STIMULATION EVALUATION FOR ELLENBURGER GAS WELLS - JM FIELD

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A significant quantity of gas reserves exists in deep, hot reservoirs such as the Ellenburger in West Texas. The technology of stimulating these reservoirs is, for all practical purposes, in its infancy. As a result, it is very difficult to define the potential increase in reserves that could be gained by effectively stimulating a gas reservoir such as in the Ellenburger. This vague potential gain, coupled with the high cost $150,000 - $250,000) and high risk associated with the mechanical aspect of the treatment, has been responsible for the relatively slow development and testing of stimulation techniques. However, faced with continually declining deliverability from these fields and gas shortages, evaluation of stimulation applications becomes necessary to enable management to make prudent operating decisions. In the JM field in West Texas, the question was posed as to increasing deliverability and possibly reserves by stimulating with a propped hydraulic fracture treatment.

LOCATION AND GEOLOGICAL INFORMATION

The JM and EBB (East Brown Bassett) fields are located in the extreme western portion of Crockett County, Texas approximately 120 miles south of Midland, Texas, (Fig. 1).

The principal dry gas formation in JM and EEB is the 1500-ft thick Ellenburger dolomite of Ordovician age. These fields can be considered, together with the Brown Bassett Field, as three separate permeable areas in a 130-mile long structural trap in the Delaware Val Verde Basin. The huge accumulation has a gas-water level at subsea depth of -12,600 ft and contains a maximum gas column of 3000 ft. Initial pressure at the gas-water level was 6600 psi, approximately the hydrostatic gradient.

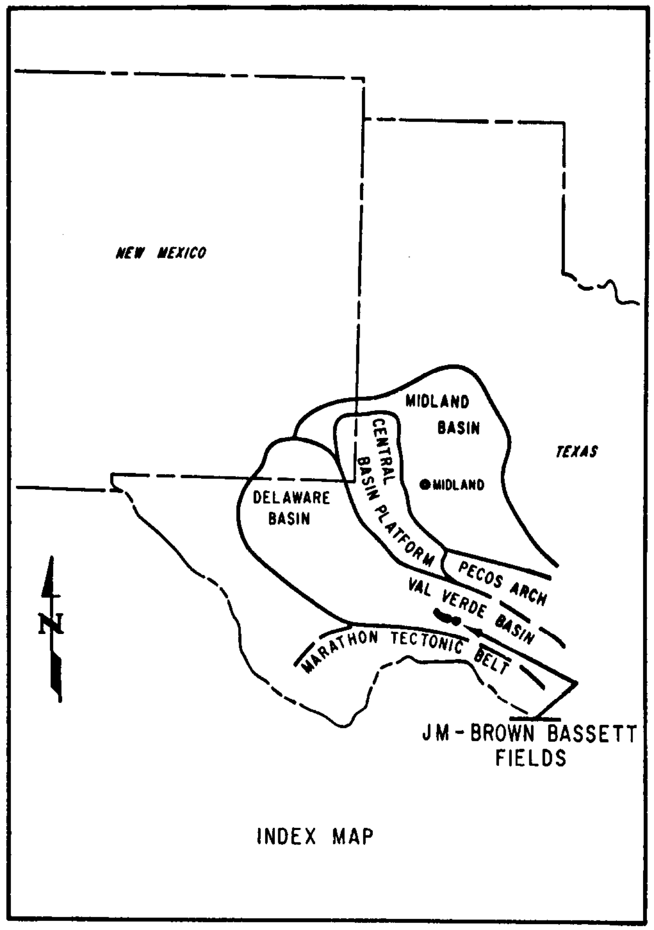

FIG. 1

Production performance of the JM and EBB fields shows them to be depletion-type reservoirs with no measurable effects of water drive. The CO_2 content ranges from 20-60%, (JM averages 24% — EBB averages 42%).

