FORREST A. GARB & ASSOCIATES, INC.

Oil Conservation Division
Case No.
Exhibit No. 3

I. INTRODUCTION

At the request of Doré Energy Corporation (Doré), Forrest A. Garb & Associates, Inc. (FGA), has reviewed available data for the Russell (Yates) oil field, located approximately 12 miles north-northeast of Carlsbad in sections 12, 13, and 14, Township 20 South, Range 28 East, Eddy County, New Mexico. Doré has indicated an interest in acquiring this oil field and is seeking recommendations from FGA for future oil recovery operations.

II. GENERAL INFORMATION

Russell field was discovered by the drilling of the 1 Neil H. Wills *et. al.* in March 1942 and produces from the Permian age Yates sand at an approximate average depth of 800 feet. The structural configuration of the field is an east-dipping monocline exhibiting a slight nosing. The reservoir is described as varying from sandy shale to shaly sand. Reportedly the trap is formed by loss of permeability on the north, west, south, and southeast as the sand becomes limy and anhydritic. A small gas cap existed initially in the southwest portion of the field. There is a small area on the northeast edge of the field where there is oil on water, but there does not appear to be any active water drive.

The data studied include information and files related to this oil field that Doré obtained from the New Mexico Oil Conservation Division, plus a limited amount of additional data obtained from industry public data sources. These data include several reports prepared by other engineering consultants at various times during the life of this field: reports on core analyses (1956, 1957, and 1962), gas repressurization (1948), and waterflooding and valuation of the unit (1964). The gas repressurization report includes both a structure map on the top of the Yates sand and a net sand isopach map of the Yates. Attachments 1 and 2 are adaptations of these two maps by FGA, respectively. FGA does not have most of the data on which these reports were based; but there is enough consistency in the data reported in, and the findings of, these reports, that we believe they are valuable and reliable documents. Also provided were old driller's logs from when the wells were drilled. These logs are verbal descriptions of the formations penetrated and are difficult and relatively inexact for use in a quantitative sense for mapping. Consequently, FGA has not undertaken to make its own versions of the structure and net sand isopach maps and instead, is using the two maps taken from the report noted above. There is a listing of most of the wells drilled, their completion depth, casing and completion program, and initial potential producing rate (Attachment 3). Most of the wells that reportedly produced water upon initial potential were drilled later in the life of the field after the waterflood had begun. Also found in these files are various and sundry notes by field personnel, copies of old scout tickets, and copies of portions of a few open hole well logs from wells in and near the field.

In addition, we have a 1985 letter written by the New Mexico Petroleum Recovery Research Center (NMPRRC), a division of New Mexico Tech in Socorro, New Mexico, that discusses the offer by the then current owner and operator of the field, Barber Oil Company (Barber), to donate the field to the New Mexico Institute of Mining and Technology (NMIMT) for testing of enhanced oil recovery (EOR) methods. This report apparently has relied heavily on the older reports, as well as the state's own data on the field. Presented in this letter are numerous statistics about the field and discussion of possible EOR scenarios.

The field was developed initially in the early and middle 1940's on a mix of ten-acre patterns and forty-acre five-spot patterns. Subsequent infill drilling has increased the well density such that most of the field area now has wells on twenty-acre five-spot patterns. There are 70 wells within the Russell Unit that either produced oil, were used as injectors, or both; the full history of these wells in this sense is not known. Some may have been used only as producers, some only as injectors, and some may have been both producers and injectors at one time or another.

Most of the wells were completed open hole. These wells were cased down to a point 50 to 100 feet above the pay zone and then "shot" with anywhere from 20 to 80 quarts of nitroglycerine placed in the planned producing interval. This was a fairly common completion and stimulation practice for tight, low porosity and permeability reservoirs in those years. Casing diameter varies from four inches to eight-and-five-eighths inches. Initial potential producing rates varied from dry holes to 288 barrels of oil per day (Bbl/D). Records indicate that less than half of the wells initially also produced water; some produced very little water and some, more water than oil. Most of those that produced significant volumes of water were part of the later phase of infill development drilling in the 1950's and 1960's.

