratory analyses have been completed as detailed in Table I-1. We are in the process of evaluating the core data in hand in order to refine the selection of samples for relative permeability measurements. A majority of the core material is still frozen and is available for use as needed. Some additional measurements are planned this year on selected samples to observe the permeability behavior of Zone II sands to lower salinity waters (lowest measurement to date is with 6000 ppm water whereas flood water is 300 ppm) and to determine the relative permeability characteristics of Darley treated¹ core samples. Results of the conventional core analysis (oil saturation, grain density, sieve and cation exchange capacity) have been previously reported¹. The following discussion will detail the results of the unconventional core analyses obtained to date.

It is well-known that core measurements of unconsolidated core samples (such as those from the Temblor Zone II) must be made at reservoir stress conditions. To determine the stress required to duplicate Zone II in situ conditions in the laboratory, three core samples were selected for measurement of porosity versus increasing triaxial stress. The results indicated that an applied stress of 900 psi was required to model the in situ conditions present at the 16-6-27 location. Previous measurements of core samples in the pilot area (primarily Well 12-7-27) indicated the required applied stress to be 800 psi (see Figure I-24). However, Well 16-6-27 is 300 feet downdip of Well 12-7-27; as such an added 100 psi seems reasonable.

Techniques and equipment developed by Shell² for preserving the integrity of cores from unconsolidated sand reservoirs were employed when obtaining the core from Well 16-6-27. However, it appears that some "slumping" of the core occurred during handling at the wellsite. This resulted in the alteration of the sand fabric such that portions of the core lost their true reservoir character. Because of this, several samples were discarded prior to analysis (see Table I-1) and a number of other stress measurements are suspect.

As previously reported¹, the Temblor Zone II sands are shaly and the formation water is fairly fresh. Under these conditions, accurate water saturation calculations from log data requires use of the Waxman-Smiths shaly sand model. The pertinent equation³ is

$$S_w^{-n^*} = \frac{R_t}{\phi^{-m^*} R_w} \quad \cdot (1 + R_w B Q_v / S_w) \quad \# \quad (1)$$

#All symbols and abbreviations are defined in Table I-2.

The cementation exponent m^* and saturation exponent n^* used in the Waxman-Smiths equation differ from the usual oilfield Archie exponents.³ Resistivity and resistivity-fluid saturation measurements must be made under conditions of in situ stress and with a known pore water resistivity, R_w . With a core measurement of Q_v , the Waxman-Smiths relation can be applied to the laboratory resistivity data to solve for m^* and n^* . This method was employed to determine m^* on three core samples and n^* on eight core samples from Well 16-6-27. A second, and probably more accurate, method was used to determine m^* on five additional core samples from Well 16-6-27. This technique⁴ involved stressing the sample and then making resistivity measurements using several (three, in this instance) different pore water salinities. The resultant resistivity measurements (measured core resistivity and water resistivity) can be plotted and solved graphically for formation factor and thence m^* ; no separate measurement of Q_v is required. The laboratory measurements used to determine m^* and n^* are presented in Table I-3. The required petrophysical calculations were made as discussed above and the resultant values of m^* and n^* for the eight Well 16-6-27 core samples are presented in Table I-4. This data, together with previous measurements from samples in other cored wells (see Figure I-2), indicate the best values of m^* and n^* for the Temblor Zone II sands are 1.70 and 1.80 respectively.

Measurements of stressed brine permeability have been made on eight core samples from Well 16-6-27 using three different brine salinities; 24,650 ppm, 14,890 ppm and 5990 ppm (Table I-5). From water salinity data in nearby wells, it was estimated that the formation water salinity at the 16-6-27 location was about 6000 ppm. However, the core data seems to

indicate that the original pore water is probably slightly more saline; an average permeability reduction of 44% was observed when brine salinity was reduced from 15,000 ppm to 6,000 ppm. The sensitivity of the Temblor Zone II sands to low salinity water is well-known¹ and will be considered in all reservoir modeling for the project. Additional stress brine permeability measurements are planned.

The value of residual oil saturation (S_{or}) to non-miscible fluid displacement (i.e., waterflood, polymer flood) must be accurately defined in order to properly evaluate the demonstration project. The First Annual Report¹ discussed this subject and the various methods which could be employed to determine S_{or} . Eight core samples from Well 16-6-27 were selected and S_{or} was measured using the countercurrent imbibition technique^{5#}. The results are presented in Table I-6 and show an average S_{or} value of about 25 percent for the Zone II sands when initial oil saturation is assumed to be 65 percent. This compares favorably with previous core measurements of 24 percent (range 20 percent to 32 percent) and the results of the inject-log-inject-log test in Well 15-9-27 where average in situ waterflood residual oil saturation was determined to be 28 ± 4 percent for the Hw and Hx sands¹. Additional measurements of S_{or} will be made concurrent with the relative permeability analyses.

Other miscellaneous core analyses that have been made on samples from Well 16-6-27 during this report period are mercury capillary pressure and X-ray diffraction measurements. The capillary pressure data has not yet been evaluated; the X-ray diffraction data is presented in Table I-7. Twelve thin sections were also prepared for geologic examination.

#A method of determining the initial-residual saturation characteristics of a core sample using toluene as the wetting phase and air as the non-wetting phase.

Cased Hole Neutron Logs

The First Annual Report¹ discusses the petrophysical data required for the reservoir model. Figure I-25 illustrates that even though there are numerous wells in the immediate pilot area, the number of wells with log data sufficient for detailed reservoir description is somewhat limited. The available logs show considerable lateral variation in the sand and fluid saturation distribution within the Temblor Zone II reservoir. Therefore, to better define these variations, some 35 wells were logged with cased hole density and/or gamma ray-neutron devices prior to 1975. Additional cased hole gamma ray-neutron (GRN) logs in the pilot area have been obtained during the well abandonment program from eight of the twenty wells plugged and abandoned to date (see Figure I-25). Several more of the remaining seven wells to be plugged and abandoned will also be logged.

Table I-8 details the wells with new GRN logs and summarizes the petrophysical results of the program. Of special note are Wells 111-27 and 91-27. They had both been previously logged with a cased hole GRN in 1969 and are located in the updip portion of the pilot area (see Figure I-4) where several sand intervals are known to be desaturated. The new GRN's logs, run six months after the start of water injection, were expected to show that some sands may have become resaturated. This was not the case as the old (1969) and new (1976, 1977) GRN log responses were about the same.

Logging Observation Well 16-6-27

This well is the focal point of the petrophysical program to monitor the changes in reservoir fluid saturation as the waterflood and polymer flood progress. A more detailed discussion of the monitoring results is included in Section III-D of this report and the following will deal with only some of the petrophysical implications of those results.

Well 16-6-27 is completed with a 400-foot, non-conductive fiberglass liner positioned opposite the Temblor Zone II reservoir interval as shown in Figure I-26. This type of completion permits induction-type resistivity logs to be run across the Zone II interval to monitor changes in the in situ reservoir fluid saturations during the demonstration project. During the period July, 1976 to July, 1977, this wellbore was logged 42 times with a conventional Dual Induction Log.

Well 16-6-27 was drilled using 35,000 ppm salt gel mud system as is the usual practice in the Coalinga Field. The Zone II sands were moderately invaded with saline mud filtrate during the drilling and coring operations. The time required to secure the non-conductive fiberglass liner was over two months and, as the wellbore remained open during this time period, invasion by the saline mud filtrate continued. Induction and laterologs were obtained prior to running the non-conductive liner on February 16, 1976. These logs indicated that severe mud filtrate invasion was present; the measured resistivity of some sand intervals had been reduced to one-half of their original (November 22, 1975) values. Log calculations further indicated the depth of this invasion was greater than 60-inches radially.

The rate at which filtrate invasion effects dissipate is of special interest to the demonstration project as an extensive cased hole logging program utilizing pulsed neutron capture (PNC) logging devices was planned for the uncompleted (behind pipe) zones in four sampling observation wells.¹ The PNC devices have several limitations; one of which is that they "see" only a short distance beyond the wellbore. If the formation at the wellbore is still invaded with mud filtrate when a PNC log is run, the

subsequent calculations will give an erroneous interpretation of the formation fluid saturations.

Figure I-28 compares the deep induction log run November 22, 1975, (immediately after Well 16-6-27 was drilled and when invasion effects were still only moderate) and the latest cased hole induction monitor log run June 6, 1977. Note that invasion of the saline mud filtrate is still evident (cased hole resistivity is less than open hole resistivity) in many of the sand intervals after one year of waterflooding and 1-1/2 years of total time. These invaded zones have apparently not been influenced by the waterflood to date. It is reasonable to assume that some of the behind pipe sand zones in the sampling observation wells which have not been affected by the waterflood are still invaded by the mud filtrate. If so, the information to be gained from logging such zones with cased hole PNC devices is likely to be limited.

Figure I-29* represents the response of a selected number of induction monitor logs across the lower Hx sand interval in Well 16-6-27. Original conductivity of this zone when logged with open hole logs in November 1975, was 100 to 125 mmhos/m. Before the non-conductive fiberglass was run,

*Figure I-29 presents conductivity of the formation as measured by the deep induction log. Conductivity is the inverse of resistivity as defined by:

$$\text{Conductivity (mmhos/m)} = \frac{1000}{\text{Resistivity (ohm m}^2\text{/m)}}$$

Formation conductivity has been presented rather than resistivity because it permits the induction log changes to be more easily seen.

the wellbore was relogged and showed that the sand conductivity to have increased to 222 to 250 mmhos/m due to deep, saline mud filtrate invasion as discussed above. The induction log run in September, 1976, shows the conductivity to have further increased (due to additional invasion or some type of annular phenomena) to about 250 to 333 mmhos/m. Since that time, conductivity gradually decreased and latest induction log presented shows conductivity to be about 100 mmhos/m, which is about the original conductivity of the zone. This sequence of conductivity changes indicates the migration of the mud filtrate away from the wellbore as a result of depletion drainage from nearby wells or the advance of a waterflood bank in this area. Additional induction logs will be required to determine which interpretation is correct.

Two other important petrophysical observations have been made using the data from the induction logging program in Well 16-6-27. First, the injected water is generally advancing through the reservoir along the bottom of the individual sand zones. A good example of this phenomenon can be seen in the E sand from 1880 feet to 1890 feet (see Figure I-28). The resistivity of the basal five feet of the zone is beginning to increase over the value recorded with the open hole logs indicating fresher pore water (probably injection water) is displacing the original reservoir fluids. The upper five feet of the zone displays lower than original resistivity indicating (in this case) that saline mud filtrate is still present near the wellbore within the radius of investigation of the deep induction log. There are zones where this phenomena does not appear such as in the Gc sand from 1949 feet to 1968 feet. However, examination of the open hole logs, cores and the complete suite of induction monitor logs indicates that the Gc interval is actually composed of four individual sands isolated by minor shale/silt breaks. Three of the zones have shown some waterflood response, and in fact,

one zone from 1953 feet to 1958 feet shows a resistivity change only in the basal two feet of the sand; the top three feet of the zone are still invaded.

The second petrophysical observation that has been made using the data from the induction logging program is that the variations in formation water salinities within the Temblor Zone II reservoir are extremely complex. The induction logs, together with sampling observation well salinity data, show that salinities vary in individual sands in as short a distance as between wellbores only 300 feet apart. The water that is being injected during the waterflood phase of the demonstration project is fresh (300 ppm) as compared to formation water ($\pm$ 5,500 ppm although it varies widely as later discussed). As a sand is flooded the measured resistivity from the induction monitor log should increase due to the replacement of saline formation water with the fresher injection water. This should occur even though the oil saturation will be reduced due to waterflooding (or polymer flooding). A slight resistivity increase over original open hole conditions can be observed in portions of the E, F, Gc, Gd and lower Hx sands as illustrated in Figure I-28. However, it can also be seen that the current monitor log resistivity is less than original open hole resistivity in zones experiencing apparent waterflood response as in the Hw and upper Hx sands, (other sands appearing like this are still invaded as previously discussed).

To explain this apparent discrepancy, comparison of selected successive induction monitor logs in one member of the Hw sand is presented in Figure I-30. Note that the conductivity gradually decrease (resistivity

increased) as the effect of waterflooding dissipated the initial mud filtrate invasion effects. The monitor log dated November 3, 1976, showed the zone to have returned to the apparent original resistivity conditions. The subsequent induction logs have recorded a gradual conductivity increase. This is unexpected; as mentioned above, conductivity should decrease (resistivity increase) as a zone is waterflooded and the more saline formation water is replaced by the fresher injected water. The explanation for the conductivity increase in the Hw sand is that a bank of water more saline than formation water has moved into the vicinity of the wellbore (within the radius of investigation of induction logs). This explanation is supported by the performance of the Hw sand in the nearby sampling observation Well 16-7-27. The water samples from the Hw sand interval in Well 16-7-27 showed a gradual increase in salinity from 6000 ppm (September to December, 1976) to $\pm 7,000$ ppm in February, 1977, and has remained constant to date. Log calculations indicate that a salinity change of the formation water (with or without a minor reduction in oil saturation) from ± 6000 ppm to ± 7000 ppm can explain the resistivity decrease from about 15 ohms to $10\pm$ ohms as recorded by the induction monitor logs across the lower Hw sand in the logging observation well. A similar salinity change has probably also occurred in the upper Hw and Hx sands causing the reduction in measured resistivity as can be observed on Figure I-28.

Similar formation water salinity variations have been detected in other areas of the demonstration project. This phenomena had been suspected ¹ but variations as severe as those documented in the single Hw sand above were not anticipated.

Sampling Observation Wells

The four sampling observation wells (see Figure I-31) are expected to provide formation water salinities and other petrophysical data to finalize the oil saturation calculations for use in the reservoir model. An extensive cased hole monitoring program¹ had been planned for the observation wells. However, it appears that additional petrophysical data cannot be gathered by such logs due to the restricted inside diameter of the gravel packs and the near wellbore invasion effects which were discussed earlier. The First Annual Report¹ detailed the procedures, techniques and risks of the PNC logging program. As the demonstration project proceeds, additional data or logging tool modifications (a small diameter Carbon/Oxygen log may become available) may permit the originally planned flood monitoring by PNC logs to be obtained.

