Economic Factors Involved in Waterflooding

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EVALUATION AND/OR ACQUISITION

Whether a property is already owned, or an operator is contemplating acquisition, an evaluation of its waterflooding potential and consideration of all economic factors involved are essential prior to actual water injection. This is a very critical stage of the property's economic picture; however, a full evaluation is often by-passed with the perfunctory decision, "All the engineering work you can do is of little importance since a pilot flood to test the reservoir's susceptibility is the only way to tell if it will flood". One can readily see that this is basically true but not the most logical sequence of events. With such an approach, many reservoirs can be placed under flood which do not have a "chinaman's chance" of being economically successful. Therefore, it is stressed that all prospective waterfloods be subjected to a critical economic evaluation before institution of a pilot flood. Periodic re-evaluation of the prospect, thereafter, is also recommended.

Potential Reserves and Rate of Recovery

In predicting secondary reserves, the experienced waterflood engineer may utilize any of several methods of prediction, such as Stiles, Dykstra-Parsons, Craig, et al, Buckey-Leverett, etc. or may resort to a "Rule of Thumb" method. It is well to utilize the more refined engineering methods if sufficient reservoir and rock control are available. Frequently, the use of the latter method is not only a matter of choice but of necessity since many older fields which have been placed under flood do not have representative engineering information available. During the period of their discovery and development, modern techniques such as core analysis, DST, logging, etc. were unknown or only embryonic in development. Consequently, when an engineer attempts waterflood performance and reserve predictions in such a field, he must often resort to "Rule of Thumb" methods if he is to come up with an acceptable answer. This is where experience comes to the front.

A list of "Rule of Thumb" factors often used by many engineers would include: (1) secondary equal to primary recovery with a range from 0.6 to 2.0 for successful floods; (2) water injection to produced oil ratio of 10 to 1 with the range from 7 to 15 dependent upon the type and nature of reservoir; (3) injectivity factor of 10-12 bbl. per net ft. of pay zone or 0.5 - 1.0 BPD per net acre-feet with a range dependent upon reservoir capacity, well spacing and array; (4) oil increase or response at 60-75% of estimated voidage fill-up; (5) oil response intensity at 60-70% of effective pattern injection rate; (6) pattern efficiency, or a conformance factor, of 65-75% of affected area dependent upon type and completeness of pattern used; (7) average watercut at economic limit of 96-98% dependent upon total produced fluid volumes, and; (8) rate of reserve recovery which is very difficult to state because of factors such as rate of development, rate of injection and pattern used; however an average high rate flood would be near 15%, 40%, 25%, 12%, 8% and 5% in recovery of secondary reserves. (See Table I)

Gross And Net Reserves

The difference between gross and net reserves on a typical waterflood is usually not a simple calculation. Acquisition financial arrangements, such as oil payments, overriding royalties, deferred production payments and reversionary carried interests etc. often make the resolution a complex task. When this problem arises, the normal procedure is to prepare an economic flow sheet in order to ascertain the exact effect of such burdens. Frequently when individual leases have different burdens, individual lease flow sheets are required, with a composite project flow sheet being the final result. Table I, a typical project economic flow sheet, is presented to show how the various burdens are normally handled when reserve and revenue predictions are being made.

COST ESTIMATION

As essential to an evaluation as reserve calculation, is cost estimation. Cost estimation can be classified into 3 groups, (1) acquisition; (2) development, and; (3) operations. Each has its own intricacies which are discussed hereafter.

Acquisition cost is dependent upon several factors: (1) worth of the property; (2) revenue producing rate; (3) tax position of seller and buyer, and; (4) potentiality of reserves and many other factors. Potentiality of reserves can generally be evaluated by the old axiom: "Market value is mainly dependent upon the degree of desire for a seller to sell and a buyer to buy". Many type acquisitions have been made, from straight cash, part cash and an oil payment, deferred oil payment, overriding royalty or a reversionary working interest. All affect the economic projection in a different manner. Again these effects can best be seen by preparation of an economic flow sheet.

