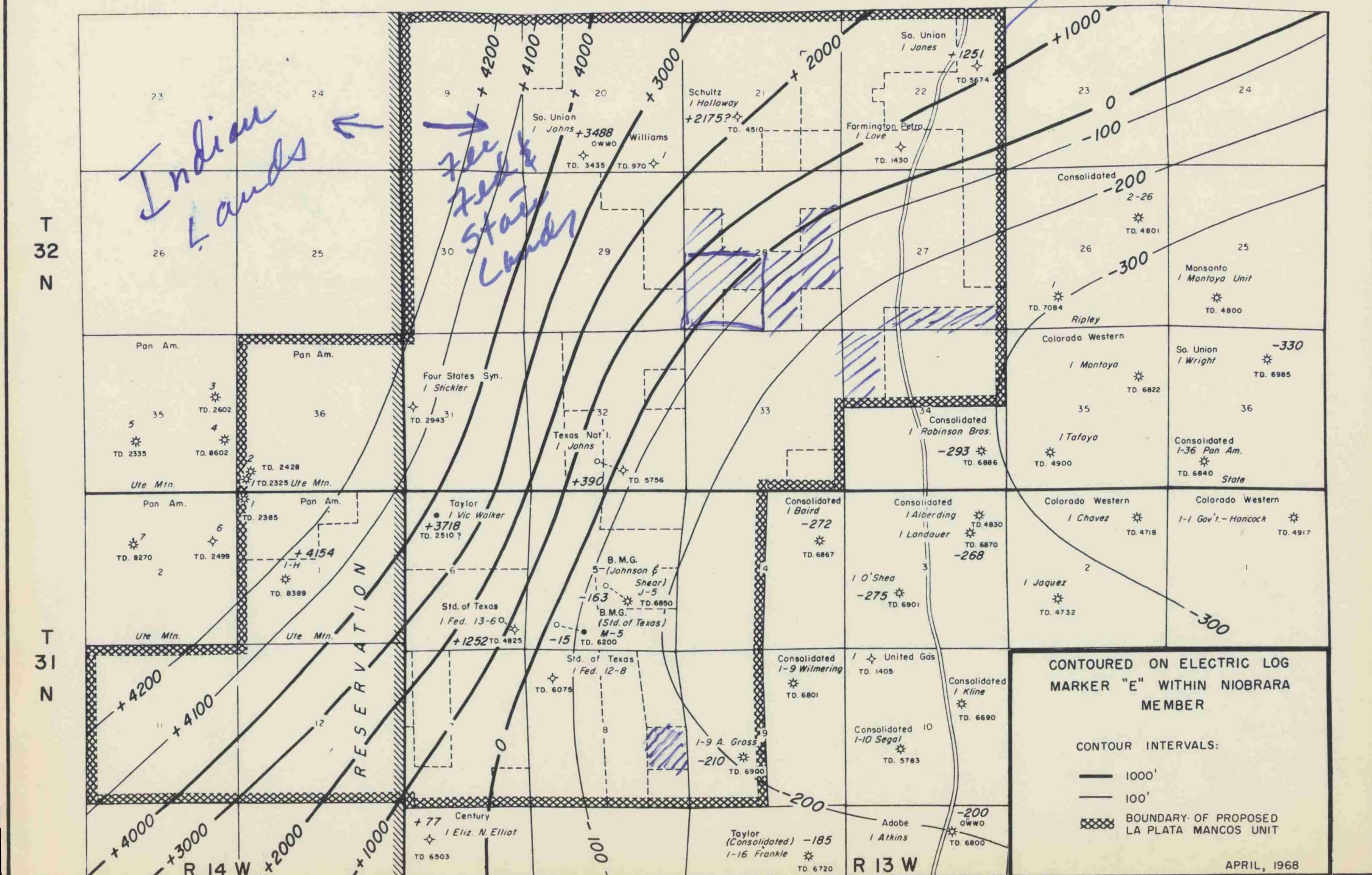
STRUCTURAL CONTOUR MAP

OF

NIOBRARA MEMBER OF MANCOS SHALE FORMATION



STRUCTURAL CONTOUR MAP

OF

NIOBRARA MEMBER OF MANCOS SHALE FORMATION

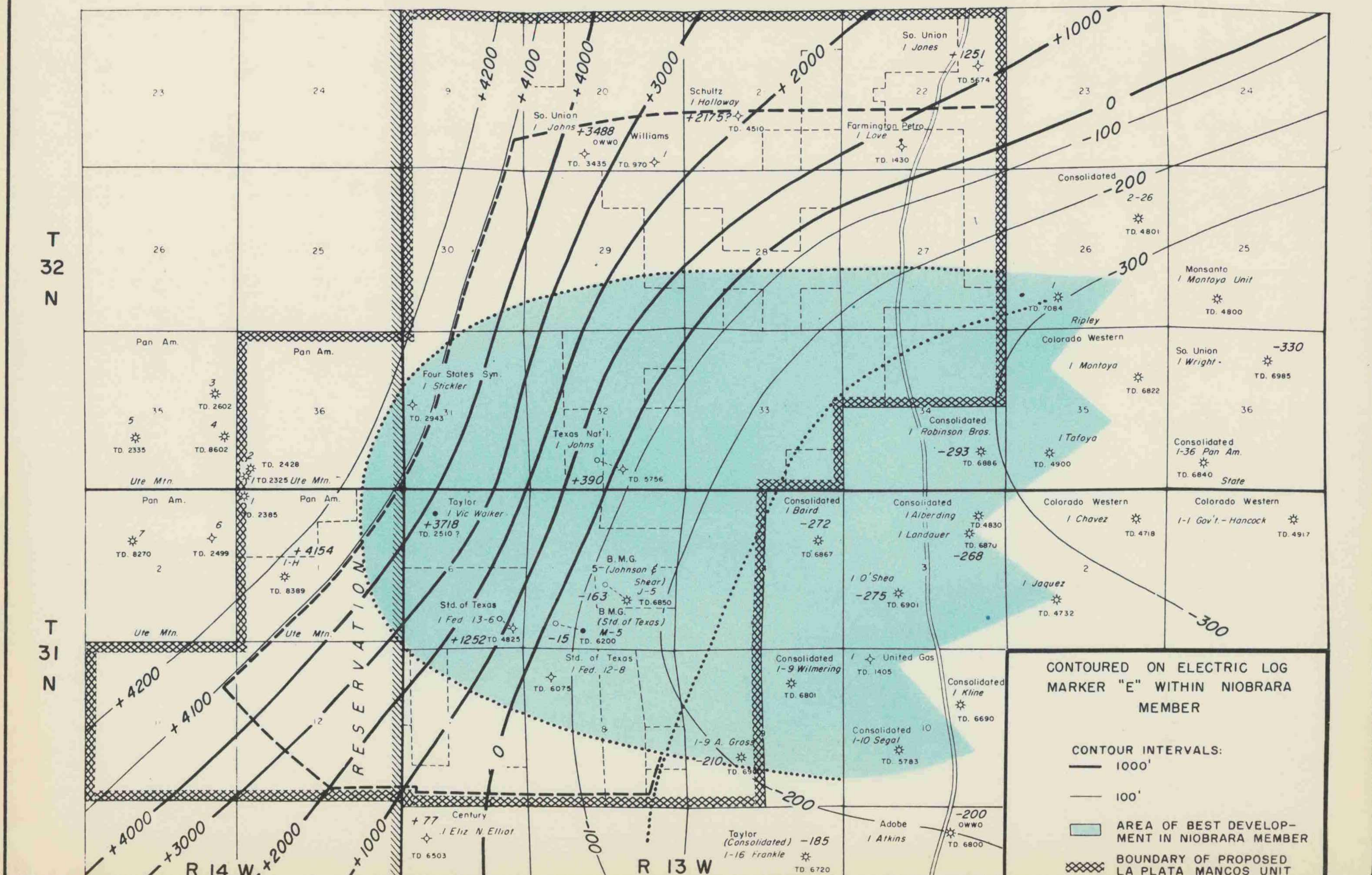


FIGURE 6

STRUCTURAL CONTOUR MAP

OF

NIOBRARA MEMBER OF MANCOS SHALE FORMATION

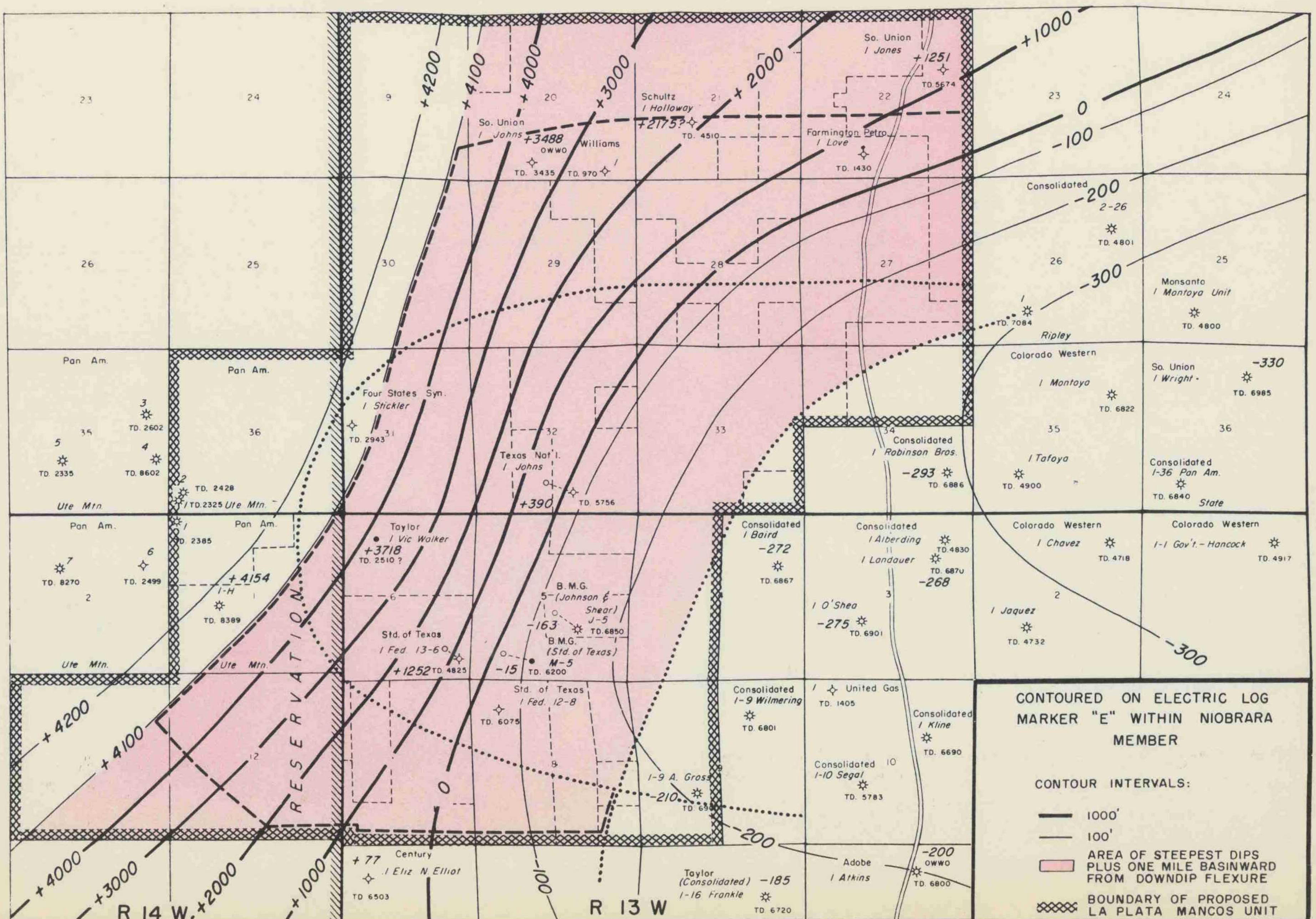


FIGURE 7

STRUCTURAL CONTOUR MAP

OF

NIOBRARA MEMBER OF MANCOS SHALE FORMATION

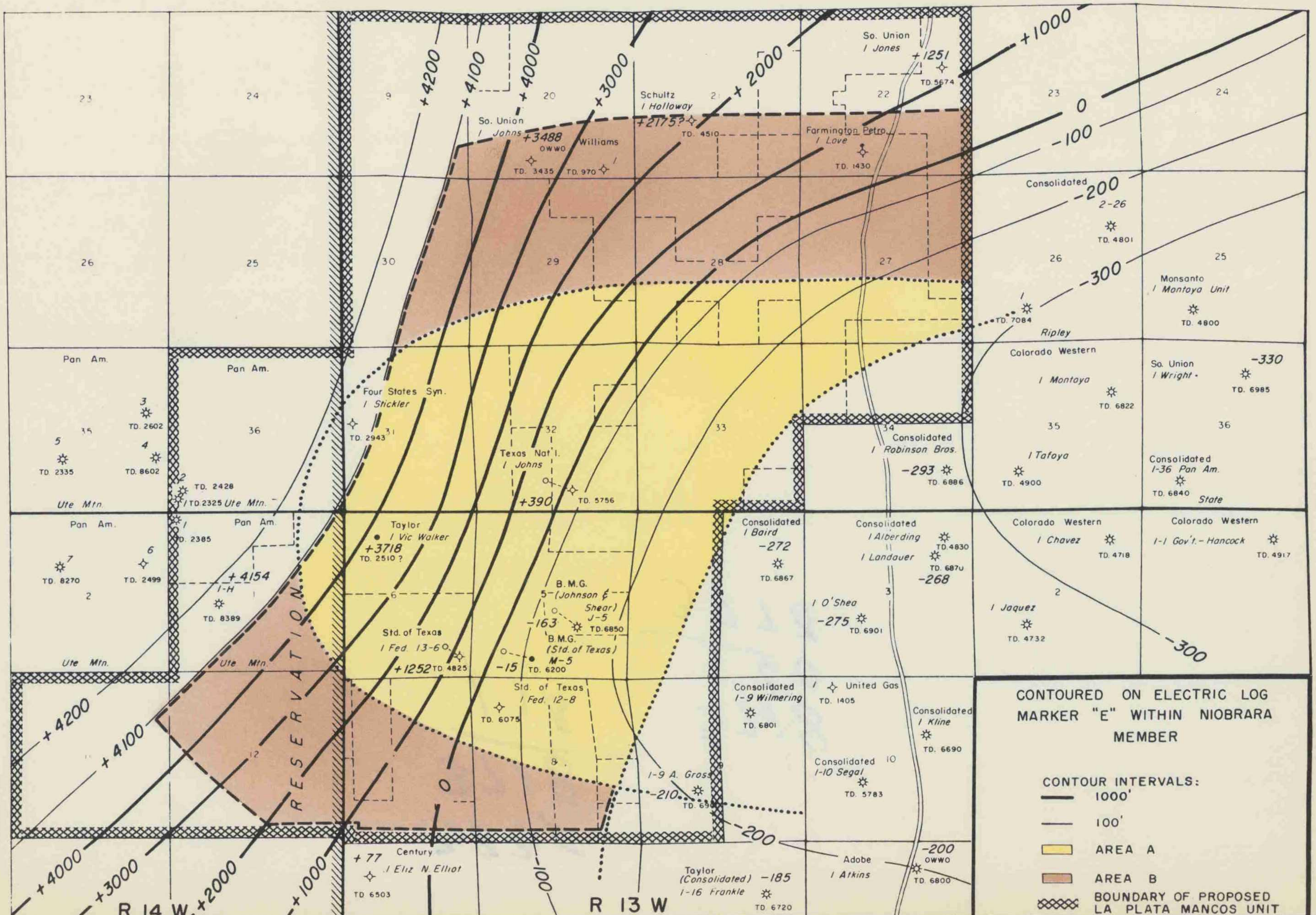


FIGURE 8

STRUCTURAL CONTOUR MAP
OF
NIOBRARA MEMBER OF MANCOS SHALE FORMATION

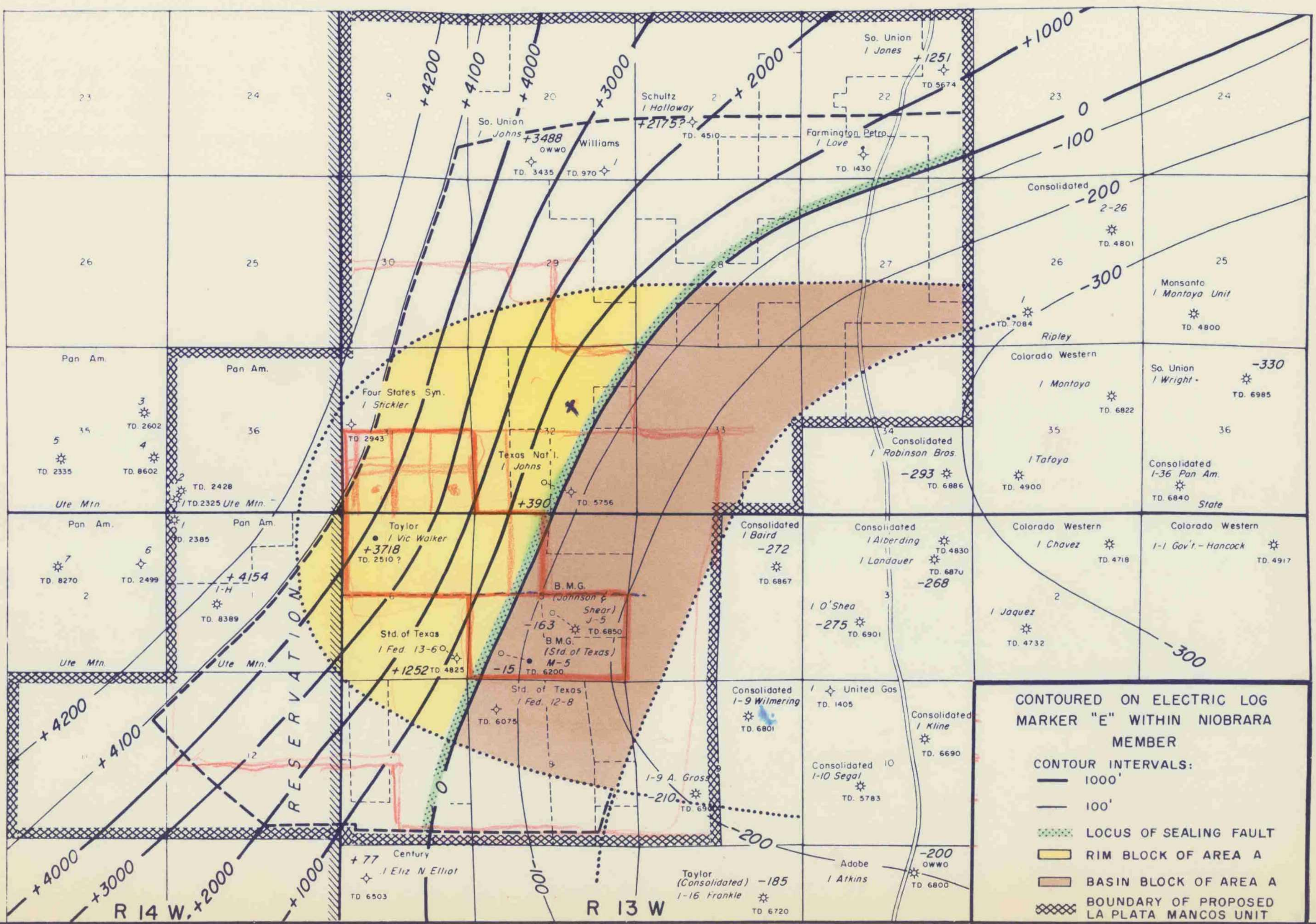


FIGURE - 9

DISCUSSION OF RESERVOIR MECHANICS AND POSSIBLE OIL RECOVERIES

PART I COMPARISON WITH OTHER POOLS

The prospective producing zone or zones are in the Niobrara member of the Mancos Shale Formation. Pools in the San Juan Basin which produce or have produced from this fractured shale, and from which generalized conclusions may be drawn respecting possible production and oil recoveries in this proposed unit, are the following:

a. Verde Gallup

b. Boulder Mancos

c. East Puerto Chiquito

d. West Puerto Chiquito.

General information as to oil in place, recoveries and reservoir characteristics of each of these pools is discussed briefly below.

VERDE GALLUP

We do not have information as to initial reservoir pressures, pressure decline, fluid samples, productivity indices or other information which would be helpful in analyzing this reservoir performance. The better part of the reservoir, however, exhibited an excellent fracture system, and many wells were completed for natural production without requiring stimulation. Unofficial estimates of productivity suggest some of the better wells may have had productivities measured in terms of thousands of barrels per day. Communication was obviously extensive throughout the field and undoubtedly large-scale migration across the pool toward the better wells resulted.

Accordingly it is difficult to estimate accurately oil recovery per acre, let alone initial oil in place. Average recoveries for the better part of the pool, however, were on the order of 500 to 1,000 barrels per acre. It is almost a certainty that any group of wells that shows greater than 1,000 barrels per acre ultimate recovery has benefited by draining adjoining tracts. About all that can be gained from a study of the Verde Gallup history is that recoveries on the order of 500 to 1,000 barrels per acre on the average (with 1,000 maximum) may be anticipated from a comparable reservoir produced under competitive conditions.

BOULDER MANCOS

More information is available for the Boulder Pool than for Verde Gallup. Ultimate production from this pool will approximate 1½ million barrels, or about 750 barrels per acre. Some pressure data is available, as well as a fluid sample. Although pressure data for this pool is not as complete as might be desired, it nevertheless is adequate to provide an approximate calculation of total oil in place. Since the oil was originally undersaturated and rates of pressure decline both above and below the bubble point are available, it is possible to calculate the amount of free gas which originally existed in the reservoir, which quantity must be known in order to properly interpret the pressure behavior and determine volume of oil in place. These figures are of course only as accurate as the pressure decline data used in the calculations. It is believed, however, that the data and resultant analyses are accurate enough to provide approximate values for these reservoir characteristics. They show 12 to 13 percent of the reservoir space originally occupied by free gas, and 4.3 to 4.4 million barrels of oil in place. This means a recovery approximating 34 to 35 percent of oil in place was realized in Boulder. The Boulder Pool exhibited an excellent fracture system. Many of the wells in Boulder were completed for natural production without requiring stimulation. Standard of Texas reported transmissibilities as high as 47 darcy feet for one of its wells, and although capacities this high are difficult to measure with accuracy, there is no doubt that the fracture system in Boulder was of a high transmissibility. One of Mobil's wells flowed uncontrolled for a short period at rates approximating 4,000 barrels per day. Such productivity would require a transmissibility on the order of 10 to 30 darcy feet. It is probable that the main fracture system in Boulder had a transmissibility in excess of 10 darcy feet. The Boulder Pool reservoir characteristics may accordingly be summarized as approximating 2,200 barrels per acre in place, 750 barrels per acre recoverable, for approximately 34 to 35 percent recovery of initial oil in place, and initially having a main fracture system transmissibility in excess of 10 darcy feet.

EAST PUERTO CHIQUITO

