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Enhancing Inactive Well Recovery Potential – A Case History

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Abstract

This paper presents an example of a method for identifying incremental productivity of inactive watered-out wells in complex reservoir structures with edge water. The method targets inactive/marginal wells associated with bypassed oil reserves and forecasts the potential of these wells through the use of dual well completions with downhole water drainage - Downhole Water Sink (DWS) technology. In DWS wells, the top completion produces oil as the water inflow is diverted by the bottom completion acting as water drain (or sink).

Described is the first step of the method, a geological analysis of reservoir compartmentalization and connectivity. The studied wells produced from a cross-bedded sand channel that had eroded the shale barrier between two normal sequence sands. The analysis identified hydraulic communication of the two sands.

The second step of the presented method involved an analysis of the reservoir and well production records to diagnose pathways of fluid movements leading to un-swept oil and well invasion with water. The lower KF sand was water flooded for ten years before the A-3 well watered out. The production data implied water coning. Moreover, displacement calculations indicated that a large amount of the oil in the KE reservoir was unswept, leaving considerable amount of by-passed reserves.

The paper conceptualizes why the bypassed oil could not be recovered from these wells, economically, with or without additional water flooding. Production schemes were designed for comparison. The system was modeled with a reservoir simulator and the results were compared with the other conventional solutions. The results clearly show a marked improvement with the use of DWS. The results indicate improved potential commercial development.

Introduction

At the current level of oil and gas prices, more and more interest is falling upon mature fields and reservoirs. Many of these mature fields and reservoirs, at first look, appear to be depleted, watered-out and of no commercial value. However, if one takes a closer look, many times there is value, just not apparent initially. The difficulty, however, is to identify this value in an efficient manner, especially when dealing with

complex reservoir structures, where diamonds in the rough are more likely to be found.

Geological analysis of the reservoir is the important first step in this process. The answer to the question, "Does the depositional environment of the reservoir and the location of existing take points (wells) support potential compartmentalization and potential bypassed oil?" must be answered.

As will be seen, the studied wells produced from a cross-bedded sand channel that had eroded the shale barrier between two sands. The analysis identified hydraulic communication of the two sands.

West Delta Block 84 Field

West Delta Block 84 Field is located off the coast of Plaquemines Parish, Louisiana, near the mouth of the Southwest Pass of the Mississippi River in about 20 feet of water, Figure 1. The field was discovered by Conoco in 1955. Wells penetrating the West Delta 84 Field encounter geologic section ages ranging from Lower Pleistocene- Lenticulina 1 to Upper Miocene, Cyclamina 3.[1] The productive reservoirs in the field range from Bulminella 1, Lower Pliocene to Rob E, Upper Miocene, Table 1.

Penetrating Wells

The focus of this study is the KEKF1 reservoir. Electric logs from wells penetrating this reservoir provided the first glimpse of the complicated nature of the geology. Sand intervals go from one extreme to the next. In one well, they may be intermixed with multitudes of shale intervals or tight and in the next well the sands may be beautiful examples of clean homogenous point bar deposits. Tracing out the meandering paths of these sands and how they were interconnected and communicating was critical for determining the locations of potential bypassed oil. Initial models of the flow paths of the permeable sands were prepared only by interpretation of the electric logs. Appendix 1 contains descriptions of the KE and KF sands penetrated by each of the wells, as well as performance data and short histories of the wells themselves.

Geology

Depositional Environment

The KEKF1 sand is Robulus E, Upper Miocene in age. The depositional environment for the sands was middle neritic (that part of the sea floor which extends from the low tide line to a depth of 200 feet) and is comprised of a series of meandering channels and point bars. This type of system migrates laterally through time giving it a shingled affect 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, suggesting the likelihood of compartmentalization and potential bypassed oil.

These meandering channels are typically characterized by strong secondary spiral flows.[2] The flows or forces tend to move fluid particles toward the outer bank of a meander. In other words, the maximum velocity is not at the center of the channel, but near the outer bank. This creates erosion on the bottom and sides of a curved channel and deposition on the inner bank. The erosion deepens the channel and widens the outer bank. The sediment derived from the erosion is moved downstream or is diffused as suspended load into lower energy environments. At the opposite side of the channel and the outer bank, where erosion is occurring, there is deposition in the form of point bars. Coarser sediment is deposited in deeper water and finer sediment in the shallower areas. The point bars accumulate in a cross-flow direction and because of this they produce sets of trough cross-bedded sands.[3] Point bars are known to produce typically fining upwards sequence.[4] The majority of the electrical logs of the 19 wells which penetrated the KE and KF sands in the area in and around the KEKF1 reservoir, had fining upwards sequences.

After the channel has migrated (in this environment as a meander cutoff) it leaves behind the point bars (deposition) and the eroded channel and outer bank (erosion). In a meandering channel depositional environment, these eroded areas are generally filled with fine overbank deposits such as mud or organic detritus, referred to as "clay plugs", thus creating impermeable or semi-permeable areas intermixed with the permeable areas (sand). These clay plugs may form trapping mechanisms for entire oil and gas reservoirs or they may form semi-permeable barriers within the midst of the reservoir, as in the case of the KEKF1 reservoir, Figure 2 and 3. These changes between permeable and impermeable strata within the reservoir create complicated flow paths which are not easily solved. Flow models were prepared, grid and input into BOAST-3PC, a public domain black oil reservoir simulator made available by the United States Department of Energy.[5]

Structural Geology

The regional subsurface geology at the depth of the KEKF1 reservoir is defined by gentle synclines and anticlines and faulting which trend east-west. The KEKF1 reservoir, 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 one hundred feet (100') each. It is trapped on the east by shale-outs in both the KE and KF sands. It is defined on the west by an oil-water contact at 11,136 feet below sea level.

Volumetric Analysis

Structural and isopach maps were prepared for KEKF1 reservoir. Using an average 24.75% porosity and an average initial water saturation of 23.5% the initial volumetric oil-in-place was calculated to be 14,934,075 STB of oil and 25.5 BCF of free and solution gas.

Material Balance Analysis

Based on the historical decline in reservoir pressures, it was believed that any water drive present was weak. Review of the stratigraphic and structural geology brings one to believe that there are simply no pathways for aquifer influx and thus it could be reasoned that there, in fact, was no aquifer influx. Basic material balance calculations were performed to confirm this observation.

The material balance method is described in numerous textbooks and is a basic, quick analytical method for determining drive type. Craft and Hawkins provided the material balance calculations.[6] Havlena and Odeh, R.A. Campbell, J.M. Campbell, Sr., Dake and Pletcher provided graphical techniques and improvements to the method.[7,8,9,10,11] These improvements, as they are concerned with oil reservoirs, were incorporated in the material balance calculations performed for the KEKF1 reservoir. Pletcher discusses the inaccuracies developed when dealing with weak aquifers such as the one which is artificially present in the KEKF1 reservoir by virtue of a now suspended waterflood into the KF sand. By comparing the recommended method for solving a material balance for a undersaturated oil reservoir with no water influx versus a Campbell Plot. Pletcher showed that a weak aquifer influx could easily be missed using the normal procedure of plotting F vs. Et. A Campbell Plot plots F vs F/Et and will show negative slope for a weak water drive.