Currently, the sampling observation wells are providing limited formation water salinity data from individual sands. The location of the sampling completion intervals with respect to their companion water injection well completion intervals are summarized in Table I-9. A summary of the formation water salinity data obtained from the observation wells is included in Table I-10. Note that there are wide variations in the individual zone salinities both by well and over time. Additional data and study will be required to fully understand the apparent wide lateral and vertical salinity variations within the Temblor Zone II reservoir before accurate petrophysical water saturation calculations can be made. A further discussion of these wells and their accompanying salinity data as related to pilot monitoring is included in Section III-D of this report.

Production Logs

The main contribution of production logs to the petrophysical evaluation program is to indicate which sands are contributing to fluid production of the well. The production logs results, when coupled with water salinity and production tests, will help complete the petrophysical water saturation calculations.

Water Salinity Data

The water sampling program¹ has collected over 3,000 water samples from July, 1976, to June, 1977. Salinity was measured on all samples and additionally, some 250 of these have been sent to various commercial laboratories for complete analysis (a typical analysis is included as Table I-11 in the Appendix). An additional 300+ samples have been stored and can be analyzed if required.

As has been previously stated¹, the Temblor Zone II formation water salinity varies from 4,000 ppm to 9,000 ppm equivalent NaCl over the project area. Data from the water sampling program now indicates that several areas of the pilot have been subjected to dump flooding from the Zone I formation, therefore, some individual sands may contain pore water with salinities as low as 2,000 ppm equivalent NaCl. These salinity variations severely affect the log calculated water saturation values. In addition, large quantities of brine (with a salinity of 35,000 ppm) were introduced into the reservoir during the Darley treatment program¹. This will make determination of original formation water salinity and project performance monitoring via salinity data very difficult in certain areas of the pilot.

All water salinity data, together with results from the logging observation well, sampling observation wells and production logs, is currently being evaluated to construct individual sand zone water salinity maps where possible. In areas where less data is available, an average Zone II formation water salinity map will also be made. After these are constructed, it will be possible to finalize the oil saturation calculations for the completed reservoir description.

References

1. Shell Oil Company: "Coalinga Polymer Demonstration Project, First Annual Report, July, 1975 - July, 1976", ERDA Report SAQ/1004-76-1, December, 1976.
2. McCollough, C. N.: "Innovations in Core Handling and Processing for Unconsolidated Cores", J. Pet. Tech. (Oct., 1972) 1191-1195.
3. Waxman, M. H., and Smits, L. J. M.: "Electrical Conductivities in Oil-Bearing Shaly Sands", Soc. Pet. Eng. J. (June, 1968) 107-122.
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5. Thomas, E. C. and Ausburn, B. E.: "The Determination of Swept-Zone Residual Oil Saturation in a Slightly Consolidated Sandstone Reservoir of the Gulf Coast", Paper SPE 5803 presented at Improved Oil Recovery Symposium, Tulsa, Oklahoma, Mar. 22-24, 1976.

I - RESERVOIR DESCRIPTION

C - RESERVOIR MODEL*

BY G. E. TINKER

Introduction

The Coalinga Polymer Demonstration Project is designed to make a direct comparison between waterflooding and polymer flooding in the Temblor Zone II reservoir of the East Coalinga field in California. The pilot will provide that data necessary to predict the performance of a full-scale supplemental recovery project with the aid of a reservoir simulator.

The present pilot site (see Figure I-31) is a representative portion of the Temblor Zone II reservoir both in terms of oil saturation and pore space continuity. It also contains most of the individual sands present in the total reservoir. The Immediate Pilot Area consists of four 22-acre inverted five-spot injection patterns, plus a 44-acre up-dip area with no injection wells. The wells outside the Immediate Project Area are required to aid in the simulation of the unconfined injection patterns.

A preliminary reservoir simulation study was completed in 1973. Table I-12 lists the reservoir and project parameters which were used in the initial simulation study. The simulation study currently being conducted should be a significant refinement to the 1973 study due to an improved reservoir description and a history match calibration. This current simulation study will be used to extrapolate the unconfined pilot performance to a full-scale supplementary recovery project.

*Figures and Tables found in Appendix I.

Reservoir Model Construction

A three dimensional simulator will be used to model the project performance. The grid pattern will be variable in the horizontal (x-y) plane and in the vertical (z) direction (variable thickness). The size of the grid blocks in the horizontal plane are shown on Figure I-32, a project map with the superimposed reservoir grid pattern. Within the Immediate Pilot Area, horizontal grid blocks of 200 feet by 200 feet have been used. In the less sensitive part of the project, outside of the four inverted five-spots, some grid blocks have dimensions ranging from 200 feet by 400 feet to 600 feet by 600 feet. The use of smaller grid blocks in the Immediate Pilot Area assures that only one well is located in a given grid block. The well contained in a given grid block is placed in the center of the block regardless of its actual location. Where the grid blocks are larger, outside the Immediate Pilot Area, more than one producing well is located in some blocks. Where this occurs, the wells have been combined into one psuedo-well.

To model the low pressure, low oil saturated, and high gas saturated up-dip region, it has been necessary to include a row of large grid blocks, not shown on the map. These large grid blocks will have the dimensions of the first indicated row of blocks in the "y" or north-south direction, but they will probably have a 2000 foot dimension in the "x" or east-west direction.

The Temblor Zone II reservoir is made up of many sand stringers, but they have been grouped into ten sands with a total thickness of about 125 feet spread out over a gross thickness of 350 feet. For purposes of reservoir simulation, these major sands have been further grouped into six

layers in the vertical or "z" direction. The reservoir simulation layers which will be used are as follows:

E-F	sands
Gc	sand
Gd	sand
X-Y-Hw	sand
Hx	sand
Js-Jv	sands

The minor X and Y sands are in sand-to-sand contact with the major Hw sand in many places and were therefore combined. The E sand and the Jv sand are of lesser importance so that they have been combined with the F and Js sands, respectively.

In order to construct the reservoir model in the total pilot area, it has been necessary to assign the following parameters to each grid block:

- (1) No flow or partial flow boundaries in the horizontal plane.
- (2) Net permeable sand thickness.
- (3) Rock and fluid properties (porosity, current oil and water saturation, residual oil saturation, and permeability for the individual sand layers).
- (4) The depth of each grid block by layer to account for deviations from the average formation dip.

The final construction step of the reservoir model will be the history matching of primary production performance and the first year of water injection, which may require adjustment of various parameters. After the calibration of the reservoir model, it will be possible to use this model to determine the waterflood base case and then begin polymer injection in the pilot area.

II - PROJECT DESCRIPTION AND OPERATION

A - WELL COMPLETIONS*

BY C. E. TIXIER

Within the Coalinga Polymer Project, five types of completions have been utilized:

1. Open hole underreamed gravel pack completions
2. Slotted liner completions.
3. Perforated cased through completions with inside gravel packs
4. Perforated cased through completions.
5. Cemented fiberglass liner completion.

Open Hole Underreamed Gravel Pack Completions

Seven of the eleven main project producers are completed using the open hole underreamed gravel pack completion. A protective casing string was cemented at the top of Zone II. The Zone II interval was then underreamed and a liner gravel packed.

The selection of gravel size and tubular sizes are discussed in the First Annual Report.¹ Figures II-1 and II-2 are schematics of two typical gravel pack completions.

Slotted Liner Completions

Four of the main project producers, as well as a majority of the nonpattern producers, were completed using a slotted liner. A protective casing string was cemented above Zone II, and a tight hole slotted liner placed across Zone II. The majority of the liners have either sawcut

*Figures found in Appendix II.

0.060-inch slots (refer to Figure II-3) or 0.008-inch button screen slots (refer to Figure II-4).

Perforated Cased Through Completions with Inside Gravel Packs

The observation wells were completed with 7-inch casing cemented through Zone II. The intervals of interest were then jet perforated and individually gravel packed using a 4-1/2-inch inner liner. On top of each liner, a jam-on packer was installed to isolate the individual zones. Figure II-5 is a schematic of one of the observation well completions. More detailed information on the gravel packing hardware and procedure is contained in the First Annual Report.¹

Perforated Cased Through Completions

All four pilot injection wells are completed with 7-inch casing which was cemented through Zone II. The selected sand intervals were jet perforated.

Fiberglass Liner Completion

The logging observation well, 16-6-27, was completed using a protective string of 7" casing, which was cemented above Zone II. A 5-1/2-inch nonconductive fiberglass liner was then installed and cemented across Zone II (refer to Figure II-6).

References

1. Shell Oil Company: "Coalinga Polymer Demonstration Project, First Annual Report, July, 1975 - July, 1976" ERDA Report SAQ/1004-76-1, December, 1976.

II - PROJECT DESCRIPTION AND OPERATION

B - SURFACE AND SUBSURFACE EQUIPMENT*

BY R. E. FROMM

C. E. TIXIER

Injection Wells

All four injection wells are equipped with wellheads which permit annular entry of wireline tools. Currently, Sperry-Sun "Permaguage" surface readout, downhole pressure sensors are installed in the annuli. This device transmits pressure to the surface via a thin, nitrogen-filled tube. At the surface the pressure is monitored by a pressure gauge and recorded continuously on a paper chart. Correction factors for the nitrogen-gas gradient are applied to translate surface readings to downhole pressures. Figure II-7 shows a typical installation for an injection well. When the wells develop surface pressure, these tubes will be removed.

The operation of the bubble tube has been quite satisfactory to date. The only maintenance required is a weekly blow-down of the tubes with nitrogen and a monthly calibration at the pressure sensing devices.

All injection wells are equipped with internally plastic-coated tubing. The internal film is expected to provide better quality water downhole and eliminate polymer degradation by minimizing exposure to steel tubulars. At present, the wells are not equipped with packers; open-ended tubing is hung about 100 to 150 feet above the top perforation in each well.

*Figures and Tables found in Appendix II.

A nitrogen blanket has been installed in annuli of the four injection wells to prevent air from being drawn into the wells. The air oxidizes the exposed casing and the reaction product, magnetite (Fe_3O_4), could cause formation impairment. Since the installation of the nitrogen blanket, no iron oxides have been detected in the bailed samples.

Production Wellhead Equipment

All observation wells and all but three production wells in the project injection patterns are equipped with annular entry wellheads. The three producers not so equipped are old wells completed with 5-1/2-inch casing and 4-1/2-inch liner, which leaves little clearance for annular running of tools. The wells on which annular entry wellheads were not installed are 273-27, 284-27, and 285-27.

Surface Lift Equipment

Production will be by means of sucker rod pumping using beam pumping units. All production wells were originally equipped with small capacity units adequate for primary production. The desired production capacity of 600 to 1,000 barrels per day of total fluid per well can be achieved with larger beam pumping units for most of the eleven main producers. The small diameter casing used in Wells 273-27, 284-27, and 285-27 will restrict production to about 500 barrels per day.

For economy, used surface beam units will be installed where possible as response occurs. The employment of large bore downhole pumps should provide acceptable production capacity when coupled with the larger beam equipment in most cases. Table II-1 lists the large surface pumping equipment that has been installed on responding wells.

Subsurface Pumping Equipment

Downhole rod pumping equipment currently in place in project wells is satisfactory for low primary production rates. As large surface units are installed to handle production increases due to flooding, subsurface equipment will be necessarily revised. Typically, the wells are now equipped with 3/4 inch API grade C or "second hand" grade D rods. In order to withstand the increased loadings due to higher production rates, it is anticipated that all major production wells will be equipped with new or top quality used API grade D sucker rods. Because of the large pump diameters to be employed in production wells, it will probably be necessary to install 7/8 inch diameter rods in units of less than 100-inch stroke; 3/4 inch rods should prove adequate in the observation wells and producers where pumps will be run in 2-7/8 inch OD or smaller tubing.

Either 2-7/8 inch or 2-3/8 inch OD tubing is now installed in the production wells. As production increases 3-1/2 inch OD tubing or 2-7/8 inch tubing pumps will be used.

Observation Wells

The testing of the observation wells is conducted using swab cups to sample the isolated zones (refer to Figure II-8). A liner top locator is used to locate the cups at the correct depth.

A dye check has been used to assure that the upper interval(s) is not communicating with the lower zone being produced. The dye check consists of dumping a colored dye down the annulus and monitoring the production from the middle or lower zone for the dye. If the dye is detected, the

production equipment is pulled and rerun with new swab cups. The use of the dye check on a frequent basis is often misleading due to contamination by the residual dye remaining in the wellbore.

Well zone test frequency has varied during the past year but has averaged a seven to ten day test per zone per month. Initially, a commingled (all three zones) production test was also made once a month. A review of the production and water salinity data showed that, when the zones were commingled, crossflow between sands occurred and water salinity data obtained from the test was poor. Commingled well tests were then discontinued and now only isolated zone tests were made.

II - PROJECT DESCRIPTION AND OPERATION

C - FACILITIES*

BY R. W. BOWMAN

T. BATES

The details of both the Injection and Production facilities are provided in the First Annual Report.¹ A brief summary of operational problems is discussed in the following section.

Injection Facilities

Figure II-9 shows the overall schematic of the polymer mixing and injection plant. The plant has operated on water since the start-up in June 1976. The system has worked well with only minor problems.

Due to D.E. leakage, a number of D.E. filter screens were evaluated. New screens have been installed, eliminating this problem. The problem arose because of our stringent water quality specifications. Even with new screens, a ten minute purge cycle, after regeneration and before going "on stream", has also been incorporated to assure good quality injection fluid.

As a result of the recent drought conditions in California the quality of the USBR (United States Bureau of Reclamation) water has been deteriorating, showing a significant increase in suspended solids, particularly in the 0.5 to 3 micron range. Depending on the quality of the incoming water, filter cycle lengths have ranged from 6 - 24 hours. D.E. body feed addition has now been initiated and has resulted in a two-fold increase in cycle length.

*Figures found in Appendix II.

The polymer mixing facility has worked with only minor problems occurring during the injectivity testing. Problems have been experienced in the mixing skid due to the use of hot water. The resultant water vapor wet the dry polymer as it was metered into the mixer, causing some plugging in the mixing equipment. The system has now been revised to allow manual cleaning to prevent polymer buildup. A duplicate polymer mixing facility will be installed for back-up to minimize down time. Also, some problems have been experienced with maintaining accurate calibration of the dilution system. This is being remedied by installing more accurate metering equipment.

Production Facilities

Figure II-10 provides a schematic of the production system. The production system has functioned with no problems since startup. The prover tank is used more than the automatic well test (A.W.T.) for well testing because of the low oil production. Thus far, the A.W.T. and the wet A.C.T. (Automatic Custody Transfer) equipment have agreed reasonably well. Gauging of the prover tank has also checked reasonably well with the wet A.C.T. panel. No changes in the production facilities are anticipated at this time.

