HIGH-PRESSURE AIR INJECTION: APPLICATION IN A FRACTURED AND KARSTED DOLOMITE RESERVOIR

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ABSTRACT

The Bureau of Economic Geology and Goldrus Producing Company have assembled a multidisciplinary team of geoscientists and engineers to evaluate the applicability of high-pressure air injection (HPAI) in revitalizing a nearly abandoned carbonate reservoir in the Permian Basin of West Texas. The characterization phase of the project is utilizing geoscientists and petroleum engineers from the Bureau of Economic Geology and the Department of Petroleum Engineering (both at The University of Texas at Austin) to define the controls on fluid flow in the reservoir as a basis for developing a reservoir model. This model will be used to define a field deployment plan that Goldrus, a small independent oil company, will implement by drilling both vertical and horizontal wells during the demonstration phase of the project. Additional reservoir data are being gathered during the demonstration phase to improve the accuracy of the reservoir model. The results of the demonstration will being closely monitored to provide a basis for improving the design of the HPAI field deployment plan. The results of the reservoir characterization field demonstration and monitoring program will be documented and widely disseminated to facilitate adoption of this technology by oil operators in the Permian Basin and elsewhere in the U.S.

TABLE OF CONTENTS

TABLES

FIGURES

6. Isopach map of younger pre-Wolfcampian carbonate units that have been truncated on the Barnhart structure.
7. Cross-section displaying the truncation on the Barnhart structure.
8. Structural contour map on top of the Ellenburger horizon.
9. Homogeneous waterflood.
10. Oil Saturation at 4000 days (fraction).
11. Homogeneous airflood.
12. Homogeneous airflood.
13. Temperature map at 100 days (°F).
14. Temperature map at 400 days (°F).
15. Temperature map at 1200 days (°F).
16. Saturation at 50 days (fraction).
17. Saturation at 400 days (breakthrough).
18. Pressure map at 100 days (psi).
19. Pressure map at 1200 days (psi).
20. Discrete Fracture System.
21. Discrete Fracture waterflood.
22. Oil Saturation at 100 days (fraction).
23. Oil Saturation at 1600 days (breakthrough).
24. Oil Saturation at 6000 days (fraction).
25. Discrete Fracture airflood.
26. Discrete Fracture airflood.
27. Temperature map at 100 days (°F).
28. Temperature map at 100 days (°F).
29. Temperature map at 2000 days (°F).
30. Oil Saturation at 100 days (just before breakthrough) (fraction).
31. Oil Saturation at 2000 days (fraction).
32. Reservoir Pressure map at 2000 days (psi).

I. INTRODUCTION

Despite declining production rates, existing reservoirs in the United States contain huge volumes of remaining oil that is not being effectively recovered. This oil resource constitutes a huge target for the development and application of modern, cost-effective technologies for producing oil. Chief among the barriers to the recovery of this oil are the high costs of designing and implementing conventional advanced recovery technologies in these mature, in many cases pressure-depleted, reservoirs. An additional, increasingly significant barrier is the lack of vital technical expertise that is necessary for the application of these technologies. This lack of expertise is especially notable among the small operators and independents that operate many of these mature, yet oil-rich reservoirs. We are addressing these barriers to more effective oil recovery by developing, testing, applying, and documenting an innovative technology that, when proven, can be used by even the smallest operator to significantly increase the flow of oil from mature U.S. reservoirs.

The Bureau of Economic Geology and Goldrus Producing Company have assembled a multidisciplinary team of geoscientists and engineers to evaluate the applicability of high-pressure air injection (HPAI) in revitalizing a nearly abandoned carbonate reservoir in the Permian Basin of West Texas. The Permian Basin, the largest oil-bearing basin in North America, contains more than 70 billion barrels of remaining oil in place and is an ideal venue to validate this technology. We have already demonstrated the potential of HPAI for oil recovery improvement in preliminary laboratory tests and a reservoir pilot project. To more completely test the technology, this project is combining a detailed characterization of reservoir properties with a field demonstration and monitoring program to fully access the effectiveness and economics of HPAI.

The characterization phase of the project is utilizing geoscientists and petroleum engineers from the Bureau of Economic Geology and the Department of Petroleum Engineering (both at The University of Texas at Austin) to define the controls on fluid flow in the reservoir as a basis for developing a reservoir model. This model will be used to define a field deployment plan that Goldrus, a small independent oil company, will implement by drilling both vertical and horizontal wells during the demonstration phase of the project. Additional reservoir data are being gathered during the demonstration phase to improve the accuracy of the reservoir model. The results of the demonstration will be closely monitored to provide a basis for improving the design of the HPAI field deployment plan. The results of the reservoir characterization field demonstration and monitoring program will be documented and widely disseminated to facilitate adoption of this technology by oil operators in the Permian Basin and elsewhere in the U.S.

The successful development of high-pressure air injection technology has tremendous potential for increasing the flow of oil from deep carbonate reservoirs in the Permian Basin, a target resource that can be conservatively estimated at more than 1.5 billion barrels. Successful implementation in the field chosen for demonstration, for example, could result in the recovery of more than 34 million barrels of oil that will not otherwise be recovered.

II. EXECUTIVE SUMMARY

The Bureau of Economic Geology and Goldrus Producing Company have assembled a multidisciplinary team of geoscientists and engineers to evaluate the applicability of high-pressure air injection (HPAI) in revitalizing a nearly abandoned carbonate reservoir in the Permian Basin of West Texas. The characterization phase of the project is utilizing geoscientists and petroleum engineers from the Bureau of Economic Geology and the Department of Petroleum Engineering (both at The University of Texas at Austin) to define the controls on fluid flow in the reservoir as a basis for developing a reservoir model. This model will be used to define a field deployment plan that Goldrus, a small independent oil company, will implement by drilling both vertical and horizontal wells during the demonstration phase of the project.

Barnhart Ellenburger field is located in the southeast corner of Reagan County, Texas. The Ellenburger at Barnhart field has undergone a complex history of fracturing and karsting associated with a composite unconformity and several periods of burial and uplift. Accordingly, high-resolution stratigraphic correlations are difficult. However, we have successfully defined several large fault compartments within the field. Reservoir continuity within each fault compartment will be fair to good, but flow continuity between is expected to be very poor. The additional description of core data suggests that karsting and associated paleocave development is much more extensive than previous recognized. The effect of karsting on the reservoir produces greater heterogeneity than in stratigraphically continuous reservoirs.

Most of the fractures seen in core are recognized to be associated with paleocave system collapse. As a paleocave system collapses during burial, it affects not only the immediate cave passage, but also affects the ceiling strata for several hundred feet above the passage (suprastratal deformation; Loucks, 2003).

Continued laboratory testing is being carried out to quantitatively assess mechanical alterations of reservoir material by the elevated temperatures near the combustion front. Simulation studies were completed with two types of injection fluids, water and air. A summary of results for a homogeneous reservoir and a reservoir with discrete fractures with relevant plots is discussed in this semiannual review.

The reservoir characterization phase (Phase 1) of the project is still on schedule (Fig. 1), but additional strong advances will depend on obtaining new core material. New cores are scheduled by Goldrus, but they have been postponed to 2004. Goldrus has moved the larger field demonstration (Phase II) to 2004. A significant step forward, however, is that in October Goldrus has put in an option on an expensive, specialized high-pressure air compressor that is necessary to start the larger scale field demonstration. They are planning to drill two new wells and reenter an old well. The technology transfer phase (Phase III) is on schedule. We are continuing to present results we have in oral presentations and papers.