III. PRESSURE MAINTENANCE SURVEY, OCTOBER 1948

An October 1948 study by Cable and Stine petroleum engineers (Cable and Stine) concluded that, even though then current producing practices were efficient, a recommended pressure maintenance program using produced-gas reinjection would prove profitable. The structure and isopach maps referred to above were produced as part of this study. The field covers 442 acres, and total reservoir volume of 8,511 acre-feet was determined from the net sand isopach map. Cable and Stine assume average porosity of 16 percent, connate water content of 35 percent, and oil formation volume factor of 1.15 reservoir barrels per stock tank barrel (RB/STB). There is no note of available data to support these assumptions; however, FGA believes them to be reasonable. Data obtained later in the life of the field do indeed reveal these assumptions to be reasonable. These parameters lead to the calculation of original oil in place (OOIP) of 701.6 barrels per acre-foot (Bbl/ac-ft) of reservoir volume, or a total OOIP of 5,971,300 barrels (Bbl). Cumulative production up to August 1, 1948, was 516,266 Bbl, 8.65 percent of OOIP.

Surface facilities in the field had been set up such that there were multiple tank batteries, each of which were fed by groups of numerous wells. These tank batteries are where the production was monitored and measured. In this study each of these tank batteries was examined as a different entity in terms of cumulative production and reservoir parameters as inferred from the maps constructed. The OOIP and projected recoverable oil were estimated by battery. Recoverable oil, by both continuation of present producing practices and by gas repressurization, was estimated for each tank battery and its associated group of wells. These estimations were made on multiple bases of reservoir examination. The performance of each group of wells was reviewed and future projections made on the basis of reservoir volumetric parameters, bottom-hole pressure decline, and production decline to an economic limit.

Cable and Stine estimated that continuation of present production practices, augmented with repressurization by reinjection of produced gas would yield total future production of 634,473 Bbl of oil. They projected that the combination of these two production practices would result in ultimate production of 1,150,739 Bbl for the entire field, 19.27 percent of OOIP. The gas repressurization program was initiated in June 1949.

Closing remarks of this study note that a "...program of pressure maintenance by water injection, if the reservoir is adapted for it and if handled properly, will generally result in a greater ultimate recovery than by gas injection." However, Cable and Stine also state that they "...do not recommend water injection into the Yates formation at this time."

IV. CORE ANALYSES AND RELATED STUDIES, 1956, 1957, AND 1962

FGA obtained analysis data on cores from four wells in the field. All of these wells were cored after the beginning of the waterflood program in the field in 1953. Additional infill drilling occurred both before and after the inception of the waterflood in order to increase the well density. Some of these data are listed in Table 1 below. The report for well 10-A was done by Stephens Engineering (Stephens); all the others were done by Cable Engineering (Cable). Various calculated oil recovery values from these core analysis reports are listed in the rightmost three columns in barrels per acre-foot. The column labeled "Primary Recovery" lists those volumes that should be recovered using no production enhancement techniques at all. The column labeled "100 Percent Waterflood" lists calculated additional oil that could be recovered by a 100 percent effective waterflood.

Table 1

			Average			Calculated		
Well No.	Date	Cored Interval (Feet)	Porosity (%)	Permeability (md.)	Water Sat. (%)	OOIP (Bbl/ac-ft)	Primary Recovery (Bbl/ac-ft)	100 Percent Waterflood (Bbl/ac-ft)
54	Dec-56	789-819	16.16	29.05	47.0	633	123	254
27	Dec-56	789-819	15.80	51.70	51.5	633	123	238
29	Jan-57	770-787	14.60	12.20	47.0	572	111	255
10-A	May-62	786-809	20.70	46.40	47.0	810	162	328

Wells 54, 29, and 10-A presented only basic core analysis data as shown above. The data for well 27 was accompanied by additional study and discussion. This well was drilled as part of a study to investigate the practicality of infill drilling, and it was one of the wells drilled to "convert" a 20-acre four-spot into a five-spot. Although these sands are shaly, at least in part, it was noted in the discussion of the analysis report that bentonitic swelling did not contribute to low or reduced permeability. In this study, Cable notes that, based on experience, it is not possible to obtain a 100 percent effective waterflood. Based on observation of reservoir performance, Cable estimates that the flooding efficiency for this reservoir likely would be approximately 55 percent. Using the average of the waterflood recovery values for these four wells (268.8 Bbl/ac-ft) and Cable's waterflood efficiency estimate of 55 percent, estimated additional waterflood recovery would be 147.8 Bbl/ac-ft.