East Puerto Chiquito is a small pool, approximately the size of Boulder, and is characterized by a comparatively inferior fracture system, at least to the extent that all but one of the wells have required stimulation in order to produce at commercial rates. No information is available as to fracture system transmissibility other than by comparison with Boulder, in which it is obviously of much lower transmissibility and probably much lower volume of oil in place per acre. The chief benefit gained from a study of East Puerto Chiquito is the apparent benefit of reservoir control which has been exercised in the manner of producing the wells. Effect of this is discussed briefly in Part III of this section.

WEST PUERTO CHIQUITO

A great deal of information has been obtained in West Puerto Chiquito as to reservoir pressures, reservoir fluid samples, and interference tests. Calculations of oil in place per acre made from interference tests at a time when the pressure was above the bubble point indicate oil in place in West Puerto Chiquito to be between 1,000 and 2,500 barrels per acre, depending upon the compressibility of the reservoir rock. Little information is available as to the compressibility of a fractured shale reservoir rock, and the resulting calculations are indefinite to the extent of this uncertainty. A reasonable estimate at this time, however, of initial oil in place in West Puerto Chiquito, determined from interference tests, would be an average of the above estimated extremes, or approximately 1,700 barrels per acre. estimate 60% recovery on gravity drainage mech.

Interference tests have placed the transmissibility of the main fracture system in West Puerto Chiquito on the order of 5 to 6 darcy feet. We summarize the information as to West Puerto Chiquito at this time as being approximately 1,700 barrels per acre in place, with a transmissibility of 5 to 6 darcy feet. West Puerto Chiquito is a relatively large reservoir. The limits have not yet been defined, but the reservoir is believed to cover in excess of 10,000 acres.

SUMMARY OF PART I

Although it is virtually impossible from cores and logs to determine the reservoir void space in these fractured shale reservoirs, a study of flow characteristics of fractured systems indicates that a net producing interval of 10 to 50 feet thickness with porosities of 2 percent ranging down to 0.5 percent will generally satisfy the requirements of reservoir volume and transmissibilities exhibited by the fractured shale reservoirs found in the San Juan Basin. One such study (1) * compares transmissibilities and diffusivity constants of fractured reservoirs with sandstone reservoirs. These studies indicate that the relatively high well productivities as compared to sandstone or intergranular limestone reservoirs (for a like volume of oil in place) are to be expected, and that a general relation may be anticipated to exist between porosity and permeability, though probably covering a wider range than for sandstone and intergranular limestone. Accordingly this relation might be used in a general way to estimate oil in place by comparing transmissibilities. Although one is ordinarily hesitant to base reserve estimates on well productivity or

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* All references are listed under Section I

formation transmissibility alone, this is often about all the data available early in the life of a fractured shale reservoir. The relation of pore volume to permeability (and hence transmissibility for comparison of zones of equal thickness) is shown in Figure 10 * at the end of this section, for one type of fractured system.

One might interpret from this Figure 10 that if two reservoirs are compared and they have approximately the same number of fractures per foot of thickness of producing section, and the zones are of approximately the same thickness, the porosity can be expected to be higher in the reservoir of higher permeability. The relation is approximately a twofold increase in porosity for a tenfold increase in transmissibility. Expressed mathematically, we may say that the ratio of pore space in the two reservoirs would approximate the ratio of their transmissibilities taken to the .3 power.

Our present estimate of fracture system transmissibility for La Plata is 1 to 2 darcy feet. If we assume it to be 1.5 darcy feet and estimate oil in place through the above described relation by comparison with Boulder (10 darcy feet, 2,200 bbl/acre STO, FVF 1.1) and West Puerto Chiquito (6 darcy feet, 1,700 bbl/acre STO, FVF 1.29) we obtain:

1,370 bbl/acre of pore space (Boulder comparison)

1,450 bbl/acre of pore space (West Puerto Chiquito comparison)

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* Reproduced from Figure 9 of Reference (1).

or an average of approximately 1,400 bbl/acre. Stock tank oil in place per acre would accordingly be 1,150 bbl/acre for a FVF of 1.2 (basin block) or 1,250 bbl/acre for a FVF of 1.12 (estimated average of the rim block). Since this method is at best approximate we now estimate, for both the rim block and the basin block, 1,200 bbl/acre of stock tank oil originally in place for the main producing zone.

