SECONDARY OIL RECOVERY IN THE CENTRAL UNIT OF
THE BISTI OIL FIELD, SAN JUAN COUNTY, NEW MEXICO

by
Keith A. Selinger

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SECONDARY OIL RECOVERY IN THE CENTRAL UNIT OF
THE BISTI OIL FIELD, SAN JUAN COUNTY, NEW MEXICO

by

Keith A. Selinger

ABSTRACT

The Bisti field is located near the center of the San Juan basin approximately 20 miles south of the town of Farmington in San Juan County, New Mexico. This field has been unitized into 4 units to provide a more economical method of operation. The Central unit, operated by Sunray Mid-Continent, is located in the central part of this field. Since the discovery of the field in 1955, the initial reservoir pressure has declined to an extent that repressuring in the producing horizon must now be used to maintain production.

The secondary recovery method now being used in the Central unit was analyzed by the use of a rubber membrane model. In conjunction with the model analysis, a sedimentation study was made of the producing horizon.
The sedimentation analysis, supplemented by the information obtained from the model study flow net, demonstrates that the results of the secondary recovery method now being used can be duplicated with a rubber membrane model.

The application of a rubber membrane model similar to the one used in this investigation would be helpful in determining the most efficient method of secondary recovery in other oil fields with low reservoir pressures.
INTRODUCTION

Purpose of Investigation

In many oil fields which have lost their primary reservoir energy, it is possible to apply repressuring methods to obtain more production. The Bisti oil field of northwest New Mexico is such an oil field.

The purpose of this paper is to examine the data obtained from a membrane-analog study and to analyze the method of repressuring now being used in the Central unit of the Bisti oil field, San Juan County, New Mexico.

Location of Area

The Bisti field is located just south of the town of Farmington, New Mexico in east-central San Juan County. The Bisti field exceeds 30 miles in length and attains a maximum width of 3 miles. The field is a linear stratigraphic trap which is situated in the west-central section of the San Juan basin (see index map, fig. 1).
Figure 1. Index Map of the San Juan Basin

After Tomkins (1957).
Limits of Study

A general review of the geology of the San Juan basin was made to show the relationship of the stratigraphy and structure of the basin to that of the Bisti field. Special emphasis was given to a study of the sedimentation because this factor determines many of the reservoir characteristics of the oil field.

There are several methods of studying the movement of fluids in a reservoir. In this investigation the rubber membrane analogy was used to study the potential distribution and to determine therefrom the fluid movement. In the past, membrane models have been used to study the flow of water in an aquifer subjected to the influence of pumping by several wells. This method, regardless of the nature of the fluid, lends itself to the solution of the complex geometry of multi-well problems.

Previous Work

Past studies of the structure, stratigraphy, and economic geology of the San Juan basin have yielded a comprehensive picture of its geology. Lindgren (1910) studied the Precambrian rocks around the margins of the
basin in evaluating the ore possibilities of the area. In 1924, Reeside described the Upper Cretaceous and Tertiary formations in the western part of the San Juan basin. Since 1924 there have been many papers written dealing with the structure and stratigraphy of the area. Outstanding among these are the papers by Beaumont, Dane, and Sears (1956), Tomkins (1957), and Sabins (1963).

In 1950 the New Mexico Geological Society organized their First Field Conference, which studied the San Juan basin. The Guidebook of the San Juan Basin was prepared for this conference. At the same time the Four Corners Geological Society was organized, and at irregular intervals since then they have published guidebooks dealing with the geology, geophysics, and oil production of the San Juan basin area.

The United States Geological Survey has published a number of professional papers, bulletins, and maps dealing with the geology of the basin.

Certain specialized information is available through publications of the United States Bureau of Mines, New Mexico Bureau of Mines, and the New Mexico Oil Conservation Commission.
Acknowledgments

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In addition a special note of thanks is due Sunray Mid-Continent Oil Company for supplying information and data used in this report.
HISTORY OF OIL AND GAS DEVELOPMENT IN THE SAN JUAN BASIN

In 1910 while drilling for irrigation water, oil was discovered near the town of Aztec in the north-central part of the San Juan basin. The first wells were shallow and small producers of oil and gas. In 1911 and 1912 further discoveries of oil and gas were made despite the widely accepted theory among geologists that the area was too "highly mineralized" to contain commercial amounts of petroleum.