Core analyses for wells 54, 29, and 10-A determined that the formation volume factor for the Yates sand is 1.05 RB/STB, which FGA corroborated by correlations based on what is known about the reservoir temperature and pressure and the oil gravity. This new value of oil formation volume factor results in calculation of a higher value of oil in place of 768.4 Bbl/ac-ft, which, in turn yields OOIP of 6,540,000 Bbl. Extrapolated to the entire reservoir, a waterflood as described above might yield 1,258,000 additional barrels of oil, 19.23 percent of OOIP.

V. VALUATION OF NEIL WILLS INTEREST IN RUSSELL FIELD, SEPTEMBER 1964

In a report by Stephens, dated September 16, 1964, that was to establish a fair market value for the Wills interest in Russell field, there is considerable additional discussion and information about the field.

A pilot waterflood program was begun in April 1953. Favorable results of this pilot project led to the beginning of fieldwide expansion of the waterflood in September 1954. This fieldwide waterflood proved successful, resulting in increased production that eventually peaked at the approximate rate of 500 barrels per day (Bbl/D) near the beginning of 1958. Cumulative production of the waterflood was 921,099 Bbl as of September 1, 1964; and cumulative production for the field was 1,916,099 Bbl, 29.30 percent of OOIP. Stephens determined that the decline rates established for each tank battery allowed reliance on projections from those performance histories in predicting ultimate recovery under then current operating practices of 2,294,000 Bbl, or 35.08 percent of OOIP.

VI. PETROLEUM RECOVERY RESEARCH CENTER STUDY, AUGUST 1985

Pursuant to Barber Oil Company's offer to donate the Russell field to the New Mexico Petroleum Recovery Research Center, the NMPRRC did some study of its own on the history of the field, the known reservoir and performance data, and what the possibilities might be for the application of further enhanced oil recovery technology. NMPRRC reported that cumulative production for the field through the end of 1984 was 2,370,000 Bbl, 36.24 percent of OOIP. NMPRRC also noted that the field produced a total of 5,551 Bbl during 1984 and likely would become uneconomic sometime during 1986 under then-current operating practices. According to IHS Energy (IHS), a public oil industry data vendor, cumulative production for the field through late 2006 is 2,383,130 Bbl. These data imply that there are approximately 4,156,700 Bbl remaining in the reservoir.

VII. ENHANCED OIL RECOVERY

FGA has estimated OOIP of 6,540,000 Bbl for the Russell field based on reservoir volume of 8,511 acre-ft, average porosity of 16 percent, initial water saturation of 35 percent, and oil formation volume factor of 1.05 RB/STB. FGA estimated the total recovery factor of 37.8 percent for the Russell field. This value is based on a volumetric sweep efficiency of 0.56 and a displacement efficiency of 0.675. The volumetric sweep efficiency is based on a mobility ratio of 2.13. The displacement efficiency is based on a residual oil saturation of 21.1 percent. The total expected production by primary and secondary recovery is estimated to be 2,472,000 Bbl based on the calculated OOIP and the estimated recovery factor. Cumulative production for the field is 2,383,130 Bbl based on available IHS production reports (Attachment 4). Remaining oil that can be produced by additional waterflooding is estimated to be 88,900 Bbl.

FGA searched the Society of Petroleum Engineers (SPE) literature for field case histories of shallow sandstone waterflood projects to determine if the calculated recovery efficiency was reasonable, based on recoveries from similar projects. The West Burkburnett field, located in Wichita County, Texas, has a development history that is very similar to the Russell field and has reservoir properties that are more favorable to waterflooding. The Burkburnett field has a higher porosity (22 percent versus 16 percent) and a lower oil viscosity (2.25 centipoises [cp] versus 5.77 cp) than the Russell field. The ultimate recovery from primary and waterflood production from the Burkburnett field was estimated to be 50.5 percent of OOIP (SPE Paper #1428, *Journal of Petroleum Technology*, August 1966). This recovery factor might be considered an upside recovery for the Russell field. Remaining oil that could be produced by additional waterflooding at this recovery factor would be approximately 919,500 Bbl.