References

1. Shell Oil Company: "Coalinga Polymer Demonstration Project, First Annual Report, July, 1975 - July, 1976" ERDA Report SAQ/1004-76-1, December, 1976.

II - PROJECT PERFORMANCE

D - WELL ABANDONMENTS*

BY C. E. TIXIER

During the past year, an extensive well abandonment program has been in progress in the area of the Coalinga Polymer Project. The major objectives of the abandonment program were to (1) eliminate all nonpattern producers within the immediate five spot patterns, (2) eliminate all idle wells in the pilot area which were not mechanically competent, (3) isolate Zone II from all upper reservoirs, and (4) eliminate crossflow within Zone II.

To achieve the latter two objectives, it was necessary to place cement across the Black Shale, the impermeable flow barrier at the top of Zone II, and across the major shale intervals within Zone II. Therefore, the abandonment procedure included a canister shot (a large explosive charge used to separate casing) adjacent to the Black Shale and the perforation of the major shale intervals before placing a cement plug across Zone II.

Table II-2 lists the twenty wells abandoned in conjunction with the Polymer Project.

*Tables found in Appendix II.

III - PROJECT PERFORMANCE

A - INJECTION WELL PERFORMANCE*

BY G. E. TINKER

C. E. TIXIER

General

The water injection has been carefully monitored as part of the data gathering process for the project. Continuous injection rates and bottom hole pressures are combined with periodic injection profile surveys to evaluate the basic injection well performance.

The injection profile surveys are critical to the evaluation of the waterflood performance. The surveys are used to determine the allocation of injection water to the various sand intervals and to detect water allocation problems which could lead to an imbalance in the injection patterns.

Injection Well History

Injection wells were tested as a part of both the project Evaluation and Development Phases. The purpose of the testing was two-fold: First, to obtain data necessary to design an optimum treatment for the prevention of wellbore damage caused by injecting fresh water into formations containing fresh water sensitive clays; second, to determine if good performance could be achieved in water injection wells without mechanical separation of the individual zones in the complex Zone II multilayered reservoir. The results of these tests are contained in the First Annual Report.¹

The injection performance curves, consisting of plots of injection rate versus bottom hole injection pressure, are shown in Figures III-1 through III-4. The well performance is considered to be good in essentially

*Figures and Tables found in Appendix III

all respects, as characterized by a constant injection rate of 1350 barrels per day per well accompanied by a steady, gradual pressure increase. As had been anticipated, the injectivity (BD per psi of bottom pressure) of an injection well has gradually decreased as the reservoir pressure increased.

The reservoir pressure history from fall-off surveys as measured at the injection wells is as follows:

	Bottom Hole Pressure, Psi	
	Updip Wells	Downdip Wells
	15-6-27	2-7-26
	15-9-27	2-9-26
Prior to Water Injection	100	210
After 9 months Water Injection	250	405

Water Bank Performance

The use of a simplified estimate of water bank size is helpful when monitoring injection volume imbalances in a multilayered reservoir. To graphically display the water bank size, the allocated injection water volumes are converted to radial frontal advances (referred to as bubbles) from each injection well for each individual sand. The six water injection profile surveys obtained from each of the four injection wells were used to allocate the injected water volumes to each of the major sand intervals. Table III-1 lists the cumulative injection into these intervals.

In order to convert the injection volumes to estimated frontal advances the following assumptions were made; (1) the ϕh (the formation porosity and thickness product) is assumed to be constant over that portion of the reservoir influenced by the injection well, (2) the waterflood moveable reservoir volume consists of all the pore space except that occupied by residual oil (23.5% of the pore volume), (3) each water bank

advances radially away from the injection well, (4) no reservoir discontinuity problems exist, (5) no water is lost from the water bank by production, (6) no interference occurs between different water banks, and (7) the displacement efficiency is assumed to be a value less than one because of the unfavorable mobility ratio. The bubble fronts (Figures III-5 through III-11) are shown for a displacement efficiency of one, as an inner limit, and 0.1, a possible lower limit of the displacement efficiency. However, the shape is idealized and cannot be used as an accurate indication of flood fronts, primarily because of interference effects between the banks, unbalanced withdrawal rates across the area and uncertainty in the actual displacement efficiency. Table III-2 is a summary of the water bank radii based upon the injected volumes shown in Table II-1 and the assumptions listed above. The simulation study will incorporate the known reservoir discontinuities and heterogeneities along with the fluid saturation distributions, mobility contrast and the unconfined nature of the project to obtain a refined prediction of sweep efficiency and flood performance.

The following statements characterize or explain the water bank performance to date:

- (1) The injection of 5300 barrels per day for one year represents an injection volume of 11% of the moveable reservoir volume within the immediate five-spot patterns.
- (2) An increase in produced fluids of only 1000 barrels per day suggests that the reservoir fluids are moving outside of the unconfined pattern.
- (3) The rapid wide-spread tracer response, mostly in the updip direction, indicates the movements of fluid through a

desaturated interval at the top of some sands or through highly permeable layers.

- (4) Based on the performance of the logging observation well, the movement of fluids in the fluid filled portion of the reservoir is restricted to the lower portion in each sand package.
- (5) The injection profiles indicate that fluids are being injected into all major reservoir sands.
- (6) A reasonable balance of injection into all of the major reservoir sands has been obtained, except for deficiencies in the G_d sand injection in Well 2-7-26, in the X-Y- H_w sands injection in Well 15-6-27 and in the H_x sand injection in Well 15-9-27.

Injection Logging

Injection well profile surveys are run periodically using a radioactive/spinner/temperature tool and consists of the following operations:

- (1) Adjusting wireline tool depths to perforated intervals by use of a magnetic casing collar locator.
- (2) Temperature logging from 100 feet above Zone II to the bottom of Zone II.
- (3) Running a spinner survey across the completion interval.
- (4) Determining flow rate in blanks between perforated intervals using radioactive tracer and one or more detectors.

Allocation of the injected fluids between sands is based entirely upon the radioactive tracer checks; the spinner and temperature logs are mainly used to assure the reliability of tracer survey results.

A detailed discussion of logging operations is contained in the First Annual Report.¹ The only modification in the logging procedure has been the use of a radioactive tool containing three detectors. The three detectors can be arranged such that "velocity checks" can be obtained in both five and ten foot casing blanks. A velocity check consists of injecting radioactive tracer while recording the time interval necessary for the tracer to move past two separate detectors of a known spacing.

When triple detectors were used, it was observed that flow rates calculated using detectors with a five foot spacing were always higher than flow rates calculated using the detectors with a ten foot spacing. The difference is believed to be a result of the velocity profile of the fluid within the casing. Therefore, before the short spaced detector could be used, a relationship between the flow rates and detector spacing had to be developed. To accomplish this, flow rates were calculated in ten foot casing blanks using both the long and short spaced detectors. It was found that the flow rates calculated using the short detector spacing were 1.18 0.02 (95% confidence limit) times greater than the flow rates calculated using the long detector spacing. This relationship is in close agreement with theory², if it is assumed that flow rates calculated from the short detector spacing represent the maximum velocity and flow rates calculated from the long detector spacing represent the average velocity of a velocity profile for rates between 500 and 1,400 barrels per day in 7-inch casing.

References

1. Shell Oil Company: "Coalinga Polymer Demonstration Project, First Annual Report, July, 1975 - July, 1976" ERDA Report SAQ/1004-76-1, December, 1976.
2. McCabe, W.L., and Smith, J.S. "Unit Operations of Chemical Engineering", 2nd ed., pp. 84-103, McGraw-Hill Book Company, New York, 1956.

III - PROJECT PERFORMANCE

B - INJECTION TRACERS*

BY B. ZEMEL

G. E. TINKER

General

Radioactive and chemical tracers are being used in the Coalinga Polymer Demonstration Project as part of the program for project monitoring. Tracers were first introduced into the injection stream of each of the four injection wells about five weeks after the start of water injection. It is also planned to inject tracers soon after the start of polymer injection. A different tracer was used in each injection well in order to determine the origin of water produced from response wells after tracer breakthrough.

Laboratory Screening Tests

A series of laboratory screening tests was carried out to determine which four tracers would be used for the program. It was recommended that three radioactive tracers and one chemical tracer be used. The tracers chosen were tritiated water, cobalt-60 in the form of potassium cobalticyanide, sulfur-35 as the sulfate ion, and iodide ion in the form of potassium iodide. These tracers were chosen on the basis of the analysis of the produced water and what was known about the chemistry of the formation. All of the tracers have been used successfully as water tracers, either by Shell or reported by others in the literature. The concentrations of the various materials chosen were based on the limitation imposed by the California regulation on maximum permissible concentration of such materials in water as well as on the estimated sensitivity of the measurement for the various tracers.

*Figures and Tables found in Appendix III

The tracers were each injected in the form of a narrow pulse, which is representative of the distribution of any element of volume injected into each of the wells.

Injection and Detection Procedures

1. Cobalt 60

Cobalt was prepared in the form of potassium cobalticyanide, $K_3Co(CN)_6$. The cobalt-60 is tied up in the complex anion as $Co(CN)_6^{-3}$ with an overall stability constant 10^{64} . Twenty millicuries of this material were injected into Well 15-6-27. The material was received in a lead-lined cylinder and injected into the well by flushing it through with a nonradioactive potassium cobalticyanide solution. One gallon samples of produced water from the surrounding wells were taken for measurement and counted by immersing a sodium iodide gamma detector in the sample. No tracer was detected at any surrounding wells, even though tests performed showed the sensitivity of the method to be in the order of .01 microcuries of tracer per barrel of water. However, many of the samples that were received contained relatively large amounts of soluble iron, far more than the water sample that had been analyzed prior to choosing this tracer. It is therefore believed that the iron in solution reacted with the cobalticyanide to precipitate a ferrous cobalticyanide either at the producing well or in the formation.

2. Tritiated Water

Five curies of tritiated water in a volume of 5 cc were injected into Well 2-9-26 by means of a hypodermic syringe. The injection line leading to the well was fitted with a silicon rubber septum, and the tritiated water was injected into the line while water was being injected

into the well. Samples were collected from surrounding wells at periodic intervals by field personnel. Since the procedure used for measuring tritiated water is simple and straightforward, all samples received were routinely filtered and counted using a liquid scintillation counter. The producing wells and the corresponding dates of all tracer responses are shown on Table III-3. The wells which showed response to tritium are indicated on Figure III-13.

3. Sulfur 35 Tagged Sulfate Ion

Sulfur-35 in the form of a dilute sulfate solution was injected into Well 15-9-27 by means of a hypodermic syringe inserted into the injection line while water was being injected into the well. Initially, 500 millicuries of sulfur-35 sulfate had been purchased; however, because of the relatively short half life of sulfur-35 (88 days) and the unanticipated delays between the purchase of the sulfur-35 and its actual injection in the well, only about 150 millicuries of sulfur-35 were injected. Because of the reduced concentration and the continued decay of the sulfur-35 with later samples, it was necessary in all cases to enrich the sulfur-35 present in a counting sample. This was done by precipitating barium sulfate and counting the suspended precipitate in a liquid scintillation counter. Because of the additional manipulations involved for this tracer, only a selected number of samples were so counted, principally samples taken from wells immediately surrounding the injector 15-9-23. The addition of bisulfite as an oxygen scavenger in the injection wells was believed to provide sufficient protection for the tagged sulfate ion.

Unfortunately, many of the samples tested had no measurable sulfate. Therefore, to avoid an enrichment procedure, a small amount of

sulfate ion was added to the water from each of the wells before carrying out the precipitation. The wells showing response to sulfur-35 are indicated on Figure III-15.

4. Potassium Iodide Tracer

Five hundred pounds of potassium iodide were added to Well 2-7-26. The iodide was dissolved in about 75 gallons of water and then injected. Water samples from the surrounding wells were taken for analysis. The iodide analysis consisted simply of measuring the voltage generated by solid state silver-iodide membrane electrode against that of a standard calomel electrode.

Analysis of several field produced waters taken previous to this injection showed a background equivalent to about 0.1 ppm. Unfortunately, the samples received from the field following the tracer injection, in most cases, had a considerably higher background count. Also, unlike the samples which had been analyzed before injecting the tracer, most contained relatively high hydrogen sulfide content. The sulfide ion interferes in the measurement for iodide when using the iodide electrode. Therefore, the samples had to be pre-treated to remove the sulfide ion before making the measurement using a transition metal ion to precipitate sulfide. Because of the high background levels at the various wells, values of iodide concentration less than 1 to 2 ppm were called zero. The wells showing response to potassium iodide are indicated on Figure III-12.

5. Iodine-125

Radioactive potassium iodide (I-125) was injected into Well 15-6-27 following the failure of the Cobalt-60 to appear in the surrounding wells. A concentration of 350 millicuries of I-125 was injected together with 500 pounds of inert potassium iodide. The tracer was monitored by counting

produced water from the surrounding wells in a liquid scintillation counter. Only one well showed the presence of I-125 using this procedure. Therefore, a number of surrounding wells were tested for the presence of I-125 after first enriching the samples by a factor of 100. This was done by first oxidizing the iodide and then extracting it into a small volume of toluene for counting. Four additional wells showed I-125 to be present by this procedure. The presence of I-125 was also verified by its energy spectrum. The wells responding are indicated on Figure III-14.

Tracer Response

The production wells responding to tracer injection are shown on Figures III-12 through III-15. The large amounts of data available for the tritium tracer resulted because of the simple detection procedure. Other tracers might have been detected over wider areas had it been possible to test more samples. The occurrence of peaks in the various tracer responses as a function of time suggest the presence of a number of paths for tracer movement through the reservoir.

The following observation regarding the tracer response can be made:

- (1) The rapid breakthrough of tritium suggests that the flow of water occurred in thin desaturated intervals at the top of some sands, in thin highly permeable layers or in thin fingers along the bottom of the sands (based on results in the logging observation well).
- (2) The tritium bypassed the sulfur-35 response area suggesting a restricted response area between the injection Well 15-9-27 (sulfur-35 area) and the up-dip wells in that five-spot.

(3) The detection of I-25 in Well 3-11-26, which is 2100 feet
downdip from the injector, Well 15-6-27, is anomalous
and is not shown on Figure 14.

