ECONOMICS OF DRILLING ON 320-ACRE SPACING UNDER COMPETITIVE OPERATIONS

One of the main difficulties in achieving wide spacing benefits in a comparatively small pool operated under competitive conditions is illustrated by the plat on the page facing, on which is shown the 320-acre tracts allotted to each producing well. Here we find 11 producers in the rim block, which has approximately 2,400 productive acres, and 10 producers in the basin block with approximately 2,000 productive acres. These are effective reservoir spacings of 220 and 200 acres per well respectively. It is obvious that an accurate estimate of pool average per well economics for the small pools cannot be made by simply translating barrels per acre recovery and official well spacing into per well recoveries. The practical implication of actual reduced drainage areas per well must be considered.

It is realized, of course, that this situation could be greatly rectified by requiring wells to be located on specific diagonal quarter-section spots. The probability of operators agreeing on such a spacing plan under the extremely erratic conditions (from the standpoint of individual well productivities) which obtain in these fractured shale reservoirs is quite remote. Because of the practical impossibility of this type spacing being set, an economic study of such a plan has not here been made.

Because of the large difference in economics of the basin block development as compared to the rim block development, these two reservoirs were analyzed separately. The overall economics of each are set out below in the same fashion as previously for the more dense development patterns.

BASIN BLOCK

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'	-	-	-	75	60	-	-
3,000 - 4,000'	-	-	-	95	76	-	-
2,000 - 3,000'	-	-	-	115	93	-	-
1,000 - 2,000'	-	-	-	135	108	-	-
0 - 1,000'	-	-	-	155	124	-	-
Below 0	9	2	11	175	140	1,575	280

SUMMARY:	PRODUCING WELLS COST	$1,575,000.00
	DRY HOLES COST	280,000.00
	WORKOVER (2 AT $50,000 EACH)	100,000.00
	TOTAL COST	$1,955,000.00
	BASIN BLOCK RECOVERY (SECTION C, PART III)	300,000 barrels
	DEVELOPMENT COST	$6.50/barrel

RIM BLOCK

Depth of wells drilled (in terms of contour interval)	Number of wells drilled Prod.	Dry Holes	Total	Per well cost Prod.	Dry Holes	Cost Prod.	Dry Holes
				$M	$M	$M	$M
Above 4,000'	1	1	2	75	60	75	60
3,000 - 4,000'	3	0	3	95	76	285	-
2,000 - 3,000'	2	1	3	115	93	230	93
1,000 - 2,000'	1	0	1	135	108	135	-
0 - 1,000'	4	0	4	155	124	620	-
Below 0	-	-	-	175	140	-	-
TOTALS	11	2	13			1,345	153

SUMMARY:	PRODUCING WELLS COST	$1,345,000.00
	DRY HOLES COST	153,000.00
	TOTAL COST	$1,498,000.00
	RIM BLOCK RECOVERY (SECTION C, PART III)	870,000 barrels
	DEVELOPMENT COST	$1.72/barrel

As stated earlier, it is impossible at this time to determine exactly the outline of the producing area and exactly which locations will afford producers and which will give dry holes. However, all oil pools have limits, and the economics reflected here will generally apply to La Plata even though the pool boundaries be somewhat different from that indicated here. We believe, however, for the pool boundaries assumed that the development (including dry holes) would likely be about as shown, and since a possible profit (though not attractive) from overall rim block development is possible, we have examined in more detail the probable individual well costs and recoveries and the resulting economics to the owners of these tracts.

The assumptions in this analysis are:

1. Each well will have a P.I. of 1.0 and no reduction in P.I. is estimated (since for the purpose of this analysis we are interested only in relative tract recoveries rather than time required to produce the oil).

2. Pressure at down-dip limit of reservoir will have straight-line decline to $\frac{1}{4}$ its initial value when $\frac{1}{2}$ of oil is produced and another straight-line decline to 0 pressure for remainder of production.

3. The pressure in (2) above will determine the fluid head above pay in each well and the P.I. will accordingly be: $\frac{\text{Feet of fluid head}}{3}$

4. Top allowable is 8 x 70 = 560 BOPD

This above described type of analysis may at first appear rather hypothetical and one might question whether such a calculation would be of much true value in estimating relative well recoveries. The method has been used, however, in the East Puerto Chiquito Pool with amazing accuracy to forecast when up-dip wells would suffer extreme drops in productivity and concurrently develop high gas-oil ratios.

We believe it shows reasonably well what might be anticipated from this steeply dipping reservoir. For the calculations to be valid, of course, there must be a common reservoir with a fracture system and wells must be completed so as to be satisfactorily in communication with it. This could likely be the case here.