The basic material balance equation is:

$$N = \frac{Np[Bt + (Rp - Rsi)Bg] - (We - BwWp)}{Bt - Bti + \left[mBti\left(\frac{Bg - Bgi}{Bgi}\right)\right]} \quad \text{.... (1)}$$

Initially it was assumed that there was no water drive and so the We term drops out leaving

$$N = \frac{Np[Bt + (Rp - Rsi)Bg] + BwWp}{Bt - Bti + \left[mBti\left(\frac{Bg - Bgi}{Bgi}\right)\right]} \quad \text{.... (2)}$$

First, the KEKF1 reservoir was analyzed before water injection began or for the period between 1955 and 1973. Assuming no water drive present during this time, a Havlena-Odeh Plot of F vs Et was prepared where:

$$F = Np[Bt + Bg \times (Rp - Rsi)] + WpBw \quad \text{............. (3)}$$

$$Et = Eo + mEg + Efw \quad \text{.................................. (4)}$$

$$Eo = Bt - Bti \quad \text{.. (5)}$$

$$Eg = \frac{Bti(Bg - Bgi)}{Bgi} \quad \text{..................................... (6)}$$

$$Efw = \frac{Bti(1 - m) \times [SwiCw + Cf(Pi - P)]}{(1 - Swi)} \quad \text{............ (7)}$$

If the assumption that no water drive is present, then the F vs Et graph should be a straight line according to Havlena and Odeh.

For the material balance analysis, F was plotted against Et for the period 1956 to 1973 (pre-waterflood), Figure 4, which is appropriate for a no water drive, gas cap present reservoir.[12] The graph shows a straight line, indicative that the no water drive, gas cap present assumption is correct. The slope of this line, 14,748,989 STB is equal to N or the original oil in place with m=0.21 representing an original gas cap in place of 7.87 BCF. This matches very well with the volumetric studies.

The same interval of time was again considered in a Campbell Plot, Figure 5. After some initial scatter of the data, where pressure information is averaged from later data, the graph depicts basically a straight horizontal line whose y-intercept is approximately 14,700,000 STB which is equal to N. Thus, the Campbell Plot confirms the Havelena-Odeh straight line interpretation that there is no water drive present and that the reservoir is a depletion type driven reservoir under primary conditions.

Analyzing the data after water injection, the approximately 5 million barrels of water injected has to be considered. This water injection should replicate a weak water drive during and somewhat after the time of the injection. Applying the same data to a Campbell Plot, but this time considering the entire history of the reservoir, results in Figure 6. Reviewing this graph, the period after water injection begins, after some initial flutter goes to a negative slope as would be expected for a weak water drive.[13] Then the graph begins a gradual return to positive slope before starting another gradual trend toward horizontal once again indicating a return to depletion drive. The shape of the curve in this interval is affected by the fact that the reservoir was shut-in for almost 9 years with no production.

Reservoir Computer Simulation Analysis

BOAST-3-PC was used for the simulation of the KEKF1 reservoir. BOAST 3-PC is a public domain reservoir simulation model made readily available by the United States Department of Energy which is a modification to the original program, BOAST, which was released in 1982.[14] It is a finite-difference, implicit pressure/explicit saturation (IMPES) numerical simulator. It includes options for both direct and iterative solution techniques. Options within the program include multiple rock and PVT regions, a bubble point tracking scheme, automatic time step control methods, material balance checks for solution stability, allowances for multiple wells per grid block scenarios and an option for rate or pressure constraints on well performance. It can simulate oil and gas recovery by fluid expansion, displacement, gravity drainage and capillary imbibition mechanisms.

BOAST Simulation

The reservoir was then grid into 26 by 15 by 3, x, y, and z, respectively. X lengths ranged in size from 150 feet to 1250 feet. Y lengths ranged in size from 125 feet to 500 feet. Z thickness was defined by the gross thickness of each layer as defined by the sand and shale thicknesses. It was set up to match the sand patterns of the interpreted net sand maps while at the same time realizing that adjustments would have to be made for the scoured channel area of the reservoir. Formal geostatistical methods were not used for the assignment of values to the individual cells. Rather, values were input by hand based upon known values and geological mapping. Modifications to obtain a history match were also analyzed and input by hand. In general, Layer 1, the uppermost layer, contained the KE sand, Layer 2 contained the shale interval between the KE and KF sands and Layer 3 consisted of the KF sand. These general situations were modified whenever the KE scoured channel sand deposition was encountered such as in the SL 2551 No. A3 and the SL 2551 No. 15 wells. The areas where Layer 2 were modified was exclusively along trends within the area of the scoured channel.

Initial simulation runs which were made to obtain a history match positively confirmed the communication of the two sands. Even though the KF sand has been scoured and replaced by the channel KE sand almost through the heart of the reservoir, the sands which replaced it are in communication with the normal KE and KF sequences. Initial simulations pressures were seriously depleted early in the life of the production from the KF sand in the SL 2551 No.1 and No. 4 wells and the wells either pressure depleted or went to excessive gas-oil ratios early in their lives. The only way to alleviate this situation was to open up flow paths through the main scour and channel fill areas.

After this major modification was made, the simulated pressures were too high and the original oil and gas in place was too high. Overall net "z" block thickness were reduced in order to more closely match the overall hydrocarbons in place as calculated by the volumetric and material balance studies and to also more closely model reduction in the reservoir pressure as production occurred. Relative permeability curves were adjusted slightly to match the actual overall producing gas-oil ratios.

After these major adjustments were made, modifying was reduced to trial and error flow path definitions for history matching of the individual wells through adjustments to the net sand and the horizontal and vertical permeabilities. All of these changes again occurred within the area of the scoured channel fill.

Bypassed Oil

Based upon the volumetric, material balance and computer simulation studies, bypassed oil is present within the KEKF1 reservoir. The bypassed oil is the result of either low oil mobility or inefficient waterflood sweepage. A basic premise for the inefficient waterflood sweepage is that the reservoirs are indeed communicating. Both wells completed in the KF and the KE sands indicate a pressure response to the KF waterflood. One can analyze this in more detail by plotting a downdip KE well, the No. A4; a scoured channel fill sand well, the No. A-3; and an updip KF well, the No. 4. This plot, Figure 7, shows all three wells reacting in the same manner, indicating that all three of these variable completions are, in fact, responding to the waterflood.

For additional analysis, an oil and water relative permeability curves was prepared. These curves are typical representations of the range of relative permeabilities for the Gulf Coast and are the curves used in the BOAST simulation. Based on these curves, mobility ratios were prepared for the entire range of water saturations. Initial connate water was set at 23.5% and initial oil saturation was set at 76.5%. Irreducible oil saturation was set at 20%. A graph of the mobility ratio (water displacing oil), was prepared and shown in Figure 8. This figure indicates that, as expected, the reservoir would produce essentially water free until the flood front approaches at a take point (a well). After this has occurred the water cut would rise rapidly and in a short period of time. In other words, the oil is very mobile until the water saturation reaches about 70%, which would be indicative of the water front. Therefore, the analysis of the mobility ratio supports the theory that the bypassed oil is a result of an inefficient waterflood not the mobility of the oil. By injecting into only the KF sand, the KE sand downdip of the scoured channel sand remains unswept by the waterflood. Wells producing from the KE sand downdip of the scoured channel realized an increase in reservoir pressure, but did not recover waterflood swept oil. Wells within the scoured channel, watered out pre-maturely with unswept portions in the upper areas of the channel sand unrecovered due to water coning into the wells from the lower portion of the sand as a result of the KF waterflood.

