West Delta Block 84—Methodology and Analysis of a Previously Orphaned Field

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Abstract

This paper describes the effort to justify, document, and confirm proven, proven, undeveloped, and bypassed remaining oil and gas reserves in West Delta Block 84 Field; at one time an orphaned field off the coast of Louisiana. The methodology used for the evaluation provides an insight into how to quickly and efficiently identify worthwhile and economic marginal properties, even with incomplete or missing information. This methodology is being used as a part of the development of an expert system for the evaluation of marginal and/or orphaned wells, reservoirs, and fields.

West Delta Block 84 is located of the coast of Plaquemines Parish, Louisiana, near the mouth of the Mississippi River in about 20 ft of water. Conoco discovered it in 1955 with the drilling of the SL 2551 No. 1 well to a total depth of 14,500 ft. It has produced over 9.8 MMSTB of oil and 21 BCF of gas. It was shut in for a period of almost ten years while languishing in and out of bankruptcy court from 1990 to 2000, and was actually orphaned by the state at one point during this time.

Available data was organized and pieced together for the field, but was still lacking in completeness. As in most cases when dealing with older marginal fields, an ability to deal with missing and incomplete information was necessary to complete the analysis.

Introduction

There are reportedly 343,030 inactive, shut-in, and/or orphaned wells nationwide, of which 34,355 are in Louisiana. In many cases, these wells are idle and orphaned, not because their resources have been depleted, but because of other factors. These factors might include low product price, high cost of operations, unrelated financial problems, or the inability or lack of resources to properly describe the reservoir and identify the potential for additional recovery, among other things. It is simply not known, with any accuracy to an outside party looking in, exactly why a well is shut in or orphaned.

Historically, small and large independent producers have entered into fields previously operated and owned by the major oil companies. These underfinanced and understaffed independents find themselves working off cash flow and unable to find the financial resources to work over the idle wells, much less do the research that many of the wells and reservoirs deserve and need. The wells may have potential, but no one has the time or the money to pursue these presumably marginal targets.

There is an incentive to identify potential in these shut-in/orphaned wells since their plugging would be terminal and, in the case of orphaned wells, would cost taxpayers money. In a period of four years, from 1996 to 2000, there were reportedly 712 wells plugged in Louisiana for US$14,090,000, which is an average cost of US$17,890 per well. Presently, there is a new powerful incentive for not plugging wells that might be returned to production as the processing price of oil has reached US$56/STB with no signs of leveling or dropping in the future.

Several Interstate Oil & Gas Commission (IOGCC) and U.S. Department of Energy (DOE) surveys revealed that the oil-producing states know the number of idle wells, but are unable to estimate potential production associated with those wells. Thus, there is a need for a method for assigning economic value to those wells.

Discussion of Methodology

A method is being developed at LSU for assigning value to inactive wells. To accomplish this task efficiently within its boundaries or limitations, an expert system is being built comprising rules of logic, computations, and an algorithm for computer programming. In this paper, a generic methodology that has been conceptually developed is demonstrated by using a real case history. It was developed as a logic base for an eventual expert system.

The design of the methodology and logic relies somewhat on original work done on the “Prospector” program written in the late 1970s. Prospector was “designed primarily to assist exploration geologists in interpreting and evaluating data on specific mineralized sites or prospects(1).” The Prospector software was specifically designated for identifying ore deposits and designed “to reduce the risk of overlooking unfamiliar possibilities(1).”

In much the same way, the logic of this methodology seeks out wells and reserves that are not considered for economic development because the opportunist possibilities have been overlooked. The simple basic problem is that there is a shut-in, orphaned, or marginal well. Future plans for the well call either for plugging it, or leaving it as a shut-in/marginal well, or bringing it back to production and reasonable commerce using a new technology.

In order to attempt new technology on marginal wells, candidates must be generated. No one will make the required investment for new technology into a shut-in, orphaned, or marginal well if the potential is not known. Questions must be answered and analysis must be performed. However, analysis is time-consuming and expensive and has a distinct possibility of being a waste of time if no candidates are identified.

A decision tree for this task follows three basic rules. They are mostly common sense, but they provide excellent guidance in the development of the basic methodology. They are as follows:

• Rule One—Speed at the expense of detail initially;
• Rule Two—No multi-tasking; and,
Methodology

Rule One: Speed at the Expense of Detail Initially

Speed must be the priority at the expense of detail, initially. This rule must be followed in order to quickly arrive at a conclusion concerning potential for success. Details come later through further study such as simulation, if needed or required.