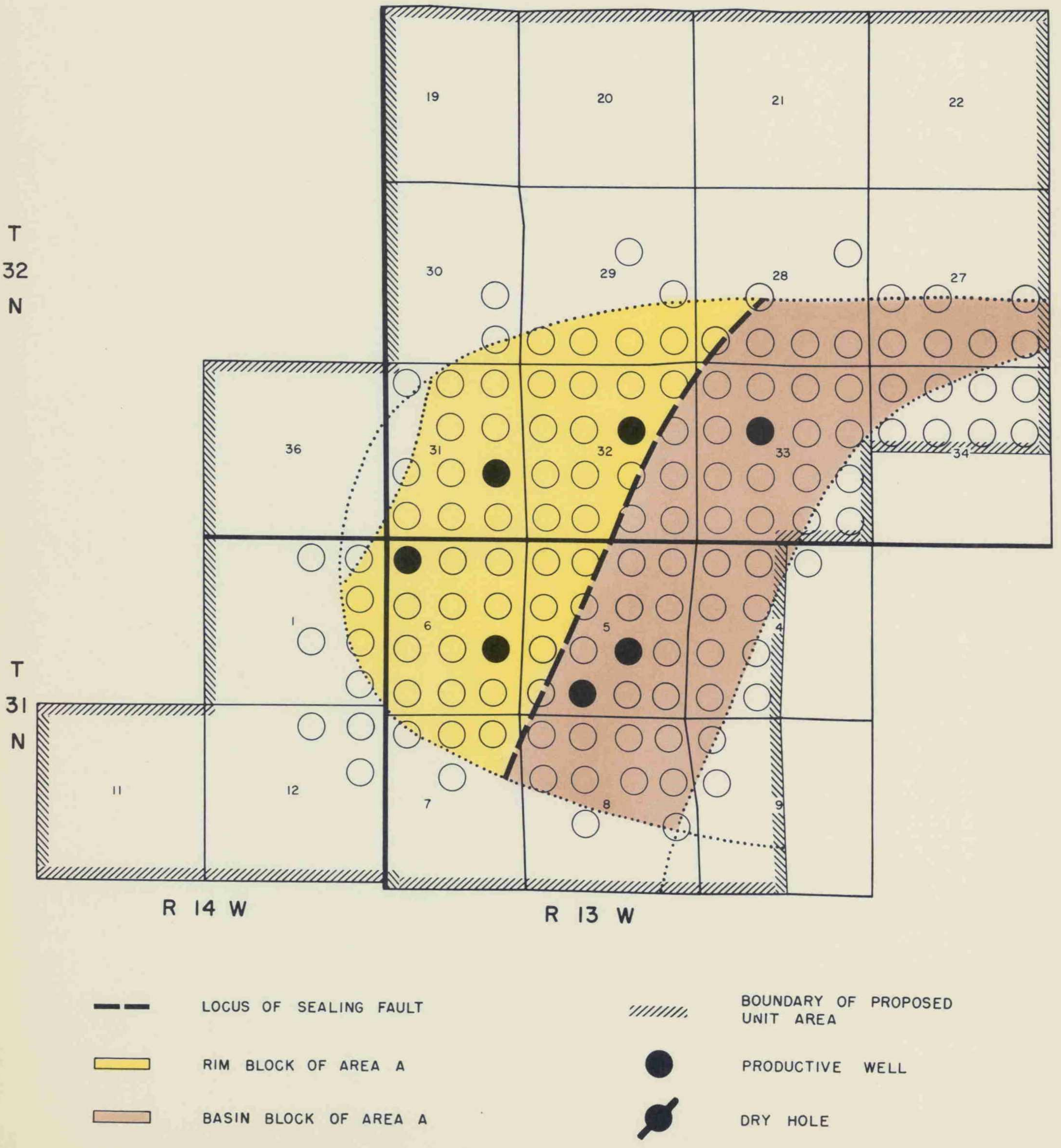
Results of this analysis are set forth in the following table:

	WELLS				
	NE 1	SE 1 SE 31 NE 31	SW 29 NE 6	SE 5	SE 29 SW 32 NE 7
PAY DATUM (feet above sea level)	4,000	3,500	2,200	1,500	500
RECOVERY FOR GROUP (M BBLS)	14	98	163	101	494
RECOVERY PER WELL	14	33	81	101	131
COST PER WELL ($M)	75	95	115	135	155
DEVELOPMENT COST ($/BBL)	5.30	2.88	1.42	1.33	1.31

The above analysis assumes simultaneous development. If the shallow wells are allowed to produce for a substantial period of time before the deeper wells are drilled they will have accordingly higher recoveries than shown above.