III - PROJECT PERFORMANCE
C - PRODUCTION WELL PERFORMANCE

BY C. E. TIXIER

G. E. TINKER

General

The performance of the pattern production wells, Figures III-16 through III-24 is characterized by a slow response to waterflooding. The exceptions are Wells 1-5-26 and 4-6-26, which are believed to be producing anomalous water. As the pilot being conducted is unconfined in nature, it is necessary that pattern producers be capable of producing at their maximum capacity. As a result, a stimulation treatment program has been undertaken to determine if wellbore impairment could be the cause of the slow response being experienced. Table III-4 lists the treatments which have been performed on the pattern producers.

Reconditioning

The stimulation program has been directed at damage which could have resulted during the drilling and completion operations of the new producing Wells 1-5-26, 1-8-26, 3-8-26, 4-6-26, and 14-7-27. Near wellbore impairment could be caused by solids invasion into the formation. The types of solids considered include native drill solids and solids inherent in the polymer drilling mud used for underreaming and gravel packing which contained bacterial debris and unhydrated polymer. Well 1-8-26 was recently stimulated using Mud Acid to determine if native drill solids could be causing impairment. The results of the stimulation are not yet conclusive as the production rate has not stabilized. Wells 1-8-26, 3-8-26, and 1-7-27 have been treated with

Bacteria Destruct*to remove suspected bacterial debris associated with the polymer drilling mud which was used. The Bacteria Destruct treatments failed to increase production. Well 14-7-27 was recently stimulated with a Sodium Hypochlorite treatment to remove suspected unhydrated polymer associated with the polymer mud. The results are inconclusive as the well is not yet producing at a stabilized rate.

Other areas of investigation include possible adverse effects caused by Darley treatment. All the pattern producers, with the exception of Well 4-6-26, were Darley treated to protect the sands from a permeability reduction caused by fresh water. The Darley treatment¹oil wets the formation to protect the clays from swelling when contacted by fresh water. Laboratory studies are planned to determine the effects of Darley treatment on the producing characteristics of a well.

Individual Well Performance

The production curves for the pattern producers are shown on Figures III-16 through III-24. The results of the production logging program are contained in Table III-5 and the results of pressure data collected are listed in Table III-6. The following is a summary of the production well performance:

<u>Well</u>	<u>Performance</u>
1-5-26	The performance of this well after Darley treatment was anomalous in that water production was higher than expected. Water analyses and production logs indicated that Zone II in this well was being dumpflooded from Zone I. Two attempts were made to eliminate the Zone I water entry. Production logs after the second cement squeeze

*The Bacteria Destruct well stimulation (furnished by BJ-Hughes, Inc.) is a specially designed chemical treatment that will break down and remove bacteria cells (in this case, derived from using a biopolymer drilling mud for enlarging the open hole prior to gravel packing) that may be plugging a wellbore.

Well Performance

job indicated that the extraneous water entry from Zone I had been eliminated. Subsequent production logs indicate that the Hw sand is the major producing interval in the well. The water analysis of the produced fluids is not characteristic of Zone II, nor is it similar to previous produced water. The performance of this well will continue to be monitored.

1-8-26 A large quantity of brine was injected into this well during the "isoflow" injection placement of the Darley treatment. Approximately six months were required to produce back the treatment fluids. Subsequent water analyses were characteristic of Zone II formation fluids. Production logs indicated the E/F sand to be the major producer, with little or no contribution from the lower sands. Most of the lower sands should also be significant contributors to production based on cumulative zonal injection in the surrounding injection wells. A recent Mud Acid stimulation treatment, using the "isoflow" injection technique, was conducted in an attempt to increase production, specifically from the Hw and Hx intervals. The results of the treatment are not yet conclusive.

3-8-26 This well has produced at a relatively constant rate from the upper sands since October, 1976. A Bacteria Destruct treatment in March, 1977, failed to increase production. The production from this well is not characteristic of waterflood response. The possible causes for the lack of response include; the lower

WellPerformance

quality and quantity of sand in this well, the low injectivity of the surrounding injectors into the major sands present in this well, and impairment.

- 3-11-26 The production rate from this well has been constant since the initiation of the waterflood. The lack of waterflood response is possibly due to distance of the well from the estimated flood fronts in the individual sands.
- 4-6-26 The production performance of this well was anomalous in that water production was higher than expected. Production logs suggested that the well was being dumpflooded from Zone I. Two cement squeeze operations were unsuccessful in eliminating the anomalous water production. A recent production log indicated major water entry from the Hx sand, with minor entry from the E/F sand (possibly from above the casing shoe). An evaluation is currently underway to determine if dumpflooding in 4-6-26 or surrounding wells has or is occurring.
- 14-7-27 After Darley treatment, the well produced at a relatively constant rate through October, 1976. At that time the water production steadily increased indicating a response to water injection. A Bacteria Destruct treatment in March, 1977, failed to increase production. The well was then restimulated with a three stage treatment consisting of Sodium Hypochlorite, Bacteria Destruct and Hydrochloric acid. The post-treatment production rate has not yet stabilized. Major production contributions are expected from the Hw and Hx sands based on cumulative injection into these sands from the nearby injection wells.

<u>Well</u>	<u>Performance</u>
118-27	A Hydrochloric acid treatment of this well was necessary to restore the pre-Darley Treatment production rate. The movement of fines is believed to be the cause of the production decrease after Darley Treatment. The well produces clean oil and has not responded to water injection. As a result, this well is being considered for stimulation.
284-27	After Darley treatment, this well produced at a relatively constant rate, indicating no response to the waterflood. Based on the significant response in nonpattern wells in the area, a Mud Acid stimulation treatment was conducted in April, 1977. Initial results indicate that the treatment was successful, as production increased by 40 BDG and 20 BDO. Attempts to locate the major zone(s) of production have been unsuccessful because of the small tubulars and the low production rates. Based on the flood fronts in the individual sands, the Gc and Hw sands should be major contributors to production.
285A-27	This well has produced at a constant rate since October, 1976. The lack of waterflood response could be normal based on estimated flood fronts in the individual sands.

Production Logging

The production logging profile surveys are expected to yield a qualitative interpretation of the performance of the production wells. The types of well completions, the operating conditions and the relatively low production rates associated with Coalinga Polymer wells are not conducive to a quantitative analysis. The gravel pack and slotted liner completions

may obscure the true entry point of the produced fluids into the wellbore. The production wells are normally operated with a fluid level near the bottom of the productive interval. Therefore, in order to obtain a conventional production log, the production equipment must be altered such that the well is pumped from above the productive interval. This, in turn, induces a back pressure on the reservoir which reduces or eliminates inflow from the individual zones.

The production log most commonly used has been the radioactive/temperature survey. This is essentially the same tool used to log injection wells. The logging operation is conducted as follows:

- (1) The wireline depths are adjusted to the liner top using a casing collar detector.
- (2) A temperature log is run from 100 feet above Zone II to total depth.
- (3) Flow rates adjacent to various shale intervals are determined using a radioactive tracer and a detector.
- (4) A radioactive tracer is ejected across the entire productive interval, referred to as a conditioning run, and the movement of the tracer is then logged.

The temperature and conditioning logs are used to assure the reliability of the tracer survey.

Velocity checks are used to estimate the flow rates. The velocity check consists of injecting a radioactive tracer and recording the time required for the tracer to move from the ejector to the detector. Radioactive tracer rate checks proceed from the top of the productive interval to the bottom of the well to minimize radioactive contamination of the

wellbore from previous checks. Whenever possible, flow rates are obtained adjacent to shale intervals. The production rate from the individual sands is determined by the difference of the flow rates in adjacent shale intervals.

In an attempt to obtain a production log from wells producing at low volumes and with no fluid levels, audio surveys were run. The successful use of the audio survey to obtain a production log has been reported in the literature. Although the data obtained from the audio surveys provided qualitative indications of fluid movement, it was difficult to analyze. A number of conditions interfered with obtaining better measurements, such as:

- (1) Because of the noise associated with the beam unit rod pumping, the audio log is run with the unit shut down. Therefore, the data recorded represents the transient noise associated with after-flow, rather than a psuedo-steady state noise.
- (2) Because of the length of time required to run an audio log, the transient noise levels may be significantly attenuated before the completion of the log.

- (3) The background noise level associated with the fluid level rising in the wellbore may prevent the detection of some after flow noises.
- (4) The low noise levels, associated with the low production rates, are not significantly higher than background noise in many cases.

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III - PROJECT PERFORMANCE

D - OBSERVATION WELL PERFORMANCE

BY D. R. MONTAGUE

C. E. TIXIER

Introduction

Five observation wells were drilled and completed within the pilot area as shown in Figure I-8. Four of these wells are designated as sampling observation wells and Well 16-6-27 is the logging (or petrophysical) observation well. These wells have provided valuable production, reservoir and petrophysical data for use in the interpretation of the demonstration project's flood performance. These results are described below.

Sampling Observation Wells 16-7-27, 15-8-27, 1-9-26, and 1-7-26

The four sampling observation wells are an integral part of the program to monitor the performance of the demonstration project. Each is completed in three individual sand intervals of the Temblor Zone II reservoir.¹ Geological correlations were made and the completion intervals were located in sand intervals that were correlative with equivalent members in the companion water injection well. Each completion interval was limited to five feet of the sand interval to permit adequate fluid sampling without distorting the reservoir fluid flow patterns. Table I-9 presents the completion data by zone for each sampling observation/water injection well pair.

The quality of the flood monitoring data obtained to date from the sampling observation wells is less than had been expected. The two areas in which questionable data arises are (1) zones producing at a low

production rate and (2) adjacent zones in the same observation well which produce at similar rates and similar salinities. The low production may be a result of wellbore impairment, partial completion in a sand package, reservoir quality and/or reservoir heterogenities. The similar production rates and salinities of adjacent producing zones suggest communication exists between the zones. This latter condition has not yet been substantiated with production logs or pressure data. A program to ascertain the condition of each sampling zone is underway. A set of pressure surveys and possibly production logs will be obtained in each observation well. This information will aid in determining the integrity of the zonal isolation and the optimum operating procedure to use in order to provide the necessary data for future project performance evaluation.

Sampling Observation Well 16-7-27 - This is perhaps the most important of the four sampling observation wells since it provides salinity data used in conjunction with the logging observation Well 16-6-27. Well 16-7-26 is completed in the Gd, Hw, and Hx Temblor Zone II sands. A summary of performance of the individual zones is as follows:

Gd sand - The production from this zone has averaged less than 2 BDW; produced water salinity is high which is characteristic of Darley treatment fluids. This zone has shown no response to the waterflood.

Hw sand - The production rate from this zone has varied between 10-25 BDW. The potassium iodide tracer from water injection Well 2-7-26 was detected in produced water samples obtained in September, 1976. The salinity of the produced water subsequently

gradually declined from 6000 ppm to 5400 ppm, possibly indicating the production of minor amounts of injection water. In February, 1977, the salinity increased to 7000 ppm, indicating a bank of formation water from a different area of the reservoir had moved into the vicinity of this well. Concurrently, the Hw and Hx zones began to produce at approximately the same rates and salinities, suggesting possible communication between the zones.

Hx sand - During the period from August, 1976, to February, 1977, the production rate from this zone varied from 5-15 BDW with a constant water salinity of 5100 ppm, indicating no waterflood response. Subsequent production data suggests possible communication with the Hw zone.

Sampling Observation Well 15-8-27 - This well is completed in the Gc, Gd and Hw Temblor Zone II sands. A summary of the performance of the individual zones is as follows:

Gc sand - This zone has produced at an average rate of 6 BDW, after producing back the Darley treatment load. The salinity of the produced water is 1450 ppm with a sulfate content of 250 ppm, neither of which are characteristic of Zone II. This zone may be (or has been) in communication with Zone I.

Gd and Hw sands - Both zones have produced at an average rate of 6 BDO after producing back the Darley treatment load. The small amounts of water produced are mainly high salinity (20,000 ppm) Darley brine. There has been no indication of waterflood response in either zone. The similar production rates suggest possible communication between the Gd and Hw zones.

The sulfur-35 tracer from water injection Well 15-9-27, was detected in the water samples obtained during a commingled production test in August, 1976. The tracer probably entered the wellbore through the Gc sand.

Sampling Observation Well 1-9-26 - This well is completed in the F, Gc and Gd Temblor Zone II sands. A summary of the performance of the individual zones is as follows:

F sand - The production rate from this zone declined from 16 BDG, 2 BDO to 3 BDG, 2 BDO during the period September to December, 1976. The produced water salinity during that time was indicative of formation water (5000 - 6000 ppm). An abrupt decrease in salinity (2600 ppm) was observed in January, 1977. The production rate at the lower salinity has since remained constant at 1 BDW.

Gc sand - The production from this zone was erratic during the period July to December, 1976. Tritium from water injection Well 2-9-26 was detected in the water samples obtained in August, 1976. In January 1977, the production rates and salinities of the Gc and Gd sands became similar, suggesting possible communication between the zones.

Gd sand - This zone produced at a constant rate of 30 BDG, 1 BDO from July, 1976, to March, 1977. The produced water salinities during that time gradually decreased from 9500 ppm to 2600 ppm, indicating waterflood response. During the period April to June, 1977, the production rate decreased to 15 BDW and the salinity of the water samples further decreased to 1800 ppm.

A series of bottom hole pressures were recently obtained from the individual zones. Using the depth of the F sand as the datum, the corrected pressures for the F, Gc and Gd zones were 137 psi, 203 psi and 211 psi, respectively.

The performance of individual zones has been characterized by constant or declining production rates and gradually decreasing water salinities. A rapid response to water injection had been expected in this well as it is only 75 feet from the pattern water injection Well 2-9-26.

Sampling Observation Well 1-7-26 - This well is completed in the F, Gc and Hw Temblor Zone II sands. A summary of the performance of the individual zones is as follows:

F sand - The production rate from this zone stabilized at 50 BDW, with a salinity of 1800 ppm, after producing back the Darley treatment load. In February, 1977, the production rate declined to 6 BDW with a salinity of 9000 ppm. This change in the production characteristics may be associated with the termination of the commingled production period in February, 1977. During periods of commingled production, it is possible that fluids from the Hw zone crossflowed into both the F and Gc sands.

Gc sand - The performance of this zone has been erratic over the entire waterflood period. Additional performance history is required to analyze the performance of this zone. Potassium iodide tracer from water injection Well 2-7-26 was detected in the produced water sample obtained in September, 1976.

Hw sand - This zone watered out in August, 1976. The average production rate, since that time, has been 100 BDW and the salinity has gradually declined from 1800 ppm to 850 ppm.