Bbl/acre in place in La Plata

if gravity drainage mech is effective, recovery could approach 60%

PART II OIL RECOVERIES BY THE GRAVITY DRAINAGE DEPLETION MECHANISM

As explained by Muskat (2) the quantitative determination of the contribution of the gravity drainage mechanism to the ultimate recovery of many oil pools is extremely difficult. There are, however, some general theoretical considerations which point so strongly to the significantly higher ultimate recovery which may be realized if this mechanism be allowed to play a substantial role in the depletion of a steeply dipping fractured shale reservoir that we believe they should not be disregarded, and accordingly every effort should be made, in producing one of these reservoirs, to take maximum advantage of this depletion mechanism.

Residual liquid saturations which may result in a reservoir depleted by gravity drainage have been variously estimated as low as 20 to 25 percent. This is for relatively permeable sandstones. One intuitively would estimate that a fractured reservoir would have even a lower residual saturation, in view of the probably lower amount of surface area exposed and probably less retention of oil by the forces of capillary action. Accordingly we believe we might reasonably expect residual saturations of 20 to 25 percent in these fractured shale reservoirs if depleted by gravity drainage. Then, for an oil-wet reservoir depleted by gravity drainage, if the original reservoir pressure can be maintained such that no shrinkage occurs in the residual oil, as much as 75 to 80 percent of the initial oil in place might be recovered by gravity drainage. On the other hand, if 10 percent of the pore space were occupied by connate water, then the residual oil saturation might be as low as 10 to 15 percent of the initial oil in place (total residual fluid saturation 20 to 25 percent). This means, then, that as high as 85 to 90 percent of the original oil in place might be recovered through gravity drainage.

As stated by Muskat [(3)] the gravity drainage mechanism is inherently rate sensitive and little benefit may be realized from a reservoir with good gravity drainage possibilities if it is depleted at a rate too fast to permit the gravity drainage to operate. Under such conditions only solution gas drive recoveries may be anticipated.

Here, then, is a tremendous difference in ultimate recoveries dependent simply on the method of operation of the pool. Solution gas drive recoveries will ordinarily be on the order of 15 percent of oil in place, and so, with gravity drainage recoveries of 75 to 90 percent, we have a five to six-fold increase in ultimate recovery possible by taking advantage of the superior depletion mechanism.

Although fractured shales appear to have characteristics which will permit high gravity drainage efficiency, they also possess the characteristic which permits extremely rapid depletion rates under the solution gas drive mechanism, which if allowed to operate will destroy the gravity drainage potential. This characteristic is the ratio of permeability to porosity. The relative values of this function for fractured systems are compared to sandstones by the data set out on Figure 10. Simply stated, this means that wells producing from fractured shale reservoirs have such high capacities to produce (with respect to oil in place) and accordingly are so rapidly depleted that the only effective producing mechanism is solution gas drive. In other words, a pool which is indiscriminately developed and produced cannot be expected to have a high gravity drainage efficiency simply through the happenstance role gravity drainage may play in the overall producing mechanism. Obviously, to enjoy the benefit of gravity drainage, a pool must be intelligently controlled and operated.

Without experience in other fields with which to make comparisons, we cannot be certain that the theoretically high gravity drainage efficiencies can be realized. We can be reasonably sure, however, that if the pool be produced in such a fashion that the solution gas drive mechanism is the primary method of depletion, there can be little hope of achieving these high recoveries.

Obviously the practical method to develop a pool with potential gravity drainage possibilities is to so regulate production that the rates will not exceed the reasonable rate of gravity drainage available from the reservoir, providing of course that these rates allow the pool to be depleted in a reasonable length of time. Muskat (4) has shown how we may estimate this rate for a particular reservoir. Applying this relation to the present case and modifying the formula so that it expresses in barrels per day per linear mile along the strike the theoretically possible rate of down-dip gravity drainage, we have constructed the graph (Figure 11) included at the end of this section.

When we realize that dips in the rim block approximate 4,000 feet per mile and that transmissibilities may be in the order of 1 to 2 darcy feet, it becomes evident from inspection of Figure 11 that for the approximately three mile distance of the strike along the rim block this reservoir can adequately support gravity drainage rates of 1,000 to 1,500 barrels per day, which at this time is believed will deplete the reservoir in a reasonable length of time.

These high rates of gravity drainage, of course, will not long obtain if pressures are allowed to decline and high gas-oil ratio wells permitted to produce. Although it is difficult to quantitatively place values on the effect of pressure reduction on gravity drainage rates, we realize that it will have adverse effects in three specific instances. These are:

1. Viscosity will be lowered.

2. There will be an increase in the relative permeability ratio of gas to oil and a consequent decrease in relative permeability of oil.

3. Reduction of pressure will probably permit the fractures to squeeze together and further reduce transmissibility.

The combination of these effects can be drastic, reducing the original gravity drainage rates by a factor measured in terms of hundreds; and consequently completely destroying any possibility of efficient gravity drainage.

We believe we have an example in the East Puerto Chiquito Pool which may be viewed on a qualitative, if not quantitative, basis, that indicates we are achieving higher efficiencies than would otherwise result, through control of production. Up-dip high gas-oil ratio wells in this pool have been shut in (by "high gas-oil ratio" in this pool we are speaking in terms of 500 to 1,500 cubic feet per barrel). This pool, which has an unquestionably inferior fracture system than Boulder and accordingly is believed to have contained originally much less oil in place per acre than Boulder, has already produced over 500 barrels per acre, and it appears may ultimately produce as much oil per acre as Boulder (750 barrels per acre) despite its inferior qualities. The reason, we believe, is because the up-dip high gas-oil ratio wells have been shut in and the maximum benefit from gravity drainage is being realized. Not only this, but East Puerto Chiquito is developed on 160-acre spacing rather than on 80-acre spacing as was Boulder. So here we have an example of an inferior reservoir drilled on wider spacing, yet realizing as good an ultimate recovery as the better pool. This can only be attributed to the more efficient method of production - which method of production is, of course, not possible under competitive conditions.

Another interesting feature has been observed in East Puerto Chiquito. This is that the up-dip wells, during the life of the pool, have become impotent in terms of ability to produce down-dip oil. Not only are the gas-oil ratios of these up-dip wells high, but they seem to have no ability to bring the oil up to the well bore. Evidently, as the gas and oil move out of smaller fractures into larger ones, a critical condition is reached at which the gas slips through the oil and leaves it below, much in the same fashion that a flowing well may cease to flow if tubing of too great a diameter is installed and excess slippage in the flow stream results. We have here a situation quite different from the usual one in which gas caps must be controlled to prevent mass migration of oil into them with consequent loss of recoverable oil. About all the up-dip wells achieve is to "boil" the gas out of the down-dip oil and dissipate the pressure.

In the La Plata Pool this same characteristic is anticipated, only to a far greater extent because of the steeper dips. The main purpose the up-dip wells can serve will be either (1) as injection wells or (2) as observation wells. In this respect the Taylor No. 1 Vic Walker can probably serve both functions, and accordingly it does not at this time seem necessary to drill another up-dip well in the rim block.

ESTIMATED RECOVERIES AS DEPENDENT UPON METHOD OF EXPLOITATION

If a main fracture system in La Plata exists as in other fractured shale reservoirs in the San Juan Basin, the ultimate oil recovery from the pool will have very little dependency on the number of wells drilled to it. It will of course be necessary to properly expose, within each fault block, all the producing zones to wells; and an adequate number of wells must be drilled within each fault block to establish the productivity required to deplete the respective reservoir in a reasonable length of time. Also, for fault blocks in the steeply dipping part of the formation, the producing wells should be located as nearly as practicable to the down-dip side of the fault block. If gas injection is instituted, it will of course be necessary to have a satisfactorily completed injection well relatively high structurally in each fault block in which gas injection is desired, and if waterflooding is used to sweep the bottoms of the fault blocks, this can probably be done with one of the producing wells not necessarily located close to the bottom of the fault block. The reason for this is the high transmissibility and steep dip of the formation will cause the water to gravitate to the bottom of the fault block and float the oil up to the producing wells.

Aside from the above listed considerations, numbers of wells or spacing of wells will have little bearing on the ultimate recovery from the pool. The important factor influencing ultimate recovery in a pool such as this is not numbers of wells but the method in which the pool is operated. If producing conditions are so controlled as to permit maximum operation of the gravity drainage mechanism, we believe recoveries as high as 70 percent of the oil in place, or even higher, may be realized. This can only be achieved, however, at reasonable rates of production by maintaining pressures above those which would normally be encountered in depletion by the solution gas drive mechanism, and keeping the gas in solution as long as possible. This can be partially accomplished by shutting in up-dip wells as soon as produced gas-oil ratios exceed the solution ratio. It will probably not be possible, however, to realize both high efficiency and high rates of production unless pressures are at least partially maintained by gas injection. Control of up-dip wells and institution of gas injection, of course, both require unitization. As to percent of oil in place which will be recoverable under competitive conditions, our only yardstick for comparison is Boulder. It is logical to conclude that Boulder's high recovery of 34 to 35 percent of oil in place is due in part to some gravity drainage and in part to a high relative permeability characteristic for its fracture system with its high transmissibility, which in itself may be caused by gravity drainage forces. With the lower transmissibility in the La Plata Pool, operating under competitive conditions, it is doubtful that recoveries will be as high. We accordingly estimate a recovery of 25 percent for the basin block and 30 percent for the rim block if development is under competitive conditions.

We estimate under unitized conditions that 70 percent of the oil in place in the rim block will be recovered and 30 percent for the basin block. Whether gas injection will be necessary to achieve this efficiency can only be estimated after the rim block wells are drilled and the reservoir characteristics better known.

These recovery figures applied to the approximately 1,200 bbl/acre estimated to be initially in place, and assuming 2,000 acres for the basin block and 2,400 acres for the rim block, yield the following:

FOR COMPETITIVE OPERATIONS

	Oil in Place (bbls)	Recoverable Oil (bbls)	Produced Oil (bbls)	Remaining Reserve (bbls)
Basin Block	2,400,000	600,000	300,000	300,000
Rim Block	2,900,000	870,000	-	870,000
			TOTAL	1,170,000

FOR UNITIZED OPERATIONS

	Oil in Place (bbls)	Recoverable Oil (bbls)	Produced Oil (bbls)	Remaining Reserve (bbls)
Basin Block	2,400,000	720,000	300,000	420,000
Rim Block	2,900,000	2,000,000	-	2,000,000
			TOTAL	2,420,000

It is, of course, possible that the rim block will contain undersaturated oil, and consequently more oil in place and more recoverable oil. This alone could add another 400,000 barrels to the rim block recovery.

PART IV VERTICAL SEPARATION OF ZONES WITHIN THE NIOBRARA MEMBER

Although one intuitively would expect vertical fracturing and vertical communication of zones within the Niobrara, and such vertical fracturing has been reported in the Verde Gallup Pool, experience in the Puerto Chiquito Pools has been to the contrary. We accordingly believe vertical separation may exist at La Plata, and certainly any drilling program should take this possibility into account and be so designed as to insure that each prospective producing zone will be satisfactorily opened to the well bore.

Apparent vertical separation of the zones within the Niobrara was observed in early wells in the Puerto Chiquito Pool. Because of this, precautions were taken in the drilling of subsequent wells to sand fracture individual zones separately. Carefully controlled drilling, testing and completion programs ensued, and although exceptionally good horizontal communication has been determined to exist in the Puerto Chiquito fractured shale reservoirs over long distances (measured in miles) no definite evidence has yet been developed as to vertical communication along the zones relatively close together (separation measured in terms of tens of feet). This vertical separation has been noted in some of the East Puerto Chiquito Pool wells even after fracture treatment.

We recognize that it seems illogical to conclude that a fractured shale reservoir could by any acts of nature be created in such a fashion as to have lateral dimensions measured in miles and at the same time have vertical limits so constrained that zones separated by vertical distances measured in tens of feet would not be in the same effective communication. We have no explanation for this enigma other than to assume the apparent producing zones are more brittle and able to retain a fracturing system than the intervening solid shales, which being less competent may tend to "flow" back into their original non-permeable states.

Regardless of the reason, however, we do know this condition to exist in similar pools, and believe operations in La Plata should be conducted under the premise that it may exist here. If we follow this reasoning, the well drilling and completion program should contemplate fracturing of the prospective producing zones individually. This will be necessary because if the sand fracture treatment enters only one zone and there are other zones in the well bore, it is entirely possible that the other zones will not be depleted by the subject well. This in turn means that substantial oil may remain unrecovered in the reservoir unless through happenstance enough wells receive fracture treatments in each of the zones to insure depletion. Since often one zone will be more susceptible to fracture treatment than the others, the chances are that this zone which breaks down more easily will be the one which will ordinarily receive the fracture treatment in all wells, unless precautions are taken to isolate the zones with separate treatments.

PART V SUMMARY

In view of the dry holes drilled in the La Plata area and the character of the fracture system as indicated by the pressure build-up test on the Benson-Montin-Greer No. M-5 Standard of Texas (as discussed in Section D herein) we classify this pool as a substandard reservoir, more comparable in character to the Puerto Chiquito Pools than to Verde Gallup or Boulder. There is not enough data available to establish the transmissibility of the main fracture system, however it now appears to be on the order of 1 to 2 darcy feet. Although this is adequate to support commercial production, it suggests that we should anticipate lower volumes of oil in place than occurred in Boulder and Verde Gallup.