III. OBJECTIVES

The primary objectives of the project are to develop, test, and document optimal methods for deploying high-pressure air injection (HPAI) technology to recover remaining hydrocarbons from an abandoned carbonate reservoir. Each of these will be accomplished in three phases of activity. The reservoir characterization phase (Phase 1) consists of (1) analysis of reservoir stratigraphy and facies, (2) characterization and modeling of reservoir matrix petrophysical properties, (3) characterization and modeling of reservoir fractures, and (4) characterization and modeling of the effects of HPAI on reservoir mechanical properties (deformation, strength, and fluid transport behavior) for both matrix and fractures. The demonstration phase (Phase 2) includes (1) deployment of vertical HPAI injector wells and horizontal oil-producing wells on the basis of stratigraphic, petrophysical, fracture, and rock mechanical models developed in Phase 1; (2) collection of additional reservoir data to further constrain and revise existing models; (3) field monitoring of the progress of HPAI using well tests; and (4) postmortem analysis and synthesis of the best strategies for deployment of HPAI well patterns. The third and final phase of the project (Phase 3, Technology Transfer) is devoted to compiling, reporting, and distributing the results of the completed project to industry.

IV. PHASE 1: RESERVOIR CHARACTERIZATION

Objectives of the reservoir characterization phase of the project are to provide the basic data for defining the distribution of key reservoir properties that control the distribution of remaining oil and the movement of injected air. Among the key issues that must be addressed in this phase are: (1) distribution of karst features and their impact on flow; (2) distribution, abundance, and orientation of fractures and their impact on flow; and (3) rock mechanics response of the Ellenburger to HPAI.

IV-1. General Geology

The general geology of the Barnhart Ellenburger field, located in the southeast corner of Reagan County, Texas (Fig. 2), has been described and discussed in the previous semiannual report. Again, however, it is important to note that the Ellenburger at Barnhart field has undergone a complex history of fracturing and karsting associated with a composite unconformity and several periods of burial and uplift. We have completed a new analysis of the burial history (Fig. 3) of the Ellenburger reservoir on the Barnhart structure. The reservoir strata was never deeply buried before the later Pennsylvanian. However, the rocks were affected by the Ouachita orogeny from the early

Mississippian through most of the Pennsylvanian. Because the Ellenburger stayed relatively near the surface, it has had several opportunities for being affected by surface derived meteoric waters (Fig. 3). These waters are believed to have produced cave development that later collapsed resulting in the development of megabreccia bodies composed of chaotic breccias and crackle breccias. This process is common in other Ellenburger reservoirs in West Texas (Holtz and Kerans, 1993; Loucks, 1999). The uplift associated with the Ouachita orogeny, may have produced additional fractures along with the recognized faulting. But because of the lack of core data in the unkarsted section of the reservoir, it is difficult to draw any conclusions at this stage of the study. We are expecting that some of the new core will be from the unkarsted section of the reservoir, and that this core will provide more information on regional fractures.

IV-2. Task 1.0 – Description and Modeling of Field Stratigraphy

Karst processes of dissolution and paleocave formation have overprinted the original depositional character of the Ellenburger Group dolomites. This overprinting has created a complicated system of original facies, karst features, and regional tectonic fractures that must be differentiated for accurate reservoir modeling and production.

IV-2.1. Subtask 1.1 – Core Description of Facies, Fabrics, and Textures

Goldrus Producing Company provided the project a 41-m (130-ft) core (Goldrus Producing Company Unit #3). This core has been described in the previous semiannual report. Two other, older, cores have now been described. However, the only data on these cores are photographs, thin sections, or core chips. (The original whole cores cannot be located.) These cores are from the Hickman #13 (Fig. 4) and the University 48-F-1 (Fig. 5) wells.

IV-2.1.1 Mineralogy

The University 48-F-1 core is predominately dolostone with some limestone in the very upper part of the core (Fig. 5). The Hickman #13 displays the same predominance of dolostone and some limestone in the upper part of the core (Fig. 4).

IV-2.1.2 Facies

The University 48-F-1 core shows collapsed paleocave facies from 9230 ft to 9410 ft (Fig. 5). Only the upper part of the core appears to be relatively undisturbed host rock. The Hickman #13 core shows collapsed paleocave facies starting at the very top of the Ellenburger carbonate section at 8795 ft and extending down to 9175 feet (Fig. 4). These two cores, along with the Barnhart core, document the strong influence that karst related cave development has had on this reservoir.

IV-2.1.3 Pore Types

The reservoir description must be approached with the idea that there is abundant intraclast and crackle breccia pores with relative dolostone intercrystalline pores. Work to identify matrix pore types is continuing based on descriptions of thin sections taken from available cores.

IV-2.2. Subtask 1.2 – Calibration of Wireline Logs

The University 48-F-1 and the Hickman #13 cores have been calibrated into the associated wireline logs (Figs. 4 and 5). There appears to be no simple relationship between the logs and the karsted core sections.

IV-2.3. Subtask 1.3 – Establishment of Stratigraphic Architecture

The majority of the wireline logs from the Barnhart field are old and of poor quality for carrying out stratigraphic or structural correlations in the Ellenburger carbonate section. We know that the uplift of the Barnhart structure (Fig. 3) and associated later erosion produced truncation of younger Paleozoic strata across the structure. To define this truncation and to produce an accurate structure map on top of the Ellenburger reservoir, we decided to do detail correlations in the siliciclastic deep-water Wolfcampian strata overlying the carbonate strata (Fig. 6). The stratigraphic markers within these deep-water strata are easily correlated and are reliable. Analyzing the strata from the top down is helping us to recognize the truncated surface (Fig. 7), define the fault compartments (Fig. 8), and produce a structure map on top of the Ellenburger Formation (Fig. 8).

IV-3. Task 2.0 – Characterization and Modeling of Matrix Petrophysical Properties

We have combined available core-analysis data with wireline-log data to characterize the matrix porosity and permeability of the Ellenburger reservoir (presented in previous semiannual report). With these data we will try to construct a simple 3-D reservoir model to serve as a basis for modeling of OOIP and HPAI injection response.

IV-4. Task 3.0 – Characterization of Fractures

Analysis of fractures from core has been presented in the previous semiannual report. As we get new core, we will continue fracture analysis.

IV-5. Task 4.0 – Characterization and Modeling of Rock Mechanical Properties and Fractures

Results concerning this task was reported on in the previous semiannual report.

IV-6. Task 5.0 – Experimental Characterization of Thermal Alteration

IV-6.1. Stimulation Results

Simulation studies were conducted with two types of injection fluids: water and air. The objective of these studies was to investigate numerically the potential of HPAI to displace oil versus a typical waterflood program. Steam injection for depths of 9000 ft is considered impractical. These simulations were performed for a variety of reservoir conditions such as homogeneous reservoir, reservoir with discrete fractures, and horizontal injector and producer. The flooding simulations were continued until the economic limit i.e. higher than 99% water cut or breakthrough at the producer. A summary of results for a homogeneous reservoir and a reservoir with discrete fractures with relevant plots is presented below. Work on the horizontal injector and producer conditions continues.