Between the years of 1920 and 1924 many "domes" or anticlines were mapped in the basin and cited as possible oil locations. In 1924, after a series of dry holes were drilled, the first well was begun on the Hospah "dome". This well was the Hurst No. 1 located in the SE NE NE Sec. 1, T. 17 N., R. 9 W. The drilling continued until 1926 at which time the well was shut down at a total depth of 1405 feet. Two years later the Midwest Refining Company re-entered the Hurst No. 1 and deepened the well to 1590 feet. At this depth oil was encountered and development of the Hospah field occurred.

In recent years the oil production from the San Juan basin has increased with the discovery of several large oil fields such as the Gallegos-Gallup field in 1954.
and the Bisti and Verde-Gallup oil fields in 1955. There are seven horizons in the basin which have yielded commercial quantities of oil. These are listed with their representative oil fields in Appendix I.
GEOLOGY OF THE SAN JUAN BASIN

Precambrian Rocks

The Precambrian rocks in the San Juan basin are composed primarily of igneous intrusives and high grade metamorphics. In addition to these there are minor occurrences of amphibolites, diorites, and gabbros.

Pre-Mesozoic Rocks

A thick and extensive section of pre-Cretaceous rocks is found in the subsurface of the San Juan basin. With the exception of the Ordovician and Silurian periods, sediments of all other Paleozoic periods are represented.

The lower Paleozoic deposits are typically marine sediments and include dolomites, limestones, shales, and sandstones. In contrast, the upper Paleozoic section consists of red beds, sandstones, and some interbedded and interfingering carbonates. The Paleozoic sedimentary section includes a number of regional unconformities which separate systems and also occur within a system.
Mesozoic Rocks

A nearly complete Mesozoic section is found in the San Juan basin, including the largely continental Triassic deposits, the mixed marine and continental Jurassic deposits, and the marine Cretaceous sediments.

Cretaceous strata in the San Juan basin are characterized by a thick shale area to the northeast and a thick sandstone area to the southwest. The two interfinger within the central portion of the basin. Where the thick shale unit is broken by the sandstone tongues, the section is subdivided into named sandstone and shale members. Where the sandstone or shale units pinch-out, the named tongues lose their identity and a new terminology for the section is developed. The result is a rather complicated nomenclature system which is shown in a diagrammatic cross section in Figure 2.

Post-Mesozoic Rocks

Unconformably overlying the Cretaceous strata is a series of Tertiary sedimentary rocks consisting of conglomerates, sandstones and shales. Locally, portions of the post-Mesozoic sedimentary sequence have been removed by erosion.
Figure 2. Upper Cretaceous stratigraphic section of the San Juan Basin. After Sabins (1963).
Regional Structure

The San Juan basin is, geologically, of relatively recent origin. The details of the pre-Cretaceous history are not known, but through most of Paleozoic time the region was not a pronounced area of sedimentation or structural deformation. In Pennsylvanian time the Paradox basin to the northwest side of the San Juan basin was an area of deposition for a thick sequence of evaporites and associated sedimentary types.

In late Paleozoic time the Uncompahgre-Zuni-Ft. Defiance and related uplifts, for the first time, broadly defined the major boundaries of the San Juan basin. During the Triassic and Jurassic, and most of the Cretaceous, the area was relatively stable. However, with the start of the Laramide orogeny the present boundaries of the basin were defined. During this later stage of formation of the basin, according to Silver (1950), the southwestern part of the San Juan basin was depressed relative to the northeastern part. The uplift in the northeast was due directly to the Laramide uplift which continued well into the Eocene.
BISTI OIL FIELD

History of the Field

In 1955 the El Paso Natural Gas Company completed their No. 1 Kelly State well which was the discovery oil well of the Bisti oil field. Since that time the boundaries of the field have been extended so that the field is now approximately 30 miles long and 3 miles wide.

Based on reports, complete to December, 1962, there are 398 wells in the pool which include 79 input wells. The cumulative production to the end of 1962 was 23,843,151 barrels. In most of the producing wells the pay horizon has been fractured to increase the permeability and thus increase production.

The early primary reservoir energy was due to solution gas drive, but as cumulative production increased the reservoir pressure declined, until it was no longer economically feasible to produce oil without applying secondary recovery methods.

To facilitate the secondary recovery operations, the Bisti field was unitized and divided (Plate I) into:

(1) the West Bisti unit operated by British American Oil
Company; (2) the Central Bisti unit operated by Sunray Mid-Continent Oil Company; (3) the Carson unit operated by Shell Oil Company; and (4) the East Bisti unit operated by Skelly Oil Company.