The areas of low permeability (as found around the M-5 and the dry holes drilled in the pool) indicate a situation similar to the Puerto Chiquito Pools, in which there are apparently small (measured in terms of acres) barren areas throughout the reservoir. Wells drilled into these barren or poorly fractured local areas will find little or no natural production. Large fracture treatments will probably be required in order to establish satisfactory communication with the main fracture system. Accordingly, the dry holes which have been drilled in Area A do not in themselves condemn any part of this area. On the contrary, analysis of the logs of these wells serves to confirm the presence of a reservoir which will support commercial wells.

The main prospective reservoirs are identified in this section as the "rim block" and the "basin block". There may be a third reservoir up-dip from the rim block across the fault which we presume lies along the point of up-dip flexure. If a small reservoir does in fact exist here, it should not be drilled until such time as a substantial pressure drop occurs in the rim block, so that pressures in wells drilled in this third area will establish the presence or absence of an impermeable barrier between this area and the rim block wells, thus permitting analysis of reservoir conditions which will dictate the method of development.

The volume of oil in place in the basin block as estimated in Part III of this section has been virtually proven from the pressure-production behavior of the Benson-Montin-Greer M-5. This is discussed in Section D herein. This confirmation by the M-5 pressure-production behavior of total amount of oil initially in place in the basin block, estimated in Part III, does not necessarily confirm either the per-acre estimate of oil in place or the basin block area as outlined therein. There is no positive data available at this time to confirm either of these estimated quantities, and the close (for the data available) agreement of the volume of oil determined by these two independent methods could, of course, merely be the result of a fortuitous choice of acreage and per-acre oil in place quantities. This total volume confirmation, though not proving the ideas advanced in this section, certainly does not detract from them.

As indicated in Part III of this section, the rim block offers the greater possibility for development at a profit. It must be recognized, however, that the volume of oil estimated for the rim block is more speculative than that shown for the basin block, as we have no pressure confirmation of reservoir volume in the rim block. If the rim block were proved to be highly faulted, such that rather than one continuous reservoir there are a number of smaller ones separated by sealing faults, it may be that the rim block will require so many wells to satisfactorily deplete it that it will be uneconomic to develop. Also it must be recognized that with the sealing fault (at the basin flexure) we cannot be certain that the lower part of the rim block in fact contains oil. It could very well have bottom water, and the estimated recoverable oil volume accordingly be reduced by the amount of reservoir space occupied by it, and which we have heretofore estimated to contain oil.

It should be recognized that the estimates made in this section of oil in place and recoverable oil apply only to the zone colored in brown on the cross-sections. Should additional reserves be developed in the B-C zones, this volume of oil will be in addition to the recoveries estimated in this section.

VALUES OF K/ϕ FOR SANDSTONE RESERVOIRS AND FOR FLOW SYSTEMS OF FRACTURES IN AN IMPERMEABLE MATRIX

FRACTURES PARALLEL TO DIRECTION OF FLOW

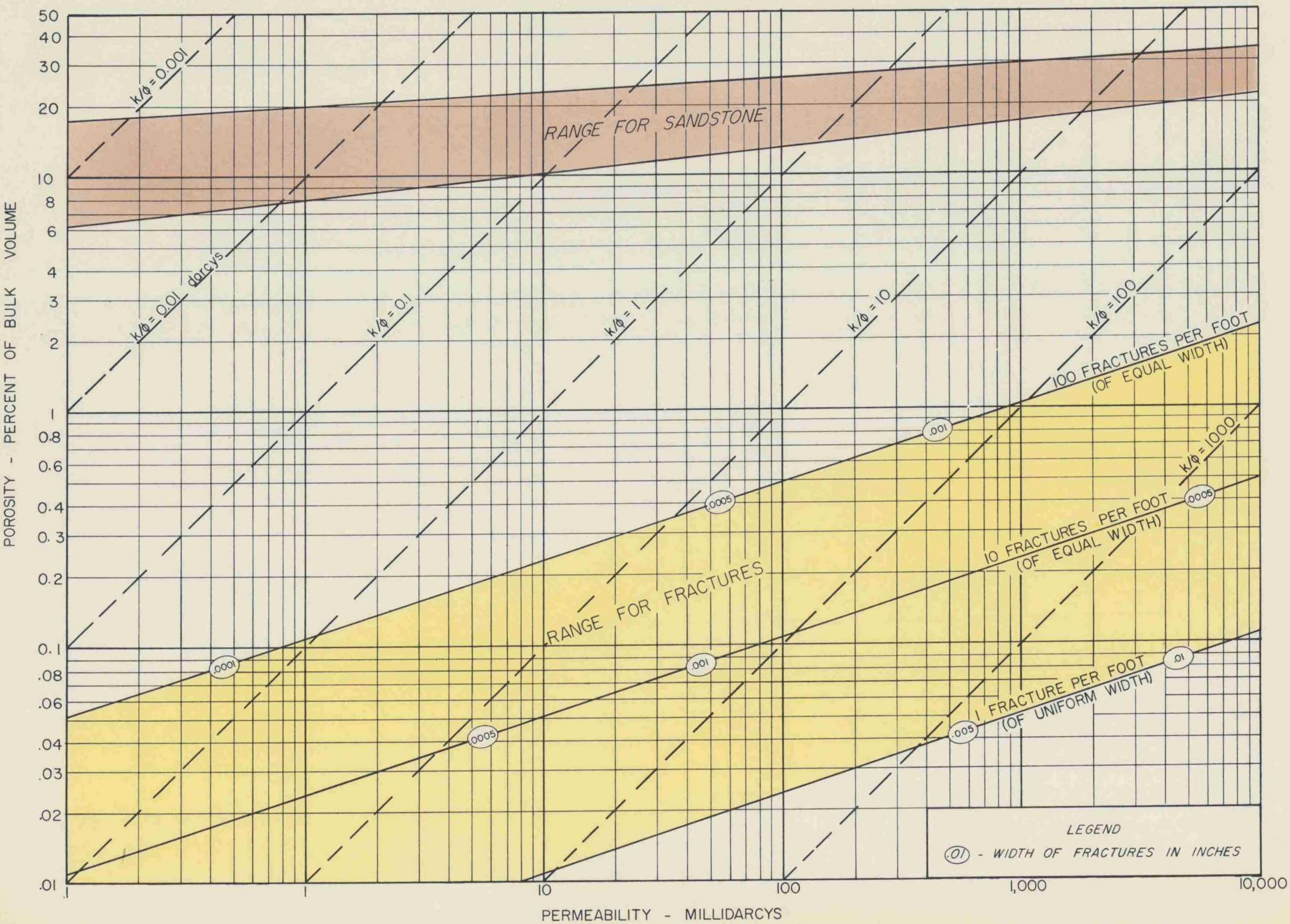
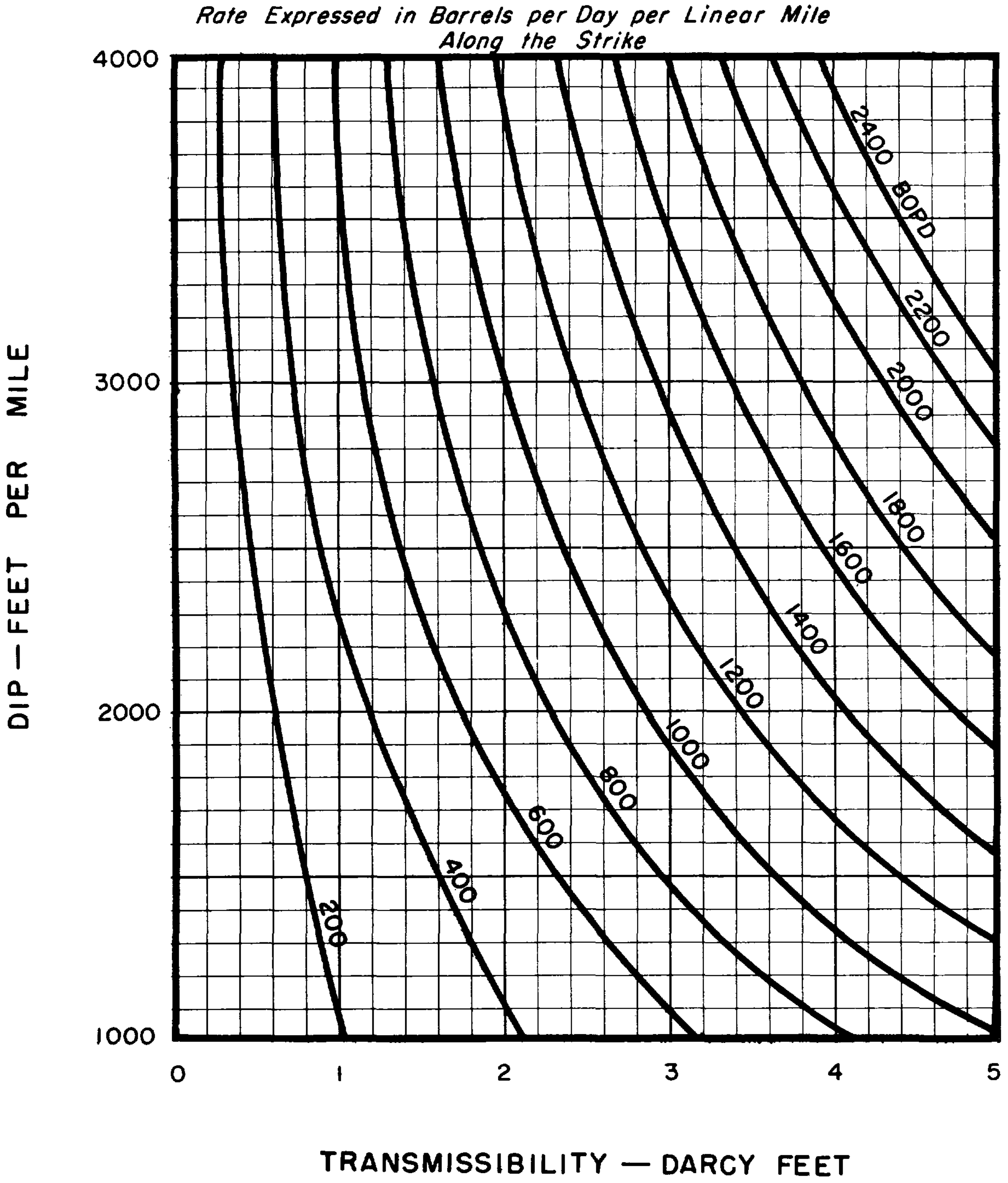


FIGURE 10

MAXIMUM GRAVITY DRAINAGE RATES
LA PLATA MANCOS RIM BLOCK

VICOSITY = 2 cp

Specific Gravity = .8



APRIL, 1968

PRESSURE-PRODUCTION DATA OF PRESENTLY COMPLETED WELLS AND INTERPRETATIONS

PART I PRESSURE-PRODUCTION DATA OF BENSON-MONTIN-GREER NO. M-5 STANDARD OF TEXAS

A. Pressure Build-Up Data for Survey run April, 1968

A bottom hole pressure build-up survey was made for the B-M-G No. M-5 Standard of Texas in April, 1968. At the end of this section is a tabulation of the data for the first twelve days shut in. Also at the end of this section are two plots of the data, being Figures 12 and 13. Figure 13 is merely a more detailed plot of the pressures taken after the second day of shut in.

B. Pressure-Production Relation for B-M-G No. M-5

Additional bottom hole pressure data of this well as furnished to us by the previous operator (Hoss) follows:

8 -6-59	1,462 pounds
September 1962	1,312 pounds

We have no information as to how long the well was shut in for the above pressures. We understand, however, that it was shut in at least 24 hours. Pressures were measured at a well depth of 5,932 feet (ground level). These pressures, plus two of the pressures taken by B-M-G in the April, 1968 survey, are plotted against cumulative production on Figure 14 at the end of this section.

C. Interpretations

1. Estimated Initial Reservoir Static Pressure

The data in Figure 14 indicates the initial reservoir static pressure in the subject well was between 1,470 and 1,480 pounds. This assumes the first pressure taken in August, 1959, was shut in long enough to approach static conditions. Since the well had only produced for a short time and the reservoir probably had a reasonably high diffusivity constant then, the measured pressure should be fairly close to the true static pressure. Since we do not have the data with which to make this determination, we can only say the initial pressure appears to be in the order of 1,475 to 1,500 pounds.

2. Current Static Reservoir Pressure

Pressures measured by B-M-G and shown on the table at the end of this section in the April survey were measured at 5,900 feet RKB. To adjust these pressures to the depth at which Standard of Texas ran its pressures requires the addition of 12 pounds to the figures shown in the April test. This means the well exhibited a 48-hour shut-in pressure of 1,058 pounds and a 12-day shut-in pressure of 1,107 pounds when adjusted to the datum of the original pressures. Both of these points are plotted on Figure No. 14. It is impossible to estimate accurately how much this pressure is below the current true static reservoir pressure. With the limited data available as to reservoir transmissibility and geometry of the reservoir, we can only make certain maximum and minimum estimates. The often used plot of $\frac{\Delta t}{t + \Delta t}$ does of course not apply in this instance [5]. Inspection of Figures 12 and 13 indicate the well is completed in a local area of permeability considerably lower than the next adjacent area. This is a typical situation in this kind of reservoir, and although we cannot state positively, it is logical to assume the transmissibility of the main fracture system will be something in excess of that shown by the last slope on Figure No. 14, which is .46 darcy feet. Allowing for errors of measurement, we accordingly estimate the minimum transmissibility at this time for the main fracture system to be .4 darcy feet. It is doubtful that the geometry of the reservoir is such that the difference in the 12-day pressure and the true static pressure could exceed that represented by a reservoir of quarter-circle pie shape in which the well is located at the point of the wedge. If this be the true situation, the actual reservoir pressure will be approximately 200 pounds higher than the 12-day shut-in pressure. If, however, the reservoir is circular in shape with the well in the approximate center and permeability is as high as 1.5 darcy feet (which seems entirely possible) then the true reservoir pressure will be less than 10 pounds greater than the 12-day shut-in pressure. Accordingly there is a wide range from 1,100 to 1,300 pounds in which the current static reservoir pressure may be. Since the maximum pressure increase noted above is probably an extreme situation, we believe it doubtful that the true reservoir pressure would be more than 100 pounds above the present 12-day pressure. Accordingly we have plotted this point on Figure No. 14 as the probable maximum pressure at this time. We can now determine from Figure 14 that the production-pressure relation for the reservoir in which the B-M-G No. M-5 Standard of Texas is completed is between 800 barrels per pound and 1,050 barrels per pound.