IV-6.1.1. Homogeneous Reservoir (Single Porosity/Permeability)

Table 1 presents the results for the water flood and air flood simulation runs carried out in a homogeneous reservoir. Water flood studies were carried out from production startup (after primary recovery) to the waterflood economic limit. An injection rate of 200 bbl/day was specified for the vertical injector along with a pressure constraint of 5000 psi. The simulation was run for 8000 days. Water breakthrough was achieved at the producer at about 6800 days with the water cut increasing to 99% at around 8000 days. Cumulative oil recovered at the end of the simulation was 210 Mbbl. Figure 9 below is a plot with all the relevant waterflood parameters obtained during the simulation. Figure 10 is an oil saturation snapshot for the reservoir at 4000 days.

Air flood studies were carried out from production startup (after primary recovery) until much after gas breakthrough at the producer. An injection rate of 750 MSCF was specified for the injector along with pressure constraint of 5000 psi to reduce numerical stability. The simulation was run for 1200 days. Gas breakthrough was achieved at the producer in the early stages of the combustion. The cumulative oil production plateaus after 400 days to a final value of 183 Mbbl at 1200 days. However, the gas production rate continues to increase with time. Cumulative methane gas production at 1200 days stands at 2 MMSCF. Figures 11 and 12 are plots of various airflood parameters recorded during the combustion run. Temperature profiles for a few grid blocks around the injector well are depicted in Figure 12. Figures 13 to 15 show the temperature maps for the reservoir at 100, 400, and 1200 days respectively. Figures 16 and 17 show the oil saturation maps for the reservoir at 50 and 400 days respectively. Figures 18 and 19 show the pressure maps for the reservoir at 100 and 1200 days respectively.

IV-6.1.2. Discrete Fracture System

To investigate the response of the two flooding techniques for a fractured system we took the homogeneous reservoir discussed above and placed random discrete fracture streaks (Figure 20). The porosity and permeability values for these fractures were assumed to be 0.01 and 10,000 md respectively. The relative permeability data for the fracture system was also accordingly modified.

Table 2 summarizes the waterflood and airflood results obtained from the simulation runs. The operating conditions here were same as for the case in homogeneous reservoir discussed previously. The simulation was run for 6000 days. Water breakthrough was achieved at the producer at about 1600 days, much earlier than compared to the homogeneous waterflood case. Water cut of 99% was registered at around 6000 days. Cumulative oil recovered at the end of the simulation was 183 Mbbl: a little lower than for the homogeneous reservoir case. The final oil recovery also showed a minor decrease. Figure 21 is a plot with all the relevant waterflood parameters obtained during the simulation. Figures 22 and 24 show oil saturation maps for the reservoir at 100, 1600 and 6000 days respectively.

The operating conditions in these experiments were same as the homogeneous airflood case. The airflood was run for 2000 days. Gas breakthrough was achieved very early at the producer at around 130 days. The cumulative oil production after 2000 days stood at about 170 Mbbl, nominally less than compared to the homogeneous airflood case. The gas production rate continued to increase with time and the cumulative production at 2000 days was recorded to be 25.35 MMSCF, significantly higher than the homogeneous case. Figures 25 and 26 are plots of various airflood parameters recorded during the combustion run. Temperature profiles for a few grid blocks around the injector well are depicted in Figure 26. Figures 27 to 29 show the temperature maps for the reservoir at 100, 1000, and 2000 days respectively. Figures 30 and 31 show the oil saturation maps for the reservoir at 100 and 2000 days respectively. Figure 32 shows the pressure map for the reservoir at 2000 days.

V. PHASE 2: FIELD DEMONSTRATION

The larger scale field demonstration phase (larger than the initial pilot phase that was reported on in the previous semiannual report) was to start in the second half of 2003, as noted on the Project Task Schedule, but Goldrus has postponed the demonstration phase to 2004. A summary of their plans is summarized in the following paragraph.

Goldrus Producing Company is in the process of implementing a revised field demonstration plan for the Barnhart Ellenburger field. The new plan calls for first increasing the air injection rate, then drilling new wells to recover oil swept by the high pressure air injection process. The first step toward implementing this new plan has already been taken; Goldrus is purchasing a large compressor battery that is capable of providing injection pressure for several injector wells. As soon as high-pressure air injection is once again underway, drilling will begin on a new vertical well, which will be completed as a producing well. Conventional core will be taken in this well to further assess the geological heterogeneities that affect fluid flow. Following completion of this well, it is likely that a second new producing well will be drilled.

VI. PHASE 3: TECHNOLOGY TRANSFER

Even though the major phase of technology transfer will start at the beginning of 2004, as noted on the Project Task Schedule (Fig. 1), we have been presenting the results of the geology of the Barnhart field.

As noted in the previous semiannual report, we presented oral, poster, and core-poster presentations outlining the progress of the Barnhart reservoir study at a special workshop last. This workshop, entitled "New Methods for Locating and Recovering Remaining Hydrocarbons in the Permian Basin, A Symposium and Workshop" was co-sponsored by the Bureau of Economic Geology, the Petroleum Technology Transfer Council, and the University Lands West Texas Operations. The symposium was presented to about 80 Permian Basin geologists, engineers, and managers in Midland/Odessa, Texas, in May. Also, a poster presentation was also delivered at the annual convention of the American Association of Petroleum Geologists in May. The titles of these presentations are:

1. Loucks, Bob, and Combs, Deanna, 2003, Pore networks in Lower Ordovician Ellenburger Group collapsed paleocave systems: examples from Barnhart field, Reagan County, Texas, presented at New Methods for Locating and Recovering Remaining Hydrocarbons in the Permian Basin, A Symposium and Workshop sponsored by the Bureau of Economic Geology, Petroleum Technology Transfer Council, and University Lands West Texas Operations. Symposium held at the Center for Energy and Economic Diversification, Midland/Odessa, Texas, May 29, 2003.

2. Combs, D. M., Loucks, R. G., and Ruppel, S. C., 2003, Ellenburger Group collapsed paleocave facies, Barnhart field, Reagan County, Texas, presented at New Methods for Locating and Recovering Remaining Hydrocarbons in the Permian Basin, A Symposium and Workshop sponsored by the Bureau of Economic Geology, Petroleum Technology Transfer Council, and University Lands West Texas Operations. Symposium held at the Center for Energy and Economic Diversification, Midland/Odessa, Texas, May 29, 2003.

3. Gale, J. F. W., Gomez, L., Laubach, S. E., Marrett, R., Olson, J. E., Holder, J., and Reed, R. M., 2003, Predicting and characterizing fractures in the Ellenburger: using the link between diagenesis and fracturing, presented at New Methods for

Locating and Recovering Remaining Hydrocarbons in the Permian Basin, A Symposium and Workshop sponsored by the Bureau of Economic Geology, Petroleum Technology Transfer Council, and University Lands West Texas Operations. Symposium held at the Center for Energy and Economic Diversification, Midland/Odessa, Texas, May 29, 2003.

4. Gomez, L. A., Gale, J. F. W., Reed, R. M., Loucks, R. G., Ruppel, S. C., and Laubach, S. E., New techniques in fracture imaging and quantification: application in the Ellenburger Group in West Texas, presented at American Association Petroleum Geologist Annual Meeting, Salt Lake City, May 11-14.