Cretaceous Stratigraphy of the Bisti Field

With three exceptions, the major stratigraphic units of the Bisti area can be considered to be the same as for the rest of the San Juan basin. The three units which are not found in the Bisti area are the Graneros Shale, the Sanastee Sandstone, and the Niobrara Shale.

In the Bisti area and southward the Mancos Shale has been subdivided into an upper and lower part. The "Upper" Mancos Shale lies above the Gallup Sandstone and the "Lower" Mancos Shale lies below the Gallup.

The Gallup Sandstone was named originally by Sears (1925) for the exposures near the town of Gallup, New Mexico. The Main Gallup Sandstone in the Bisti area is part of a widespread, non-productive, regressive sandstone deposit. It consists of an Offshore sand facies and a Beach sand facies. The remaining section of the Gallup sandstone has been subdivided into the following units:
(1) Low SP facies; (2) Bar sand facies; (3) Back-Bar facies; and (4) Fore-Bar facies.

In the Bisti area the Offshore sand facies grades downward into the "Lower" Mancos Shale and is in turn variously overlain by the Bar sand facies, the Back-Bar facies, the Beach sand facies, the Low SP facies, or the Fore-Bar facies. The Offshore sand facies is characterized as very fine grained, with abundant cement and matrix.

The Beach sand facies is limited to an area south and southwest of the Bar sand facies (Fig. 3). The Beach sand facies is a medium- to coarse-grained sandstone. This sand is overlain by the "Upper" Mancos Shale and underlain by the Offshore sand facies. The Beach sand facies is equivalent in time to the Back-Bar, Bar, Low SP, and Fore-Bar facies. The Beach sand differs from the Offshore sand facies in that it is coarser grained and relatively clean with only a minor amount of clay and mud matrix.

Sabins (1963) has applied the term "Low SP facies" to a stratigraphic interval because on electric logs it is characterized by a low self potential (SP) reading. This interval may be either a shaly sand, or a shaly interval which separates one bar sand from another. The unit
Figure 3. Outlines of effective Bar sands. After Sebines (1963).
regionally overlies the Offshore sand facies and is overlain by the Bar sand facies.

The Bar sand facies forms the stratigraphic trap in the Bisti field. This facies consists of three distinct sand units which have been designated, from the base upward, as the Carson, Huerfano, and Marye sands (Fig. 4).

In the central portion of the Bisti field the Carson Bar sand is limited to less than 1 mile in width and 9 miles in length. The maximum thickness of this unit is 30 feet. This bed is equivalent stratigraphically to the Huerfano sand which is found in other parts of the field.

The Huerfano sand overlies the Offshore sand facies and is separated from it by a 10 foot thick Low SP facies. The Huerfano sand reaches a thickness of 30 feet and attains a maximum length of 24 miles and maximum width of 2 miles. The Huerfano sand, which is equivalent to the Carson sand, is separated from the overlying Marye sand by a thin Low SP facies.

The uppermost Bar sand is the Marye sand. This sand unit is overlain by the "Upper" Mancos Shale and underlain by a thin Low SP interval which in turn is underlain by the Huerfano sand. The Marye unit is the best
Figure 4. Stratigraphic section of Bisti Field. After Sabins (1963).
developed and most extensive of the three bar sands in the area. The Marye sand unit ranges from 1 to 2 miles in width, with a length of 30 miles and a thickness of 40 feet. Where well developed, the sand is clean, but it grades northeasterly into the silty shale of the Fore-Bar facies. To the southwest the Marye sand grades into the fine-grained Back-Bar sand facies. The Marye sand, which trends in a northwest-southeast direction is the main oil producing zone in the Bisti field.

Northeast from the Bar sand facies, and stratigraphically equivalent to it, is the fine-grained Fore-Bar facies. The Fore-Bar facies rest directly upon the Offshore sand facies which comprises most of the Main Gallup Sandstone. The Fore-Bar facies is equivalent in time to the Bar sand facies, Low SP facies, Beach sand facies, and the Back-Bar facies. To the southwest the Bar sand grades into a fine-grained sandstone called the Back-Bar facies. This Back-Bar facies is a long, narrow belt which occupies the area between the Bar sand facies and the Beach facies (Fig. 4).

The Back-Bar facies, like all of the other facies, parallels the strand line of the Cretaceous seas and has a general northwest-southeast trend.
Covering the Beach, Back-Bar, Bar and Fore-Bar sand facies is the "Upper" Mancos Shale. This shale is a transgressive marine tongue extending in a southwestern direction which completely overlies the Bisti area and serves as the upper seal for the stratigraphic trap.