Rule Two: No Multi-Tasking

Multi-tasking is inefficient. From experience, it is very easy to review too much at one time.

Rule Three: Proceed Even When There is Missing Information

Marginal wells and reservoirs typically are older ones, which may have had multiple operators and have inconsistent, missing, or unrecorded data.

Whatever data is available should be used and analyzed quickly. If candidates are identified based on substandard data, once it has been screened, then detailed data recovery may be performed, if warranted.

The methodology allows for interpolation, extrapolation, analogical comparisons, and assumptions in order to move forward quickly, whenever reasonable. By using consistent deductive reasoning or analogies to generate necessary data, the analysis may proceed.

Physical Steps

While adhering to the above rules, chronological physical steps are necessary for efficiency. The analysis must be performed at a reservoir level, initially. Once the reservoir is identified, the following steps should be taken:

1. Identify sources of information and data. Gather the accessible data and organize it;
2. Describe the general stratigraphy and regional structural geology;
3. Identify all productive sands and separate reservoirs within the field and prepare structural and isopachous maps(3). Reduce focus to most likely candidates based on size if dealing with an area or field;
4. Measure the bulk volume of the candidate reservoirs;
5. Determine or assign average porosity, saturation, permeability, API gravity, viscosity, initial pressure, present pressure, bubble point pressure, initial solution gas-oil ratio, and the formation volume factors for oil and gas of each reservoir;
6. Calculate initial oil and/or gas in place;
7. Summarize the history of each well within a reservoir and separate all production and tests by well and reservoir into manageable spreadsheets to determine the oil and gas produced to present. Attempt to collect the entire history of production for each reservoir. In some cases, older production records will be difficult to obtain, and if this is the case, then concentrate on recent history going back in time only so far as is easily manageable;
8. Determine remaining oil and gas in place and determine the drive mechanism either by pressure/production analysis through material balance or analogy based on decline curves; and,
9. If remaining oil and gas is favourable, continue with more detailed analysis and economic valuation. Once the remaining oil and gas in place are identified, one can begin to analyze the potential reserves, if warranted. Based on the volumetric analysis outline above, one can identify which reservoirs deserve further analysis without considering potential reserves whatsoever. An incremental recovery of the initial oil and gas in place is the only concern. Once chosen for further study, target reservoirs and wells may be further analyzed by computer simulation, geologic modelling, physical well inefficiencies, well completion design, and/or specific implementation of a new technology.

West Delta Block 84 Field—An Example

As an example and case history for the implementation of this methodology, West Delta Block 84 Field is described. The initial evaluation of this field took only two weeks. The potential was recognized and the studies grew in detail.

West Delta Block 84 is located off the coast of Plaquemines Parish, Louisiana, near the mouth of the Mississippi River. Conoco discovered the field in 1955. It was operated by CATCO, which included working interest partners of Conoco, Chevron, and Texaco, until September 1988 when a very small independent, S. Parish Oil Co., bought out CATCO’s interest and took over operations. To date, the field has produced over 10 MMSTB of oil and 21 BCF of natural gas.

Step One—Identify Sources of Information and Data

Initially, for West Delta Block 84 Field, the majority of the data was obtained from a public source, the Louisiana Department of Natural Resources (DNR). Examples of such data include:
1. Production data: reported on a lease-unit-well (LUW) basis (several wells and reservoirs may be included in one report). Information includes oil and gas production for the lease-unit-well;
2. Individual well tests: in the past, these were taken approximately every quarter, whereas now they are biannual. Information from these tests include daily production rates, gravity, flowing tubing pressures, and sometimes shut-in tubing pressures and bottomhole pressures;
3. Well histories: includes depths of perforated intervals, directional surveys, casing programs, initial tests, and other miscellaneous information;
4. Electric well logs; and,
5. Various reports filed in regard to the KF-1 reservoir waterflood. Information included various particulars and maps on the KF-1 reservoir characteristics.

Step Two—Describe the General Stratigraphic and Regional Structural Geology

Stratigraphy

The GR sand is the shallowest interval which has produced within the West Delta 84 Field. It is Buliminella 1 section, Lower Pliocene in age. It was deposited in an inner to middle neritic environment (that part of the sea floor which extends from the low tide line to a depth of 60 m or 200 ft)(3). The KE and KF sands are Robulus E, Upper Miocene in age. The depositional environment for these sands was also middle neritic. Inner and middle neritic environments are characterized by a series of meandering channels and point bars. This type of system migrates laterally through time giving it a shingled effect and places numerous trough shaped cross-bedded sand channels in communication with one another. Permeability barriers, both complete and partial, are characteristic in this type of depositional sequence.