An example of this occurrence is the No. A3 well. A plot of its historical water-oil ratios, Figure 9, shows water free production for the first two years, until December 1969, and an average water-oil ratio of 0.29 Bbl/STB for another 10 years after this, to December 1979. Water cut begins to increase rapidly at this time resulting in a 90% water cut at the time it was shut-in a year and a half later in June 1981.

Pursuing this analysis a little farther, a Buckley-Leverett Frontal Advance[15] was calculated for the reservoir. The equation for a Buckley-Leverett analysis is as follows:

$$x = \left[\frac{5.615 \times qt}{Porosity \times x \times havg}\right] \times \frac{\partial fw}{\partial Sw} \quad \text{...............(8)}$$

$$\frac{\partial fw}{\partial Sw} = \frac{\left[\left(\frac{uw}{uo}\right) \times b \times \left(\frac{ko}{kw}\right)\right]}{\left[\left(1 + \left(\frac{uw}{uo}\right) \times \left(\frac{ko}{kw}\right)\right)^2\right]} \quad \text{...............(9)}$$

The KF waterflood began in January 1973 and ended in 1983 after injecting 5.6 million barrels of water. A simple Buckley-Leverett analysis was performed on the reservoir for the KF-1 waterflood. If downdip portions of the reservoir were inefficiently swept, then the Buckley-Leverett calculations would predict a longer time than actual for when the water front would encounter the most downdip productive well which produces from either the normal KF sand or the scoured channel fill sand, i.e. the No. A3.

The water front would have to move approximately 2500 feet from the injector wells before encountering the No. A3 well. Based on an average thickness of 25 feet, a waterfront width of 3000 feet and a water to oil viscosity ratio of 0.26, Buckley-Leverett predicted it would take three times longer, or approximately 8000 days, for the waterfront to encounter the No. A3 well than it actually did. In actuality, it only took 2500 days after the beginning of the waterflood into the No. A1 and No. A9 wells for the waterfront to reach the No. A3 well. This means that either the water front width is not as wide as estimated or that the thickness swept is smaller than estimated. Either way, it can be concluded that a large amount of the downdip reservoir was unswept.

Predictive Studies

Once a history match was made, the task of designing the most efficient manner to recover the remaining reserves awaited. Predictions included having no additional work, no secondary recovery mechanisms, no pressure maintenance and continued production through the lone active well (the No. 18), additional well workovers with no secondary recovery mechanisms and no pressure maintenance put into place, the previous two scenarios with secondary recovery and pressure maintenance present (in the form of an additional waterflood both in existing injection completions and additional completions) and enhanced recovery through "Downhole Water Sink" (DWS)[16] technology with and without an additional waterflood.

any production, with the exception of the No. 18 well which was only shut-in for a period of eight years (1990 to 1998) and fifth, there remains a substantial amount of oil to be recovered. Primitive DWS completions were simulated in these three wells. All three indicated additional oil recovered. The lowermost completion was simulated producing the water encroaching from the bottom portion of the sand channel and the upper completion was simulated producing the oil and gas reserves. This scenario was simulated with and without waterflood.

"Downhole Water Sink" (DWS)

Based on historical observation and the simulation, two of the wells developed water cones in later life just after the KF waterflood ended even though they were completed in the KE sand, the No. 15 and the No. A3 wells. The No. 18 well is also believed to be on the brink of an oil/water cone and has probably not encountered one yet due to the long period that the reservoir was shut-in and the on/off production rates it is currently being produced under (there is currently no pipeline and so the well ends up being shut-in one week out of the month waiting on a tow because storage capacity has been reached). This, in turn, has probably lowered the continuous production rate of the well below the critical rate, which is known to reduce the breakthrough time of a cone.[17] Water coning in the oil field is a well known phenomenon. Muskat[18] first presented an analytical model of water coning in1949. Later, Wheatley[19] simulated an analytical based oil/water coning model. One method for controlling water coning is by the DWS technology. This technology involves a dual downhole completion where the lowermost completion is made below the oil/water contact and the uppermost completion is made above the oil/water contact. The two completions are separated by a packer or some other means. The idea is to draw down the water away from the oil zone completion and thus prevent a water cone from developing. Widmyer[20] originated the idea with two completions, but both in the oil zone. Driscoll[21] later refined the idea by having multiple completions with the lowermost completion below the oil/water contact. Wojtanowicz, Xu and Bassiouni[22] refined these concepts even further into a more workable and successful method when they simulated a dual completion using a "tailpipe water sink." in 1991. Water was produced through the lowermost completion through perforations in the casing in the water zone and then up open tubing which was separated from the uppermost oil zone perforations by a packer with the oil zone completion being producing up the annulus between the tubing and the casing. The DWS technology developed by Wojtnaowicz et al was first tested in the field by Hunt Petroleum Corp in Nebo-Hemphill Field in the "Top of the Wilcox" zone notoriously known for its heavy crude and extreme susceptibility to water coning. Results of the completion were very successful both scientifically and economically.[23,24] A Joint Industry/Louisiana State University project-DWS Initiative has now field tested numerous reservoirs all over the world with good results.[24] The KEKF1 reservoir could offer a unique opportunity for the DWS technology. First, it is a naturally depletion drive reservoir with no natural water influx; second, it has had a water-flood with a known amount of water injected (influx) into the lower sand lobe (KF) which essentially simulates a bottom water drive when considering the KE sand, it has at least two wells and possibly a third developing that have water cones, fourth, it has essentially been shut-in for the last ten years without

Simulated Predictions

All predictions following are set at a constant flow rate to either a watered out situation, a maximum gas/oil ratio or a minimum reservoir pressure for comparison purposes only. One of BOAST's weaknesses is its ability to handle the Gas/Oil ratio. Once a gas/oil ratio begins to increase during a simulation, BOAST has a tendency to be erratic and increase and decrease rapidly and suddenly so much that the simulation will reach the maximum set gas/oil ratio value and "blow up"

the simulation. The maximum gas\oil ratio, therefore, in the simulation run is set at a very high level in order to ward off some of these erratic "blow ups" allowing it time to settle back down to reasonable values.

Additional recovery with less time should be realized with modifications and tweaking of flow rates and injection rates during the course of the recovery. The following prediction simulations were intended for identifying general strategies only and not developing exact or specific plans.

Prediction 1

The lone producing well, #18, was allowed to continue producing at 140 barrels of oil a day until November, 2001. It was kept at this rate because this has been the average monthly production from the well over the last 6 months while some facility work is completed. It was increased to 300 BOPD after November and allowed to produce until the maximum GOR of 50,000 SCF/STB was reached. At this time, the well was allowed to blowdown the remaining gas cap at 1000 MCFD until a minimum reservoir pressure was reached. This simulation resulted in an additional recovery of 274,400 barrels of oil and 11.6 BCF of gas after a period of 22 years.