Petrographic Characteristics of the Gallup Sandstone

Sabins (1963) has made a detailed study of the petrographic characteristics of the Gallup Sandstone and this information is summarized in the following paragraphs.

The Offshore sand facies has an average median grain size of 3.0 phi to 4.0 phi and an average maximum grain diameter of 1.0 phi to 3.0 phi. The sorting values (σφ) range from 0.5 to 1.0 (moderately sorted range). This sand is essentially uniform in a lateral direction throughout the area under consideration. The vertical change is one in which the sand grains become coarser toward the top. This change in grain size together with the fact that as the grain size increases, the clay content decreases, points to a shallowing of the water in which the Offshore sand was deposited.
The sand of the Beach sand facies, in general, is coarser than the sands of the Offshore facies. The average median diameter of the Beach facies ranges from 2.0 phi to 4.0 phi, and clay is almost totally absent.

The Low SP facies, when plotted on a histogram shows a very distinctive bimodal pattern. This is due to the presence of clay material mixed with the coarse sand. Near the top of the facies the sand grains become finer and finer until the base of the coarser Bar facies is reached.

The Marye Sand Member has a size range of 1.0 phi to 3.0 phi. The maximum particle diameter of the sand is -1.0 phi to 1.0 phi. The individual sand grains are sub-angular to subrounded. The sorting figures range from 0.5 to 1.0 (moderately sorted) and are relatively constant throughout the Marye sand.

The Huerfano Sand Member has an average median diameter of 2.0 phi to 3.0 phi, and a maximum particle diameter of 0 phi to 1.0 phi. This sand, like the Marye, is moderately sorted and shows the same degree of rounding. As in the Offshore facies, the Huerfano Sand shows an increase in particle size towards the top of the bar.
and a subsequent decrease in clay material. This has been interpreted as indicating a shallowing of the sea. The Carson Sand Member, in general, is similar to the Huerfano unit.

The Back-Bar facies are made up of sand and silty shale with a few interbedded sandstones. This unit is poorly sorted, with the sand and silt contents as high as 50 percent.

The Fore-Bar facies differs from the Back-Bar facies in that the sand and silt fraction is less abundant, and is finer-grained.

In the "Upper" Mancos Shale the sand and silt make up a relatively small percent of the total. In general the sands are fine-grained, with the exception of a few limited areas in which portions of the underlying Bar sands appear to have been reworked and later incorporated within the lower part of the overlying Mancos Shale.

Morphology of the Bar

During much of Late Cretaceous time, the San Juan basin was an area of marginal encroachment by the Cretaceous seas with the open sea to the northeast and the
land mass to the southwest. During this interval the strand lines trended northwest-southeast. To the southwest of the strand line the deposits are in part continental and the proportion of continental deposits to marine deposits increases in that direction. In the area northeast of the strand line the deposits are principally of an offshore marine character. Due to the repeated transgression and regression of the sea in a northeast-southwest direction there is extensive intertonguing of the continental and marine deposits.

Structure

Contours on the top of the Gallup Sandstone show a homoclinal dip of 75 feet per mile to the north. Subsurface information shows no apparent closure on the Gallup Sandstone.

Oil and Gas Entrapment

As structural closure on the Gallup Sandstone is absent, entrapment of the oil and gas is the result of stratigraphic variation in the section. The principal factor in the localization of the oil is the distribution
of the more permeable zones in the bar sands.

Porosity and Permeability

Depositional environment to a large extent controls the porosity and permeability of a formation. The primary porosity and permeability of a sand is controlled by such factors as grain size, sorting, rounding, packing, and particle shape. These are governed by the source of material and the mode of transportation but deposition is the primary controlling factor. Because of extensive winnowing of the sand by wave action the Bar sands are usually well sorted. The clay material has been washed away leaving a clean sand with higher porosity and permeability.

In 1957 Sunray Mid-Continent engineers made a statistical study of the porosity and permeability of the producing horizons in the Central unit. They found that 97.35 percent of the total permeability capacity was in the reservoir rock with permeabilities greater than 1.1 millidarcy. Each individual producing horizon shows a wide variation in permeability with the lower and upper limits at 1.0 millidarcy to 432 millidarcy. An average permeability of 9.05 millidarcy and an average porosity of 14.43 percent were assigned to the producing sand in the Gallup Sandstone.
MEMBRANE MODEL

General Statement

It has been shown that the surface of a deflected membrane can be made to assume the shape of a potential surface. As the potential surface of the membrane can be represented by a linear logarithmic solution of the Laplace equation, and the confined flow of a fluid in two dimensions can be represented by a similar solution, the membrane method can be applied to the solution of multiple-well problems.

