TECHNICAL NOTE ON TRANSIENT PRESSURE ANALYSIS
FOR FLOW SYSTEMS WITH CONSTANT PRESSURE OUTER BOUNDARY
FOR THE OIL PRODUCING FRACTURED SHALE RESERVOIR OF THE NIOBRARA
MEMBER OF THE MANCOS FORMATION
WEST PUERTO CHIQUITO POOL
CANADA OJITOS UNIT
RIO ARRIBA COUNTY, NEW MEXICO

PRESENTED IN CASE NOS. 7980, 8946, 8950 AND 9111
BEFORE THE OIL CONSERVATION COMMISSION OF THE
NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

JUNE 13, 1988

BACKGROUND

Wells in the West Puerto Chiquito Mancos pool produce from a stratified reservoir within the Niobrara member of the Mancos formation. The three principal zones are locally designated "A", "B", and "C". The zones have a high degree of lateral communication, but are isolated vertically by the intervening plastic shales; except that reservoir-wide a certain degree of communication exists among the zones. This is thought to be the result of occasional faults, or possibly man-made communication through wellbores and hydraulic fracturing.

The reservoir geometry is one of "tight blocks" surrounded by a high capacity fracture system. The high capacity fracture system contains a substantial proportion of the total reservoir oil. This is in contrast to the typical "naturally fractured reservoir" which comprises a matrix porosity laced with fractures.

This unusual reservoir geometry of the West Puerto Chiquito pool was first determined in 1965 from pressure buildup and drawdown tests in conjunction with interference testing; and reported to the New Mexico Oil Conservation Division in November, 1966 in conjunction with Case 3455.

Cores of wells in early development (1960's) of the West Puerto Chiquito pool showed the producing formation to be fractured. It was not, however, the typical naturally fractured reservoir in which a matrix porosity is laced with fractures. This was evident from pressure data. Although not as much information on analysis of transient flow tests was available then as later, there was enough to confirm from the early well tests that the reservoir was <u>not</u> that of matrix porosity laced with fractures.

Fundamental characteristics required that pressure buildup plotted against log time for a well completed in a reservoir of matrix porosity laced with fractures would show a flat curve early, and then increasing in slope.

Such was not the case for the West Puerto Chiquito wells. Rather they showed steep initial buildups (or drawdowns), and then flattening sharply. The flattening of the curves meant the "radius of drainge" had reached a boundary; and the physical properties shown by the tests were those only of the area within the bounds of these small reservoirs.

The sizes of the reservoirs were estimated two ways:

1. From the time required to establish steady state conditions ($r^2 = 4nt$), using apparent physical properties to determine the diffusivity constant; and

2. Assuming an rw volume to be that of the frac treatment volume that carried sand in excess of 1/2# per gallon.

The calculated "reservoirs" were quite small: 20 to 80 acres.

Interference tests run concurrently with the build-ups showed communication over long distances, however; meaning that the overall reservoir contributing to the production covered - in some cases - several thousand acres. So here was a situation contrary to the reservoir engineer's basic concept of applicability of pressure build-up tests in analyzing reservoirs.

One virtue generally recognized, of pressure build-up data over that of cores and logs was that such pressure build-up data represented a relatively large area of the reservoir with consequent increase in reliability of computed properties. A single test might reflect the properties of a well's entire spacing unit, for example, and be quite useful in forecasting production behavior and future reserves.

Such was not the case here. Clearly, wells were draining thousands of acres, yet the build-up tests covered only 20 to 80 acres (defining properties on the order of only 1% of the drainage area).

Only one kind of reservoir geometry is satisfied by this pressure behavior: a set of "tight blocks" surrounded, and interconnected, by a high capacity fracture system. Permeability of the tight blocks was apparently that of fractures also - just tighter fractures than that of the high capacity system.