Some acquisition parameters are as follows: (1) 60-70% of discounted future net worth; (2) 30-35% of future income non-discounted; (3) $2,000 per bbl. of daily production or $1.00 - $1.25 per bbl. of primary reserves based on $3.00/bbl. oil or prorata for any deviation therefrom, and; (4) 25-35¢ per bbl. of predicted secondary reserves. Other evaluating criteria are: (1) risk-to-gain ratio (RTG) with a range of 10-20 to 1 being acceptable but a specific value namely dependent upon the degree of risk, and; (2) Return-on-investment (ROI) with an acceptable range somewhere near 3-6 to 1. Other evaluations may be average annual rate of return (AARR), capital expenditure to return, etc. which are also used by some engineers but don't appear to have as wide acceptance as the

TABLE I
XYZ PROJECT
ECONOMIC FLOWSHEET

	YEARS					
	1ST	2ND	3RD	4TH	5TH	TOTAL
GROSS OIL PRODUCED - BBLS.	150,000	400,000	250,000	120,000	80,000	1,000,000
COMMON ROYALTY - 1/8 x 8/8	18,750	50,000	31,250	15,000	10,000	125,000
OVERRIDING ROYALTY - 1/16 x 7/8	8,203	21,875	13,672	6,563	4,375	54,688
OIL PAYMENT - $100,000 OUT OF 1/4 x 7/8	32,813	4,224	-	-	-	37,037
NET OIL PROD. TO W.I. -BBLS.	90,234	323,901	205,078	98,437	65,625	783,275
VALUE OF W.I. PROD. @ $2.70 PER BARREL	$243,632	$874,533	$553,711	$265,780	$177,187	$2,114,843
COSTS TO W.I.						
DEVELOPMENT						
TANGIBLE	$ 35,000	$ 43,000	$ 40,000	-	-	$ 118,000
INTANGIBLE	25,000	30,000	20,000	-	-	75,000
OPERATING	55,000	55,000	55,000	55,000	40,000	260,000
ACQUISITION	100,000	2,000	-	-	-	102,000
WATER PLANT, SUPPLY WELLS	46,500	41,000	10,000	-	-	97,500
TOTAL	$261,500	$171,000	$125,000	$ 55,000	$ 40,000	$ 652,500
W.I. NET INCOME	($17,868)	703,533	428,711	210,780	137,000	1,462,343
CUMULATIVE W.I. NET INCOME	($17,868)	685,665	1,114,376	1,325,156	1,462,343	1,462,343
DISCOUNT FACTOR @ 6% PER ANNUM	.9709	.9151	.8625	.8131	.7664	
DISCOUNTED CUM. W.I. NET INCOME	($17,348)	627,453	961,149	1,077,484	1,120,740	$1,120,740

first group for evaluating secondary recovery prospects.

Development costs cover a veritable "waterfront" since they are dependent upon many features, i.e. time and type of well completion, well density, drilling required, injection pattern desired, age and condition of equipment, water supply potential, power source, etc. The need for additional development work adds the greatest burden of cost. Usually the fields discovered and developed during the 1930's and early 40's require extensive re-development or remedial well work since well completion practices during this period were not competent for pressure injection programs. Other examples of field and well conditions which necessitate additional development expenditures would be incompletely developed reservoirs, high lift capacity water supply, expensive power source, proximity to cultivated lands and extremely varying terrain. Because of the wide variation of influence by these variables, the range of development costs can be from a modest $250 per acre up to a severe $3000 per acre.

Operating costs also vary due to a number of reasons such as operating depth, fluid volumes, injection pressure, style of operation, water supply power source and allowables. It is self-evident why most of these factors effect operating costs; however, a few may need clarification.

Style of operation can significantly but subtly influence operating costs. Two basic styles exist: (1) operation using production type personnel with all engineering supervision carried out at a distant office, and; (2) conducting the waterflood with a trained, experienced engineer-production supervisor assigned to the project or projects being responsible for all facets of field level decisions and operations. To the author, the latter, an "experto credite" philosophy which literally says "Let the expert have his head" is the preferred choice since it allows the use of a specialist who is highly trained and who is in daily contact with project problems, thus being able to recognize problems and apply a solution in time to be optimum in effect. Delay of a few weeks can often mean the difference between a highly or moderately successful flood - or, worse yet, a failure. Also the latter method of operation has, in our experience, resulted in lower operating costs.

It should be readily apparent that restricted production rates, created by allowable restrictions or limited financing, will result in greater operating costs. This is an adverse feature which should be avoided if at all possible since resultant profit will be less, not to mention the reduction in ultimate recovery due to restricted rates. This latter feature has been discussed at length in the literature.[2]

Table II presents average development and operating costs on 9 waterfloods with the cost expressed in the conventional dollar per bbl. and dollar per well per month method. Considerable range will be noted in these with the reasons being discussed in the Field History Section.