History

Prandtl advanced in 1903 the use of a membrane under uniformly distributed pressure as a means for determining stress distributions in a prismatic bar subjected to torsion. Later, in 1939, Zworykin used the rubber membrane model for the study of electrostatic fields. He further proved that for small deformations about the horizontal plane the vertical height of the free surface of the membrane can be expressed in the same mathematical form as the potential in an electrostatic field.
A deflected membrane will adjust to the deformation by assuming a shape governed by

\[
\frac{\partial^2 z}{\partial x^2} \left[ 1 + \left( \frac{\partial z}{\partial y} \right)^2 \right] + \frac{\partial^2 z}{\partial y^2} \left[ 1 + \left( \frac{\partial z}{\partial x} \right)^2 \right] - 2 \frac{\partial^2 z}{\partial x \partial y} \frac{\partial z}{\partial x} \frac{\partial z}{\partial y} = 0
\]

(1)

If then the deflections are kept small so that it is found that the terms

\[(\frac{\partial z}{\partial x})^2 \approx 0 \quad (\frac{\partial z}{\partial y})^2 \approx 0\]

(2)

then by substituting these values in equation (1) it becomes

\[\frac{\partial^2 z}{\partial x^2} + \frac{\partial^2 z}{\partial y^2} \approx 0\]

(3)

The use of the rubber membrane was then expanded and used by the Germans to examine the flow around wing structures and through turbines. Later, in the United States the membrane theory was applied to electron flow in vacuum tubes.

**Construction and Equipment**

In order to use a thin rubber membrane to predict the flow into wells, the equipment shown in Figure 5 was constructed. Various types of rubber sheets were considered for use in this test with dental dam, obtained from uncut sheets, proving most satisfactory for this problem.

The rubber sheet was clamped under uniform tension to an aluminum frame which was then placed in a frame
holder. The frame holder was 80 inches long and 36 inches wide and was equipped so that the aluminum frame and rubber sheet could be held in a horizontal position. The frame holder consisted of a wooden frame constructed so that the central portion was open. The frame holder resembled a table sans top. A somewhat rectangular boundary was impressed upon the membrane from below. The boundary simulated an equipotential surface surrounding that section of the field under consideration.

Small wooden dowels, which served as probes, were attached to adjustable clamps and movable rods. These movable rods were in turn attached to guide rails placed parallel to the long dimension of the table. The rubber was deflected by the probes from either above or below. The probes which deflected the membrane upward represented input wells whereas the deflections downward simulated withdrawal wells.

To measure the deflections of the membrane a photogrammetric method was used. This method required the building of a tubular frame with a special camera housing, to allow the camera to be mounted directly over the deflected portion of the membrane (Fig. 6).
Figure 5. CAMERA AND MODEL

Figure 6. PHOTOGRAFIC SYSTEM
Two overlapping vertical pictures were taken of the deflected membrane. The two photographs were examined by means of a mirror stereoscope and points of equal elevation were determined using a parallax bar.

Theory

The rubber membrane analogy may be adapted readily to the solution of problems dealing with recharge and discharge of wells. It has been shown by Zworykin that the free surface of a rubber membrane satisfies the differential equation (1), provided that the following three conditions are satisfied: First, the equation representing the conditions of the membrane must approach the Laplace equation \( \frac{\partial^2 z}{\partial x^2} + \frac{\partial^2 z}{\partial y^2} = 0 \). Second, the analogy will be correct if all deflections of the membrane are less than \( 15^\circ \) from the horizontal. Third, the tension of the membrane in the horizontal plane must be uniform in all directions.

The equation of the rubber membrane conforms to Poisson's equation \( \frac{\partial^2 z}{\partial x^2} + \frac{\partial^2 z}{\partial y^2} = \frac{\gamma T}{T} \) in which the ratio \( \frac{\gamma T}{T} \) represents a membrane weighing \( \gamma T \) pounds per unit surface area under a uniform tension \( T \).
If the horizontal tension $T$ in the membrane is large compared to the vertical forces due to the weight of the membrane then the ratio will approach zero. As this ratio approaches zero, the form of the membrane surface approaches the Laplace equation.