Additional papers and poster presentations on the Barnhart field and the associated geology were presented at the 2003 Fall Symposium of the West Texas Geological Society in Midland, Texas. The Barnhart core was displayed along with the poster by Combs, Loucks, and Ruppel (2003). The titles of these presentations are:

1. Combs, D. M., Loucks, R. G., and Ruppel, S. C., 2003, Lower Ordovician Ellenburger Group collapsed paleocave facies and associated pore network in the Barnhart field, Texas, in Hunt, T. J., and Lufholm, P. H., The Permian Basin: back to basics: West Texas Geological Society Fall Symposium: West Texas Geological Society Publication #03-112, p. 397–418.

2. Loucks, R. G., 2003, Understanding the development of breccias and fractures in Ordovician carbonate reservoirs, *in* Hunt, T. J., and Lufholm, P. H., The Permian Basin: back to basics: West Texas Geological Society Fall Symposium: West Texas Geological Society Publication #03-112, p. 231–252.

3. Gomez, L. A., Gale, J. F. W., Reed, R. M., Loucks, R. G., Ruppel, S. C., and Laubach, S. E., 2003, New techniques in fracture imaging and quantification: application in the Ellenburger Group in West Texas, in Hunt, T. J., and Lufholm,

P. H., The Permian Basin: back to basics: West Texas Geological Society Fall Symposium: West Texas Geological Society Publication #03-112, p. 419-420

VII. RESULTS AND DISCUSSION

The project is continuing data-collection, which is dependent on the Goldrus drilling and coring new wells, and is assembling the data into products that can be used to define the architecture and, hence, plumbing of the field. The best possible estimate of the plumbing of the field is essential to our understanding injector/producer relationships in order to analyze sweep patterns.

As noted previously, a basic understanding of the pore network is emerging, but more work is necessary to populate the field with correct pore types. As we define the host rock versus collapsed paleocave breccias and fractures, we will be able to apply our pore network model more accurately. New core and log data that we will obtain from Goldrus Producing Company in 2004 will help with this task.

The experimental work on the effects of high temperature on artificial fracture development is proceeding as planned. The test apparatus is providing the desired results, as mentioned in the last semiannual report.

Goldrus Producing Company has now acquired the large compressor necessary to inject the quantity of high-pressure air necessary to test the HIAP concept. With the compressor in place, they will be drilling several new wells in 2004. At least one of these wells will be cored (and possibly a second well will be cored), which will provide critically needed data. The next semiannual report should have some solid conclusions about the ability of high-pressure air injection on reviving Barnhart field.

VIII. CONCLUSION

The reservoir architecture of the Barnhart field is more complex than was previously known. The fault compartmentization and the strong role of paleocave development have added additional heterogeneity to the reservoir model. Early test results, however, indicate that on a local scale, reservoir continuity is good. This local continuity may be the result of coalescing by fractures associated with paleocave collapse. As the well tests and monitoring program renews in

2004, we will be able to select injector/producer patterns on the basis of the plumbing in the field that we now have developed a better perspective.

The complex pore network in this partly karsted field presents a challenge on how to populate a field model with reservoir quality data. Our research effort on this task is providing data that has not been available for other karsted fields. Separating collapsed-paleocave-associated fractures and interclast pores from tectonic-associated pores in cores is difficult and little research has been completed on this topic before this study. It will be a major engineering task to integrate these findings into a flow model.

The experimental data are providing information on the effect of high-temperature processes on the rocks, especially fracturing of the rocks. This information is an important contribution because it allows us to better understand the sweep efficiency in this relatively low-quality reservoir.

IX. REFERENCES

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back to basics: West Texas Geological Society Fall Symposium: West Texas Geological Society Publication #03-112, p. 231–252.

Prediction Run	Production Period, days	Cumulative Production			Oil Recovery	Produced oil to injected volume
		Oil, MBBL	Gas (CH_4), MMSCF	Water, MBBL		
Water Flood	8000	209	0	1.85	0.718	0.836 bbl/bbl
Air Flood	1200	183	2	0	0.63	690 bbl/MMSCF

Table 1. Airflood versus waterflood for homogeneous reservoir.

Prediction Run	Production Period, days	Cumulative Production			Oil Recovery	Produced oil to injected volume
		Oil, MBBL	Gas (CH_4), MMSCF	Water, MBBL		
Water Flood	6000	183	0	214	0.696	0.416 bbl/bbl
Air Flood	2000	169.5	25.35	1	0.65	188 bbl/MMSCF

Table 2. Airflood versus waterflood for discretely fractured reservoir

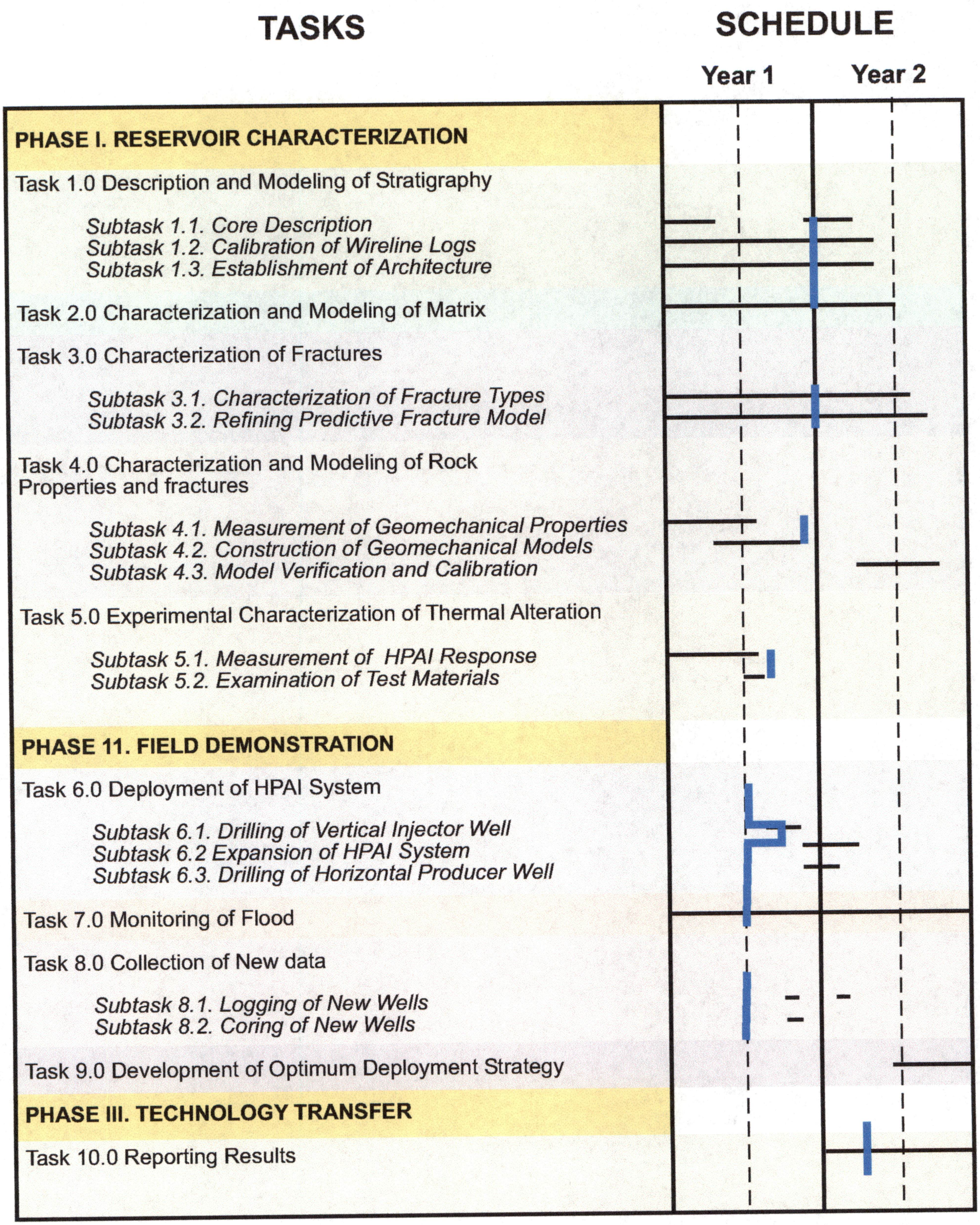

Figure 1. Project task schedule. Blue line shows actual progress. The tasks that are behind schedule have been delayed until Goldrus resumes activity in 2004.