3. Total Reservoir Oil in Place

Although we do not have a fluid sample analysis for oil from this well, we would judge from gas-oil ratio, reservoir temperature and initial pressure that it would be comparable to that found in West Puerto Chiquito. If this be true, we can estimate [6] the compressibility of the reservoir system to be on the order of 350×10^{-6} to 400×10^{-6} for the average pressure decline from inception to the present date. With 400×10^{-6} and 800 barrels per pound, we arrive at 2 million barrels in place, and using 350×10^{-6} and 1,050 barrels per pound, the result is 3 million barrels in place. Accordingly we estimate as the two extremes 2 million and 3 million barrels of oil. A fair estimate at this time of total oil in place would be an average of the two extremes, or 2½ million barrels.

4. As indicated above, the M-5 is completed in a local area of low permeability. The size of this local area of low permeability can be calculated [7] following the work of Miller, Dyer and Hutchinson [8]. This indicates the reservoir volume in the area of low permeability (.047 darcy feet) to be about 6,000 barrels. This means, then, that if the well were subject to a sand-fracture treatment of a volume of 6,000 barrels, it would be connected to a part of the reservoir with higher permeability and accordingly the well's productivity would be increased. It is, of course, possible that if the fracture treatment were conducted at high enough injection rates, some channelling would result and it would not be necessary to saturate

the entire 6,000 barrels to achieve a satisfactory treatment. Two or three thousand barrels might be enough. If a treatment is planned for this well, however, it probably should be designed to reach the higher permeability of .46 darcy feet. This volume of oil has not been calculated, but it would be substantially greater than the 6,000 barrels indicated to reach the first break in permeability. If this part of the reservoir could be reached with a fracture treatment, the productivity of the well could be increased approximately ten to one, from its present 100 barrels per day capacity to approximately 1,000 barrels per day. Workover on this well is not at this time recommended, however, as we are not certain as to the mechanical condition of the well and if it would stand such a treatment. In addition, although the fracture treatment would probably enter the zone now producing, there is some question in this regard, since the well is completed with about 800 feet of open hole. At the present time it seems a more logical course of action would be to fracture the adjoining well (B-M-G No. J-5 Johnson) which well is approximately 2,000 feet from the M-5, rather than risk mechanical failure of the M-5 which might result from the fracture treating process.

5. All interpretations of data are necessarily based on the assumption the M-5 is producing from one zone and that no "thief" zones have affected the pressure build-up test. We believe this is true - but of course, under the circumstances must qualify our interpretation to this extent.

PRESSURE-PRODUCTION DATA OF TAYLOR NO. 1 VIC WALKER

The Taylor No. 1 Vic Walker was completed in February, 1968 and produced approximately twenty days, when it was shut in March 8th for a pressure build-up survey. Data regarding this test is set out on the schedule at the end of this section. Under conditions governing this pressure build-up the conventional plot of $\frac{\Delta t}{t + \Delta t}$ is useful. Accordingly such a plot was made and is enclosed at the end of this section as Figure No. 15. In interpretation of the data shown on Figure 15, we have assumed that the oil is saturated and that accordingly the diffusivity constant is not so high as to invalidate the type calculation used [(9)]. With this qualification, we make the following interpretations:

1. Transmissibility in the vicinity of the well is approximately 2.5 darcy feet.

2. The change in slope of the points plotted at about the 10-day period after shutting in the well indicates some type of boundary condition affecting the pressure build-up in the well. This could of course be the result of an overall decrease in permeability at distances away from the well, or it could be a straight-line boundary as for instance a fault at a distance of approximately 2,000 feet from the well.

3. There is no evidence from the pressure build-up data of a "closed" type reservoir. Rather the plot has the typical appearance of well pressure building up under "infinite

conditions". Accordingly no estimate can be made as to the size of the reservoir other than to know that it is something greater than the volume of oil which can be calculated from this data, which indicates a minimum reservoir measured in terms of hundreds of acres.

4. Pressures have not yet been run in this well, but it is possible to estimate the static bottom hole pressure in the vicinity of the well at this time from estimated density of the column of oil in the well. From the plot of Figure 15 we estimate the static fluid level to be on the order of 1,380 feet. This means an oil column of 940 feet above the E marker in this well. With an estimated average density of the oil column of .35 psi/foot, we arrive at an estimated pressure at the 2,320 foot depth in this well of 329 pounds.

5. If we adjust this pressure to the datum at which the M-5's first pressures were taken (which is + 102 feet subsea after correcting for depth difference due to deviation of hole) we arrive at a pressure for the comparable datum approximating 1,500 pounds (using estimated reservoir gradient of .33 psi/foot).

PART III SUMMARY

In addition to the interpretations previously set out in this section, the pressure data indicate that a fault lies between the two wells herein discussed. We say this for the following reasons:

1. There appears to be continuity in the general area of all zones which appear prospectively productive.

2. Both wells are obviously in communication with reservoir areas of substantial size. The M-5 reservoir is measured in terms of thousands of acres and the Vic Walker No. 1 reservoir has a minimum size measured in terms of hundreds of acres. Accordingly these two wells should be in communication, since they are only one mile apart. They are not, however, for their pressures, adjusted to the same datum, are at least 300 psi apart. Moreover, this current pressure in the No. 1 Walker, adjusted to the datum of the first pressures in the M-5, indicates approximately 1,500 pounds, which is the approximate value estimated for the virgin pressure of this area.

3. Although it may be possible for a steeply dipping reservoir to contain oil with varying degrees of gas in solution, the fractured shale reservoirs thus far discovered in the San Juan Basin have contained oil with the same (from field measurements) volume of gas in solution, regardless of the depth difference. Here are two wells with substantially different volumes of gas in solution. The M-5 gas-oil ratios have been reported at approximately 500 cubic feet per barrel, where the No. 1 Walker gas-oil ratio is estimated to be on the order of 50 cubic feet per barrel.

. Pressure data of the M-5 indicates if an interference test is conducted with wells of this character it will take a long time (months, and perhaps over a year) for wells on relatively wide spacing to show the type interference which will be required to demonstrate communication to the Oil Conservation Commission when applying for wider spacing. It is probably just such a set of reservoir conditions as is indicated by the M-5, and unfortunate circumstances of well locations and production rates, which caused failure of Mobil's attempt to establish interference in Boulder.

. Since the relative permeability of the oil in the vicinity of the M-5 is probably less now than originally due to presumed presence of some free gas in the reservoir, it is likely that the initial transmissibility was two or three times as great as now. Accordingly this would place initial minimum transmissibility in the main fracture system around the M-5 as something in excess of 1 to 1.5 darcy feet.

SCHEDULE OF DATA

PRESSURE BUILD-UP TEST
FOR
BENSON-MONTIN-GREER DRILLING CORP.
NO. M-5 STANDARD OF TEXAS

APRIL, 1968

DATE	TIME	DAYS SHUT IN	PRESSURE AT 5900' RKB : ECHOMETER	B.H. BOMB
4- 3-68	10:00 AM	0.12	505	
4- 4-68	10:00 AM	1.12	887	
4- 5-68	12:30 PM	2.2		1046.4
4- 6-68	12:30 AM	2.7		1058.2
	12:30 PM	3.2		1067.5
4- 7-68	12:30 AM	3.7		1074.0
	12:30 PM	4.2		1078.2
4- 8-68	12:30 AM	4.7		1079.8
	9:00 AM	5.05		1082.5
	10:30 PM	5.6		1083.5
4- 9-68	10:30 AM	6.1		1084.9
	10:30 PM	6.6		1086.7
4-10-68	10:30 AM	7.1		1087.7
	10:30 PM	7.6		1088.4
4-11-68	10:30 AM	8.1		1089.3
4-15-68	10:30 AM	12.1		1095.1

NOTE: Well was producing approximately 100 BOPD prior to shutting in.

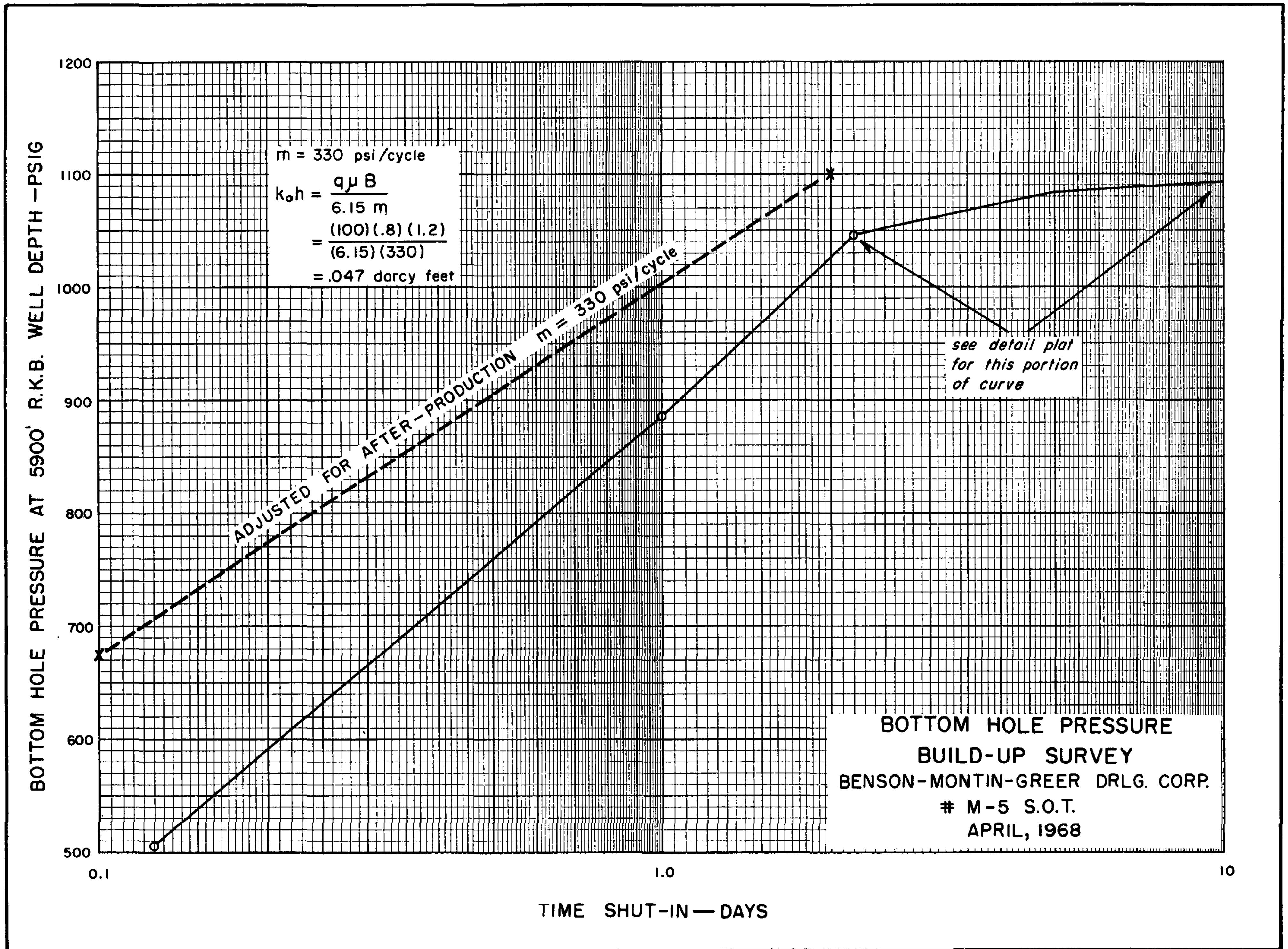

BOTTOM HOLE PRESSURE AT 5900' R.K.B. WELL DEPTH —PSIG
1200
1100
1000
900
800
700
600
500
0.1
1.0
10
TIME SHUT-IN — DAYS
m = 330 psi/cycle
$k_o h = \frac{q \mu B}{6.15\ m}$
$= \frac{(100)(.8)(1.2)}{(6.15)(330)}$
= .047 darcy feet
ADJUSTED FOR AFTER-PRODUCTION m = 330 psi/cycle
see detail plat
for this portion
of curve
BOTTOM HOLE PRESSURE
BUILD-UP SURVEY
BENSON-MONTIN-GREER DRLG. CORP.
M-5 S.O.T.
APRIL, 1968