Prediction 2

All wells in the reservoir which were still producing when shut-in were put back on line at their last test rates without a waterflood with the exception of the No. 12 well. This well, when included in the simulation, was unable to sustain expected production from the start. It was therefore removed from consideration as a possible workover target for these simulation studies. It is believed now that this well may be separated from the main reservoir by a semi-impermeable barrier. All other wells and perforated intervals were left as they were. The No. A3 immediately went off line after watering out. All other wells produced for varying amounts of time as they either watered out or reached a maximum gas/oil ratio and were shut-in. This scenario recovered an additional 890,000 barrels of oil and 10.3 BCF going off line in the year 2014 or 13 years.

Prediction 3

All wells in the reservoir which were still producing when shut-in were put back on line (except the No. 12) at their last test rates with the waterflood re-started as set up previously for the KF-1 waterflood. All perforated intervals were left as they were. This scenario resulted in wells watering out rapidly resulting in no improvement over Prediction 1 or 2 and was thrown out as a possible strategy.

Prediction 4

The No. A3 and No. 18 wells were recompleted by plugging off their lower sets of perforations and producing from their uppermost set of perforations while bringing on all other wells (except No. 12) with no waterflood, as in Prediction 2. This resulted in these two primary wells reaching a maximum gas/oil ratio rapidly resulting in no improvement in oil recovery and this also was thrown out as a possible strategy.

Prediction 5

In this prediction, the No. A3 and No. 18 wells were recompleted by plugging off their lower sets of perforations and producing from their uppermost set of perforations while bringing on all other wells with the KF-1 waterflood setup brought back on line. This resulted in an improvement in the recovery of the bypassed oil with an additional 1,500,000 barrels of oil being recovered after 29 years. The time of recovery should be improved with additional modifications to flowrates. All predictions herein are set at a constant for comparison purposes only as mentioned above.

Prediction 6

This prediction is exactly the same as Prediction 5 with the exception that a "DWS" dual completion is set in the No. A3 well. Water production rate was set at one-third oil production rate. This resulted in a water cone breakthrough in the No. A3 well 120 days later than in Prediction 5 and an additional recovery of 15,000 barrels of oil. Considering that the well would be worked over anyway to bring back on line, the prediction indicates that a "DWS" system would be profitable even with the limited assistance of 120 days. Going over or under one-third ratio resulted in no advantage in retarding a water cone breakthrough.

Prediction 7

Knowing that the original KF-1 waterflood was inefficient, with this scenario the No. A3 and No. 18 wells were recompleted by plugging off their lower sets of perforations and produced from their uppermost set of perforations while bringing on all other wells with the KF-1 waterflood setup brought back on line with additional injection completions in the KE sand from the same injections wells. This scenario resulted in the recovery of an additional 1,700,000 barrels of oil, a 13% increase from Prediction 5 where only the original KF-1 waterflood was brought back on line.

If there are, indeed, unswept portions of the downdip reservoir which would benefit from additional waterflood, then an oil bank should be created by the additional injection. In order to simulate this oil bank the water injection only was simulated without additional production. A graph, Figure 10, was prepared showing the average oil saturation for the matrix 7x-9x, 3y-5y, 1z-1z through the history match (includes production) and then one year after a new waterflood (without production). The matrix represents a portion of the downdip portion of the KE-1 sand near the No. A4 well. The graph illustrates the initial oil saturation of 76.5% before production, a decreasing oil saturation before, during and after the original waterflood to 44%, and an increase one year after the beginning of the new waterflood to 47%. This is as expected if there is, indeed, an oil bank created and thus a benefit from a new waterflood.

Prediction 8

This prediction is exactly the same as Prediction 7 with the exception that a "DWS" dual completion is set in the No. A3 well. Water production rate was again set at one-third oil production rate. This resulted in a water cone breakthrough in the No. A3 well 100 days later than in Prediction 7 and an

additional recovery of 12,000 barrels of oil. Considering that the well would be worked over anyway to bring back on line, this prediction again indicates that a "DWS" system would be profitable even with the limited assistance of 100 days. Going over or under one-third ratio again resulted in no advantage in retarding a water cone breakthrough.

Conclusion

There are many new insights on this reservoir as a result of this study. They are as follows: The KE-1 and the KF-1 reservoirs are indeed one communicating reservoir. The structural and stratigraphic interpretation of the reservoir has been improved because of new technologies in the form of 3-dimensional seismic data, processing, interpretation software and workstations and computer simulation and the application of old technology in the form of classic volumetric analysis and material balance analysis. Based upon new volumetrics, material balance analysis and computer simulation the original oil in place for the reservoir is 14.5 million barrels and the original gas in place is 30 BCF of which 22 BCF is solution gas and 8 BCF is gas cap or free gas. The reservoir contains bypassed oil. All of the gas reserves may be recovered by conventional techniques through the lone producing well, No. 18, if given enough time. The original KF waterflood was inefficient and poorly designed and resulted in a loss of oil recovery, which may still be recovered with the implementation of a newly designed waterflood. The simulation of a "Downhole Water Sink" (DWS) completion in the No. A3 well indicates an increase to break-through time of an imminent water cone into a new upper set of perforations. Bypassed oil may be recovered through several techniques. Based on prediction runs on BOAST, the best case scenario analyzed thus far, resulting in the most recovery of the bypassed oil pay is by implementing the following: Workover the No. A4, No. 4 and No. 15 wells in order to produce from their existing completions. Workover the No. 18 well to plug off its existing lower set of perforations, which appears to be the source of all of its produced water. Workover the No. A3 well to plug off its existing lower and upper set of perforations, reperforate the well for dual completion with one set below the existing lower set of perforations and one set above the existing uppermost set of perforations. The new lower set of perforations should produce water by using the "DWS" technology at approximately one-third the oil rate from the new uppermost perforations to increase the time to break-through of an imminent water cone. Re-complete the No. A9, No. A1 and No. A13 for water injection not only through the existing KF sand perforations but also additionally into any permeable KE sand penetrated in the wells. The initial injection rate should be approximately twice the combined oil rate from all producing wells. Do not return to production the No. 12 well. There is an indication from the simulation that the well is not in total communication with the rest of the reservoir and it is believed that this well may be separated by a semi-impermeable barrier. The No. 12 well should be brought on line only at the time of final gas cap blowdown and only if other wells are not performing as expected.

Risk and economic conclusions are as follows: It is extremely risky to produce a field with only one well. If the well goes down so does the cash flow. One of the above scenarios indicated producing a substantial amount of the remaining oil reserves and a lion's share of the gas reserves if given enough time. However, this scenario assumes that the lone well produces every day without delay. From past experience, this is not always the case and, in fact, it is a very unlikely one. In order to increase the well count from more than one, workovers must be performed. This study indicates that a small amount of old technology, in the form of a resurrection of a waterflood and a small amount of new technology, in the form of the "DWS" method will greatly increase the ultimate recovery of the "lost" reserves. While working on the standard workovers, it would be prudent and timely to consider working on the novel workovers as well. To risk is to bring opportunity. To risk with knowledge is to succeed.