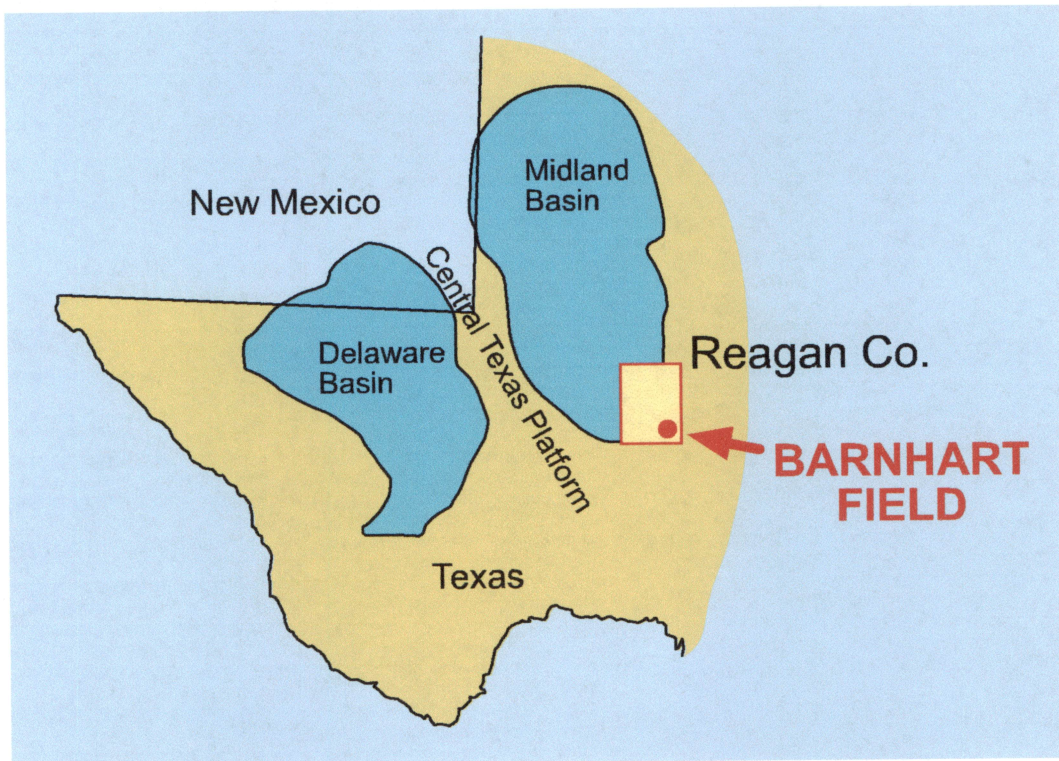

Figure 2. Regional map of Permian Basin showing the location of Barnhart field. The Delaware Basin, Central Basin Platform, and Midland Basin are included only for orientation purposes and are not intended to imply that they existed when Ellenburger strata were deposited.

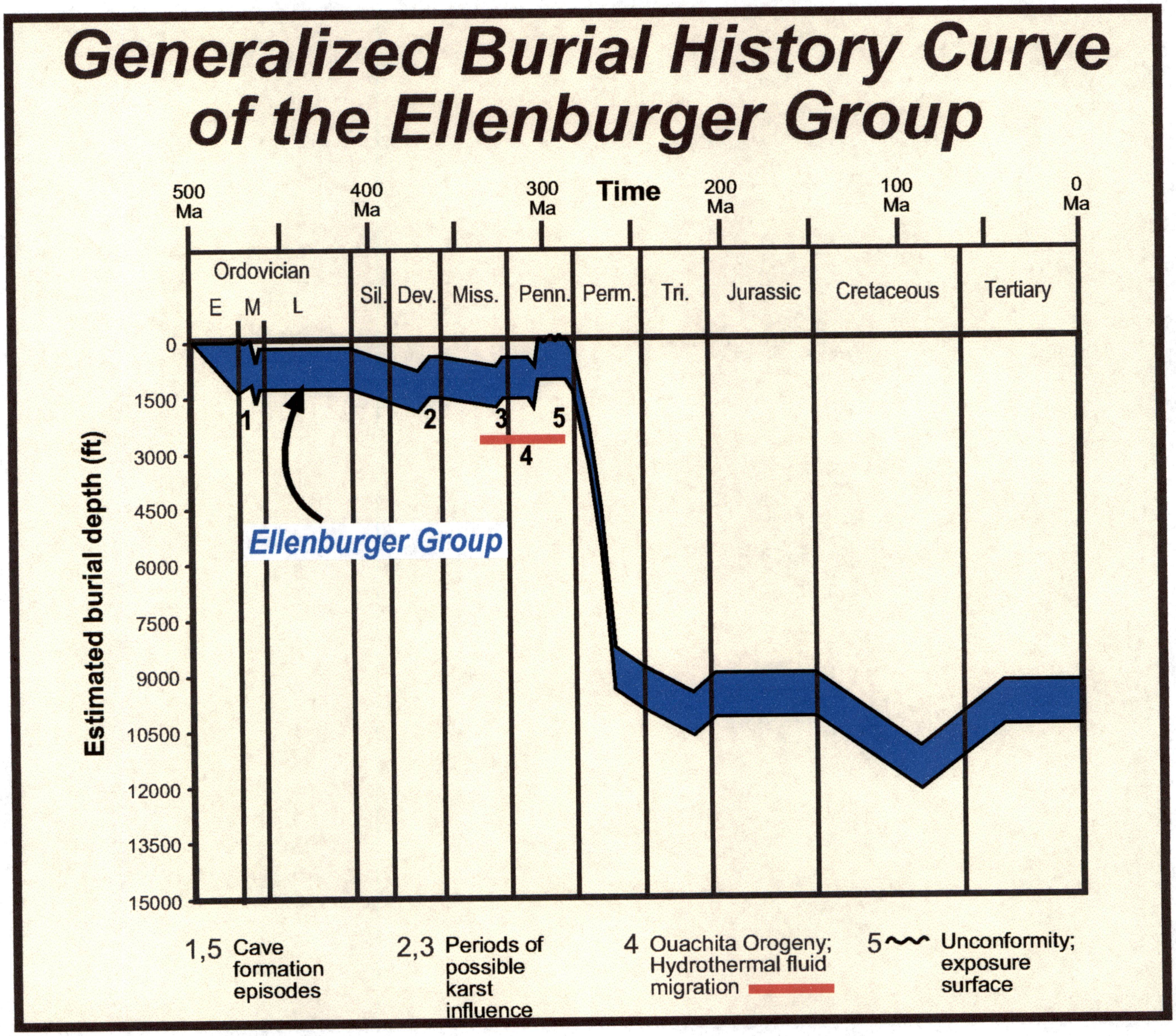

Figure 3. Burial history curve of the Barnhart field area showing that the Ellenburger reservoir remained within 1000 to 1500 feet of the surface until late Pennsylvanian time. Definite karsting of the reservoir rock took place in the Middle Ordovician and in the Late Pennsylvanian times.