FIGURE 12

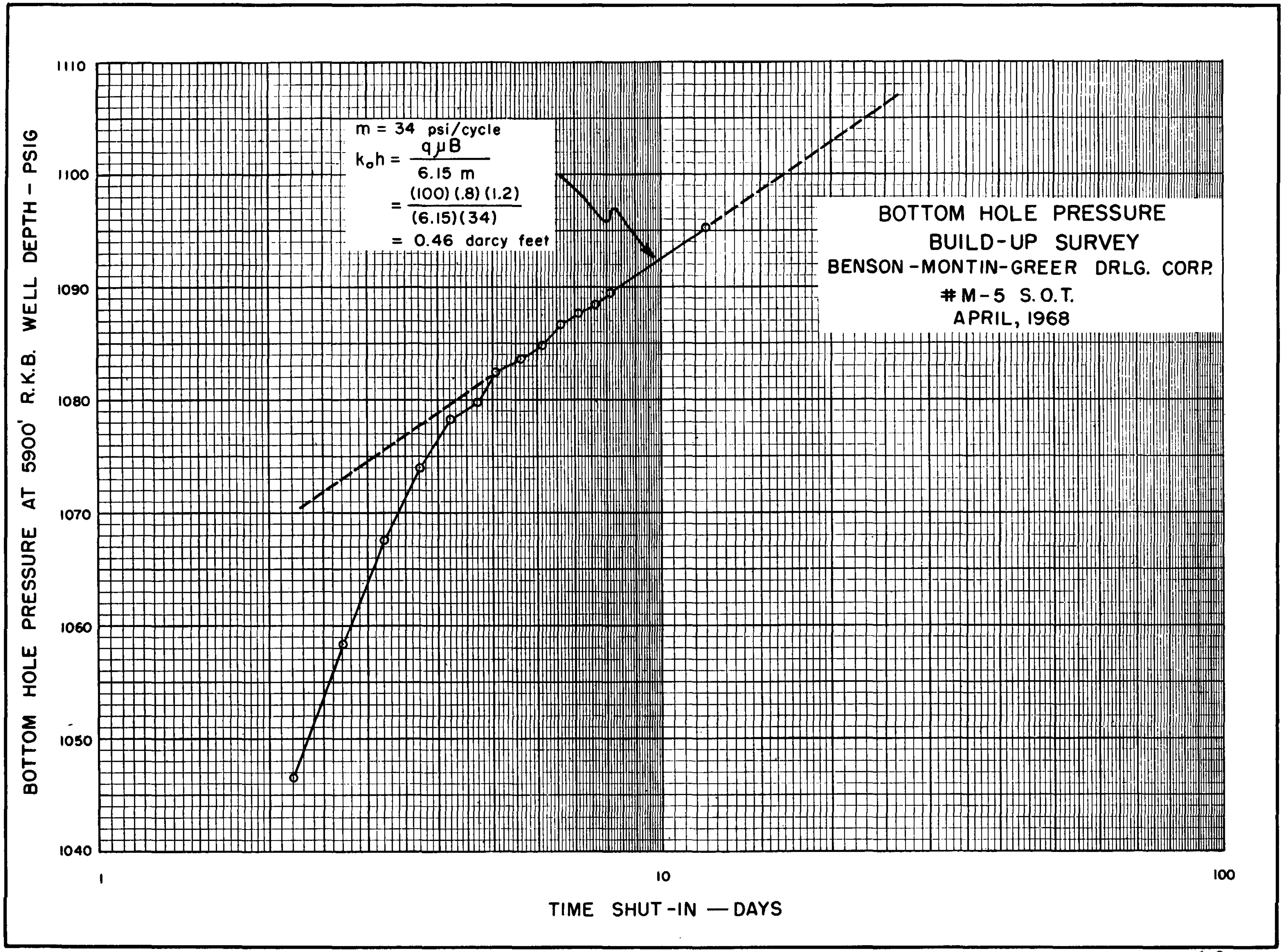

BOTTOM HOLE PRESSURE AT 5900' R.K.B. WELL DEPTH - PSIG
1110
1100
1090
1080
1070
1060
1050
1040
1
10
100
TIME SHUT-IN — DAYS
m = 34 psi/cycle
$k_o h = \frac{q \mu B}{6.15\ m}$
$= \frac{(100)(.8)(1.2)}{(6.15)(34)}$
= 0.46 darcy feet
BOTTOM HOLE PRESSURE
BUILD-UP SURVEY
BENSON-MONTIN-GREER DRLG. CORP.
#M-5 S.O.T.
APRIL, 1968

FIGURE 13

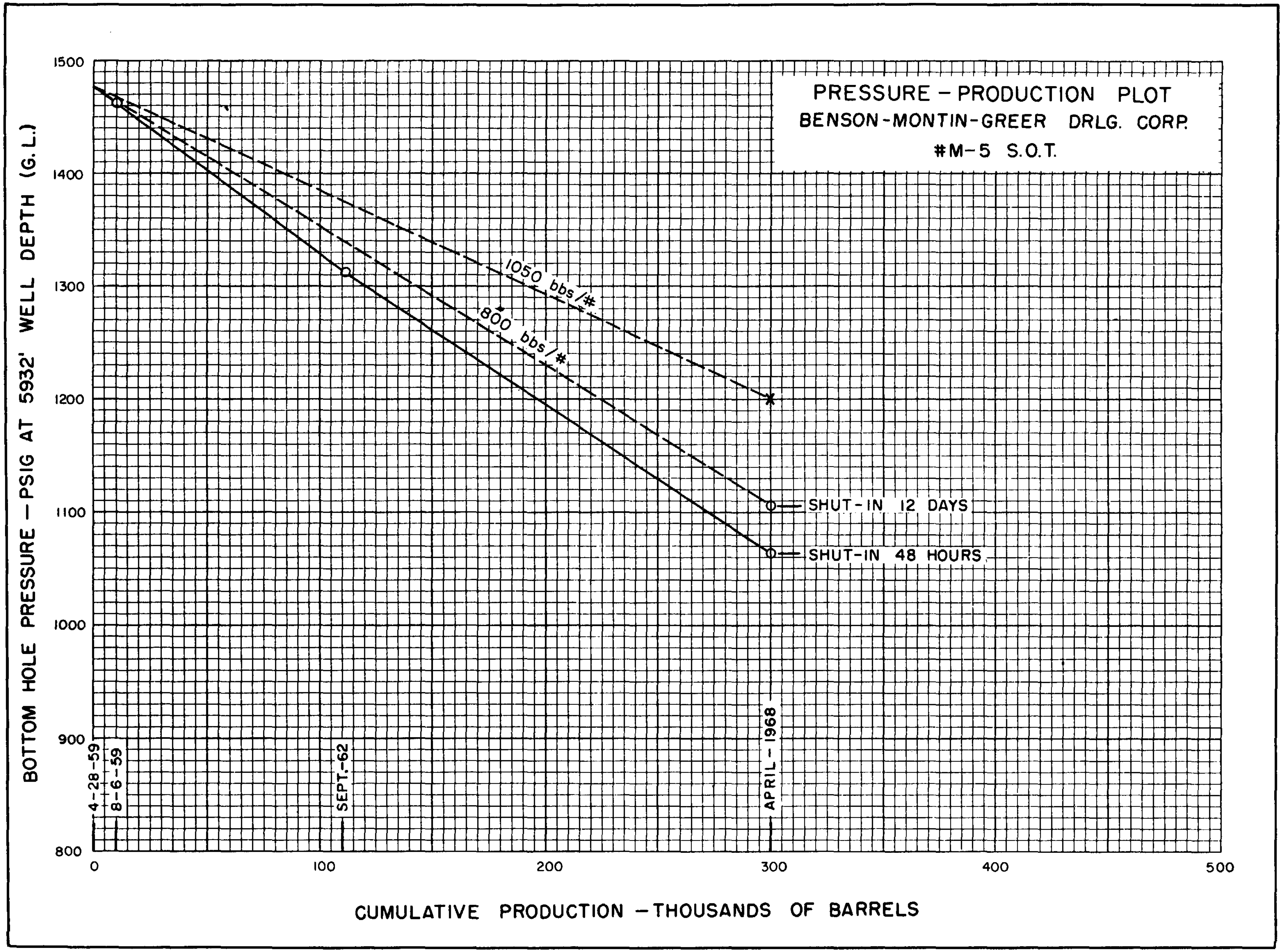

PRESSURE - PRODUCTION PLOT
BENSON-MONTIN-GREER DRLG. CORP.
#M-5 S.O.T.
BOTTOM HOLE PRESSURE - PSIG AT 5932' WELL DEPTH (G.L.)
CUMULATIVE PRODUCTION - THOUSANDS OF BARRELS
1500
1400
1300
1200
1100
1000
900
800
0
100
200
300
400
500
4-28-59
8-6-59
SEPT.-62
APRIL-1968
1050 bbs/#
800 bbs/#
SHUT-IN 12 DAYS
SHUT-IN 48 HOURS

FIGURE 14

LLOYD B. TAYLOR #1 VIC WALKER
PRESSURE BUILD-UP SURVEY

WELL HISTORY PRIOR TO SHUTTING IN:

1. SAND-FRAC TREATMENT $\pm$ 500 BBLS. OIL, 20,000# 20/40 SAND.

2. RECOVERED LOAD OIL IN 5 DAYS, 2-13 TO 2-18-68.

3. FIRST NEW OIL 2-18-68.

4. PRODUCED LAST 12 DAYS IN FEBRUARY, 1,272 BBLS. OIL

   PRODUCED FIRST 7 DAYS IN MARCH TILL 8:30 AM 3-8-68
   MARCH PRODUCTION 653 BBLS. OIL (DOWN ONE DAY).

5. PUMPING RATE WHILE PRODUCING $\pm$ 110 BOPD

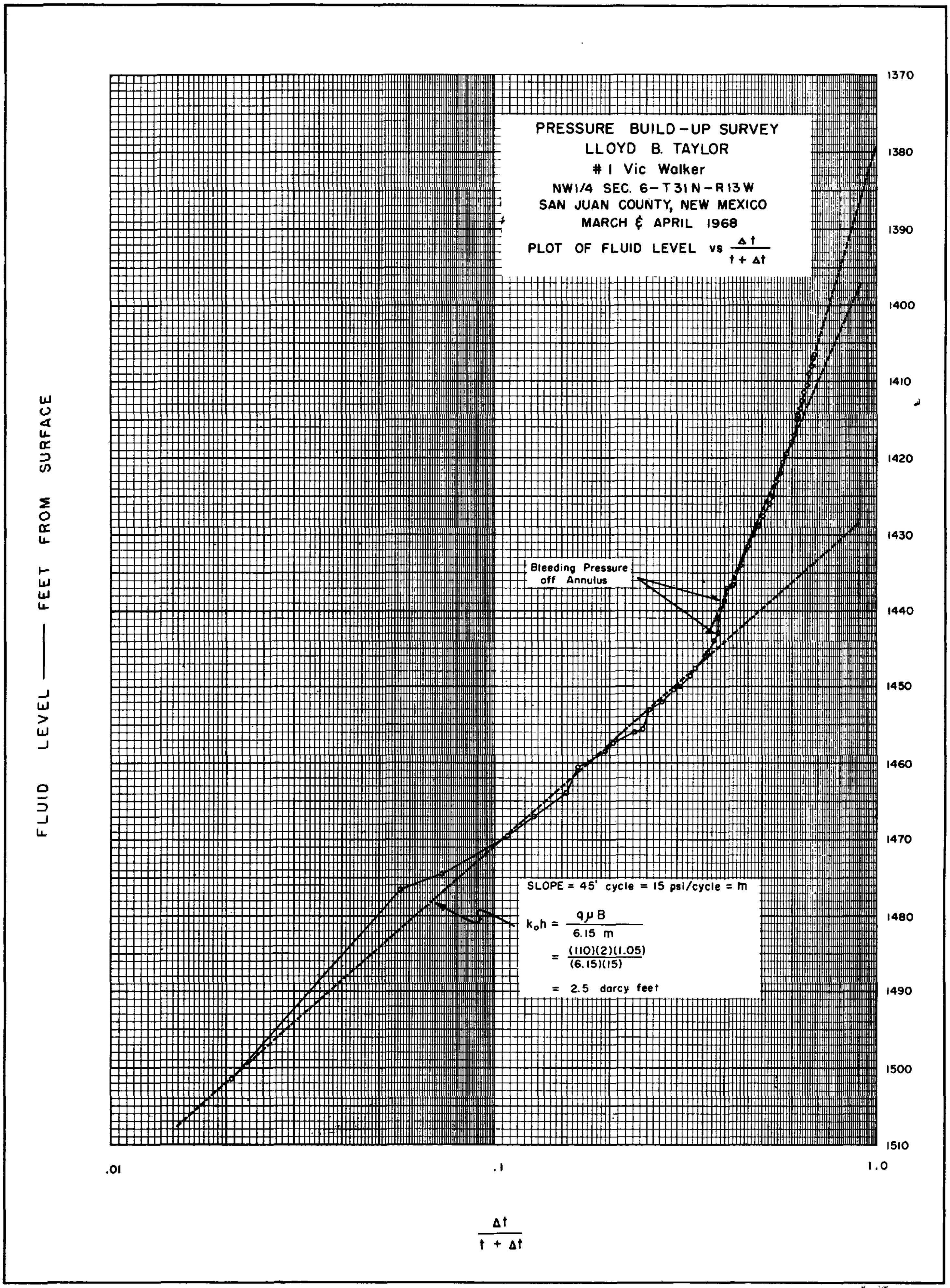
$$\frac{1272 + 653}{110} = 16.6 \text{ days} = \text{time } t, \text{ for use in plot of pressure vs. } \frac{\Delta t}{t + \Delta t}$$

FLUID LEVELS MEASURED WITH FLOAT ON WIRE LINE (ZEROED AGAINST SWAGE)

DATE	TIME	Δt (days)	$16.6 + \Delta t$ (days)	$\frac{\Delta t}{16.6 + \Delta t}$	FLUID LEVEL (feet from surface)
3- 8-68	5:00 PM	.35	16.95	.0206	1501½
3- 9-68	8:40 AM	1.00	17.60	.0568	1476½
	4:00 PM	1.31	17.91	.0730	1474½
3-10-68	9:15 AM	2.03	18.63	.1090	1469½
	6:00 PM	2.40	19.00	.126	1467
3-11-68	9:15 AM	3.03	19.63	.154	1464
	4:45 PM	3.33	19.93	.167	1460½
3-12-68	9:15 AM	4.03	20.63	.195	1458½
	4:00 PM	4.31	20.91	.206	1457½
3-13-68	9:15 AM	5.03	21.63	.232	1456
	4:40 PM	5.33	21.93	.243	1455½
3-14-68	8:45 AM	6.00	22.60	.255	1453
	4:15 PM	6.32	22.90	.276	1452