Summary of Sampling Observation Well Results

The four sampling observation wells have provided data to monitor and evaluate the demonstration project's performance to date. Water

salinity data from Well 16-7-27 has aided in the interpretation of the monitor induction logs from the logging observation Well 16-6-27. In the future, the four sampling observation wells will be used to monitor polymer injection response and provide produced polymer samples which will be used to analyze the in situ polymer quality.

Logging Observation Well 16-6-27

Well 16-6-27 was completed with a 400 foot, non-conductive fiberglass liner positioned across the Temblor Zone II reservoir. This type of completion permits induction-type resistivity logs to be run to monitor changes in the in situ fluid saturations caused by fluid injection. The details regarding the completion design are presented in the First Annual Report.¹

The logging observation well has two distinct advantages over the previously discussed sampling observation wells. First, it is a passive observation or monitor point; the fluid flow paths established by injection are not disturbed as no formation fluid is physically sampled. Second, induction logs can be run whenever desired to "sample" or monitor the entire Zone II interval.

Formation resistivity is directly related to reservoir fluid saturations via the Waxman-Smiths equation (See Section I-B). The total fluid saturation in the sand pore space will be made up of varying percentages of oil, formation water, injected water and foreign water (mud filtrate invasion, dumpflood water, Darley treatment brine or formation water from another part of the reservoir). Any change in the percentage saturation of any one of the fluids near the 16-6-27 wellbore (within the radius of investigation of the deep induction log) should be detectable.

Translating the observed induction log resistivity changes into actual reservoir fluid saturation changes may not be possible. In order to calculate water (or oil) saturation from the Waxman-Smiths equation, the value of formation water resistivity (R_w) must be known. Based upon the variations in water salinity observed to date in the pilot area, the value of R_w varies with time in most of the sand packages and cannot yet be quantified (see Section I-B). Additional water salinity data is being collected in the pilot area as the waterflood progresses. It may be possible to quantify oil saturation changes observed by the induction monitor logs in the latter stages of the demonstration project using production and other reservoir performance data together with the reservoir simulation.

Well 16-6-27 was logged 42 times during the period July, 1976, to July, 1977, using a conventional Dual Induction log (Table III-7). Figures III-25* and III-26* present a selected number of these logs obtained during this period. The resistivity changes observed within the individual sands can be grouped into four categories:

Type I - The measured resistivity gradually increases to the original open hole value then no further resistivity changes are

*Figures III-25 and III-26 present formation conductivity as measured by the deep induction log. Conductivity is the inverse of resistivity as defined by:

$$\text{Conductivity (mmhos/m)} = \frac{1000}{\text{Resistivity (ohm m}^2/\text{m)}}$$

Conductivity has been presented rather than resistivity because it permits the induction log variations to be more easily seen.

recorded on subsequent logs. (As described in Section I-B, the formation sands were deeply invaded with high salinity mud filtrate during the time between the original open hole log and the installation of the liner. The high salinity brine invasion caused the last open hole and subsequent cased hole resistivity logs to record lower resistivities than the original open hole values.) This response indicates some fluid movement is occurring in the zone which is due to either water injection or production from the zone in a nearby well.

Type II - Same as Type I except the measured resistivity has continued to increase after returning to the original open hole value. This response indicates some higher resistivity fluid (probably injection water though possibly oil or fresher formation water) is moving through the zone in the area of the logging observation well.

Type III - Same as Type I except the measured resistivity gradually decreased after returning to the original open hole value. This response indicates a bank of more saline, foreign water (probably Darley treatment water or formation water from another part of the reservoir) is moving through the zone in the area of the logging observation well.

Type IV - No change in resistivity. This indicates no apparent response to the waterflood occurred in the particular zone.

Figure III-27 presents the open hole induction log run November 22, 1975, (which measured original formation resistivity) and the latest cased hole induction log run June 3, 1977, obtained from the logging observation Well 16-6-27. It has been annotated to indicate sand zones where (1) mud

filtrate invasion is still present (Type IV resistivity change), (2) resistivity changes have been observed indicating apparent waterflood response (Type I, Type II, or Type III resistivity change), and (3) intervals where no changes have been observed or zone is silt/shale and not of interest.

The following is an interpretation of the resistivity changes observed to date in the logging observation Well 16-6-27 (refer to Figure III-27 for sand and zone locations).

E sand - The upper portion of the sand is still invaded (Type IV). Lower portion has exhibited a Type I resistivity change which began in January, 1977. The resistivity had returned to its original open hole value on the last monitor log available (June 3, 1977).

F sand - Most of this interval is still invaded (Type IV). Exceptions are two thin sand zones where a Type I and Type II resistivity change was noted in late 1976.

Gc sand - This zone is composed of four sand stringers with small silt/shale breaks separating them. Each zone has exhibited a Type I response within the past year.

Gd sand - Minor Type I resistivity changes have been observed in three sand stringers in this zone; the remaining sand stringer is still invaded (Table IV). This lack of waterflood response has also been observed in the Gc sand in both of the nearby observation wells 15-8-27 and 16-7-27. (Note: The monitor log resistivity increase in the thin zone at the base of the Gd sand is probably due to thin bed effects on the induction logs).

X sand - Type I resistivity change.

Y sand - Type I resistivity change, though all the mud filtrate invasion has not yet dissipated.

Hw sand - This sand has two major units, both of which have exhibited Type III resistivity changes. The same type of performance has been observed in the Hw sand in the sampling observation Well 16-7-27.

Hx sand - This sand has two major units. The upper unit has exhibited a Type III resistivity change. The lower unit appears to be exhibiting a Type II resistivity change. This sand has been the most active response zone in the logging observation well (see also Figure I-6).

Js - Jv sand - Both zones are still invaded (Type IV). There has been no water injection into the thin, poor quality Jv sand in the pilot area.

Summary of Logging Observation Well 16-6-27 Results

Three general observations can be made from the induction monitor logs obtained during the period covered by the Second Annual Report.

1. No significant amounts of injection water have yet been detected near the 16-6-27 wellbore within the radius of investigation (about fifteen feet) of the induction monitor log.
2. About one-half of the net permeable sand in Well 16-6-27 is still invaded by saline mud filtrate indicating no waterflood response or fluid movement after one year of injection.

3. Most of the fluid movement is occurring along the basal portion of the sand intervals or stringers (see Section I-B), which is characteristic of poor mobility displacement.

The logging observation well has proved to be a valuable part of the pilot project monitoring program. The induction monitor logs have been successful in gathering data required to further evaluate the demonstration project performance. The program is continuing and a Dual Induction log is being run every ten days.

References

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III - PROJECT PERFORMANCE

E - PROJECT PRODUCTION FUNCTION

BY G. E. TINKER

General

Temblor Zone II in the East Coalinga Field is a gravity drainage reservoir comprised of complex channel sand deposits. The reservoir has produced oil since 1901. The moderate viscosity oil results in an unfavorable water displacement mobility ratio of 14. A mobility ratio of 1.0 is considered favorable for a successful waterflood. Polymer flooding is an option for supplemental recovery because the addition of small amounts of the chemical greatly increases the injected water viscosity which is expected to reduce the mobility ratio of the water displacement process from 14 to less than 1.5, which would improve the efficiency of the waterflood.

Primary Production Performance

The wells in the Immediate Pilot Area had recovered 1,900,000 barrels of primary oil by January 1, 1977. The remaining primary reserves for this portion of the reservoir are about 700,000 barrels. Figure III-28 is a production history and forecast for wells in the Immediate Pilot Area. The estimated primary oil performance is a continuation of a ten percent decline shown by the project wells since the beginning of 1972.

Supplemental Production Performance

The performance of various supplemental oil recovery processes were estimated in the preliminary 1973 reservoir simulation study for the wells in the Immediate Pilot Area. Comparative results from the 1973 study are shown on Figure III-29 and Figure III-30. The 1973 study, while preliminary in nature, should give a general indication of how the pilot

operation should perform. This study used the same injection patterns, essentially the same production well configuration, the same fluid properties, similar fluid saturation, the same 5300 BD water injection rate as the pilot, and it allowed for the unconfined injection patterns by simulation of a large area of the reservoir. The current reservoir simulation study will have the benefit of an improved reservoir description and a history match calibration so that the predictive production function should be more reliable than the 1973 prediction.

Based upon the 1973 study, the total fluid production rate from the demonstration project should amount to 3700 BD in July, 1977. The current production rate is 2700 BD which includes about 400 BD of extraneous water production from two wells (Section III-C). Evaluation of the current total fluid production indicates that the loss of fluids out of the pilot area may be greater than originally predicted, which may hinder the determination of a clear cut waterflood base case. To assure that the main producers are operating in an efficient manner, a stimulation treatment program has been undertaken (Section III-C).

Some off-pattern wells planned for abandonment have been kept on production to generate waterflood response data that was not being furnished by the main producers. The production rate and the watercut from some of these wells have increased to the point where they will be shut-in to increase the response from the main producers.

The evaluation of the waterflood portion of the project will be concluded when a clear watercut trend has been established, which is dependent upon an increase in total fluid production. After polymer injection has been initiated, the minimum time required to evaluate the polymer flood

will be determined by the establishment of a new watercut trend. This trend should be established prior to completion of the injection of the optimum polymer slug.

Assuming that the project performs as envisioned, the following items describe the production performance that is expected from the pilot operation.

- (1) Typical primary production rates vary from 20 to 100 BDG with a 60 percent watercut. Individual sands having any oil desaturation will have a reservoir pressure close to atmospheric pressure so that the gravity drainage production rate may be 2 BDG or less from each sand.
- (2) Water injected into a sand with oil desaturation should result in a slow production response as the gas-saturated porosity fills with liquid. Oil displaced into a desaturated region should result in a resaturation loss of moveable oil because the gravity drainage residual oil saturation (0.130) is less than the water displacement residual oil saturation (0.235).
- (3) Water injected into a fluid-filled sand, which is common in the down-dip portion of a gravity drainage reservoir, should result in a very fast production response in producing wells.
- (4) Considering the unfavorable water displacement mobility ratio of this reservoir, water injection should result in rapid water breakthrough after a good oil response and the displacement of formation water.
- (5) Following this water breakthrough, during the Water Injection Phase, the initial good oil response should decline rapidly

as the total volume and the watercut increase. Because of movements of reservoir fluids out of the unconfined project area, total fluid production is expected to be less than the sum of the injection rate plus the gross primary production rate even after fill-up of gas space.

- (6) Polymer injection should reduce the bypassing of oil by the injected water and create a uniform oil bank which would result in an increased oil production rate and a decrease in watercut. The gross production rate should decrease during periods when the high viscosity polymer spearhead brings the normal injection rate down because of surface pressure limitations.

IV - POLYMER INJECTION

A - POLYMER PLANT TESTING*

BY R. W. BOWMAN

T. BATES

A series of polymer and water injection tests were conducted in a polymer test well outside the injection patterns. A schematic of the polymer mixing and injection plant is shown in Figure IV-1.

The polymer was blended according to the following procedure: A 6,000 ppm polymer solution was made up with 50°C. USBR water, enzyme and a biocide. Next the solution was sheared through shear plates with a differential of 250 - 300 psi, producing an average shear of $5 \times 10^5 \text{ sec.}^{-1}$. As a final step in the mixing procedure, the polymer solution was diluted to a concentration of 300 ppm before D.E. filtration. Quality control consisted of viscosity, filterability, and polymer and oxygen concentration analyses. Table IV-1 indicates the average filterability criteria which were used in the polymer facility. Figure IV-2 provides the average viscosity expected for the 300 ppm solution.

During the testing of the polymer mixing facilities, the quality control measures detected a periodic growth of bacteria in the polymer solution stored for 2 - 3 days. The bacteria growth results in a degradation of polymer solution. To prevent this problem from occurring in future operations, a change of biocide or an increase in the amount of biocide will be made.

*Tables found in Appendix IV.

IV - POLYMER INJECTION

B - POLYMER INJECTION TESTS

BY G. E. TINKER

General

Water and polymer field injection tests are being conducted in the region of the Coalinga Polymer Demonstration Project. Previous testing was carried out from December 1970, through February 1972, to choose the most suitable polymer for this project. The injection tests consisted of injecting polymer solutions of various types to gather data for comparison of different polymers and to determine the degree of in situ mobility control. Kelco's Xanflood^R Biopolymer, referred to in all test evaluations as Kelzan MF, has been determined to be satisfactory for use in the demonstration project.

Current Biopolymer Injection Tests

The current series of biopolymer injection tests started in January 1975, with water injection into Polymer Test Well 9-/-27. This was the same well used for previous testing, having been completed in eight feet of one of the Hx sands of the Temblor Zone II formation. After extensive injection into this sand, it has been determined that the zone of injection was not in communication with its equivalent sand in the Coalinga Polymer Demonstration Project. This geological circumstance has made it possible to continue the polymer testing program coincidental to the demonstration project.

Figure IV-3 is a plot of injection rate (BD) and bottom hole injection pressure (psi) as well as injectivity (BD injection per psi).

Previous tests have shown that plots and calculations involving these parameters are an effective means to describe and evaluate the performance of a water or polymer injection. All the injection events are shown on these plots to help describe the series of tests. Table IV-2 explains all the injection events for the current program from January 1975 through April 1977.

Kelzan MF (Xanflood^R) was injection tested in February 1975, September 1975, and September-December, 1976. An effort was made to establish a water injection base case prior to each of the polymer tests. A comparison of the stable injectivity of the water injection base case (I_0) and the stable injectivity of the polymer injection period (I_1) is an indication of the in situ mobility value of the polymer. As a procedure to measure any injection wellbore impairment that developed during polymer injection, the stable water injectivity following the polymer injection (I_2) and the injectivity following any stimulation treatment (I_3) are determined. Table IV-3, the comparison of polymer injection tests, shows pertinent injectivity values, polymer concentration, polymer and water viscosity, and ratios that compare these quantities.

During the 1972 injectivity test, the injection well became seriously impaired during the injection of polymer. The impairment is believed to have resulted from bacterial debris associated with the polymer. In the three subsequent polymer injection tests, the polymer was enzyme-treated to destroy the bacterial debris and then D.E. filtered to give the polymer solution the required filtration qualities.