NOMENCLATURE

dVb = Bulk Volume for particular contour slice, acre-feet
h = Contour value which represents net thickness of sand, feet
An = Area covered for the nth contour, acres
Bg = gas formation volume factor, rbSCF
Bo=oil formation volume factor, rb/STB
Rsi=initial solution gas/oil ratio, scf/stb
Rs=solution gas/oil ratio, scf/stb
Bt=total or two phase oil formation volume factor=Bo+Bg(Rsi-Rs)
Bw=water formation volume factor, rb/STB
Cf=formation compressibility, vol/vol/psi
Cw=water compressibility, vol/vol/psi
Eg= gas expansion, rb/STB
Efw=formation and water expansion, rb/STB
Eo=oil expansion, including original complement of solution gas, rb/STB
Et=Total expansion, rb/STB
G=Original gas in place, MSCF
Gp=Cumulative gas production, MSCF
m=Ratio of gas cap original gas in place to original oil in place at reservoir conditions, dimensionless
N=Original oil in place, STB
Np=Cumulative oil production, STB
p=Pressure, psia
Rp=Cumulative produced gas/oil ration, SCF/STB
Swi=Initial water saturation, fraction
We=Cumulative water influx, rb
Wp=Cumulative water production, STB
z=Gas deviation factor, or compressibility factor, dimensionless
q=Reservoir throughput, reservoir barrels per day
t=time, days
w=average width of zone, feet
havg=average net thickness in feet
uw=water viscosity, centipoise
uo=oil viscosity, centipoise
b=y-intercept of Sw vs.ko/kw
ko=effective oil permeability, md
kw=effective water permeability, md

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Appendix 1

SL 2551 #1

The discovery well of the field and the first well to produce the KEKF-R1 reservoir through the KF sand was the SL 2551 #1. It was drilled in March, 1955 and was placed on production in June, 1955 with perforations at 10857-62', or in the KF sand. The top of the KE sand is 10,790' measured depth (MD) or 10,727' subsea (ss). The top of the KF sand is 10,860' MD /10,826' ss. Therefore, the top of the KE sand is above the gas/oil contact of 10,800 ss and the top of the KF sand is below the gas/oil contact.

The sands are described in cores as sand, fine to medium grained, grey-green in color to a sandy shale. The KE sand, Layer 1 in the simulation grid, has three distinct sand lobes with distinct shale breaks between each layer in this well. Overall gross thickness of the KE sand in this well is 70 feet with an overall net sand of 22 feet. The KF sand, Layer 3 in the simulation grid, has one distinct sand lobe separated by a shale interval, Layer 2 in the simulation grid, between it and the KE

sand. Overall gross thickness of the KF sand is 36 feet with an overall net sand of 13 feet.

The initial test was flowing 267 barrels of 36.1 API gravity oil per day (BOPD), 333 thousand cubic feet of gas per day (MCFD) and 0 barrels of water (BWPD) at a flowing tubing pressure (ftp) of 2050 pounds per square inch (psi) on a 10/64 inch choke. In December 1956, it began producing a small amount of water, one percent (1%). The basic sediment and water percent (BS&W) for this well was never greater than 21% and when the well was shut-in in October 1964, because of sand problems, the BS&W was only three percent (3%). The gas oil ratio (GOR) also continued to increase until the well was shut-in. It's original GOR was at 1248 standard cubic feet of gas per stock tank barrel of oil (SCF/STB) and increased to as high as 4495 SCF/STB in September, 1964. The well, even though it was one of the most optimally and strategically located wells within the reservoir, was never brought back on line after it sanded up and was eventually plugged and abandoned in July, 1987. Its cumulative recovery from the reservoir was 536,000 barrels of oil, 1308 million cubic feet of gas and 49,000 barrels of water

SL 2551 #4

The SL 2551 #4 was drilled in November, 1956 and completed in December. It was placed on production on December 16, 1956 with perforations at 10914-25 feet in the KF sand. The KE sand top is at 10829 MD/10777 ss, while the KF sand top is at 10890 MD/10840 ss. No cores were available for this well. From electric log review, the KE sand consists of one sand lobe, Layer 1 in the simulation grid. The KF sand, Layer 3 in the simulation grid, consists of 2 sand lobes with no distinct shale interval separating the two. The uppermost sand lobe is the most well developed of all of the sands in these sets. The KE and the KF sands are separated by a distinct shale interval, Layer 2. Gross sand for the KE sand is 61 feet with the net sand calculated to be 12 feet . The gross sand interval for the KF is 56 feet with net sand calculated to 56 feet.

The initial test was 242 BOPD, 580 MCFD, 0 BWPD on a 10/64 inch choke with a flowing tubing pressure of 2350 psi. The GOR was 2396 SCF/STB and the oil gravity was 34 API. It produced water free until June, 1957. The GOR remained steady for about three years and then began to increase steadily until it reached above 20,000 SCF/STB when it was shut-in in August, 1979. The well experienced mechanical problems thereafter and was never brought back on line successfully. The bottom hole pressure (BHP) had decreased to 2212 psi in July, 1974 but responded to the KF waterflood with an increase to 2638 psi in September, 1976. The well was later recompleted in the JM for a non-commercial test. The well remains shut-in with miscellaneous tools, wireline and tubing junk in the hole, which is unfortunate due to its optimum location in the reservoir as well. Its cumulative recovery from the reservoir was 663,000 barrels of oil, 2976 million cubic feet of gas and 63,000 barrels of water. It has never produced above the lower KF sand.

SL 2551 #12

SL 2551 #12 was drilled in August, 1961 and completed in September, 1961 in the KE sand. This well is within the gas cap of the reservoir. It was placed on production with perforations at 10691-99 feet. The KE sand top is 10680 MD/10638 ss, while the KF sand top is 10740 MD/10698 ss. The KE sand, Layer 1 in the simulation grid, consists of one sand. Cores taken from KE sand reported an average 134 md permeability and an average 28.7 % porosity. The KF sand, Layer 3 in the simulation grid, consists of one well developed sand lobe and one less developed sand lobe. A thick shale sequence, Layer 2 in the simulation grid, is between the KE sand and the KF sand. Gross thickness of the KE sand is 60 feet with 20 feet net sand. The gross thickness of the KF sand is 30 feet with 18 feet net sand.

The initial test was 56 BOPD, 931 MCFD, 0 BWPD on a 8/64 inch choke. The GOR was 16,625 SCF/STB and the oil gravity was 56 API. The GOR remained steady at about 20,000 SCF/STB. The well only produced until February, 1969 when it was shut-in to conserve the gas cap drive energy. The well is currently shut-in waiting on a gravel pack. The KF sand has never been produced from this well.

SL 2551 #15

SL 2551 #15 was drilled in April, 1965 and completed in the KE sand with perforations at 10980-86 feet, or Layer 1 of the simulation grid. The KE sand in this well is a good example of a scoured channel fill. It defines an area of communication paths between the KE1 and the KF1 sands in forming the KEKF-R1 reservoir. The sequence of depositional events which the No. 15 well penetrates begins with the KF sand being deposited, then eroded away by a KE channel and then being refilled with KE sand sediment. Therefore, the KF sand does not really exist in the well, but the sand which replaced it, is in communication with the KF sand. The lion's share of this channel sand was placed in Layer 1 of the simulation grid. Layer 2, which would normally consist of the shale separating the KE and the KF sands, has also been eroded away and filled with channel sand. Layer 3 which normally is defined by the KF sand is now placed in the bottom portion of the channel sand in order to simulate the flow paths of the reservoir. The top of the KE sand is 10960 MD / 10928 ss. The KE has a gross thickness of 80 feet with 45 feet of net sand. Core analysis reports an average permeability of 467 md and an average porosity of 29.5%.