DATE	TIME	Δ t (days)	16.6 + Δ t (days)	$\frac{\Delta t}{16.6 + \Delta t}$	FLUID level (feet from surface)
3-15-68	8:45 AM	7.0	23.6	.297	1450½
	4:30 PM	7.33	23.9	.306	1450
3-16-68	7:40 AM	7.96	24.6	.324	1448½
	4:00 PM	8.31	24.9	.334	1447½
3-17-68	9:15 AM	9.03	25.6	.352	1446
	4:30 PM	9.33	25.9	.360	1445½
3-18-68	9:15 AM	10.03	26.6	.376	1444
				Bled pressure off annulus	
	4:45 PM	10.34	26.9	.384	1443
				Bled pressure off annulus. Fluid level	1441
3-19-68	8:15 AM	11.0	27.6	.398	1438½
				Bled pressure off annulus. Fluid level	1438
	4:45 PM	11.3	27.9	.405	1437
3-20-68	8:15 AM	12.0	28.6	.420	1436½
	5:15 PM	12.3	28.9	.425	1436
3-21-68	8:30 AM	13.0	29.6	.440	1434
	PM				1433
3-22-68	AM	14.0	30.6	.458	1431½
	PM				1431
3-23-68	AM	15.0	31.6	.475	1430
	PM				1429½
3-24-68	AM	16.0	32.6	.490	1429
	PM				1428½
3-25-68	AM	17.0	33.6	.505	1427½
	PM				1427
3-26-68	AM	18.0	34.6	.524	1426
	PM				1425½

DATE	TIME	Δt (days)	$16.6 + \Delta t$ (days)	$\frac{\Delta t}{16.6 + \Delta t}$	FLUID LEVEL (feet from surface)
3-27-68	AM	19.0	35.6	.535	1425
	PM				1423½
3-28-68	AM	20.0	36.6	.546	1423
3-29-68	AM	21.0	37.6	.559	1422
3-30-68	AM	22.0	38.6	.570	1420½
	PM				1420
3-31-68	AM	23.0	39.6	.581	1419½
	PM				1419
4- 1-68	PM	24.3	40.6	.597	1418
4- 2-68	AM	25.0	41.6	.602	1417
4- 3-68	AM	26.0	42.6	.612	1415
4- 4-68	AM	27.0	43.6	.620	1414½
4- 5-68	AM	28.0	44.6	.627	1413½
4- 6-68	AM	29.0	45.6	.636	1412½
4- 7-68	AM	30.0	46.6	.644	1411½
4- 8-68	AM	31.0	47.6	.652	1410½
4- 9-68	AM	32.0	48.6	.660	1410
4-10-68	AM	33.0	49.6	.666	1409
4-11-68	AM	34.0	50.6	.672	1408
4-12-68	AM	35.0	51.6	.680	1407
4-13-68	AM	36.0	52.6	.683	1406½



PRESSURE BUILD-UP SURVEY
LLOYD B. TAYLOR
1 Vic Walker
NW1/4 SEC. 6-T31N-R13W
SAN JUAN COUNTY, NEW MEXICO
MARCH & APRIL 1968
PLOT OF FLUID LEVEL vs $\frac{\Delta t}{t + \Delta t}$
Bleeding Pressure off Annulus
SLOPE = 45' cycle = 15 psi/cycle = m
$k_o h = \frac{q \mu B}{6.15\ m}$
$= \frac{(110)(2)(1.05)}{(6.15)(15)}$
= 2.5 darcy feet
FLUID LEVEL —— FEET FROM SURFACE
1370
1380
1390
1400
1410
1420
1430
1440
1450
1460
1470
1480
1490
1500
1510
.01
.1
1.0
$\frac{\Delta t}{t + \Delta t}$

FIGURE 15

DRILLING AND COMPLETION METHODS AND COSTS

As indicated in Part IV of Section C herein, experience in other fractured shale pools in the San Juan Basin has shown vertical separation of producing zones and the necessity to separately sand fracture each zone in the Niobrara from which production is desired.

To insure that fracture treatment will reach each potentially productive zone, it is necessary that casing (or liner) be cemented through the entire section in which the zones occur. It is, of course, possible in some instances to drill through the pay zone with mud and conventionally cement the production casing. If, however, drilling is attempted in this manner and the hydrostatic pressure of the mud column breaks down the producing zones and a large volume of mud enters the fractures, the producing ability of the reservoir near the well bore may be so adversely affected that it can never be made to produce at economical rates, even after fracture treatment.

It is accordingly recommended that completion be made by keeping mud off the prospective producing zones. This is accomplished by setting an intermediate string of casing at or near the top of the Niobrara and drilling in with rotary tools, using air or gas as the circulating medium, or with cable tools. If the choice is rotary tools and in the course of drilling too much natural free oil is encountered to permit "dusting" and continued drilling, it may be possible to change to oil as the circulating medium and successfully continue the drilling. Because of this contingency, the intermediate casing should be set through the marker "A" shown on the cross-section in Section B herein, as experience has shown that the Mancos Shale above the Niobrara may seriously slough if exposed to drilling with oil.

Since in at least the first few wells this casing point should not only be below the "A" marker for reasons set out above, it should also be set above the "B" marker, in order to expose to possible production the zones lying between "B" and "C" on the cross-section. This means a carefully controlled casing point, and because of possible faulting, particularly in the area of steep dips, it will be extremely difficult to project. More than one correlation log may be required to determine this casing point, which of course adds to the expense.

Once the hole is made, a liner must be properly cemented through the producing interval. To cement a liner in such a fashion as to protect any possible exposed fractures from cement is in itself a tricky project. By all means this operation should be conducted in a relatively straight hole. Maintenance of a straight hole in drilling in this area will be difficult and expensive. Dips of the beds here are in some places twice as steep as the steepest dips encountered in the Verde Gallup Pool, and straight hole drilling will accordingly be more difficult.

Once a properly cemented liner is set through the prospective producing zones, separate fracture treatment of the zones can only be insured by stage fracture treatments, setting bridge plugs between the stages, or by the "limited entry" procedure. Either method is expensive. If the well is treated in stages there is the possible additional cost of rental of the pumping equipment and rig time, as well as risk in drilling out the bridge plugs. If a limited entry fracture treatment system is used, larger diameter casing is required in order to insure adequate flow rates at the required pressures, especially for the deeper wells.

Under the circumstances, with the information available from other fields, and the number of dry holes already drilled in the subject area, a drilling program for this project should be based only on the assumption that it will be difficult and costly to establish production, and plans should be made accordingly. We believe it would be extremely unwise to drill additional wells in this area in the same manner that all of the dry holes were drilled.

Accordingly we recommend, among other things, that large sand fracture treatments be used in completion attempts, even though the prospective producing zones show no natural production. Also, since the wells will be treated with several thousand barrels of frac oil, it will be necessary to install pumping equipment to attempt to recover the frac oil, even though the well ultimately turns out to be a dry hole. As a result, the dry hole cost is practically the same as the cost of a completed producer, with the exception of the removable equipment.

Since the producing zone or zones are at this time only tentatively identified, all of the three unit obligation wells should be planned to test by sand fracture treatment not only the zones between markers D and E, but also the zones between markers B and C. In addition, an attempt should be made to core the well in Section 32 through the zones below the E marker and possibly the zone just above.

These obligation wells probably should be drilled with rotary tools, setting 7-5/8" casing between markers A and B, and drilling the prospective producing zones with air or gas. A $5\frac{1}{2}$" liner should be cemented with a lap into the 7-5/8" of 200 to 300 feet.

The zones between markers D and E should be fraced with a limited entry procedure insuring treatment of at least two of the three colored zones between these two markers. A bridge plug should then be set between markers C and D and the three zones between markers B and C should be treated by limited entry sandfrac.

These first three wells should then test the B-C zones separately from the D-E zones, in order that future drilling and completion methods be accordingly planned.

Experience in drilling wells in similar fashion in the Puerto Chiquito Pools has resulted in total well costs of $75,000.00 per well for shallow wells and an average of $175,000.00 per well for 6,000 to 7,000 foot wells. The same general range of costs is anticipated here at La Plata.

ECONOMICS OF DEVELOPMENT UNDER COMPETITIVE OPERATION

It is of course impossible at this time to forecast accurately the exact area which will be developed or the number or quality of the wells which will be drilled. It is apparent, however, that for the oil recoveries and well costs estimated herein, development of the area at a profit cannot be realized under competitive conditions with any conventional spacing pattern, even 320 acres per well. Examples of fieldwide economics have been calculated, the results of which are set out herein, showing development costs and oil recoveries of 40-acre, 80-acre, 160-acre and 320-acre competitive development programs. It is realized, of course, that under the more dense spacing programs all of the wells would not be drilled because the field would be depleted before the wells could be drilled. It is interesting, however, to compare economics which might result if locations were drilled on the various spacing patterns set out above.

As economics of each of the patterns is reviewed, one is inclined to think that wells would never be drilled under such conditions. On the other hand, when we realize that wells will be completed here with potentials measured in terms of thousands of barrels per day, we can understand how company managements might, under the wider spacings, authorize the drilling of more wells than are necessary to efficiently deplete the reservoir, if operations are conducted competitively.

As a basis for comparison of economics of the various spacings, it is assumed that Area A would be productive and that recoveries would be as shown under Section C, Part III, which is 1,170,000 barrels. A plat is presented for each of the spacing plans showing producing wells and locations of probable dry holes. For the 320-acre spacing plan only, costs and recoveries are shown, not only for the field as a whole but for individual wells, and by company ownership of the tracts on which they are drilled.

As to well costs, figures for the 320-acre spacing plan were based on those referred to in Section E herein, prorated for intermediate depths. For the 40-acre pattern, costs were estimated to be one-half as much, for the reason that under such a program wells would be drilled as cheaply as possible - perhaps with mud and running the risk of mud damage. Where so many wells are drilled, however, it is not necessary that all wells be properly completed, and through happenstance enough wells would probably penetrate the producing zone at points where the reservoir was not fractured and permit completion without losing mud to the formation. If successful frac treatments resulted in only 10 or 15 percent of the wells so drilled, the reservoir could be depleted. Also, for the closer spacing, allowables will be less and pumping equipment smaller and less costly. Costs for the intermediately spaced wells (80 acres and 160 acres) were arbitrarily prorated between these two extremes. The costs are accordingly summarized as follows:

PER WELL COST ESTIMATES FOR SPACINGS AND DEPTHS INDICATED

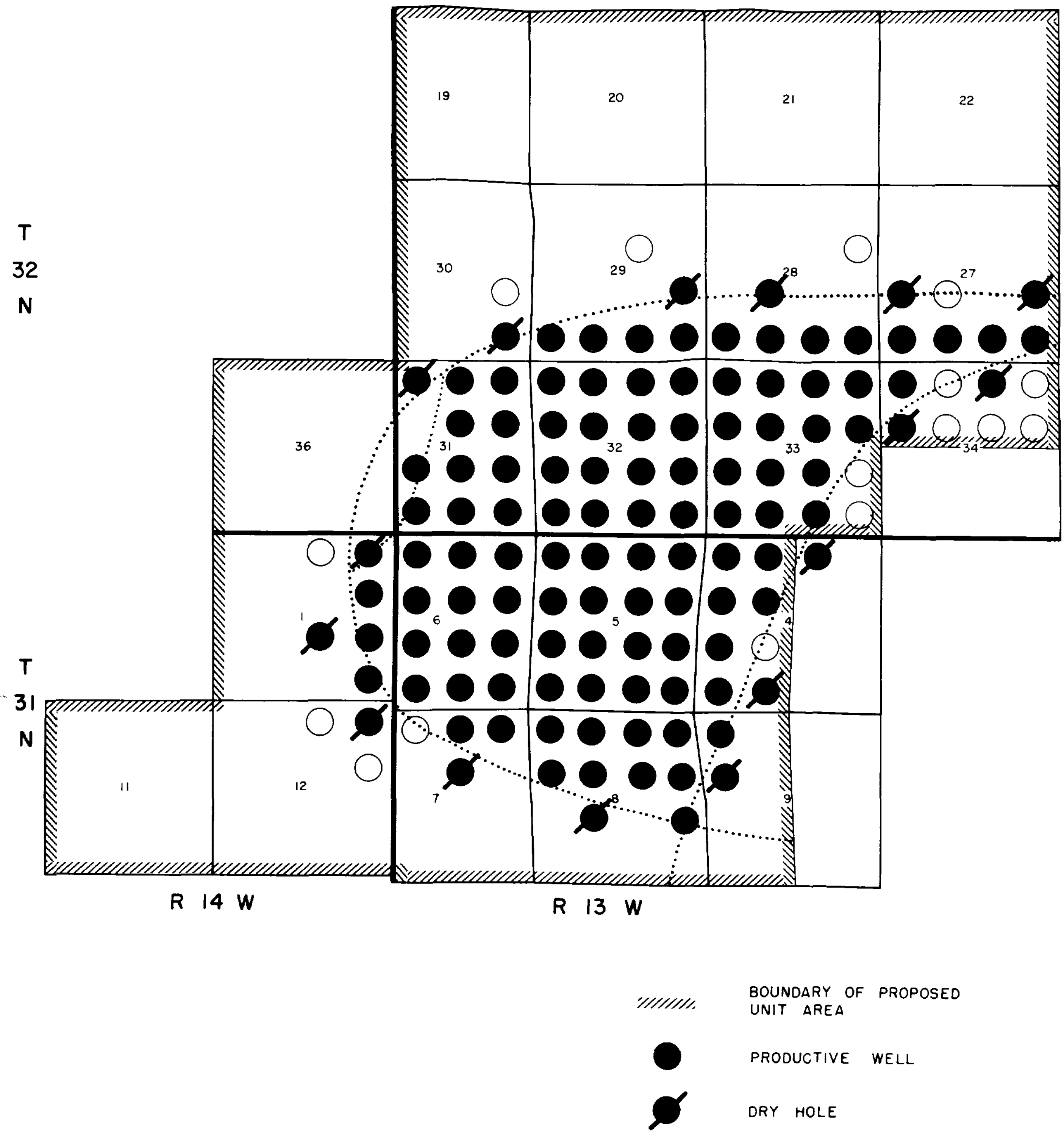
COMPLETION DEPTH (for contour interval shown)	SPACING 40 acres ($M)	80 acres ($M)	160 acres ($M)	320 acres ($M)
Above 4,000	37	50	63	75
3,000 - 4,000	47	63	80	95
2,000 - 3,000	57	76	95	115
1,000 - 2,000	67	90	112	135
0 - 1,000	77	103	130	155
Below 0	87	116	145	175

Dry holes are estimated at 80 percent of producing well cost.