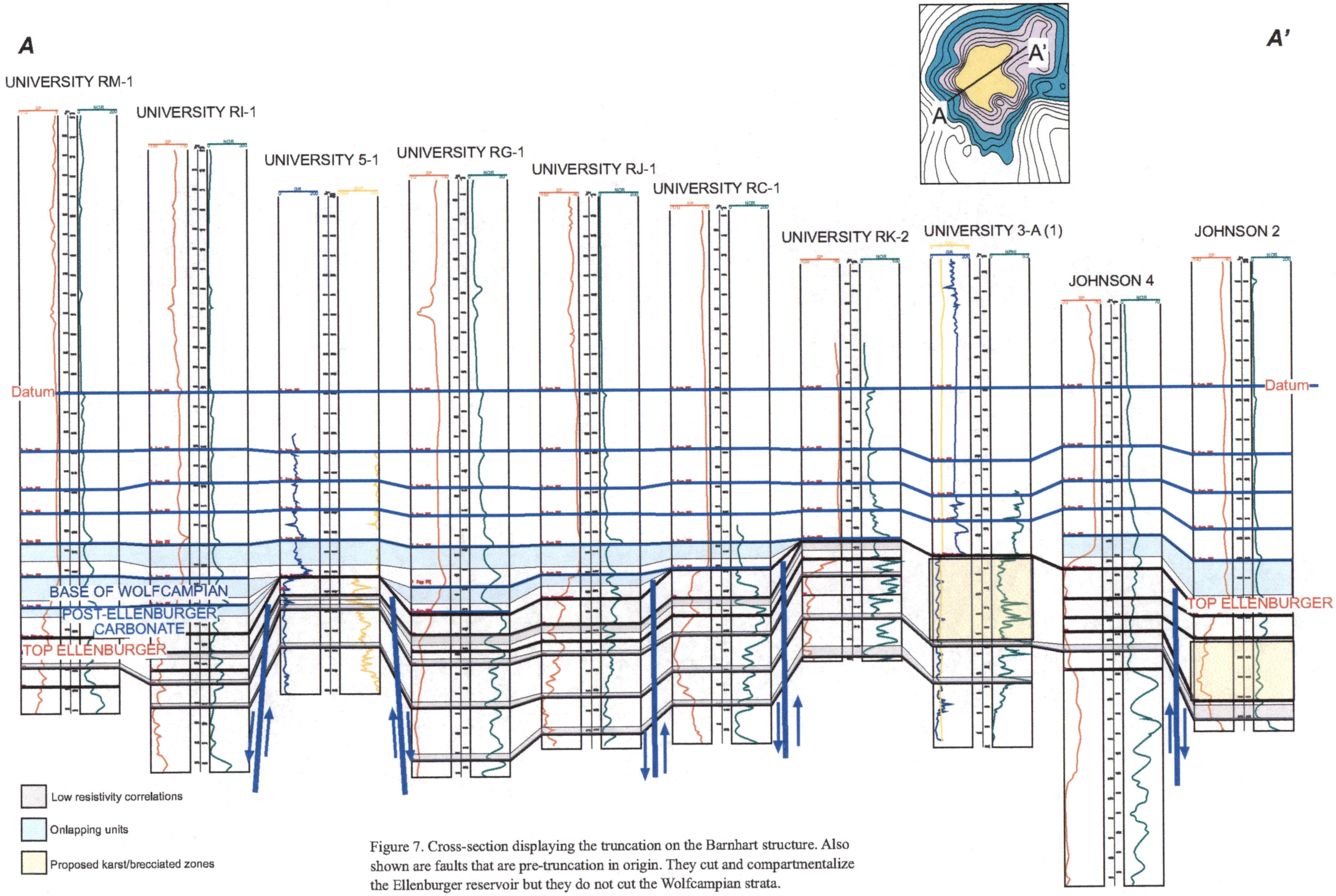

Figure 7. Cross-section displaying the truncation on the Barnhart structure. Also shown are faults that are pre-truncation in origin. They cut and compartmentalize the Ellenburger reservoir but they do not cut the Wolfcampian strata.