Structural Geology

The regional subsurface geology is defined by gentle synclines and anticlines and faulting which trend east-west. The structure dips to the west at approximately 10 degrees and is trapped to the north and south by down-to-the-south normal faults with approximate vertical displacements of 30 m or 100 ft each. Reservoir limits are defined either by its structure (oil-water and gas-oil contacts), or faulting, or stratigraphy in the form of shale-outs.
Step Three—Identify All Productive Sands and Separate Reservoirs Within the Field and Prepare Structural and Isopachous Maps

At the present time, the field contains five productive Lower Pliocene and Upper Miocene aged sands: KE, KF, GR, KP, and JM. Initial geologic and engineering studies placed the four sands into eight individual reservoirs (KEKF-1, KE-9, KE-A10, GR, KP, KE-5, KE-2, and JM) containing a total of 30 completions. Two of the sands, the KE and KF, were quickly determined to be in possible communication through deductive reasoning based on a thick channel sequence cutting through the middle of the reservoir. It was also recognized that there are numerous sands above and below these four known producing sands that have never been fully evaluated, leaving a large amount of upside potential to the acreage.

The reservoirs are trapped by structure, faulting, and stratigraphic mechanisms. Two of the reservoirs, the KE-KF-1 and the KE-A10, were waterflooded to some extent. The KE-2, KEKF-5, and KE-9 are smaller reservoirs and are set aside at this point for future assessment if more detailed evaluation is warranted based on the larger reservoirs. If the larger reservoirs do not support a more detailed study of the field, then the smaller ones are very unlikely to become productive. Focus at this point, therefore, moves to the most likely economically successful larger reservoirs within the field.

Step Four—Measure the Bulk Volume of the Candidate Reservoirs

Oil-water and gas-oil contacts were estimations based on all available data. Acre-feet of bulk reservoir volume were obtained by planimeter and use both the trapezoidal and pyramidal formulas as simply described by Craft and Hawkins(4).

Step Five—Determine Average Porosity, Saturation, Permeability, API Gravity, Viscosity, Bubble Point Pressure, Initial Solution Gas-Oil Ratio of Each Reservoir, and the Formation Volume Factors for Oil and Gas

Table 1 presents the raw, measured, or calculated data for the KEKF-1, KE-A10, and GR reservoirs.

<table>
<thead>
<tr>
<th>TABLE 1: Engineering data.</th>
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<tr>
<td><strong>KEKF-1 Reservoir</strong></td>
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<td>Gas gravity</td>
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<td><strong>GR Reservoir</strong></td>
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Step Six—Calculate Initial Oil and/or Gas In Place

Using volumetrics, the original oil and gas in place is calculated for the KEKF-1, KE-A10, and GR reservoirs. Table 2 summarizes these calculations.

Step Seven—Summarize the History of Each Well Within a Reservoir and Separate All Production and Tests by Well and Reservoir Into Manageable Spreadsheets

Target reservoirs within the field originally contained 30.7 MMSTB of oil and 53.8 BCF of gas. To date, from these target reservoirs, the field has produced 9.0 MMSTB of oil (29.3% of oil in place) and 17.7 BCF of gas (32.9% of gas in place). Table 3 summarizes the historical production for the KEKF-1, KE-A10, and GR reservoirs.

Step Eight—Determine Remaining Oil and Gas In Place and Drive Mechanism

**KE-KF-1 Reservoir**

It is determined through material balance that the KE-KF-1 is a gas cap/solution gas driven reservoir with a partial water drive(5). Cumulative production from the...
reservoir is 4.638 MMSTB, 11.3 BCF, and 2.5 MMBW. This represents 31% of the original oil in place and 40% of the original gas in place. Based on the drive type mechanism and placement of existing wells, potential reserves are in the neighbourhood of 1.4 MMSTB of oil and 8 BCF of gas.

**KE-A10 Reservoir**

It is determined through material balance that the KE-A10 is a strong water drive reservoir. Cumulative production from the KE-A10 reservoir is 2.6 MMSTB, 1.8 BCF, and 1.5 MMBW. This represents 23.6% of the original oil in place and 31% of the original gas in place. Based on the drive type mechanism and placement of existing wells, potential reserves are in the neighbourhood of 9.4 MMSTB of oil and 3.2 BCF of gas.

**GR Reservoir**

It is determined through a near constant reservoir pressure throughout the productive history of the GR reservoir that it is a strong water drive reservoir. Cumulative production from the GR reservoir is 2.6 MMSTB, 1.8 BCF, and 1.5 MMBW. This represents 23.4% of the original oil in place and 31% of the original gas in place. Based on the drive type mechanism and placement of existing wells, potential reserves are in the neighbourhood of 1.4 MMSTB of oil and 0.9 BCF of gas.