Its initial test on May 15, 1965 was 204 BOPD, 175 MCFD 0 BWPD with 1350 psi flowing tubing pressure on a 9/64 inch choke. The GOR was 857 SCF/STB and the oil gravity was 37 API. The well produced from January, 1966 until late 1983. At this time perforations were added from 10960 to 10980 feet. By then, the well had produced 448,000 barrels of oil, 608 million cubic feet of gas and 121,000 barrels of water. After the second set of perforations were added, the well produced until January, 1987 when it was shut-in with a water cut of 60%. A bottom hole pressure taken in April, 1985 recorded 2300 psi, confirming that it responded to the KF sand waterflood. This and other responses in wells completed in the KE sand were the first indications that the two sands were in communication. As of January 1987 the well had produced a total of 786,000 barrels of oil, 1169 million cubic feet of gas and 383,000 barrels of water. At present the well is shut-in with sand over the perforations.

SL 2551 #18

SL 2551 #18 was drilled in May, 1980 and completed in July, 1980 in the KE sand with perforations from 10941-64 feet MD. The well did not penetrate the KF sand, but based on stratigraphy studies discussed herein, it is believed that this is the scoured channel fill depositional area as seen in the SL 2551 No. A-3 and No. 15 wells. The KE sand in the #18 well is very similar in description to the No. 15 and No. A3 wells. It is a well developed blocky sand that has at least 60 feet of gross thickness with 55 feet of net sand, very typical of a channel sand. The top of the KE is 10900' MD / 10825' ss.

Its initial test on July 26, 1980 was 144 BOPD, 675 MCFD, 0 BWPD with 1107 psi flowing tubing pressure on a 24/64 inch choke. The GOR was 4700 SCF/STB and the oil gravity was 30 API. In August 1983, perforations were added at 10900-25 feet. The well is currently producing at a rate of 300 BOPD, 500 MCFD with approximately a 60% water cut and GOR of 1200 SCF/STB. As of September, 2001 the well had produced 636,000 barrels of oil, 1161 million cubic feet of gas and 1,500,000 barrels of water.

SL 2551 #A1

SL 2551 #A1 was drilled in November, 1965 and completed in October 1966 as a dual producer. The top of the KE is 11080 MD / 11014' ss and the top of the KF is 11150' MD / 11084' ss. The long string produced the KF sand with perforations at 10941-64 feet. The short string produced the KE sand with perforations at 11123-33 feet. The KE sand, Layer 1 in the simulation grid, is very poorly developed and almost completely shaled out. From core analysis, what little KE sand is present had an average permeability of 55.3 md and an average porosity of 18.8%. Gross thickness for the KE is 70 feet with only 13 feet net sand. In contrast to the KE sand, the KF sand, Layer 3, is well developed in this well. It has 70 feet of gross thickness with 60 feet of net sand. Core analysis reports that the KF sand has an average permeability of 424.5 md with 26.5% porosity.

The initial test for the long string, the KF sand, on October 1966 was 198 BOPD, 156 MCFD, 0 BWPD with 1000 psi flowing tubing pressure on a 9/64 inch choke. The GOR was 798 SCF/STB and the oil gravity was 36 API. The long string, KF sand, produced until December 1970 when it was shut-in due to paraffin problems. A test in May, 1970 reported 231 BOPD from the long string. As of December, 1970 the KF sand had produced 309,000 barrels of oil, 380 million cubic feet of gas, and 25,000 barrels of water. The long string, according to the records, was never worked over to attempt to put back on line.

The initial test for the short string, the KE sand, on October 15, 1966 was 72 BOPD, 37 MCFD, 0 BWPD with 1100 psi flowing tubing pressure on a 9/64 inch choke. The GOR was 511 SCF/STB and the oil gravity was 35 API. This well was placed on production in July 1966. The short string, KE sand, never produced well due to the tightness of the zone in this well. It was produced until May, 1967 when it was shut-in. The KE sand produced a total of 3000 barrels of oil, 3 million cubic feet of gas and 0 barrels of water. In 1972, this well was converted into an injection well for the KF waterflood.

SL 2551 #A-3

SL 2551 #A-3 was drilled in November 1966 and completed in December 1966 in the KE sand. This well, as did the SL 2551 No. 15, penetrated a thick KE channel sand. The top of the KE is 11180 MD / 10875' ss. This is a fine example of a scoured channel fill similar to that seen in the #15 well, except even more developed. The KF sand has been completely scoured away and replaced by the KE channel deposition. It also defines an area of communication paths between the KE1 and the KF1 sands in forming the KEKF-R1 reservoir. The channel sand was placed in all three layers. The KE has a gross thickness of 110 feet with 84 feet of net sand. There was no core analysis available for this well. Perforations were placed at 11264-69, with an alternate set at 11227-32. It is believed that the upper set of perforations were never produced. The initial test from the lower set of perforations on January 13, 1967 was 218 BOPD, 107 MCFD, 0 BWPD with 940 psi flowing tubing

pressure on a 10/64 inch choke. The GOR was 492 SCF/STB and the oil gravity was 36 API. The well was placed on production in January, 1967 and it produced until July, 1981 when it was shut-in with a water cut above 90%. Cumulative production from the perforations at 11264-11269 was 810,000 barrels of oil, 1992 million cubic feet of gas and 264,000 barrels of water. This well is optimally located for recovery of additional primary and secondary reserves if completed in the upper portion of the sand, but it has water coned in the present completion. It is presently shut-in with wireline and cement junk in the hole.

SL 2551 #A-4

SL 2551 #A-4 was drilled in January 1967 and completed in February 1967 in the KE sand, Layer 1 of the simulation grid. The KF sand, Layer 3 of the simulation grid, is completely shaled out in this well. The top of the KE is 11360' MD / 11016' ss. The KE sand consists of two sand lobes. There is poorer quality sand separating the two, but no distinct shale interval. It has an overall gross thickness of 60 feet with a net sand of 14 feet. Core analysis reports an average permeability of 549 md and 29.9% porosity.

Perforations were placed at 11369-74 feet, KE sand, and its initial test on February 22 1967 was 269 BOPD, 414 MCFD, 0 BWPD with 1650 psi flowing tubing pressure on a 10/64 inch choke. The GOR was 1536 SCF/STB and the oil gravity was 36 API. The well produced from February 1967 to March 1990 when it was shut in with a water cut of 50%. Cumulative production from the well is 442,000 barrels of oil, 474 million cubic feet of gas and 286,000 barrels of water. This well also responded to the KF sand waterflood with both an increase in production and an increase in bottom hole pressure. The upper portion of the KE sand in this well has never been perforated and it is located in a very favorable position.

SL 2551 #A-5

SL 2551 #A-5 was drilled in February 1967 and completed in March 1967 in the KE sand. Both the KE and KF sands penetrated in this well are very poor quality and have extremely low permeability. The top of the KE is 11130' MD / 10879' ss and the top of the KF is 11200' MD / 10949' ss. The KE has a gross thickness of 70 feet with only 5 feet of net sand while the KF has a gross thickness of 52 feet with only 9 feet of net sand. The KF sand was initially perforated at 11210-15 feet, Layer 4, but failed to test and then the well was perforated at 11147-52, Layer 2, in the KE sand. The well failed to produce after it initially tested the KE sand at 102 BOPD, 60 MCFD, 0 BWPD with 450 psi flowing tubing pressure on a 10/64 inch choke. The GOR was 592 SCF/STB and an oil gravity of 36 API. The well was later converted to a water source well for the KF sand waterflood from sands at 3988 to 4244 feet.