From an interference test run in 1965, an average transmissibility (Koh) of about 6 darcy feet was determined for this zone in the initial area of development. (Koh's for individual wells' tight blocks ranged from .02 darcy feet to .4 darcy feet: far less than the reservoir average). An area of several thousand acres was "sampled" by the test. At that time the oil was undersaturated, such that the indefinite value of the formation compressibility was significant in calculating per acre oil in place. For the estimated range of 7×10^{-6} to 23×10^{-6} for Cf the calculated volume of oil in place ranged from 2500 stock tank barrels per acre to 1000. At that time the average of about 1700 barrels per acre was used as a best first estimate for the C zone.

In 1967 a well was completed within the area sampled by the 1965 interference test (unit well E-10) showing for its test area a Koh of 1.5 darcy feet and confirming the existence of the high capacity fracture system. (Although the existence of a high capacity fracture system was identified by the initial interference test, the highest Koh measured in an individual well prior to the drilling of the E-10 was only .4 darcy feet.)

In 1968 another interference test was run covering a part of the area initially tested, and it showed a Koh of about 2 darcy feet. At that time some fre gas had developed and it was estimated that original Koh of this area would have been 2.5 to 3.5 darcy feet.

Also in 1968, a steady state line drive test over another part of the initially tested area revealed a Koh of about 10 darcy feet. The average Koh of these last two tests (6 darcy feet) checked closely with the 6.4 darcy feet initially determined by the 1965 test.

The transmissibility measured by the above tests represented the reservoir average for that of the high capacity fracture system plus that of the tight blocks.

Accordingly, and as reported in 1966, the high capacity fracture system itself - although impossible to measure directly - would be substantially higher.

The calculated oil in place from the 1968 interference test showed 1600 stock tank barrels per acre. Since the oil was saturated at that time, the value of the formation compressibility was of little significance in making this calculation.

Since the value of oil in place by this second test approximated the average of that using the high and low estimates of Cf in the 1965 test, it is believed that the average of those high and low compressibilities used would give the best estimate of Cf ($\pm$ 15 x 10^{-6}).

Since that time, laboratory tests have been reported on cores from this formation taken about 10 miles west of the test area, ranging from 6 x 10^{-6} to 100 x 10^{-6} ; but since it is impossible to simulate in the laboratory the reservoir conditions of the formation, the operator of the Canada Ojitos Unit gives more credence to the field test data than that of the laboratory. The extreme variation in laboratory results (a factor of sixteen to one) alone confirms the low order of reliability of the laboratory data.

In the 1960's, the estimate of a tight block's size was made by first estimating its effective "rw volume" (as compared to rw distance), with the effective rw volume being the volume of the frac treatment that carried sand in excess of 1/2# per gallon.

To further examine the reservoir properties of tight blocks, tests were made with a gas injection well completed with small (2-3/8") tubing on a packer (small wellbore storage or afterflow) to obtain transient flow data for estimating the size and properties of a tight block. Thus there was eliminated the unknown effect on the data of a pressure buildup of an oil well in which during early times following shut-in both gas and oil flow into the wellbore, the fluids segregate and in many wells in this pool, oil - by counterflow - is forced back into the formation all the time pressure in the wellbore is increasing.

A pressure fall-off test was run in 1969 in one of the Canada Ojitos Unit wells completed in the oil portion of the reservoir and later converted to injection (K-13). At that time the highest accuracy in pressure measurements was obtained through use of a surface dead weight tester and then converting these pressures to bottom hole pressures by adding the calculated weight of the column of gas.

This posed the obvious problem of matching early time pressures with exact shut-in time; so after the sensitive electronic bottom hole pressure gauges became available in the 1980's another test was run on the K-13. The results are about the same as before (reported to the Oil Conservation Division in 1969, and to the USGS in 1980 showing the type curve analysis). The details of this recent test are included herein.

For a well completed in a tight block, the pressure behavior of the early and middle time periods reflects the properties of the tight block only. To estimate characteristics of the bulk of the reservoir volume from such a buildup curve, one is reduced to analyzing the late time period. Prior to the availability of the data from sensitive pressure gauges, analyses of this part of the curve was considered impossible.

That has changed with the more accurate information now available. Care is, of course, required in analyzing this part of the build-up. Some examples of analyses of this part of the buildup curve are included herein.