HISTORY

Sun Oil Company drilled the discovery well for

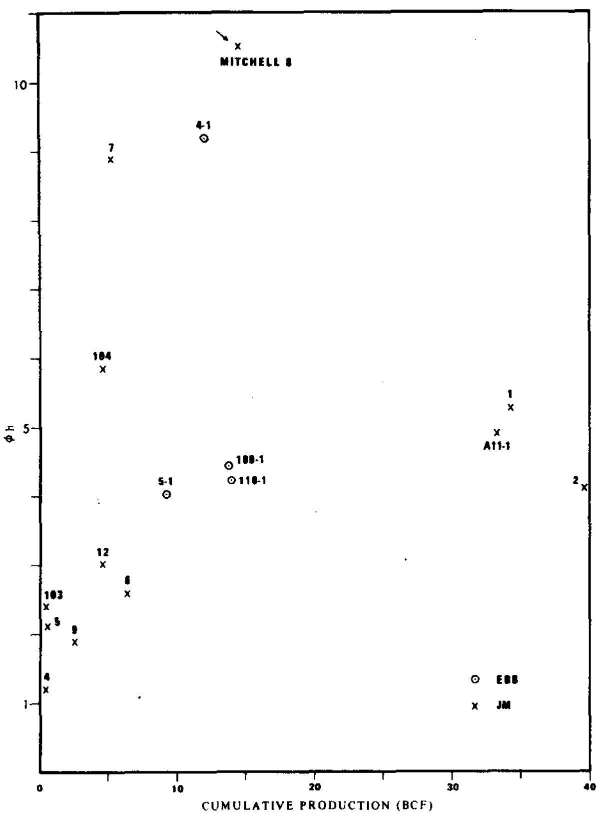

FIG. 2—ϕh VS. CUMULATIVE PRODUCTION FOR JM AND EAST BROWN BASSETT FIELDS

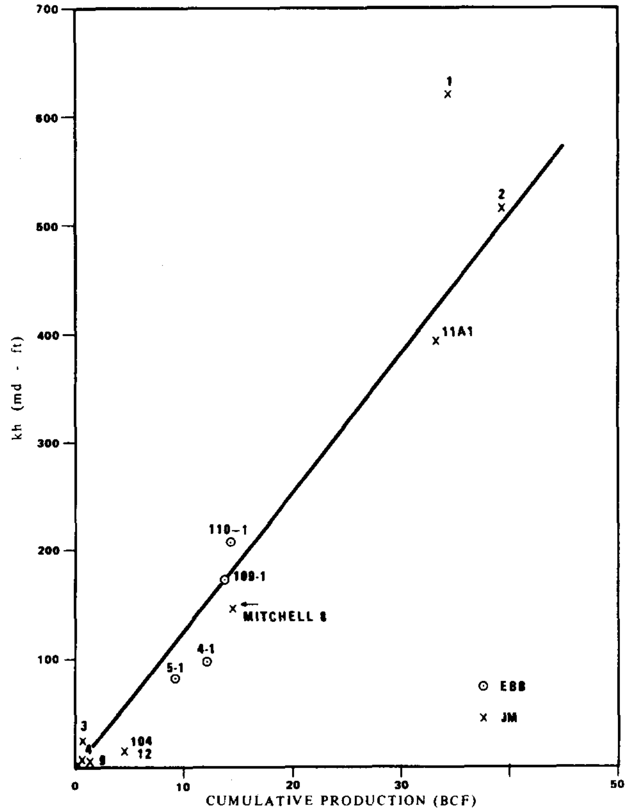

FIG. 3—kh VS. CUMULATIVE PRODUCTION FOR JM AND EAST BROWN BASSETT FIELDS

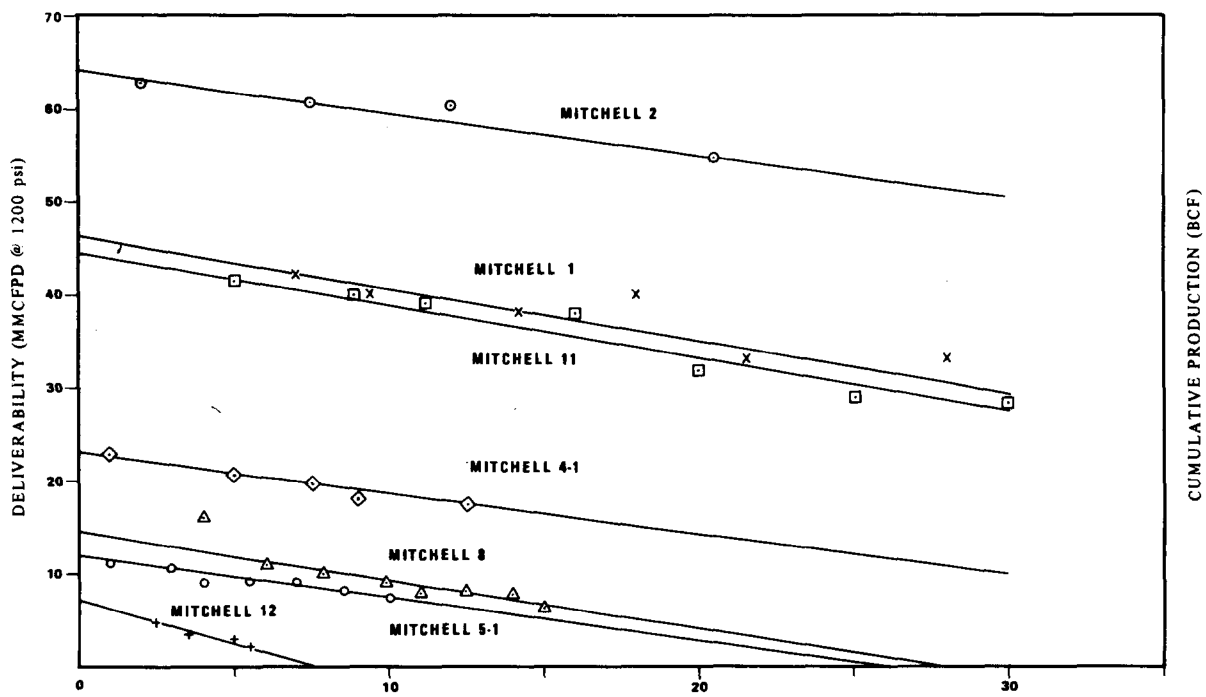

FIG. 4—DELIVERABILITY VS. CUMULATIVE PRODUCTION FOR JM AND EAST BROWN BASSETT FIELDS

seen there are quantitative differences in deliverability between wells; however, Fig. 4 shows all wells exhibiting a normal decline. Sufficient points were available to give us confidence in the predictability of deliverability decline for each well. A point significantly below the established decline would have been potentially an excellent candidate for stimulation.

Another performance-related tool is a plot of "C" factor versus cumulative production, Fig. 5, to evaluate changes in the reservoir that would affect deliverability. In the context of this analysis, "C" is calculated from flowing conditions with the equation

$$C = \frac{q \mu Z}{(P)^2 - P_{wf}^{\,2}}$$

or may be calculated from:

$$C = \frac{T_{sc}\ Kh}{50.304\ P_{sc}\ T\left[\ln(re/rw) - .75 + s\right]}$$

the equation for semi-steady state flow in a gas well. With this approach we avoid having to determine Kh and skin to calculate flow. This approach has been very effectively utilized in the Southern Region to select deep, tight gas wells that would respond to fracture treatment. It is interesting to note that a comparison of "C" factors determined from deliverability tests shows McAllen Ranch wells three orders-of-magnitude poorer than JM wells ("C" factors at JM are on the order of 1×10^{-6} and Southern Region's are 1×10^{-9}). This would seem to indicate that, although McAllen Ranch and JM have very similar permeabilities in the range of 0.1-1.0 md, JM wells have a much higher capability to produce. The Southern Region's success in using this method results from good stimulation candidates being identified by declining "C" factors with cumulative production. This would indicate changes in the reservoir characteristics (Kh or S) that are reducing the wells' ability to produce. However, in our case Fig. 4 shows that "C" factors for JM wells have been relatively unchanged.