**Darcy's Law**

In 1856, Darcy studied the flow of water through a homogeneous, porous medium. He proved that the rate of flow of a fluid through a porous medium was proportional to the pressure gradient and to the cross sectional area at right angles to the flow and inversely proportional to the length of flow of the fluid. This law has been stated as:

$$Q = KA \frac{(h_1 - h_2)}{L}$$

\(Q\) = volume rate of flow  
\(K\) = constant of proportionality  
\(A\) = cross sectional area  
\(L\) = length of flow  
\(h\) = hydraulic head
Darcy's experiments were confined to flow of water through sands which were 100 percent saturated with water. In these tests the driving force of this single phase fluid is the hydraulic head. Later experimentors found that Darcy's law could be extended to other fluids and that the constant of proportionality $K$ could be rewritten $k/u$ where $u$ is the viscosity of the fluid and $k$ is a property of the rock itself. When dealing with the movement of oil and multiphase fluid flow the driving force then becomes the pressure differential. Equation (4) can then be rewritten as

$$Q = \frac{k}{\mu} \frac{A}{L} \Delta P$$  

(5)

$Q$ = volume rate of flow  
$k$ = permeability  
$\mu$ = viscosity  
$A$ = cross sectional area  
$P$ = pressure gradient  
$L$ = length of flow

A comprehensive study of the analogy between Darcy's law and other equations can be found in Karplus (1958). In this investigation the deflections or $z$ displacements of the membrane were made according to the
pressure gradients imposed upon the producing horizon by
the injection of fluids at the input wells.

Calibration of the Membrane

The maximum displacement used in the test was de-
termined experimentally by depressing the membrane and
letting the top of the probe represent the bottom hole
pressure of an imaginary well. When the displacements
were plotted against the logarithm of the radius out from
the probe an approximately linear relationship was found
to exist. If the Laplace equation was satisfied exactly,
the equation of the membrane surface could be written

\[ z = A \log r + B \]  \hspace{1cm} (6)

where \( z \) is the vertical deflection, \( r \) the distance out
from the probe, and \( A \) and \( B \) are integration constants.

Walker (1948) has shown that by applying equation

(1) the differential equation of the surface becomes

\[ \frac{d^2z}{dr^2} + \frac{1}{r} \left[ 1 + \left( \frac{dz}{dr} \right)^2 \right] \frac{dz}{dr} = 0 \]  \hspace{1cm} (7)

the solution of which is

\[ z = a \, \text{arc} \, \text{cosh} \, \frac{r}{a} + b \]  \hspace{1cm} (8)

where \( a \) and \( b \) are integration constants.
It was found then that for small changes in the gradient equation (8) closely approximates equation (6) and the membrane analogy will hold. Where the membrane deviates from the linear relation (Fig. 7) the gradient is increasing and equation (8) does not approach equation (6).

By examining the behavior of the membrane near the probe it becomes evident that the maximum deflection of the probe can be determined. Thedeparture of the membrane surface from the straight line as shown in Figure 7 is due to the rapid increase in slope near the probe and to the increase in tension of the rubber. The maximum deflection used in the test was 1.44 inches.
Figure 7. Membrane Calibration.
RESULTS OF INVESTIGATION

General Statement

As it would be impractical to analyze a large number of wells, a group of five wells were chosen and a test run on these. Figure 8 shows the location of the five wells with respect to the Central Bisti unit. The rubber membrane was fixed into position and then deflected as previously described. The deflections used are listed in Appendix II.

Calhoun (1953) has shown that the withdrawal and injection of fluids will create pressure gradients uniformly in all directions out from a well as long as the fluid properties remain constant. In any such system where there is a variation in the pressure, flow can occur. The direction which this flow will take is governed by the amount of potential difference or pressure difference. If the pressures existing in the producing formation can be duplicated in the model, then the flow patterns which fluid particles will follow can be traced.

The pumping and injection rates for the month of April 1961 were simulated in this test. Changes in the
permeability within the field could not be represented with the membrane so it was assumed that the injected area was of uniform permeability. Also, in the Central unit, the material used for the repressuring fluid was LPG, gas and water. In the model it was assumed that a single phase fluid was being injected.

Observations

Figure 9 shows the flow net obtained from the membrane test. If this flow net is analyzed in terms of the volume rate of flow of oil, then some comparison can be made between the recovery in the model and the recovery in the field. Amyx, Bass, and Whiting (1960) have shown that the modified form to Darcy's equation (4), as converted to oil field use is

\[ Q = 1.127 \frac{k}{\mu} A \frac{(P_1 - P_2)}{L} \]

\[ Q = \text{volume rate of flow, barrels per day} \]
\[ k = \text{permeability of the medium, darcys} \]
\[ \mu = \text{viscosity of the fluid, centipoise} \]
\[ P_1 = \text{pressure at the inflow face, pounds per square inch} \]
\[ P_2 = \text{pressure at the outflow face, pounds per square inch} \]
FIGURE 9 FLOW NET DERIVED FROM MEMBRANE MODEL STUDY.
A = area of inflow, square feet
L = length of flow, feet

From the calculations shown in Appendix III it becomes evident that the estimated quantity of oil recovery in the model study approaches that attained in the field.