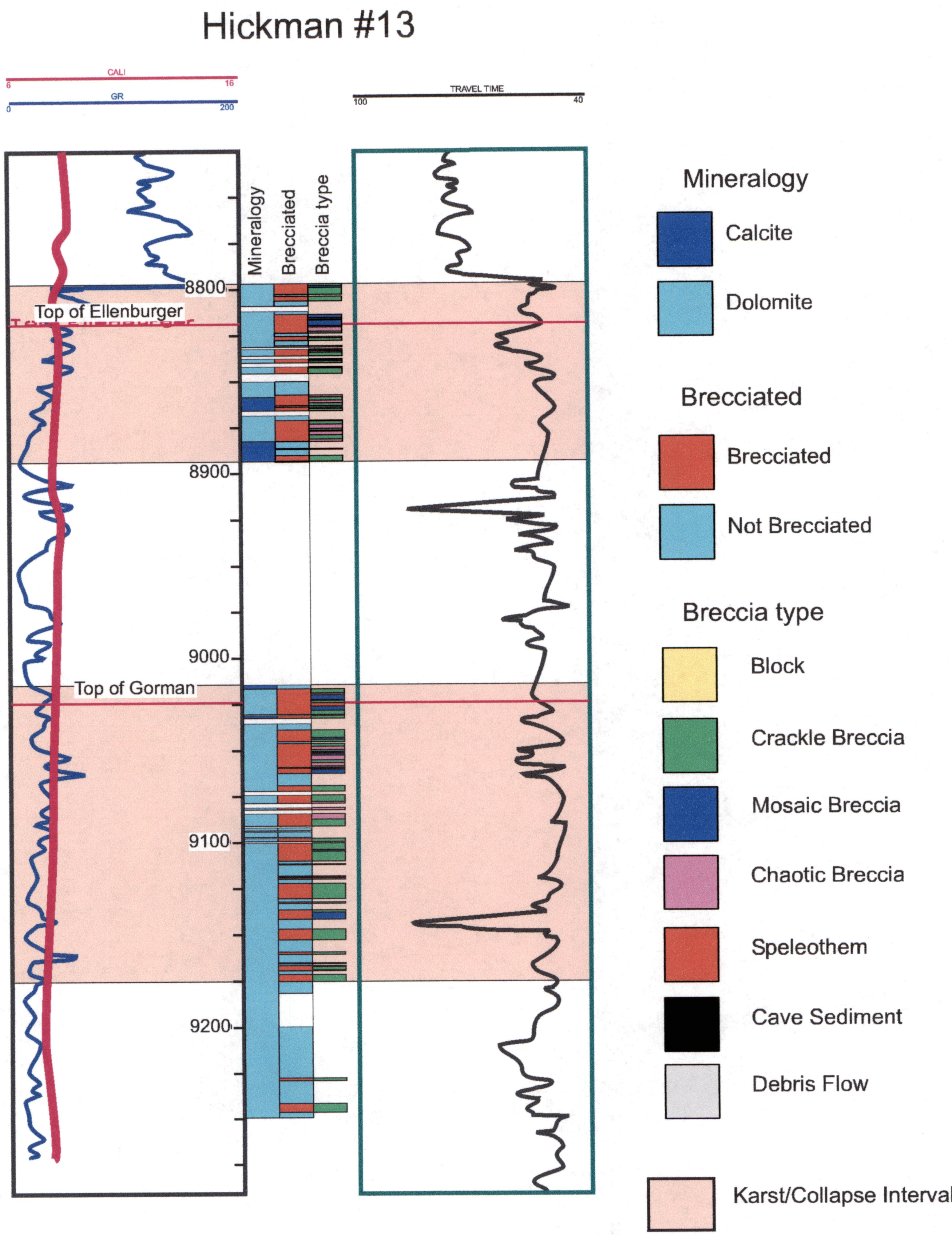

Figure 4. Hickman #13 well showing cored interval and calibration of core to the wireline log.

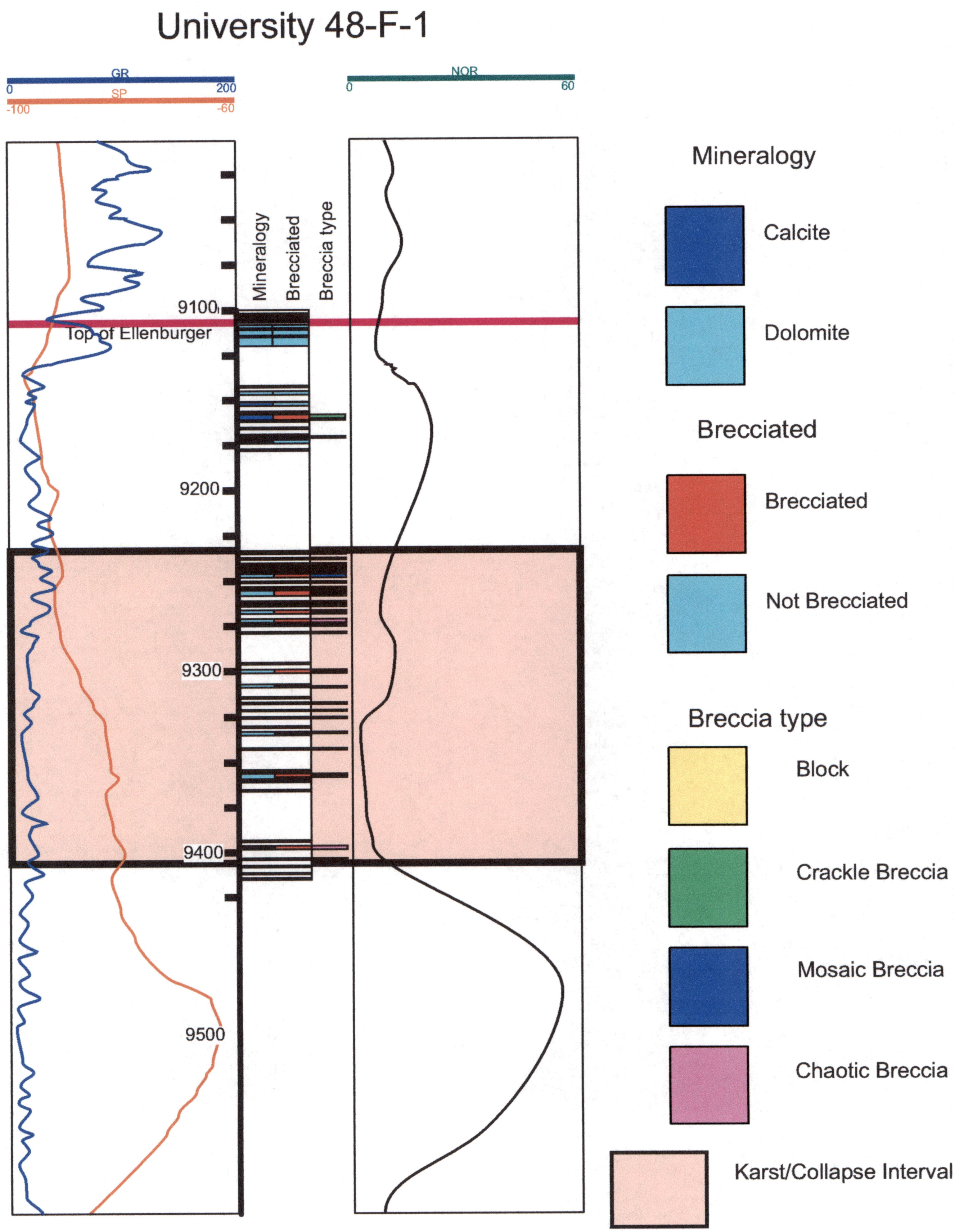

Figure 5. University #48-F-1 well showing cored interval and calibration of core to the wireline log.