Table 4 summarizes the reserves from all of the target reservoirs.

**Step 9—If Remaining Oil and Gas is Favourable, Continue With More Detailed Analysis and Economic Valuation**

It is decided that a more detailed study should be made. A simple value of reserves in the ground and a discounted cash flow (DCF) valuation is used to establish the initial economic value of the project.

**Methods for Evaluating Oil Projects**

**Value per BOE**

One must simply have an estimate of the in-place reserves. This method is based on determining a regional or national experience value per barrel of oil equivalent (BOE) reserve in the ground. The unit value is then multiplied by the proven reserves. Gas reserves are converted to oil-equivalent in accordance with the ratio of currently experienced prices per MCF as compared with the price per barrel of oil. Likewise, adjustment could be made for lifting costs, taxes, and net revenue interest when appraising a property and comparing it with recent sales of slightly different properties in the local area.

**Discounted Cash Flow**

A discounted cash flow analysis (DCF) is another simple method for valuating an oil and gas project. However, it can take various forms. These include Net Present Value, Risked Present Worth, Three-Year Cumulative Cash, and Present Worth at 25%, as described below. Gustavson actually takes these different forms and creates a methodology for arriving at a “fair market value” by averaging these and other simple methods.

**Net Present Value**

The Net Present Value (NPV) of an investment is calculated by discounting the future net cash flows to time zero and summing them. In its simplest form, the equation for net present value can be expressed as:

\[
NPV = \sum_{j=0}^{L} \frac{NCF_j}{(1+i)^j}
\]

The NPV is called the “Expected Value” when the calculation includes probability numbers to consider risk in a quantitative and explicit manner.

**Risked Present Worth**

This method is based on selecting a present worth out of the reserve report utilizing a discount rate close to the prime rate. This value must be adjusted for risk. The risk is further broken down into several factors reflecting both operator risk and mechanical risk of the well.

**Three-Year Cumulative Cash**

This amount is determined by adding up the cumulative net revenue to the property over the first three years of production.

**Present Worth at 20%**

This method utilizes the net present value of the future cash flow from a property discounted at the rate of 20%.

**Economic Evaluation of West Delta 84 Target Reservoirs**

Using the outlined techniques, it is established that the fair market value of the target reservoirs within West Delta Block 84 is US$43.7 MM. Table 5 outlines the breakdown and calculation of this figure. At the time this analysis was performed, the range of values for oil and gas was US$26.00 to US$28.50 and US$2.50 to US$4.75, respectively.

**Conclusions**

1. A simple method has been developed to identify primary candidates from a pool of inactive wells (orphaned, marginal, and/or shut-in) having potentially the highest value of property.
2. The logic of this method has been demonstrated step-by-step using data from an actual field with a large number of inactive wells. The example shows effective identification of valid well candidates. The candidates should be given the lowest priority in the plugging/abandonment program and the highest priority for an improved recovery program.
### Conversion To SI Units

- 1 cubic foot (cf) = 0.02832 cubic metres (m³)
- 1 barrel (bbl) = 0.159 cubic metres (m³)
- 1 pound per square inch (psi) = 6.895 kilopascal (kPa)
- 1 foot (ft) = 0.3048 metres (m)
- 1 cubic foot (cf) = 0.02832 cubic metres (m³)

### NOMENCLATURE

- STB = stock tank barrel
- MMSTB = million stock tank barrels
- MMBW = million barrels of water
- SCF = standard cubic feet
- BCF = billion cubic feet
- NCFj = net cash flow for the period j, US$
- NPV = net present value, US$
- L = project life, years
- i = interest rate, decimal
- MMUS$ = million US$
- interfering Wells Valuation and Recovery of Bypassed Reserves From Water-drive Reservoirs in Louisiana.”

### Acknowledgements

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### TABLE 5: Fair market value.

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<td>KEKF-1 Reservoir</td>
<td>$24,855,220</td>
<td>$12,693,488</td>
<td>$24,786,324</td>
<td>$28,221,221</td>
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<td>KE-A10 Reservoir</td>
<td>$10,531,879</td>
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<td>$11,313,015</td>
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<td>GR Reservoir</td>
<td>$7,219,120</td>
<td>$6,890,933</td>
<td>$8,735,369</td>
<td>$13,267,537</td>
<td>$11,920,250</td>
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</tr>
</tbody>
</table>

### REFERENCES


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