The flow net, for the sake of calculations, was divided into quadrants. Each quadrant contained one injection well and five resultant flow lines. From Figure 9 it can be shown that the flow lines and pressure contours form an orthogonal grid of small squares. Applying equation (1) to any square, bounded by adjacent flow lines, will result in the rate of flow per day that will pass between these two flow lines. Two such calculations were made in each quadrant. The eight resulting rates of flow were then added and an average rate of flow derived. This average was then multiplied by the number of flow lines to give an average flow rate per day for the fluid entering the producing well. To convert the flow rate from barrels per day to barrels per month a conversion factor of 30 days per month was used. An estimate of 11,340 barrels per month was obtained from the above procedure.
Appendix III is divided into six headings. The column marked "Area" pertains to the eight orthogonal squares. The headings designated "Flow Net Length" and "Flow Net Width" refer to the dimensions of the eight squares as measured directly from the flow net. "Field Length" and "Field Width" apply to the actual dimensions as converted to distances in the field. The column marked "Barrels per day" appears to rate of flow passing through the respective areas.

Pressure data, from 77 operating wells, indicate that there are zones of higher reservoir pressure located in the central portion of the field. These zones of high pressure range from 800 pounds per square inch near the fringes of the sand bar to 1400 pounds per square inch near the top of the bar. By examining the lithologic and pressure data it was found that the high pressure zones were limited to the crest of the sand bar where greater porosity and permeabilities were developed. Near the edges of the sand bar where the facies change, the pressures are lower. Information obtained from producing wells indicates that there was not an initial gas cap present in the Central Bisti unit at
the time secondary recovery methods were initiated. It is concluded that the zone of high pressure is due to the 10 LPG injection wells located along the major axis of the reservoir. Injection of fluids and gas along the crest of the sand bar will produce a zone of high pressure very similar to a gas cap.

Isopach maps, supplied by Sunray Mid-Continent Oil Company, were examined and the pay horizon was found to thicken to the north.

No indication of this thickening of the pay horizon or increase in the permeability was obtained from the flow net. If provision were made to simulate these changes in permeability, then a variation in the spacing of the equipotential lines would occur.

Effects of Sedimentation

Between September 1955, when the first well was drilled in the Central Bisti unit, and July 1959, when the area was unitized, the initial reservoir pressure dropped from 1,612 psig to 817 psig. The drop in reservoir pressure along with a loss in well productivity induced a pilot LPG test to be initiated in 1957 (Fig. 8).
This pilot test was made to evaluate miscible-phase flooding and potential unitization for the area. This pilot test was located on the crest of the sand bar and consequently, in the area with the greatest porosity and permeability. Near the center of the sand bar the particle size of the reservoir rock increases and as a result the permeability also increases. When the injected fluid passes from the flanks of the sand bar, with a low permeability, to the crest of the bar with a higher permeability, a change in the flow direction results. This highly permeable zone offers less resistance to fluid flow and therefore acts to short circuit the flow down the central axis of the field. The pilot test should have a higher recovery than a similar test area on the flanks of the sand bar. If the results of the pilot test were used as an indicator for the amount of recoverable petroleum in the unit, then the recovery figures would be over estimated.

Effects of Spacing

There are several factors which govern the areal distribution of the fluid-injection wells in secondary
recovery operations. A reduction in the distance between injection wells increases the rate at which production develops, and in turn shortens the life of the operation. Reducing the distance between adjacent wells means increasing the number of wells in the area. Although closer spacing gives better control and shorter operation life, it requires that more wells be drilled per unit area. A detailed study of the economic problems of the Central unit is beyond the scope of this report, therefore no recommendation as to well spacing can be made.
SUMMARY

The Bisti field is an oil field which has expended its primary reservoir energy due to production. Secondary recovery methods are now being used in this field to recover additional oil. In the Central unit a five spot injection network is being used.

With the rubber membrane model it was shown that the recovery from one well in the field could be duplicated in the laboratory. LPG, gas and water are being injected into the pay horizon but from the model study it appears that the same recovery could be obtained by injecting water only.