The economics for each of the well spacing patterns, 40-acre, 80-acre, 160-acre and 320-acre, are set out individually on the pages that follow.

PLAT OF PROPOSED LA PLATA MANCOS UNIT

SHOWING WELL LOCATIONS IF AREA A IS
DRILLED UNDER COMPETITIVE CONDITIONS
ON A WELL SPACING PATTERN OF
40 ACRES PER WELL.
(ASSUMING ONLY AREA A TO BE PRODUCTIVE)



ECONOMICS OF DRILLING ON 40-ACRE SPACING UNDER COMPETITIVE OPERATIONS

Drilling costs of the development plan on the page facing are summarized as follows:

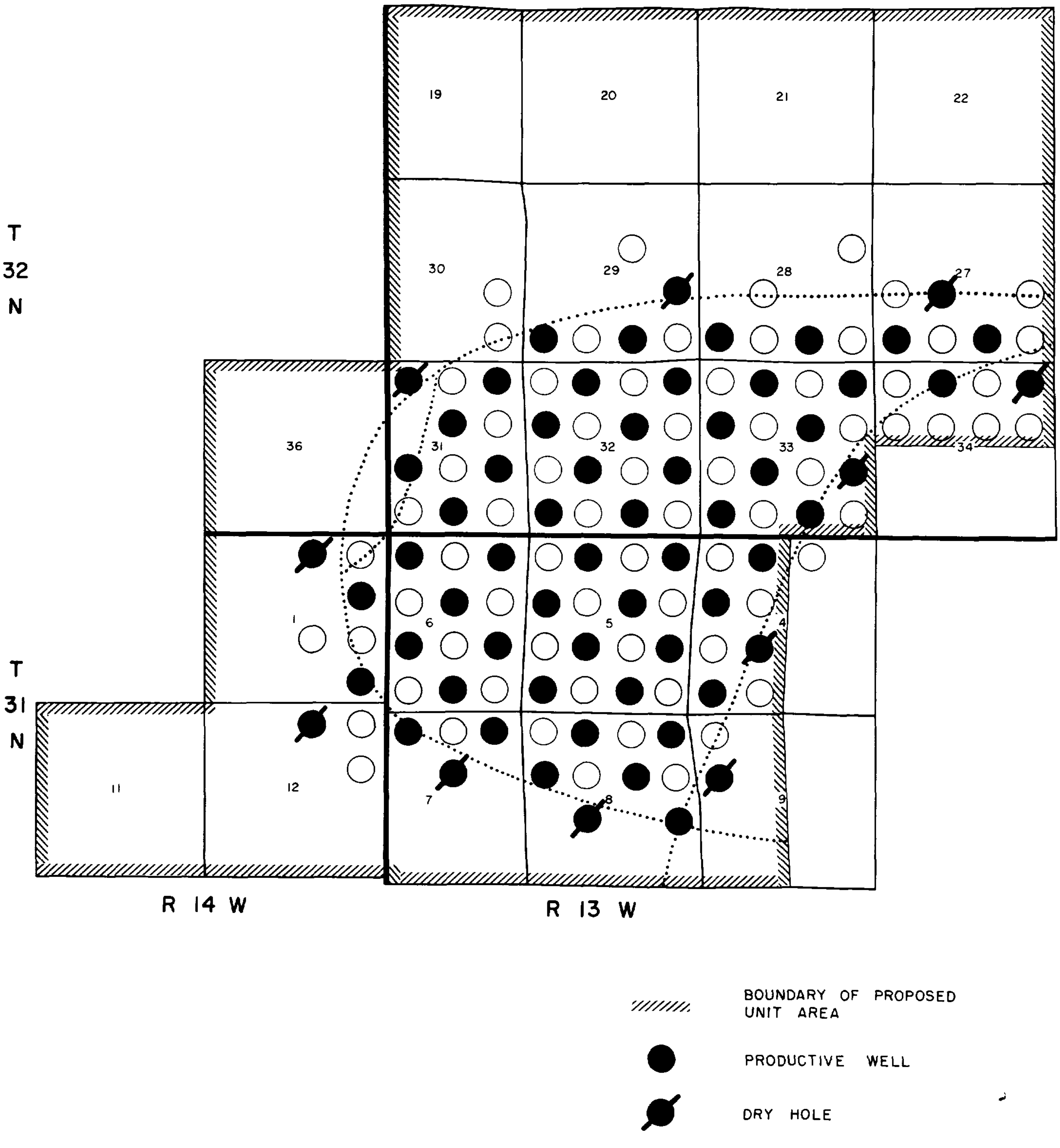
Depth of wells drilled (in terms of contour interval)	Number of wells drilled			Per well cost		Cost	
	Prod.	Dry Holes	Total	Prod.	Dry Holes	Prod.	Dry Holes
				$M	$M	$M	$M
Above 4,000'	7	3	10	37	30	260	90
3,000 - 4,000'	10	1	11	47	38	380	38
2,000 - 3,000'	8	1	9	57	46	370	46
1,000 - 2,000'	11	1	12	67	54	740	54
0 - 1,000'	12	1	13	77	62	920	62
Below 0	54	9	63	87	70	4,700	630
TOTAL	102	16	118			7,370	920

SUMMARY:	PRODUCING WELLS COST	$7,370,000.00
	DRY HOLES COST	920,000.00
	TOTAL COST	$8,290,000.00
	OIL RECOVERED	1,170,000 barrels
	DEVELOPMENT COST	$7.07/barrel

PLAT OF PROPOSED LA PLATA MANCOS UNIT

SHOWING WELL LOCATIONS IF AREA A IS DRILLED UNDER COMPETITIVE CONDITIONS ON A WELL SPACING PATTERN OF 80 ACRES PER WELL

(ASSUMING ONLY AREA A TO BE PRODUCTIVE)



ECONOMICS OF DRILLING ON 80-ACRE SPACING UNDER COMPETITIVE OPERATIONS

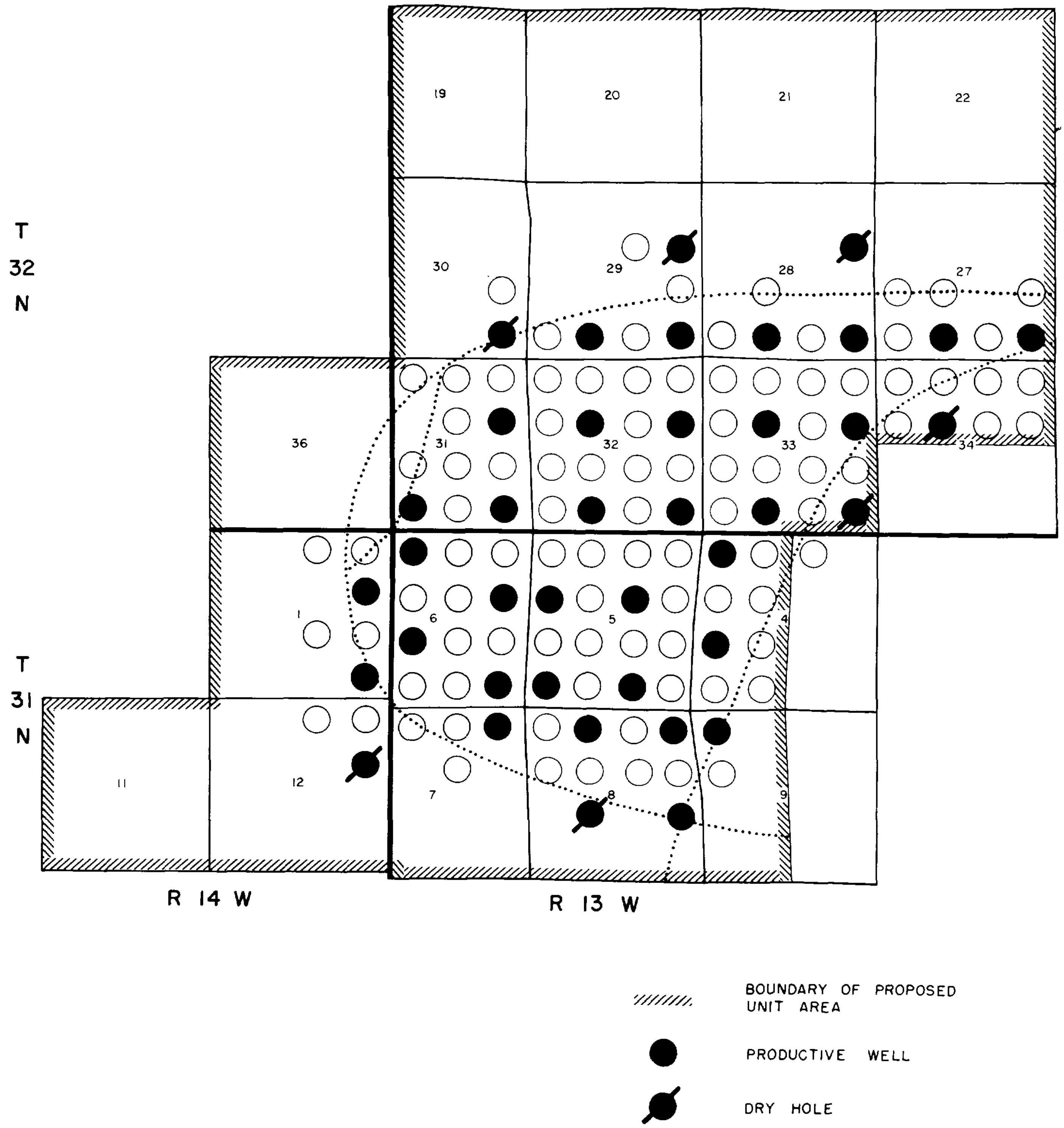
Drilling costs of the development plan on the page facing are summarized as follows:

Depth of wells drilled (in terms of contour interval)	Number of wells drilled			Per well cost		Cost	
	Prod.	Dry Holes	Total	Prod.	Dry Holes	Prod.	Dry Holes
				$M	$M	$M	$M
Above 4,000'	4	2	6	50	40	200	80
3,000 - 4,000'	6	1	7	63	50	380	50
2,000 - 3,000'	3	0	3	76	61	230	-
1,000 - 2,000'	5	1	6	90	72	450	72
0- 1,000'	7	1	8	103	82	720	82
Below 0	27	6	33	116	93	3,130	558
TOTALS	52	11	63			5,110	842

SUMMARY:	PRODUCING WELLS COST	$5,110,000.00
	DRY HOLES COST	842,000.00
	TOTAL COST	$5,952,000.00
	OIL RECOVERED	1,170,000 barrels
	DEVELOPMENT COST	$5.08/barrel

PLAT OF PROPOSED LA PLATA MANCOS UNIT

SHOWING WELL LOCATIONS IF AREA A IS
DRILLED UNDER COMPETITIVE CONDITIONS
ON A WELL SPACING PATTERN OF
160 ACRES PER WELL
(ASSUMING ONLY AREA A TO BE PRODUCTIVE)



ECONOMICS OF DRILLING ON 160-ACRE SPACING UNDER COMPETITIVE OPERATIONS

Depth of wells drilled (in terms of contour interval)	Number of wells drilled			Per well cost		Cost	
	Prod.	Dry Holes	Total	Prod.	Dry Holes	Prod.	Dry Holes
				$M	$M	$M	$M
Above 4,000'	3	1	4	63	50	189	50
3,000 - 4,000'	3	0	3	80	64	240	-
2,000 - 3,000'	2	1	3	95	76	190	76
1,000 - 2,000'	3	1	4	112	90	336	90
0- 1,000'	5	0	5	130	104	650	
Below 0	16	4	20	145	116	2,320	464
TOTALS	32	7	39			3,925	680

SUMMARY:		
	PRODUCING WELLS COST	$3,925,000.00
	DRY HOLES COST	680,000.00
	TOTAL COST	$4,605,000.00
	OIL RECOVERED	1,170,000 barrels
	DEVELOPMENT COST	$3.83/barrel

PLAT OF PROPOSED LA PLATA MANCOS UNIT

SHOWING WELL LOCATIONS IF AREA A IS DRILLED UNDER COMPETITIVE CONDITIONS ON A WELL SPACING PATTERN OF

320 ACRES PER WELL

(ASSUMING ONLY AREA A TO BE PRODUCTIVE)