SL 2551 #A-9

SL 2551 #A-9 was drilled in August 1967 as a dry hole being too far downdip to encounter a productive sand in either the KE or KF sand sets. The top of the KE is 11373' MD / 11103' ss and the top of the KF is 11433' MD / 11163' ss. The well encounters a transitional oil/water contact between 11420' MD / 11150' ss to 11450' MD / 11180' ss. This compares to a clear oil/water contact of 11440' MD / 11193' ss seen in the #A-13 well. The KE sand, Layer 1 in the simulation grid, is very poorly developed and almost completely shaled out. It has an overall gross thickness of 70 feet with only 20 feet of net sand.

The KF sand, Layer 3 in the simulaion grid, is well developed in this well. It has a gross thickness of 56 feet with 50 feet of net sand. It contains two sand lobes with a poorly developed sand interval between them. There is no distinct shale interval. It was set up as an injection well with perforations at 11439-78 feet in the KF sand. An alternate set was added at 11373-93 but were never injected into or produced from. Injection into this well began in September 1973 with intial injectivity at 7500 BWPF on a vacuum. The well is currently shut-in and could still be used for injection.

SL 2551 #A-11

SL 2551 #A-11 was drilled in September 1967 and completed in October 1967 in the KF sand, Layer 1 in the simulation grid, and the KE sand, Layer 3 in the simulation grid. Perforations were placed in the KF sand at 11271-85 feet, with an alternate set of perforations placed in the KE sand at 11242-48 feet.

The KE sand top is 11,193 MD/ 10,943 ss. The KF sand top is 11,262 MD/ 11012 ss. The KE consists of 3 distinct sand lobes separated by distinct shale intervals. It has an overall gross thickness of 69 feet with 35 feet of net sand. The KE consists of two distinct sand lobes separated by distinct shale intervals. It has an overall gross thickness of 68 feet with 49 feet of net sand.

The initial test from the KF sand from the perforations at 11271-85 feet was 203 BOPD, 160 MCFD 0 BWPD with 500 psi flowing tubing pressure on an 8/54 inch choke. The GOR was 790 SCF/STB and the oil gravity was 38 API. Due to mechanical problems in the well, however, the well was shut-in. In August 14, 1970 the well was recompleted with perforations at 11242-48 feet. The initial test from this completion was 242 BOPD, 1027 MCFD, 0 BWPD with 1800 psi flowing tubing pressure on a 13/64 inch choke. The GOR was 4244 SCF/STB and the oil gravity was 37 API. The well produced from January 1971 to June 1972 when it was shut-in. At the time it was shut in the well was producing water free and with a GOR of 6500 SCF/STB. Cumulative production from this completion in the KE sand was 51,000 barrels of oil, 324 million cubic feet of gas and 278,000 barrels of water.

The well was then recompleted in November 1975 with perforations set at 11182-273 covering both the KE and KF sands. It tested 251 BOPD, 251 MCFD, 63 BWPD with 500 psi tubing pressure on gas lift on a 16/64 inch choke. The GOR was 1000 SCF/STB and the oil gravity was 35 API. It produced until October 1982 when it was shut-in with a water cut of 90 percent. Cumulative production from these perforations was 289,000 barrels of oil, 427 million cubic feet of gas and 486,000 barrels of water.

SL 2551 #A-13

SL 2551 #A-13 was drilled in January 1968 and completed in February 1968 in the KF sand with perforations at 11423-28 feet. The KE sand, Layer 1 in the simulation grid, is completely shaled out in this well. The KF sand top is 11410 MD / 11163 ss. It penetrates an oil/water contact at 11440 MD 11193 ss, which is the interpreted original oil/water contact for the reservoir. The KF sand, Layer 3 in the simulation grid, consists of two distinct sand lobes, separated by a poorer quality sand interval. Overall gross thickness of the KF sand is 80 feet with 66 feet of net sand.

The initial test on February 7 1968 was 180 BOPD, 83 MCFD, 0 BWPD with 800 psi flowing tubing pressure on a 10/64 inch choke. The GOR was 463 SCF/STB and the oil gravity was 35 API. The well produced until June 1969 with a cumulative production of 43,000 barrels of water, 48 million cubic feet of gas and 60,000 barrels of water. It was later converted into a water injection well for the KF sand waterflood and is presently shut-in but available for additional injection.

SL 2553 #3

SL 2553 #3 was drilled in August 1956 and completed in March 1964 in the KE sand with perforations at 10548-70. Its initial test was 215 BOPD, 4110 MCFD, 0 BWPD with 3300 psi flowing tubing pressure on a 16/64 inch choke. The GOR was 19166 SCF/STB and the oil gravity was 61 API. The well produced until August 1965 when it was shut-in to conserve the gas cap drive energy for the reservoir. Cumulative production from the well was 48,000 barrels of oil/condensate, 953 million cubic feet of gas and a small amount of water. The well was plugged and abandoned in 1969. It is questionable based on the 3-D seismic and the fact that the well did in fact produce some water whether this well did in fact penetrate a portion of the KEKF-R1 reservoir. It is more likely that this well penetrated an isolated KE sand body that is not in communication with the KEKF-R1 reservoir.

Tables

Table 1 - Geologic Time Scale - Lower Pleistocene through Lower Miocene AGE		
PLEISTOCENE	Late Quaternary	
	Prairie	
	Montgomery	Trimosina A
	Bentley	Angulogerina B
	Williana	Lenticulina 1
PLIOCENE		**Buliminelle 1**
MIOCENE	UPPER	**Robulus E**
		Bigenerina A
		Cristellaria K
		Amphistegina E
		Cyclammina 3
		Discorbia 12
		Robulus 15
		Camerina L
	MIDDLE	Bigenerina 2
		Textularia W
		Bigenerina humblei
		Cristellaria I
		Cibicides opima
		Amphistegina B
		Robulus L (43)
		Camerina 1
	LOWER	Discorbis bolivarensis
		Marginulina ascensionensia
		Siphonina davisi
		Planulina palmerae

Figures

Figure 1 – West Delta 84 Location (From LADNR SONRIS Website)