The February 1975 Kelzan MF Test No. 1 was too short to furnish conclusive data on mobility control, but the stimulation recovery factor

of 1.81 indicated that significant impairment developed during or after the polymer injection. In an attempt to remove the suspected impairment, a Bacteria Destruct treatment was conducted. This treatment is designed to break down and remove injected bacterial cells that might impair the wellbore. The effectiveness of these suction wash treatments indicate that any bacterial debris impairment is probably a near-wellbore surface plugging phenomenon.

The September 1975 Kelzan MF Test No. 2 was also short and inconclusive as far as the effect of mobility control from the injected polymer. The stimulation recovery factor from this test also indicated wellbore impairment in the injection well. One complicating factor associated with this test was the reduction of injectivity from about 1.3 BD per psi to 0.9 BD per psi one week before the start of polymer injection. The reduced injectivity suggests the development of wellbore impairment during water injection.

Over the next ten months, injection Well 9-7-27 was tested and stimulated a number of times during normal water injection in an effort to determine the cause of wellbore impairment. Bottom hole suction wash samples taken from the perforations indicated that corrosion products in the form of magnetite were forming in the casing-tubing annulus of the well which resulted in plugging the wellbore. Bacteria found in these same suction wash samples were of an insufficient quantity to cause wellbore impairment. The corrosion products were probably caused by oxygen being introduced into the annulus through the wellhead while water was injected on a vacuum. A nitrogen blanket was installed on the well after a stimulation treatment in mid-August 1976. After this, a steady water injection base case was established for a period of one month.

The Kelzan MF Test No. 3 started in September 1976. This test was characterized by rapid injectivity fall-off similar to the 1972 Kelzan MF test where no effort was made to purify the polymer solution. This performance was not expected because good quality polymer solutions were maintained throughout the test. As the injection pressure increased, the injection rate was decreased in 100 BD increments not to exceed surface pressure limitations. Following most of the rate decreases, the reduction of pressure was not in agreement with theoretical calculations suggesting a high degree of wellbore impairment. Suction wash samples taken from the well during the follow-up water injection period indicated very little corrosion products, but quantities of bacteria sufficient to cause wellbore impairment were found.

An investigation is underway to determine the reasons for the poor performance of Test No. 3. Once the study is completed, future polymer injection tests are probable.

APPENDIX I
RESERVOIR DESCRIPTION

TABLE I-1
CORE ANALYSIS DATA SHEET
LOGGING OBSERVATION WELL NO. 16-6-27

DEPTH	IR (INITIAL RESIDUAL- AIR- TOLUENE)	PIR (PETROPHYSICAL RESEARCH)	FOR (PRODUCTION/OPERATION/RESEARCH)	C (CATION EXCHANGE CAPACITY)	G (GRAIN DENSITY)	P _s (POROSITY AND SATURATION)	S _t (SIEVE ANALYSIS)	X (X-RAY DEDUCTION)	T (THIN SECTION)	ST (STRESSED SAMPLES)	P (POROSITY)	K _s (RELATIVE PERMEABILITY TO OIL AT S _w)	K _w (RELATIVE PERMEABILITY TO WATER AT S _w 100%)	M (MIN FACTORS) $\frac{K_w}{K_s}$, $\frac{P}{S_t}$	PP (PILOT SAMPLE FOR CONFINING PRESS)	P _s (PILOT SAMPLE FOR SOLVENT)	FW (FRESH WATER SUSCEPTIBILITY)	GRAY (OIL GRAVITY-CHROMATOGRAPHY)	CAPILLARY PRESSURE	FULL RELATIVE PERMEABILITY
1903.7																				
1905.6																				
1909.7	●																			
1911.4																				
1916.8																				
1918.75	●																			
1931.9																				
1933.7																				
1939.5																				
1952.3																				
1959.3																				
1964.7																				
1966.0	●																			
1970.3																				
1972.8																				
1980.7																				
1982.1																				
1986.7	●																			
1992.7																				
1993.8																				
1997.7																				
1999.9																				
2002.0																				
2004.0	●																			
2021.2																				
2027.9																				
2036.8																				
2044.2																				
2045.4	▲																			
2049.5																				
2052.5																				
2054.6																				
2060.2																				
2073.9																				
2076.4	●																			
2079.0																				
2102.2																				
2105.8																				
2107.8	●																			
2110.4																				
2113.0																				
2122.2																				
2131.5	●																			
2133.5																				
2136.3																				
2155.2																				
2161.9																				
2164.1																				
2166.8	▲																			
2172.2																				

SEE NOTE

SEE NOTE

● MEASUREMENT/ANALYSIS COMPLETED AS OF JUNE 1, 1977
▲ NOT COMPLETED
NOTE: POOR QUALITY SAMPLE THEREFORE ANALYSIS NOT COMPLETED

TABLE I-2
NOMENCLATURE

ϕ	= porosity, fractional bulk volume
B	= equivalent conductance of the clay counter ions (liter equiv ⁻¹ ohm ⁻¹ m ⁻¹)
CEC	= cation exchange capacity (meq/100 gms)
F	= formation factor
I	= resistivity index
m*	= cementation exponent for shaly sands
NaCl	= sodium chloride
n*	= Waxman - Smits saturation exponent for shaly sands
m	= cementation exponent for clean sands
n	= Archie saturation exponent for clean sands
ppm	= parts per million
Q _v	= cation exchange capacity per unit pore volume (meq/ml)
R _t	= formation resistivity (ohm-meter)
R _w	= formation water resistivity (ohm-meter)
S _{oi}	= initial oil saturation, fractional pore volume
S _{or}	= waterflood residual oil saturation, fractional pore volume
S _w	= water saturation, fractional pore volume
CBL	= cement bond log
CCL	= casing collar locator
CNL	= Compensated Neutron log
C/O	= Carbon/Oxygen log
DIL	= Dual Induction-Laterolog 8
DLL	= Dual Laterolog
FDC	= Formation Density Compensated Log
GRN	= gamma ray-neutron (also GNT)
IES	= Induction-electrical survey

TABLE I-3
CORE ANALYSIS DATA¹: m and n
WELL NO. 16-6-27

<u>Depth</u> <u>(Ft.)</u>	<u>Sand</u>	<u>Porosity</u> <u>(%)</u>	<u>R_w²</u>	<u>F</u>	<u>m</u>	<u>I</u>	<u>Sw</u> <u>(%)</u>	<u>n</u>
1909.7	F	30.9	.255	6.50	1.59	6.61	33.0	1.70
1918.75	F	27.3	.255	9.47	1.73	2.73	57.2	1.80
1966.0	Gc	22.8	.255	10.41	1.58	5.30	42.8	1.97
1986.7	Gd	28.4	.581	7.22	1.57			
			.255	7.93	1.64			
			.138	8.33	1.68	4.65	42.0	1.77
2004.0	Gd	29.3	.581	6.82	1.56			
			.255	7.53	1.64			
			.138	7.94	1.69	4.56	40.5	1.68
2076.4	Hw	29.1	.581	6.91	1.57			
			.255	7.24	1.60			
			.138	7.40	1.62	7.10	33.0	1.77
2107.8	Hx	27.4	.581	7.22	1.53			
			.255	7.66	1.57			
			.138	7.86	1.59	5.11	40.4	1.80
2131.5	Hx	31.5	.581	6.37	1.60			
			.255	6.67	1.64			
			.138	6.83	1.66	6.27	32.6	1.64

¹All values measured at an applied stress of 900 psi. Nomenclature defined in Table I-2.

²R_w values are ohm-meters at 23°C.

TABLE I-4

PETROPHYSICAL ANALYSIS¹: m^* and n^*

WELL NO. 16-6-27

Depth (Ft.)	Sand	Qv_m ²	Qv_c ³	m^* ⁴	n^*
1909.7	F	.08		1.65	1.81
1918.75	F	.30		1.90	2.04
1966.0	Gc	.26		1.71	2.21
1986.7	Gd	.12	.14	1.73	1.87
2004.0	Gd	.15	.14	1.74	1.78
2076.4	Hw	.07	?	1.66?	1.82
2107.8	Hx	.08	.09	1.62	1.80
2131.5	Hx	.06	.06	1.69	1.64

¹Raw data from Table I-3. Nomenclature defined in Table I-1.² Qv_m is cation exchange capacity measured using a standard laboratory method.³ Qv_c is cation exchange capacity calculated from Waxman-Smit equation after graphically determining m^* . Note close agreement between the calculated Qv and the Qv measured on a separate companion sample.⁴ m^* determined from Waxman-Smits equation for samples 1909.7, 1918.75 and 1966.0. m^* determined graphically as discussed in text on remainder of samples.

TABLE I-5

CORE ANALYSIS DATA: BRINE PERMEABILITY

WELL NO. 16-6-27

Depth (Ft.)	Sand	Brine Permeability ¹ , md		
		24650 ppm NaCl	14890 ppm NaCl	5990 ppm NaCl
1909.7	F	925	932	756
1918.75	F	0.49*	0.24	0.065
1966.0	Gc	266	240	139
1986.7	Gd	294	247	130
2004.0	Gd	489	437	310
2076.4	Hx	649	601	328
2107.8	Hw	180	138	30.6**
2131.5	Hx	234	195	57.3***

¹All measurements made with an applied stress of 900 psi. Core flooded with highest salinity brine and then successively with the lower salinities.

*Sample from a silt layer in the F sand which would not be considered pay.

**Large volume of clay material was produced with this salinity.

***Small volume of clay material was produced with this salinity.

TABLE I-6

CORE ANALYSIS DATE: S_{or}

WELL NO. 16-6-27

<u>Depth</u> <u>(Ft.)</u>	<u>Sand</u>	S_{or}^1 <u>(%)</u>
1909.7	F	25.5
1918.75	F	17.8
1966.0	Gc	33.5
1986.7	Gd	26.0
2004.0	Gd	27.0
2076.1	Hw	25.1
2107.8	Hw	22.0
2131.5	Hx	24.0

¹Values based on $S_{o1} = 65\%$. Nomenclature defined in Table I-2.

TABLE I-7

X-RAY DIFFRACTION DATAWELL NO. 16-6-27

Crystalline Component	Weight Percent							
	1905.6'	1909.7'	1918.75'	1966'	1970.3'	1980.7'	1986.7'	2004'
Quartz	77	77	72	77	79	62	72	72
Feldspar	10	10	15	10	10	15	15	15
Dolomite	3	3	3	3	3	3	3	3
Pyrite	5	5	5	5	3	10	5	5
Clay	~5	~5	~5	~5	~5	10	~5	5

Clay Fraction (<2 microns)

Montmorillonite	100	100	80	100	100	60	80	80
Illite	-	-	20	-	-	30	20	20
Kaolinite	-	-	-	-	-	10	-	-

Crystalline Component	Weight Percent								
	2044.2'	2076.4'	2102.2'	2107.8'	2122.2'	2131.5'	2164.1'	2167.1'	2171.2'
Quartz	77	77	77	82	62	82	72	84	72
Feldspar	10	10	10	5	20	5	10	10	15
Dolomite	3	3	3	3	3	3	3	3	3
Pyrite	5	5	5	5	5	5	5	3	5
Clay	~5	~5	~5	5	10	~5	10	~5	5

Clay Fraction (<2 microns)

Montmorillonite	80	60	40	40	50	30	80	80	80
Illite	10	20	30	-	25	30	20	20	20
Kaolinite	10	20	30	60	25	40	-	-	-

TABLE I-8

CASED HOME GAMMA RAY-NEUTRON LOG RESULTS¹

<u>Well No.</u>	<u>Previous Logs Available</u>	<u>Date of New GRN²</u>	<u>Results of New Cased Hole GRN</u>
30-26	None	11-11-76	Provided net permeable sand thickness at this location.
2-26	Cased hole GRN	12-02-76	Well cleaned out to 2314'. Log provided net permeable sand thicknesses from 2143' to 2314'.
91-37	Cased hole GRN	12-22-76	New GRN has same response as 1969 CRN.
111-27	Cased hole GRN	1-13-77	New GRN has same response as 1969 GRN.
295-27	Open hole IES	1-23-77	New GRN confirm previous data from Well Nos. 296-27 and 685A-27 and indicates apparent pay in only the E, F, Gd and portions of the Hw sands. Other sands are tight and/or desaturated. Additional analysis of this log is in progress.
292-27	Open hole IES	2-9-77	New GRN together with previous IES now shows that portions of the Gd, X, Hw, Js and Hv sands are tight. Log correlates well with open hole CNL-FDC in Well No. 1-5-26.
119-27	None	2-26-77	Provided net permeable sand thicknesses at this location.
57-27	None	3-12-77	Response of GRN was poor due to large (8-5/8") casing size.

¹All cased hole neutron logs were Go International calibrated gamma ray-neutron logs.

²Abbreviations defined in Table I-2.

TABLE I-9

COMPLETION ZONE COMPARISON BETWEEN
SAMPLING OBSERVATION AND WATER INJECTION WELL PAIRS

	<u>Gd Sand</u>	<u>Hw Sand</u>	<u>Hx Sand</u>
Observation Well No. 16-7-27 sampling completion interval	2048-2053*	2161-2166	2205-2210
Water injection Well No. 15-6-27 injection completion interval	1926-1929*	2012-2025	2064-2085
	<u>Gc Sand</u>	<u>Gd Sand</u>	<u>Hx Sand</u>
Observation Well No. 15-8-27 sampling completion interval	1918-1923	1949-1954	2046-2051
Water Injection Well No. 15-9-27 injection completion interval	1893-1896	1920-1934	2016-2023
	<u>F Sand</u>	<u>Gc Sand</u>	<u>Gd Sand</u>
Observation Well No. 1-9-26 sampling completion interval	2089-2094	2123-2128	2141-2146
Water Injection Well No. 2-9-26 injection completion interval	2098-2110	2120-2149	2154-2168
	<u>F Sand</u>	<u>Gc Sand</u>	<u>Hw Sand</u>
Observation Well No. 1-7-26 sampling completion interval	2024-2029	2058-2063	2181-2186
Water Injection Well No. 2-7-26 injection completion interval	2060-2103	2116-2131	2248-2260

*All perforations in the completion intervals are referenced to the open hole gamma ray log.