FGA estimated the total mobile OOIP in the Russell field to be 4,417,200 Bbl. The remaining mobile oil is estimated to be 2,034,000 Bbl. FGA believes this oil may be a good target for tertiary recovery. Because of the low volume remaining to be produced by additional waterflooding, FGA would recommend pursuing tertiary recovery without additional waterflooding.

NMPRRC provides some information about what then was a new recovery process that had been developed in the laboratory by NMPRRC and Shell Development, using caustic, surfactant, and polymer flooding. Shell's laboratory tests reportedly recovered 50 percent oil cut, but it is not known if this means they had a 50 percent oil cut in the produced fluids or they recovered 50 percent of the oil in place at the beginning of the test. NMPRRC also notes that "Properly designed surfactant field tests have recovered 35% OIP (Marathon) to 60% OIP (Exxon)." Again, it is not clear whether or not this actually means that these tests recovered those respective percentages of the oil in place at the time the test began; but it is important to understand that these were actual field tests and not laboratory tests.

Surtek, located in Golden, Colorado, is an engineering firm that specializes in the study, design, and implementation of enhanced oil recovery methods. The centerpiece of the technology they offer is alkaline-surfactant-polymer (ASP) flooding. FGA has some knowledge of successful projects that Surtek has done. Surtek claims that this technology can recover up to 20 to 30 percent of OOIP at low cost. If this is correct, and if the Russell field were amenable to ASP flooding, it would mean the recovery of an additional 1,308,000 Bbl to 1,962,000 Bbl from the Yates sand.

If Doré plans to pursue additional water injection in the Russell pool, FGA would recommend producing from one or more of the following wells: Turner 7, Turner 9, Turner 10, Turner 11, Turner 20, Turner 23, Wills 12 and Wills 16. These wells each have cumulative oil to cumulative water ratio of 0.40 or greater. Cumulative production available for all wells and production ratios for wells that have not been converted to injectors are shown in Attachment 4. Injection wells should be drilled downdip of these producers, with the exception of Turner 7 due to loss of sand downdip of the Turner 7. The injection rates should not exceed the parting pressure of the formation. A step rate injection test should be performed on new injection wells in order to determine the fracture gradient. Injection rates would be limited to about 40 barrels of water per day (BWPD) in each injection well at a fracture gradient of 0.8 pounds per square inch per foot of depth (psi/ft). It is possible that the parting pressure was exceeded in previous injection. The estimated bottom hole injection pressure was about 760 psi, based on a surface injection pressure of 400 psi, as projected in the Russell Joint Account report dated December 31, 1956. This bottom hole pressure corresponds to a gradient of 0.95 psi/ft, which may have exceeded the formation parting pressure. The estimated cumulative water produced is significantly less than the estimated cumulative water injected. Estimates for the cumulative water produced ranges from 8,484,800 to 8,624,000 Bbl and the estimated cumulative water injected is 14,705,300 Bbl. If the formation was fractured during injection, some of the water may have been lost outside of the formation.

The use of existing wells for either production or injection must consider carefully the condition of the wellbore. Those original wells that were shot with nitroglycerine likely may be in poor condition. The Yates formation interval may be rubble-ized or otherwise may not be amenable to proper fluid movement, and the casing seat and cement job may have been compromised as a result of the nitroglycerine shot. This could be another way injection water could have been lost outside of the formation. Use of wells like these as injectors probably would be unwise because it is unlikely that adequate control over injected fluids could be exercised. Wells that were drilled in the 1960's may be in better condition, but even these are at least 40 years old. Available records are not clear as to whether these wells were shot open hole or were perforated. In any case it probably is better to drill new wells for injectors. These wells can be cored and can be logged with a proper set of modern tools. Because the Yates interval contains mixed lithologies, this will facilitate better interpretation of the rock types and reservoir properties. The cores will provide the basis for accurate determination of additional data necessary to properly plan injection rates, pressures, and fluids to be used, whether Doré decides to use water injection or proceed directly to implementation of tertiary recovery techniques. FGA's preference for tertiary recovery, without the intermediate step of additional waterflooding, is founded on the premise that waterflooding alone would recover so little additional oil, would add considerably to operating expense with little compensatory return, and would delay the operation of a more efficient tertiary recovery project that would provide better economic results and would recover that incremental oil remaining to be recovered by waterflood.