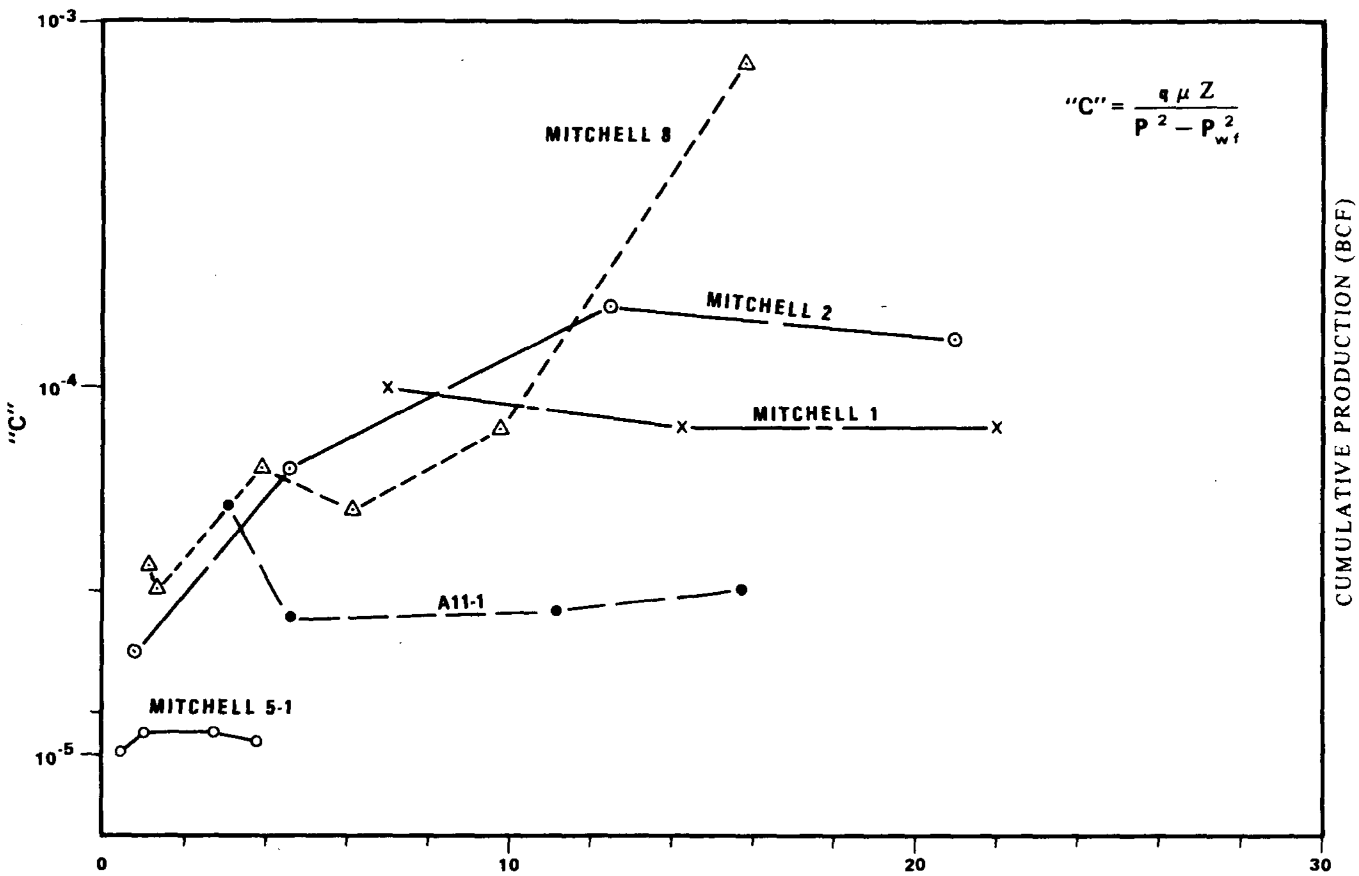

FIG. 5—"C" VS. CUMULATIVE PRODUCTION FOR JM AND EAST BROWN BASSETT FIELDS

The final evaluation tool was to run a BHP buildup in the Mitchell No. 8 to detect a positive skin. Both the conventional Horner analysis, Fig. 5, and the Extended Muskat method were used to evaluate the buildup. Both techniques indicated that the well had a negative skin and calculated quantitative values were relatively close.