Table III lists most of the variables which affect or influence the 3 basic costs. The reader will probably think of more but the list covers most of them. This list may serve as a guide or check list when a flood prospect is being evaluated thus helping the engineer be sure all factors have been considered.

TABLE II
SCHEDULE OF ECONOMIC DATA

Flood Location & Description	Acres	Wells	Secondary Recovery: Cum. Recovery to 1-1-64	Secondary Recovery: Ultimate Recovery	Costs to 1-1-64: Operating $/Bbl.	Costs to 1-1-64: Operating $/W/M	Costs to 1-1-64: Development $/Ac.	Costs to 1-1-64: Development $/Bbl.
West Texas Yates & Queen @ 3050 ft.	320	30	2,053,253	2,448,000	$0.416	$267	$2751	$0.429
West Texas Queen @ 2100 ft.	430	37	715,869	898,400	0.921	213	1540	0.925
North Texas Strawn @ 3600 ft.	150	30	618,636	630,000	0.692	205	1673	0.406
New Mexico Queen @ 3000 ft.	1880	47	3,104,788	3,268,300	0.335	323	292	0.177
West Texas Yates & Queen @ 3050 ft.	320	32	1,351,698	2,124,100	0.357	232	2003	0.477
North Texas Caddo Conglomerate @ 4500 ft.	2500	116	2,029,137	2,760,000	0.645	255	322	0.397
New Mexico Grayburg @ 2850 ft.	120	11	481,485	654,000	0.233	465	2306	0.575
West Texas Seven Rivers @ 1000 ft.	350	38	1,894,854	1,894,854	0.307	249	1263	0.233
West Central Texas Moutray @ 1600 ft.	140	23	185,267	185,267	0.791	145	261	0.197

TABLE III
FACTORS WHICH INFLUENCE WATERFLOOD COSTS

ACQUISITION COSTS

1. Burdens assigned by seller
   - a. Cash
   - b. Excess common royalty
   - c. Overriding royalty
   - d. Oil payments
   - e. Deferred cash payments
   - f. Carried interests
2. Development obligations
   - a. Acreage deadlines
   - b. Depth limitations

DEVELOPMENT COSTS

1. Water availability
   - a. Depth
   - b. Capacity
   - c. Quality
   - d. Corrosivity
2. Degree of field development
   - a. Original
   - b. To effect pattern desired
3. Well conditions
   - a. Pipe program
   - b. Liners
   - c. Cleanouts
   - d. Stimulation methods
4. Power source
   - a. Gas
   - b. Electricity
5. Equipment size and condition
6. Spacing rules

OPERATING COSTS

1. Operating depth
2. Fluid volumes
3. Injection pressure
4. Style of operation
5. Power source
   - a. Gas
   - b. Electricity
6. Water volume, quality and corrosivity
7. Weather
8. Terrain
9. Size of project
10. Personnel
11. Allowables

EFFECTS OF RESTRICTED PRODUCTION

Sufficient coverage of the effect on ultimate recovery from imposing restrictions on production rate is available in the literature. Some comments on the effect on the economic picture are believed appropriate. Obviously, any restriction which extends a project's operating life with increased costs, with no increase in revenue, can severely affect the economic picture. For instance, if a restriction of development rate and/or of allowables is applied which increases operating life 20%, the net increase in total costs will be approximately 10% when it is realized that development and operating costs are normally about equal.

Since there are many who advocate that ultimate recovery is reduced by imposing allowable restrictions[2], plus the adverse effect on the economic picture, it appears extremely hazardous to a project to apply these restrictions.

FIELD CASE HISTORIES

Now to investigate the economics of several fields covering a wide area with different depth reservoirs and which were flooded at different injection rates. Reference to Table I will reveal that of the 9 projects, development costs varied from \$261.00 per acre to \$2751.00 per acre and from 17.7¢ per bbl. to 92.5¢ per bbl. Operating costs varied from 23.3¢ per bbl. to 92.1¢ per bbl., and \$145 per well per month to \$465.00 per well per month. It is interesting to note that, of the latter, the lowest operating cost, in cents per bbl., was also the highest in dollars per well per month, which is easily explainable by the fact that this occurred on a small project which is flooding very efficiently at a very high rate. But let's take a closer look at each individual project.