PLAT OF PROPOSED LA PLATA MANCOS UNIT

SHOWING WELL LOCATIONS IF AREA A IS DRILLED UNDER UNITIZED CONDITIONS (ASSUMING ONLY AREA A TO BE PRODUCTIVE)



ECONOMICS OF DEVELOPMENT UNDER UNIT OPERATION

Because of the relatively high degree of communication (in relation to total oil in place) inherent in fractured shale reservoirs, they are ideally suited for development under unitized operation. Not only can a higher ultimate recovery be realized through unit operation, but the oil can be recovered with a fewer number of wells than results under competitive conditions. The La Plata Pool is no exception to this general rule. If the main fracture system here carries a transmissibility of 1 to 2 darcy feet (which is inferred from data of the two producing wells now in the area) and individual fault blocks are as large as is presently indicated, Area A can be depleted with no more than ten wells, and possibly with as few as eight, if they are successfully connected to the fracture system, and if they are located as shown on the plat facing this page.

The two presently producing wells are shown on this plat (southwest quarter of Section 5 and northwest quarter of Section 6) as well as the three unit obligation wells:

Southeast quarter of Section 31
Southeast quarter of Section 6
Northeast quarter of Section 32

In addition, the plat indicates the well in the southeast quarter of Section 5 worked over to become a producer, and that one new well is drilled in the basin block.

Should the workover on the well in the southeast quarter of Section 5 be successful, consideration might then be given to refracturing the well in the southwest quarter of

Section 5. If this workover also proves successful and the well in Section 33 has a high capacity, it will not be necessary to drill additional wells in the basin block, and one of the two wells in Section 5 could be shut in as an observation well for interference test purposes for the basin block.

As to the rim block, the well in the northwest quarter of Section 6 could be shut in as an observation well for interference tests in this block. It is possible that the working interest owners will want to keep this well permanently shut in as an observation well useful for determining the rate of pressure decline, from which estimates might be made as to the size of the rim block reservoir and whether additional wells should be drilled. * Obviously the exact drilling pattern and recovery estimates will be revised as wells are drilled and pressure and production data obtained.

Using drilling costs in the analysis in the preceding section for 320-acre spacing, total cost to the working interest owners other than Taylor for the development plan described above would be:

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* In this connection it might be well to consider initial completion only in the D-E zone in wells in the rim block, in order to more accurately evaluate the pressure behavior. This means additional expense when the B-C zones would later be stimulated. The cost might be well repaid, however, through the saving of not drilling unnecessary wells.

			$ M
Obligation wells:	SE 31		95
	SE 32		155
	SE 6		135
Development well	NW 33		175
Workover	SE 5		50
Purchase (est.)	SW 5		150
Workover	SW 5		50
			$ 810

For this cost the cross-assigned working interest owners could expect to recover 2,400,000 barrels (Section C, Part III) less the amount of oil going to Taylor for his participation in the unit. Taylor's share of the ultimate recovery will depend partly on how fast the other wells are drilled and exactly what acreage is considered by the U.S.G.S. to be productive in establishing the participating area. It is estimated at this time that Taylor's share of the oil under a divided type unit operation (as now planned) and with a reasonably timed development program will amount to approximately 8 percent of the total pool production, or about 200,000 barrels. Oil recovery, then, to the cross-assigned interest owners would approximate 2,200,000 barrels for a development cost of $810,000.00, or approximately 37 cents per barrel. The above figures are for unit operations without gas injection. If gas injection is required in the rim block (to maintain producing rates as high as desired and still permit the depletion mechanism to be primarily gravity drainage) an additional cost approximating $100,000.00 might be required. Only analysis of the facts after the wells are drilled will determine whether it would be preferable to inject gas as compared to drilling additional wells should the productivity be not as high as necessary to produce the oil in the time desired. If the owners elect to inject gas, it is doubtful that makeup gas would have to be purchased, since the basin block produced gas would be available, as well as gas from the rim block production. Accordingly, additional development cost would approximate another 5 cents per barrel, raising the total to 42 cents per barrel if gas injection were initiated in the rim block.

In addition to the other usual advantages of unitization which include, of course, centralized tank batteries and cost savings from this standpoint, it is probable that unitization would bring about a higher price for the produced oil. Presently oil is being trucked from Taylor's well at a cost of 25 cents per barrel. Oil from the Benson-Montin-Greer M-5 Standard of Texas moves through a six or seven mile flowline to a tank battery in the Verde Gallup Pool, where it is sold for top price. This, of course, would not be a very practical arrangement for each operator to independently consider.

As to the pipeline company extending its system to La Plata, a unitized operation will present a more stable picture, and the company will be able earlier to make its plans for gathering the La Plata oil. An important factor here, of course, would be a central tank battery, possible under unit operation.