RECOMMENDATION

Based on the analysis discussed above it was concluded stimulation *could not* significantly improve deliverability of the Ellenburger formation in the JM field. Another risk considered in making a negative recommendation was potential damage that could be incurred in an attempted fracture treatment due to water blockage resulting from the unfavorable capillary effects of very low permeability and relatively low pressure.

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ACKNOWLEDGMENT

The authors wish to express their appreciation to Shell Oil Company for permission to publish and present this paper.

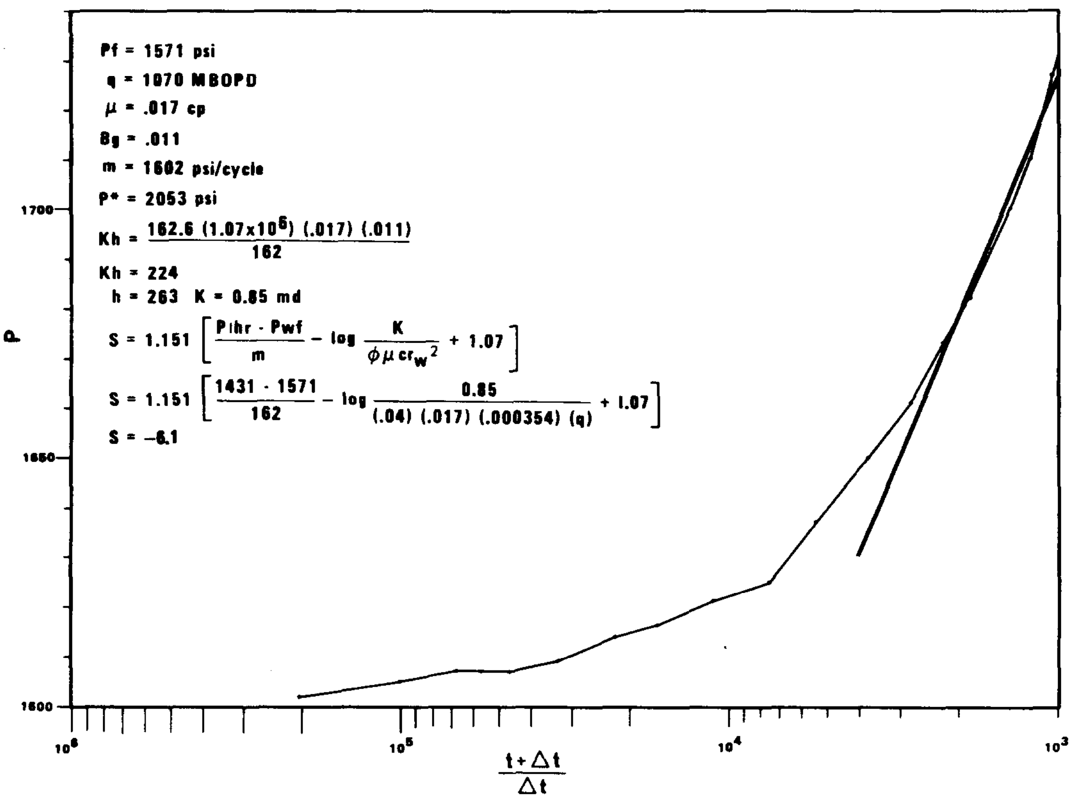

FIG. 6—BHP BUILDUP, MITCHELL NO. 8, JM FIELD, 8/20/73