From the sedimentation study it is evident that the high energy environment under which the sand bar was deposited controls to a large extent the flow of the oil in the pay horizon. The highly permeable zone along the central axis of the sand bar is a direct result of this environment.

Channeling of injected fluids through the oil might occur near wells which have been highly fractured. As the water is forced into the producing horizon it will follow the open fractures and eventually find its way up
to the more permeable zone and then channel along the crest of the sand bar.

A rubber membrane model of the type used in this experiment would be of value in determining a secondary oil recovery program. The conditions existing in an area such as the Central unit can be duplicated with the membrane model and an optimum injection program can be planned.
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APPENDIX I
PRODUCING OIL FIELDS IN THE SAN JUAN BASIN

<table>
<thead>
<tr>
<th>Producing Horizon</th>
<th>Field</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pictured Cliffs Formation</td>
<td>Fulcher-Kutz Field</td>
</tr>
<tr>
<td>Cliff House Sandstone</td>
<td>Blanco Field</td>
</tr>
<tr>
<td>Menefee Sandstone and Shale</td>
<td>Blanco Field</td>
</tr>
<tr>
<td>Point Lookout Sandstone</td>
<td>Blanco Field</td>
</tr>
<tr>
<td>Hospah Sandstone</td>
<td>Hospah Field</td>
</tr>
<tr>
<td>Gallup Sandstone</td>
<td>Verde-Gallup Field, Gallegos-Gallup Field, Bisti Field</td>
</tr>
<tr>
<td>Dakota Sandstone</td>
<td>Fulcher-Kutz Field, W. Kutz Field</td>
</tr>
</tbody>
</table>
APPENDIX II

DEFLECTIONS USED IN THE MEMBRANE MODEL

<table>
<thead>
<tr>
<th>Wells</th>
<th>Bottom Hole Pressure</th>
<th>Deflection</th>
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<tbody>
<tr>
<td>GI-3-L</td>
<td>1365 pounds per square inch</td>
<td>1.167 inch</td>
</tr>
<tr>
<td>GI-4-L</td>
<td>1360 pounds per square inch</td>
<td>1.150 inch</td>
</tr>
<tr>
<td>GI-5-L</td>
<td>1420 pounds per square inch</td>
<td>1.250 inch</td>
</tr>
<tr>
<td>GI-6-L</td>
<td>1300 pounds per square inch</td>
<td>1.040 inch</td>
</tr>
<tr>
<td>7</td>
<td>1462 pounds per square inch</td>
<td>1.440 inch</td>
</tr>
</tbody>
</table>
## APPENDIX III

### RESULTS OF MEMBRANE MODEL

<table>
<thead>
<tr>
<th>Area</th>
<th>Flow Net Length in inches</th>
<th>Flow Net Width in inches</th>
<th>Field Length in feet</th>
<th>Field Width in feet</th>
<th>Bbls. per day</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>.5</td>
<td>0.8</td>
<td>104</td>
<td>166</td>
<td>19.65</td>
</tr>
<tr>
<td>2</td>
<td>.55</td>
<td>1.0</td>
<td>114</td>
<td>208</td>
<td>22.40</td>
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<tr>
<td>3</td>
<td>.45</td>
<td>1.0</td>
<td>93.6</td>
<td>229</td>
<td>29.82</td>
</tr>
<tr>
<td>4</td>
<td>.45</td>
<td>0.9</td>
<td>93.6</td>
<td>187</td>
<td>24.40</td>
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<tr>
<td>5</td>
<td>.90</td>
<td>1.5</td>
<td>187</td>
<td>312</td>
<td>20.41</td>
</tr>
<tr>
<td>6</td>
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<td>1.1</td>
<td>271</td>
<td>229</td>
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<td>7</td>
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<td>0.9</td>
<td>187</td>
<td>187</td>
<td>12.25</td>
</tr>
<tr>
<td>8</td>
<td>0.9</td>
<td>0.85</td>
<td>187</td>
<td>177</td>
<td>11.55</td>
</tr>
</tbody>
</table>

Total: 150.88

Total barrels per day produced: 150.88 barrels
Number of Areas: 8
Average area production per day: 18.86 barrels

Average area production per day: 18.86 barrels
Number of flow lines in area: 20
Total production per day: 378 barrels

Total production per day: 378 barrels
Days per Month: 30
Barrels per month: 11,340 barrels

Estimated recovery by model: 11,340 barrels per month
Actual recovery in field: 11,961 barrels per month