Project A

Project A is a flood being conducted in both the Yates and Queen reservoirs, jointly at first but later separately, which has performed very satisfactorily. The main feature herein is the very high development costs of \$2751.00 per acre, which result from the need for almost complete re-drilling of the project since the original wells had been abandoned. Nonetheless, the project has been an outstanding success and the development costs, in cents per barrel, have been reasonable. This is mainly due to the excellent secondary recovery of 1.69 times primary recovery.

Project B

This project, being conducted in the Queen sand at 2100 ft, is a slower rate flood than Project A since the sand quality is not as good. Considerable drilling, occasioned by acquisition obligations, made development costs reach \$1540./acre. The slower rate flood caused the operating costs to be 92.1¢ per bbl. but the dollar per well per month figure is a low \$213./W/M which indicates very efficient operations.

Project C

Project C is a flood being operated in the Strawn Sand of North Texas at a depth of 3000 ft. Here not much development drilling was necessary; however the water supply was expensive and the need for large producing equipment, to combat early excessive water production, caused development costs to be high at \$1673./acre and operating costs to be 69.2¢ per bbl. Operating costs expressed in dollars per well per month have been a moderate \$205./well per month which is mainly the direct result of flowing production late in the life of the flood.

Project D

This is a unitized waterflood being conducted in the Queen Sand which occurs at an average depth of 3000 ft. Minimum development drilling was necessary. The water supply is very shallow, prolific, and fresh -- of course, produced water is reinjected. The flood has been a high rate flood necessitating the handling of high flood volumes which require large producing equipment. The development costs were a very low \$292. per acre due to the above and due also to the fact that the well spacing made 80 acre five-spots.

Operating costs have been \$323./W/M which is a direct reflection of high fluid volumes and the need to use electrical power. The cost per bbl. has been relatively low at \$0.335. per bbl. which is also a reflection of the excellent flood performance, high fluid volumes and operating techniques.

Project E

This project is being conducted in the Yates and Queen reservoirs with the main contribution coming from the Queen. Approximately 1/2 of the project required development drilling. Also the flood has been a high rate flood. The resultant development costs of \$2003/acre are a direct reflection of the development drilling.

Operating costs have been a mid-level \$232./W/M and \$0.357/bbl. which is very good for this depth flood.

Project F

This is a large unitized project being conducted in the Caddo Conglomerate at an average depth of 4500 ft. Minimal development drilling has been incurred; however, the water supply has been costly and not adequate for complete requirements, resulting in controlled expansion of the project. Resultant developmental costs have been a very low \$322. per acre to date which is mainly due to the wide spacing (50 - 80 acre five spots).

Operating costs have been an excellent \$255/W/M which is due to an excellent gas supply from the gas cap area of the field and the large concentration of wells in the project (150 wells). The costs per bbl. have been 64.5¢ per bbl. which is very reasonable considering the fact that it has been necessary to produce high, early water-cut volumes of oil.

Project G

This is a very small, 140 acre flood being conducted in the Loco Hills member of the Grayburg zone at an average depth of 2850 ft. Due to incomplete definition of the reservoir, it has been necessary to do extensive development work on this project resulting in a development cost of \$2306./acre. This figure is also a direct reflection of the size-cost ratio of the project.

Operating costs have been a high \$465./W/M which is a reflection of the small well count and the need to purchase water from a commercial water line at a rate of 2.0¢ per bbl.

The cost is a very healthy 23.3¢ per barrel which is a result of the very excellent rate performance of the project.

Project H

The flood was conducted in the shallow 1,000 ft. Seven Rivers sand which performed outstandingly. There was significant development drilling on the project since approximately 1/2 of the field was undeveloped during its primary life. Water supply was shallow. fresh and prolific. Produced water was reinjected without undue difficulty. High producing rates were experienced which required large producing equipment. The net effect of all this was a development cost of \$1263./acre which is relatively high for this depth; however large reserves made it a reasonable 23.3¢ per bbl.

Operating costs were a very reasonable \$249. /W/M considering the very high fluid volumes. This was 30.7¢ per bbl.

Project I

This was a relatively small operation conducted in the Moutray Sand in West Central Texas which occurs at an average depth of 1600 ft. Minimum development work was necessary and, fortunately, an alluvial deposit at 20-25 ft. proved an adequate water supply source. Resultant development costs were \$261./acre.

Operating costs were a low \$145./W/M; however the cost per bbl. was above average - 79.1¢ per bbl. due to the rate of production. Considering all factors, this was a successful venture.

REFERENCES

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