TABLE I-10

FORMATION WATER SALINITY SUMMARY
FROM SAMPLING OBSERVATION WELLS

COALINGA POLYMER PILOT

<u>Observation Well No.</u>	<u>Completion Zone</u>	<u>Best Estimate Formation Water Salinity¹</u>	<u>Remarks</u>
16-7-27	Gd	7100-8200?	Zone impaired. Low production rates makes salinities suspect - samples probably are contaminated with Darley brine.
	Hw	5200-6000 ₂ 6700-7000 ²	September to December, 1976 February, 1977 to current.
	Hx	5100+ 6400-700 ²	September to December, 1976 January, 1977 to current.
15-8-27	Gc	-	Zone flooded out immediately after producing back its Darley load.
	Gd	-	Zone has produced only oil and Darley water - no formation water.
	Hw	-	Same as Gd - these two zones probably in communication.
1-9-26 ³	F	5000-5500	Zone is currently impaired and has watered out.
	Gc	5900-7200?	Salinities always erratic.
	Gd	5500-6000?	Good samples not obtained until three months after water injection - samples may have some flood water contamination.
1-7-26 ⁴	F	7200-7500?	Zone appeared to flood out immediately after producing back its Darley load. However, in February salinity increased to 7200-7500 ppm where it remained until May. Salinity now down to 1800 ppm.

<u>Observation Well No.</u>	<u>Completion Zone</u>	<u>Best Estimate Formation Water Salinity¹</u>	<u>Remarks</u>
	Gc	-	Salinities too erratic for accurate estimate to be made.
	Hw	-	Zone flooded out immediately after producing back its Darley load.

¹Water salinity determined from conversion of the samples measured resistivity into equivalent parts per million (ppm) sodium chloride using published chemical tables.

²Hw - Hx intervals in Well No. 16-7-27 are currently in communication. See text for further explanation of this apparent salinity change.

³Well No. 1-9-26 has been suspected of having all three sands in communication since the start of water injection. Recent pressure test data indicates Gc and Gd are communicated and the F sand is still isolated. However, since January, 1977, all zones have had approximately the same salinities.

⁴March, 1977, well tests and water salinity measurements indicate the Gc and Hw sands are in communication.

TABLE I-11

TYPICAL LABORATORY WATER ANALYSIS

COALINGA POLYMER PILOT

Well No. 16-7-27, Hw Zone, Sample taken 12-25-76.

<u>Constituents</u>	<u>Parts Per Million</u>	<u>Grains Per Gallon</u>
Carbonate, CO ₃	0.0	0.00
Bicarbonate, HCO ₃	3794.2	221.88
Chloride, Cl	1843.9	107.83
Sulfate, SO ₄	25.0	1.46
Sulfide, S	0.0	0.00
Nitrate, NO ₃	0.0	0.00
Silica, SiO ₂	110.8	6.47
Calcium, Ca	32.0	1.87
Magnesium, Mg	14.6	0.86
Sodium, Na	2574.2	150.54
Boron, B	14.1	.82
Iron, Fe	1.2	.07
TDS	6386.2	373.49
pH @ 25 C		7.1
Conductivity: Microhos/cm @ 25°C		10,320
Resistivity: Ohm-meters @ 25°C		0.97

Petrophysical calculation of equivalent NaCl = 5533 ppm.

TABLE I-12
COALINGA POLYMER PROJECT
TEMBLOR ZONE II RESERVOIR PROPERTIES AND
PROJECT PARAMETERS

DEMONSTRATION PROJECT

Project Area (Acres)	132
Reservoir Thickness (Feet)	125
Number of Layers	8
Injection Rate (Bbl./Day)	5,400
Number of Injection Wells	4
Porosity	.265
Permeability (md)	50-480
Initial Oil Saturation (in region of no oil desaturation)	.650
Water Displacement Residual Oil Saturation	.235
Gravity Drainage Residual Oil Saturation	.130
Oil Gravity ($^{\circ}$ API)	21.0
Reservoir Temperature ($^{\circ}$ F)	100
Oil Viscosity at Reservoir Temperature (cp)	25.0
Water Displacement Mobility Ratio	14.0
Current Oil In Place (S.T. Bbl.)	17,780,000
Movable Oil In Place (S.T. Bbl.)	10,295,000
Future Primary Oil Recovery (S.T. Bbl.)	710,000
Polymer Flood Recovery (Fraction of Movable Oil In Place)	.326
Polymer Flood Recovery (S.T. Bbl.)	2,645,000
Water flood Recovery (Fraction of Movable Oil In Place)	.267
Waterflood Recovery (S.T. Bbl.)	2,040,000
Polymer Flood Over Waterflood (S.T. Bbl.)	605,000

FULL-SCALE PROJECT

Project Area (Acres)	2,600
Injection Rate (Bbl./Day)	120,000
Number of Injection Wells	120
Number of Producing Wells	200
Polymer Flood Recovery (S.T. Bbl.)	35,000,000
Waterflood Recovery (S.T. Bbl.)	27,000,000
Polymer Flood Over Waterflood (S.T. Bbl.)	8,000,000

COALINGA FIELD INDEX MAP – POLYMER DEMONSTRATION PROJECT

TYPE LOG EAST COALINGA FIELD

< TYPE LOG DEPTHS: (100-5770) STD. O. CO. - 215 Sec. 35, T.19S, R.15E.
Wells Depth (100-5770) SHELL - 363X Sec. 15, T.19S, R.15E.

EAST COALINGA FIELD
SCALE: 1"=500'
DATE: AUG. 1954

KT-11-44

COALINGA FIELD

TYPE LOG
SECTION 27
TEMBLOR ZONE II RESERVOIR
WELL 256A-27

ZW 2455 BB

FIGURE I-15

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FIGURE I-24

WELL SCHEMATIC

LOGGING OBSERVATION WELL NO. 16-6-27

COALINGA POLYMER DEMONSTRATION PROJECT

ZW 1587 7/76

OPEN HOLE LOG COMPARISON
LOGGING OBSERVATION WELL NO. 16-6-27
COALINGA POLYMER DEMONSTRATION PROJECT

**DEEP INDUCTION LOG COMPARISON
AFTER JULY, 1976 - JUNE, 1977 WATERFLOOD
LOGGING OBSERVATION WELL NO. 16-G-27
COALINGA POLYMER DEMONSTRATION PROJECT**

INDUCTION MONITOR LOG COMPARISON: Hx SAND WATERFLOOD PERIOD 9-76 TO 6-77

LOGGING OBSERVATION WELL NO. 16-6-27

NOTE: CONDUCTIVITY DATA OBTAINED FROM SCHLUMBERGER WELL SERVICES 6FF40 INDUCTION LOG RUN IN FIBERGLASS CASED WELLBORE. DATA HAS BEEN NORMALIZED TO REDUCE MINOR PERTURBATIONS ARISING FROM USING DIFFERENT INDUCTION TOOL SETS.

INDUCTION MONITOR LOG COMPARISON: HW SAND WATERFLOOD PERIOD 9-76 TO 6-77 LOGGING OBSERVATION WELL NO. 16-6-27

NOTE: CONDUCTIVITY DATA OBTAINED FROM SCHLUMBERGER WELL SERVICES 6FF40 INDUCTION LOG RUN IN FIBERGLASS CASED WELLBORE. DATA HAS BEEN NORMALIZED TO REDUCE MINOR PERTURBATIONS ARISING FROM USING DIFFERENT INDUCTION TOOL SETS.

FIGURE I-30
ZW 2527 A 6/77

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APPENDIX II

PROJECT DESCRIPTION AND OPERATION

TABLE II - 1

LARGE LIFT EQUIPMENT CURRENTLY INSTALLED

COALINGA POLYMER PROJECT

<u>WELL</u>	<u>MAXIMUM STROKE LENGTH (INCHES)</u>	<u>GEAR BOX SIZE (INCH - POUNDS)</u>
1-5-26	86	320,000
1-8-26	84	228,000
4-6-26	84	160,000
273-27	84	320,000
275-27	64	228,000
284-27	100	160,000

TABLE II - 2
COALINGA POLYMER PROJECT
LIST OF ABANDONED WELLS

<u>Section 26</u>	<u>Section 27</u>
2-26	57-27
6-26	91-27
11-26	111-27
30-26	112-27
31-26	119-27
32-26	182-27
37-26	256-27
105-26	275A-27
134-26	292-27
	295-27
	296-27

**SCHEMATIC
GRAVEL PACK
OLD PRODUCTION WELL
WELL 3-11-26**

ZV-204 B

FIGURE II-1

PRODUCTION WELL I-8-26

DERRICK FLOOR
1034' ABOVE
SEA LEVEL

TOP OF E SAND
@ 1964'

8-5/8" 32[#]/FT., K-55, LT & C
CEMENTED W/SURFACE RETURNS @ 1965'

7" 23[#]/FT., K-55 VFJ
LEAD SEAL ADAPTER @ 1942'
PERF'D 1951/2233' W/32 ROWS OF
0.030" UNDERCUT SLOTS
2" LONG ON 6" CENTERS
PACKED w/ 10x16 US SIEVE GRAVEL

TOP J_s SAND
@ 2236'

T.D. 2233'

**SCHEMATIC
TIGHT-HOLE LINER
OLD PRODUCTION WELL
WELL 285-27**

**DERRICK FLOOR
1018' ABOVE
SEA LEVEL**

**TOP OF E SAND
Ø 1814'**

**5-1/2" 14 #
1814'
CEMENTED
w/100 SACKS**

**4-1/2" 16.6 #
1793' / 2135'**

**BASE OF Jv SAND
@ 2134'**

**PERF'D 60 MESH 14 ROWS
2 1/2" SLOTS 6" CENTERS
1815' / 2135'**

T.D. 2165'

ZV-204 A

FIGURE II-3

PRODUCTION WELL 118-27

SAMPLING OBSERVATION WELL 1-7-26

ZV-2046
FIGURE II-5

**SCHEMATIC
LOGGING OBSERVATION
WELL 16-6-27**

FIGURE II-6

INJECTION WELL 2-9-26

ISOLATION PACKER CONFIGURATIONS WELL 1-7-26

- NOTES: A) USE 5-3/4" + CROWS FOOT FOR LINER-TOP STOP SUB
 B) TUBING IS 2-3/8", EVE, J-55
 C) LINER IS 4-1/2" 11.6 #/FT
 D) DOUBLE FACING CUPS SHOULD BE USED AS ILLUSTRATED
 E) WHEN PRODUCING AN INDIVIDUAL ZONE OTHERS ARE BLANKED OFF TO PREVENT CROSS FLOWING
 F) PUMP SHOE AT INDICATED INLET PORTS

FIGURE II-9

POLYMER PROCESSING AND INJECTING FACILITIES.
COALINA POLYMER PROJECT

COALINGA POLYMER PROJECT PRODUCTION SYSTEM

APPENDIX III
PROJECT PERFORMANCE

TABLE III - 1

CUMULATIVE INJECTION INTO

TEMBLOR ZONE II FROM 1-1-75 TO 4-30-77

<u>Injection Sand Interval</u>	<u>Well 2-7-26 MB</u>	<u>Well 2-9-26 MB</u>	<u>Well 15-6-27 MB</u>	<u>Well 15-9-27 MB</u>	<u>Total MB</u>
E	0	60	12	61	133
F	98	33	72	82	285
Gc	29	54	52	82	217
Gd	9	31	57	50	147
X-Y-Hw	279	104	54	171	608
Hx	70	126	147	20	363
Js	0	37	25	0	62
Jv	0	0	0	0	0
Total	485	445	419	466	1,815

TABLE III - 2

WATER BANK RADDII BASED UPON INJECTION INTO
TEMBLOR ZONE II FROM 1-1-75 TO 4-30-75

Injection Sand Interval	Well 2-7-26 Feet		Well 2-9-26 Feet		Well 15-6-27 Feet		Well 15-9-27 Feet	
	<u>Z* = 0.1</u>	<u>Z* = 1.0</u>	<u>Z* = 0.1</u>	<u>Z* = 1.0</u>	<u>Z* = 0.1</u>	<u>Z* = 1.0</u>	<u>Z* = 0.1</u>	<u>Z* = 1.0</u>
E	Not Completed		794	251	397	126	732	231
F	462	146	347	110	599	189	658	208
Gc	416	132	495	157	647	205	689	218
Gd	272	86	491	155	558	176	572	181
K-Y-Hw	821	260	737	233	389	123	689	218
Hx	639	202	763	241	821	260	288	91
Js	Not Completed		360	114	565	179	0	0
Jv	Not Completed		Not Completed		0	0	0	0

* Z = Displacement Efficiency

TABLE III-3
SUMMARY OF INJECTION TRACER RESULTS
COALINGA POLYMER PROJECT

<u>Injection Well</u>	<u>Tracer</u>	<u>Tagged Chemical Form</u>	<u>Date Tracer Injected</u>	<u>Responding Producing Well</u>	<u>Date Tracer Detected</u>
2-7-26	Potassium iodide	KI	8-2-76	1-8-26	9-19-76
				1-7-26	9-12-76
				16-7-27	9-18-76
				1-5-26	8-15-76
				38-26	9-10-76
				29-26	9-16-76
				4-26-26	8-31-76
2-9-26	Tritium (H-3)	H ₂ O	8-2-76	1-8-26	2-7-77
				1-9-26	8-13-76
				3-8-26	3-1-77
				3-11-26	9-5-76
				285A-27	12-27-76
				105-26	9-4-76
				285-27	8-17-76
				165-27	10-6-76
				113-27	8-17-76
				15-8-27	8-23-76
				121-27	10-16-76
				116-27	2-1-77
				118-27	1-12-77
15-6-27	Cobalt 60 (Co-60) Iodine 125 (I-125)	(Co(CN) ₆) ⁻³	8-2-76	None	--
		KI	12-2-76	1-8-26	2-7-77
				3-11-26	2-6-77
				116-27	2-1-77
				34-27	1-16-77
15-9-27	Sulfur-35 (S-35)	SO ₄ ⁻²	8-2-76	292-27	2-7-77
				285A-27	8-6-76
				285-27	8-17-76
				284-27	9-9-76
				283-27	8-5-76
				275-27	8-24-76
				274-27	9-19-76
				273-27	9-13-76
				14-7-27	9-8-76
				15-8-27	8-6-76

TABLE III - 4
SUMMARY OF ALL PRODUCTION WELL RECONDITIONING
COALINGA POLYMER PILOT

<u>Well</u>	<u>Date</u>	<u>Type and Results of Reconditioning</u>
1-5-26	10/75	Clay stabilization treatment using Darley treatment.
	7/76	Cement squeeze to shut-off extraneous water. The job failed.
	11/76	A second cement squeeze to shut-off extraneous water entry. The job was successful.
1-8-26	12/75	Clay stabilization treatment using Darley treatment.
	6/76	Treated well with Bacteria Destruct solution followed by HCl. The stimulation regained the lost production.
	5/77	Stimulation with mud acid using Iso-flow technique. The results of the treatment are being evaluated.
3-8-26	10/76	Clay stabilization treatment using Darley treatment.
	3/77	Treatment with Bacteria Destruct. Inflow performance of the well did not improve following the treatment.
3-11-26	1/76	Clay stabilization using Darley treatment.
4-6-26	7/76	Cement squeeze to shut-off extraneous water entry. The anomalous water production was not eliminated.
	11/76	A second cement squeeze to shut-off extraneous water entry. The job was unsuccessful.