Figure 2 – KEKF1 Reservoir Top of Sand Map
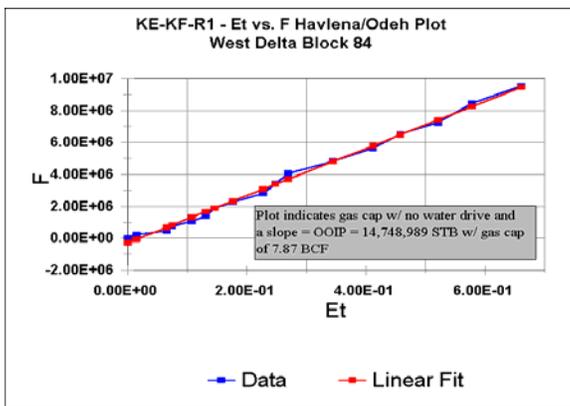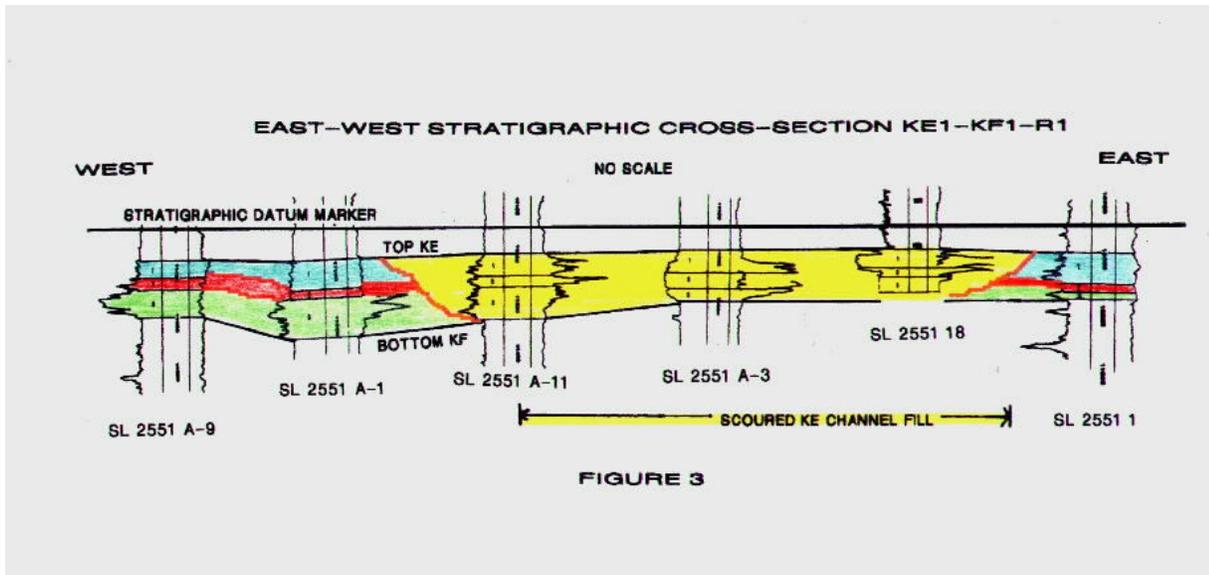
FIGURE 3

Figure 4 – KEKF1 Havlena-Odeh Plot
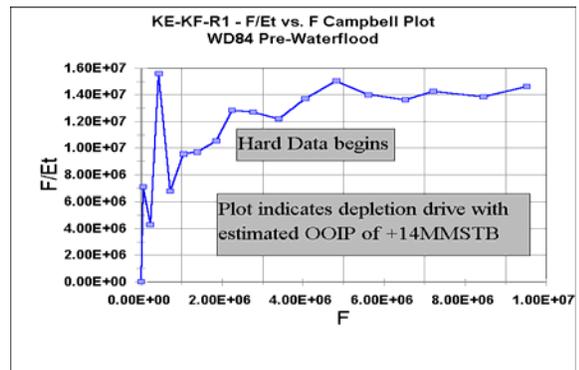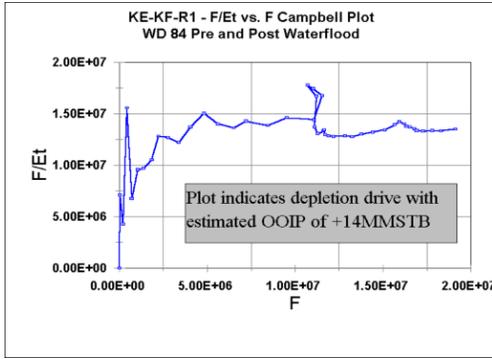

Figure 5 – KEKF1 Campbell Plot-Pre-Waterflood

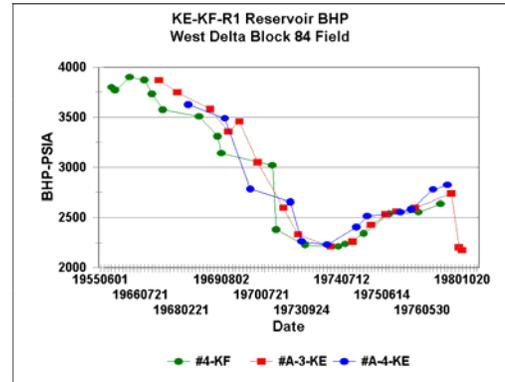**Figure 6 – KEKF1 Campbell Plot-Post Waterflood**
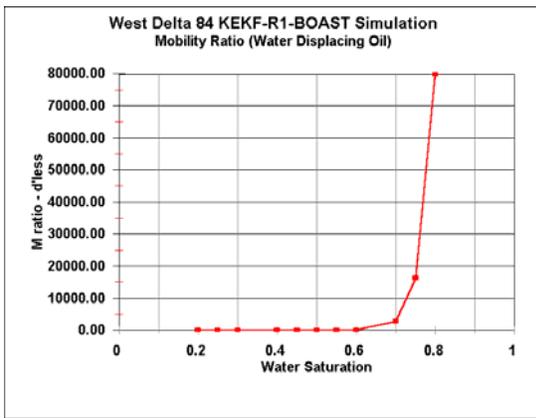

Figure 7 – KEKF1 Botton Hole Pressure Comparison

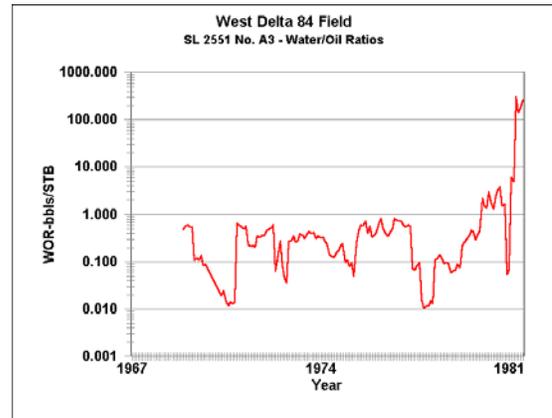Figure **8 – KEKF1 Mobility Ratio**
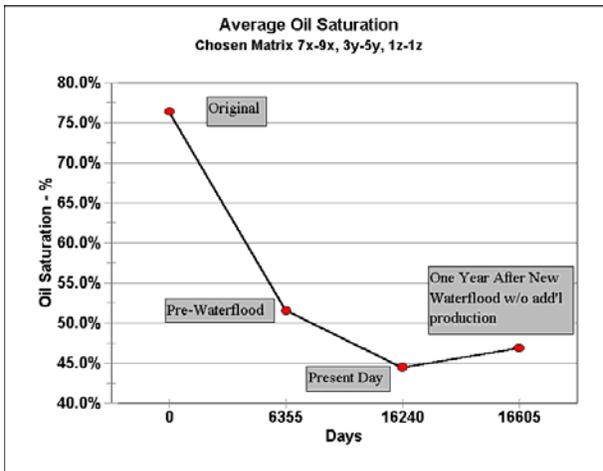

Figure 9 – SL 2551 No. A3 Water/Oil Ratios

Figure 10 – KEKF1 Average Oil Saturations for Chose Matrix