TABLE III - 4

<u>Well</u>	<u>Date</u>	<u>Type and Results of Reconditioning</u>
14-7-27	11/76	Clay stabilization using Darley treatment.
	3/77	The well was treated with Bacteria Destruct. The inflow performance of the well did not improve following the treatment.
	5/77	Treatment with bacteria destruct sodium hypochlorite and HCl. A circulating washer was used to placed individual treatments. The results of the treatment are being evaluated.
118-27	2/76	Clay stablization using Darley treatment.
	6/76	Acid wash using HCl. The treatment resulted in a 25 BDG/25 BDO improvement. (This production rate was the same as the pre-Darley treatment rate.)
284-27	2/76	Clay stabilization using Darley treatment.
	4/77	Stimulation with mud-acid. The treatment resulted in a 75 BDG/25 BDO increase in inflow.
285A-27	2/76	Clay stabilization using Darley treatment.

TABLE III-5
PRODUCTION LOGGING RESULTS
COALINGA POLYMER PILOT

<u>Well</u>	<u>Date</u>	<u>Type of Log</u>	<u>Results</u>
1-5-26	3/30/76	Water Entry	Fluid entry from Hw (77%) and Js (23%) sands.
	6/18/76	Audio Log	Indications of dumpflooding.
	9/10/76	Audio Log	First squeeze job unsuccessful, indications of dumpflooding.
	11/18/76	Audio Log	Second squeeze job was successful. Major inflow coming from Hw and E/F sands.
	3/15/77	Water Entry	All inflow entering from Hw sand.
1-8-26	4/2/76	Water Entry	All fluids entering from E/F sand.
	11/18/76	Audio Log	Indications of dumpflooding, but not substantiated by water analysis.
	2/2/77	Water Entry	All water entering from E/F sand.
3-8-26	3/31/76	Water Entry	All fluids entering from E/F sand.
	8/6/76	Audio Log	Major inflow coming from E/F and Gc sands.
	9/9/76	Audio Log	Major inflow coming from E/F sand.
4-6-26	4/1/76	Water Entry	Major entry from E/F (65%) and Hw (35%) sands.
	6/17/76	Audio Log	Indication of dumpflooding.
	9/9/76	Audio Log	First squeeze job failed. Indication of dumpflooding.
	12/17/76	Audio Log	Second squeeze job failed. Indication of dumpflooding.

TABLE III - 5

<u>Well</u>	<u>Date</u>	<u>Type of Log</u>	<u>Results</u>
4-6-26	3/1/77	Water Entry	Possible dumpflooding into X sand.
	4/21/77	Water Entry and Oil Entry	Major water entry from E/F (29%) and Hx (71%) sands. Oil entry from E/F and Gd sands.
	5/2/77	Audio Log	Fluid entry from E/F and X sands. Pump shoe noise distorted data from Hx sand.
14-7-27	11/17/76	Audio Log	Log inconclusive.
118-27	11/19/76	Audio Log	Major inflow from Y/Hw sand.

TABLE III- 6

PRESSURE BUILDUP DATA

COALINGA POLYMER PILOT

<u>WELL</u>	<u>DATE</u>	<u>BOTTOM HOLE PRESSURE-PSIG (72-HOUR)</u>	<u>DEPTH OF PRESSURE BOMB (FEET)</u>
1-5-26	1/25/77	212	2245
1-8-26	11/23/76	202	2206
1-8-26	1/28/77	209	2206
3-8-26	11/9/76	265	2357
3-8-26	2/22/77	299	2357
3-11-26	2/25/77	148	2374
3-11-26	4/29/77	161	2402
4-6-26	1/31/77	325	2417
14-7-27	12/2/76	97	2059
118-27	12/20/76	53	1948
118-27	2/15/77	63	1948
284-27	11/12/76	66	2014
285A-27	11/16/76	104	2244

TABLE III - 7

SUMMARY OF DUAL INDUCTION LOGS
OBTAINED IN WELL NO. 16-6-27
JULY, 1976 TO JULY, 1977

<u>SHELL LOG NO.</u>	<u>DATE</u>	<u>SHELL LOG NO.</u>	<u>DATE</u>
4	7-13-76	24	12-29-76
5	7-22-76	25	1-5-77
6	7-29-76	26	1-11-77
7	8-5-76	27	1-19-77
8	8-16-76	28	1-27-77
9A	8-13-76	29	2-8-77
9B	8-13-76	30	2-15-77
10	9-7-76	31	2-24-77
11	9-14-76	32	3-1-77
12	9-20-76	33	3-10-77
13	9-28-76	34	3-22-77
14	10-5-76	35	3-31-77
15	10-13-76	36	4-11-77
16	10-19-76	37	4-21-77
17	10-27-76	38	5-2-77
18	11-3-76	39	5-16-77
19	11-10-76	40	5-25-77
20	11-24-76	41	6-3-77
21	12-1-76	42	6-13-77
22	12-8-76	43	6-25-77
23	12-15-76

FIGURE III-1

FIGURE III-2

FIGURE III-3

FIGURE III-4

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ZW 2455G

FIGURE III-9

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**JS SAND
WATER BANK
AS OF 4-30-77**

- LEGEND -

- ⊙ EXISTING INJECTION WELL
- EXISTING OLD PRODUCTION WELL
- EXISTING NEW PRODUCTION WELL
- ◆ EXISTING OBSERVATION WELLS
- S SAMPLING
- L LOGGING
- ✦ PLUGGED & ABANDONED

DISPLACEMENT EFFICIENCY

INNER CIRCLE 1.0
OUTER CIRCLE 0.1

**SHELL OIL CO.
EAST COALINGA FIELD
FRESNO CO. CALIFORNIA**

**SECTION 26-27 TEBLOR ZONE II
POLYMER PILOT AREA
CONTOURS ON TOP BLACK SHALE**

REV. 5/15/77

ZW 2455B
FIGURE III-II

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ZW 2-155

FIG1 III-12

151

ZW 2455H

FIGURE III-15

FIGURE III-16
PRODUCTION RATE VS TIME
WELL 1-5-26

FIGURE III-17
PRODUCTION RATE VS TIME
WELL I-8-26

FIGURE III-18
PRODUCTION RATE VS TIME
WELL 3-8-26

FIGURE III-19
PRODUCTION RATE VS TIME
WELL 3-II-26

FIGURE III-20
PRODUCTION RATE VS TIME
WELL 4-6-26

FIGURE III-21
 PRODUCTION RATE VS TIME
 WELL 14-7-27

FIGURE III-22
PRODUCTION RATE VS TIME
WELL I18-27

FIGURE III-23
PRODUCTION RATE VS TIME
WELL 284-27

FIGURE III-24
PRODUCTION RATE VS TIME
WELL 285-A-27

INDUCTION MONITOR LOG COMPARISON WATERFLOOD PERIOD 6-76 TO 12-76

LOGGING OBSERVATION WELL NO.16-6-27
COALINGA POLYMER DEMONSTRATION PROJECT

**INDUCTION MONITOR LOG COMPARISON
WATERFLOOD PERIOD 1-77 TO 6-77
LOGGING OBSERVATION WELL NO. 16-6-27
COALINGA POLYMER DEMONSTRATION PROJECT**

**DEEP INDUCTION LOG COMPARISON
AFTER JULY, 1976 - JUNE, 1977 WATERFLOOD
LOGGING OBSERVATION WELL NO. 16-6-27
COALINGA POLYMER DEMONSTRATION PROJECT**

COALINGA POLYMER PROJECT PRODUCTION HISTORY AND FORECAST WELLS IN IMMEDIATE PILOT AREA

FIGURE III-28

RESERVOIR SIMULATION STUDY
EAST COALINGA FIELD
PROCESS COMPARISON
OIL PRODUCTION & WATER INJECTION

FIGURE III-29

FIGURE III-30

APPENDIX IV
POLYMER INJECTION

TABLE IV-1

FILTERABILITY^{A)} OF 300 PPM
ENZYME TREATED^{B)} KELZAN SOLUTIONS

<u>LOCATION</u>	<u>FILTERABILITY</u>
MAKE UP TANK BEFORE SHEAR	150
HOLDING TANK AFTER SHEAR	950
BEFORE D.E. FILTRATION AFTER STATIC MIXER	1100
AFTER D.E. FILTRATION	4200

A) FILTERABILITY - 20 PSI THROUGH 1.2 μ M.P. FOR 5 MIN.

B) TREATMENT- 6000 PPM CONCENTRATE MADE UP AT 50° C. WITH
250 PPM ALCALASE 6 O, 500 PPM NaHCO_3 ,
50 PPM V-3201 BIOCIDES
MAKE UP TIME 5 MIN. AGITATION 25 MIN.
TRANSFER THROUGH SHEAR PLATES AT 300 Δ P 6 MIN.
DILUTION TO 300 PPM.
KELZAN LOT NO. XFL 15495.
D.E. STANDARD SUPERCCEL, 20 LBS/100 SQ FT.

TABLE IV-2
COALINGA POLYMER PROJECT
TEST WELL 9-7-27
BIOPOLYMER INJECTION EVENTS

Injection Event	Date	INJECTION RATES		Remarks
		Beginning B/D	End B/D	
				Initial conditions: well had been shut-in since 3-1-72 and was treated with Bacteria Destruct and HCl during 12/74.
A	1-4-75	500	500	Water injection started.
B	2-11-75	300	300	Kelzan MF Injection Test No. ¹ ₁ , 220 ppm, 3.3 cp at 7.3 sec. ¹ ₁ . Injected 2500 bbl polymer.
C	2-18-75	300	500	Water injection started.
D	3-5-75	500	500	Treated well with Bacteria Destruct and HCl. Resume water injection.
E	4-8-75	500	0	Treated well with Bacteria Destruct and HCl. Shut-in well for 20 days, pressure fell off to 20 psi.
F	4-29-75	500	500	Water injection started.
G	9-6-75	500	500	Kelzan MF Injection Test No. ¹ ₂ , 320 ppm, 4.2 cp at 7.3 sec. ¹ ₁ . Injected 6400 bbl polymer.
H	9-19-75	500	500	Water injection started.
I	9-28-75	0	0	Shut-in well.
J	10-3-75	0	0	Treated well with Bacteria Destruct and HCl.
K	10-9-75	0	0	Cement squeezed casing hole 40 ft above perfs.
L	12-10-75	500	500	Water injection started.
M	2-5-76	0	0	Shut-in well, pressure fell off to 6 psi.
N	2-9-76	500	500	Water injection started.
O	4-17-76	0	0	Treated well with Bacteria Destruct and HCl.
P	4-18-76	500	500	Water injection started.
Q	5-18-76	0	0	Re-Darley treated well.
R	5-20-76	500	500	Water injection started.
S	8-19-76	0	0	Treated well with Bacteria Destruct and HCl. Installed nitrogen blanket to exclude oxygen from casing.
T	8-21-76	500	500	Water injection started.
U	9-23-76	500	300	Kelzan MF Injection Test No. ¹ ₃ , 336 ppm, 3.9 cp at 7.3 sec. ¹ ₁ . Injected 6400 bbl polymer.
V	10-10-76	200	50	Continuation of polymer injection, 300 ppm, 4.2 cp at 7.3 sec. ¹ ₁ . Cumulative injection 9200 bbl polymer.

Injection Event	Date	INJECTION RATES		Remarks
		Beginning B/D	End B/D	
W	11-8-76	100	100	Water injection started.
X	11-19-76	300	100	Continuation of polymer injection, 300 ppm, 3.5 cp at 7.3 sec ⁻¹ . Cumulative injection 11,000 bbl polymer.
Y	12-6-76	100	400	Water injection started. Injection profile survey indicates no migration of water to upper sand.
Z	2-8-77	0	0	Bailed fill from well.
A'	2-9-77	400	400	Resumed water injection. Injection profile survey indicates migration of water to upper sand.
B'	3-11-77	0	0	Shut-in well, pressure fell off to 113 psi.
C'	3-14-77	360	400	Water injection started.
D'	3-30-77	0	0	Suction washed perf and bailed for samples.
E'	3-31-77	360	400	Water injection started.
F'	4-7-77	0	0	Shut-in well, pressure fell off to 50 psi. End of current injection testing.

TABLE IV-3
COALINGA POLYMER PROJECT
TEST WELL 9-7-27
COMPARISON OF POLYMER INJECTION TESTS

Average Test Parameters	Kelzan MF Test No. 1	Kelzan MF Test No. 2	Kelzan MF Test No. 3
cp = polymer concentration, ppm	220	320	320
w = viscosity of injection water at 100°F, cp	.64	.64	.64
p = viscosity of polymer at 100°F, 7.3 sec. ⁻¹ shear rate, cp	3.3	4.2	3.91
I ₀ = prepolymer-water stable injectivity, B/D/psi	.82	.92	1.03
I ₁ = polymer stable injectivity, B/D/psi	.40	.57	.10
qp = polymer stable injection rate, B/D	300	500	100
I ₂ = follow-up water stable injectivity, B/D/psi	.72	.62	.36
I ₃ = post-stimulation stable injectivity, B/D/psi	1.30	1.03	1.03*
p/ w = viscosity ratio at 7.3 sec. ⁻¹	5.16	6.56	6.11
IRF = I ₂ /I ₁ injectivity recovery factor	1.80	1.09	3.6
SRF = I ₃ /I ₂ stimulation recovery factor	1.81	1.66	2.86*

*Well not as yet stimulated, I₃ and SRF based upon the ability to restore injectivity to prepolymer injectivity with wellbore stimulation treatment.

POLYMER MIXING AND INJECTING PLANT

FIGURE IV-1
ZV-285B

THE EFFECTS OF SHEAR ON THE VISCOSITY OF BIOPOLYMER AND WATER

COALINGA POLYMER PROJECT
WELL 9-7-27
BIOPOLYMER INJECTION TEST