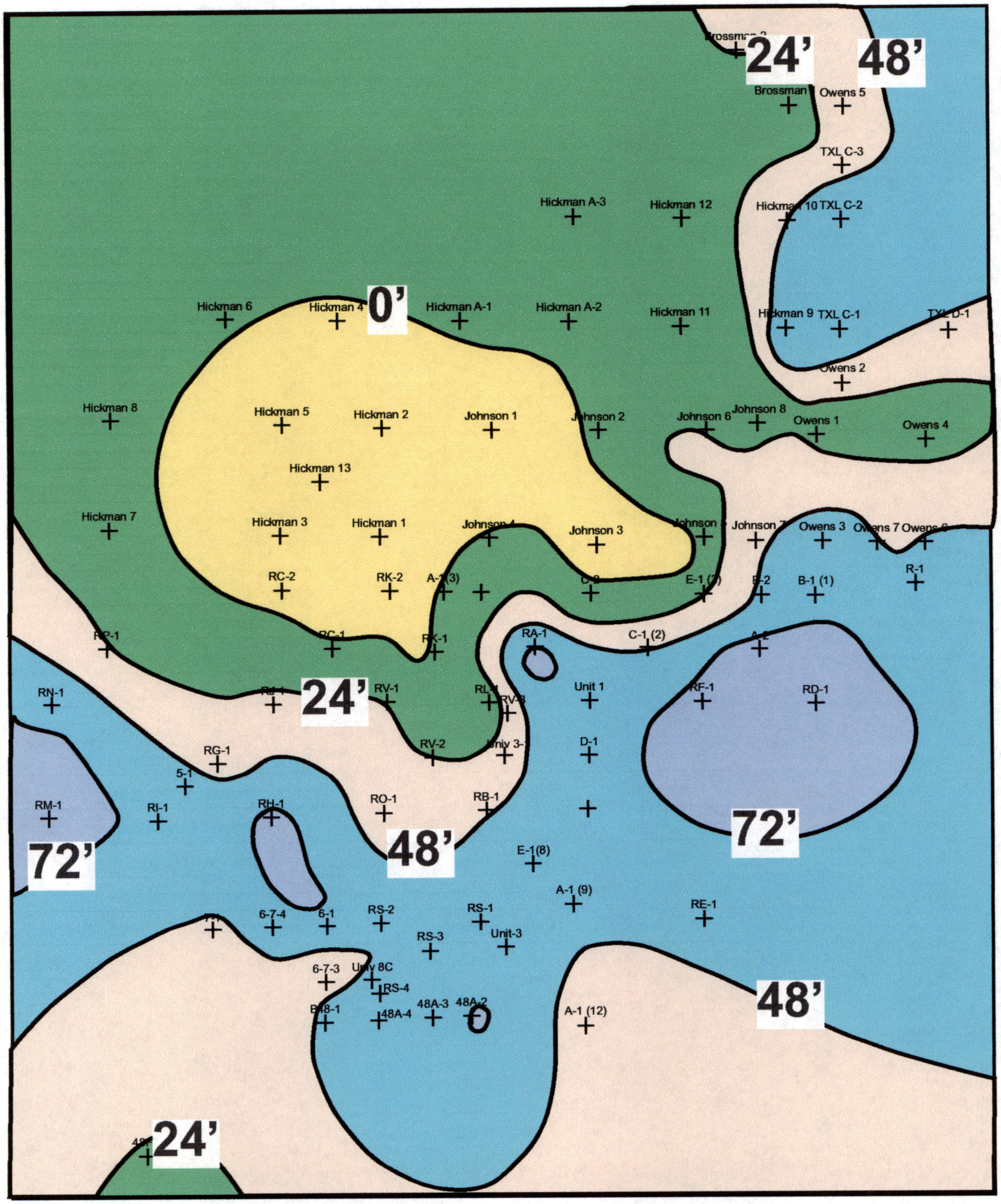

Figure 6. Isopach map of younger pre-Wolfcampian carbonate units that have been truncated on the Barnhart structure. The zero-isopach area (yellow) shows area of the intensive erosion where the upper units of the Ellenburger reservoir were removed during Pennsylvanian exposure.

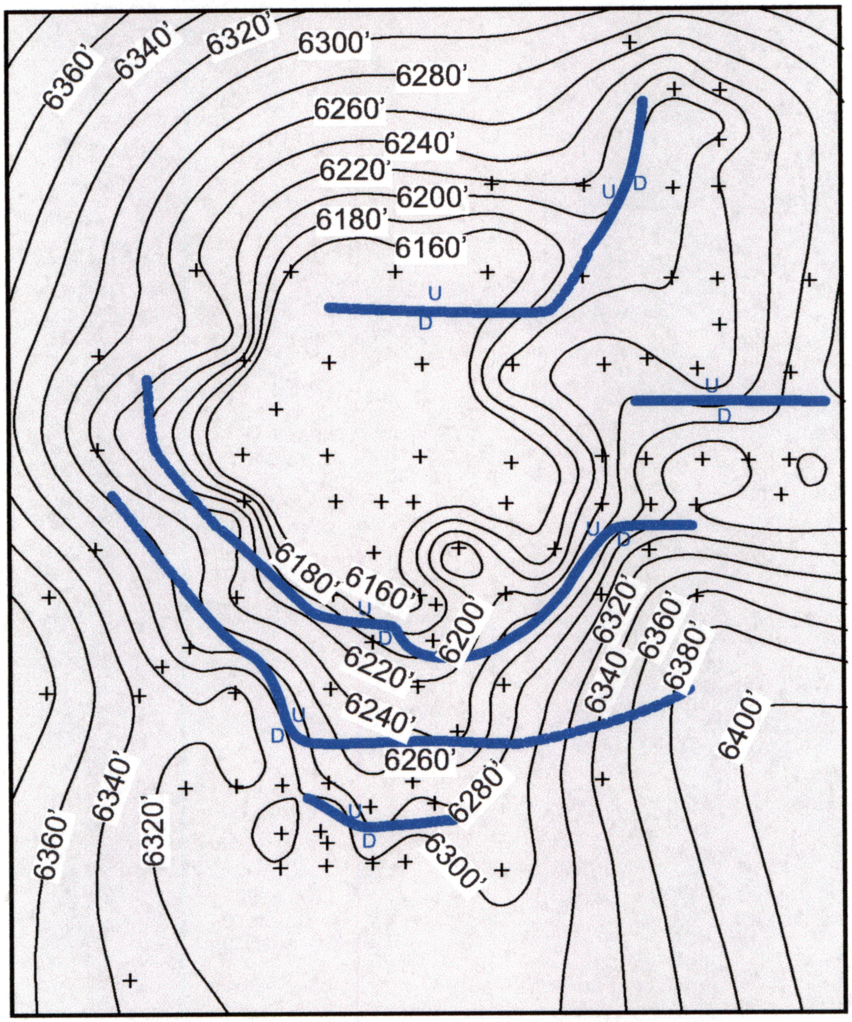

Figure 8. Structural contour map on top of the Ellenburger horizon. This is the first structure map that actually defines the top of the Ellenburger horizon. Other structural maps pick the uppermost carbonate unit as a structural horizon. This map thus shows the true structure of the top of the Ellenburger Formation. Major faults are shown as blue lines.

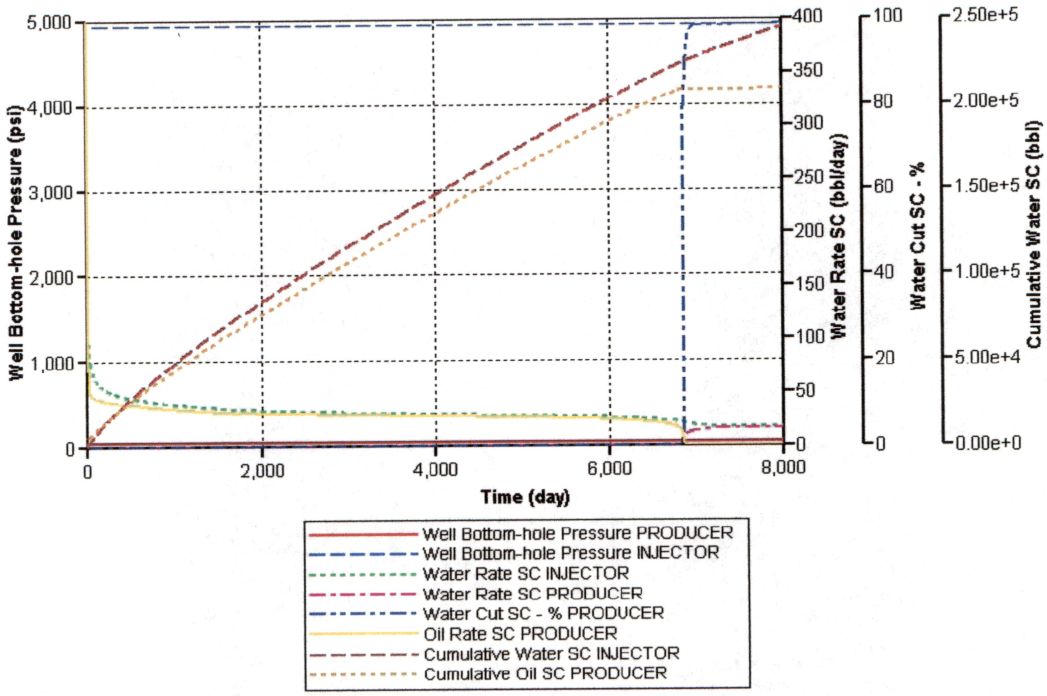

Figure 9. Homogeneous waterflood.

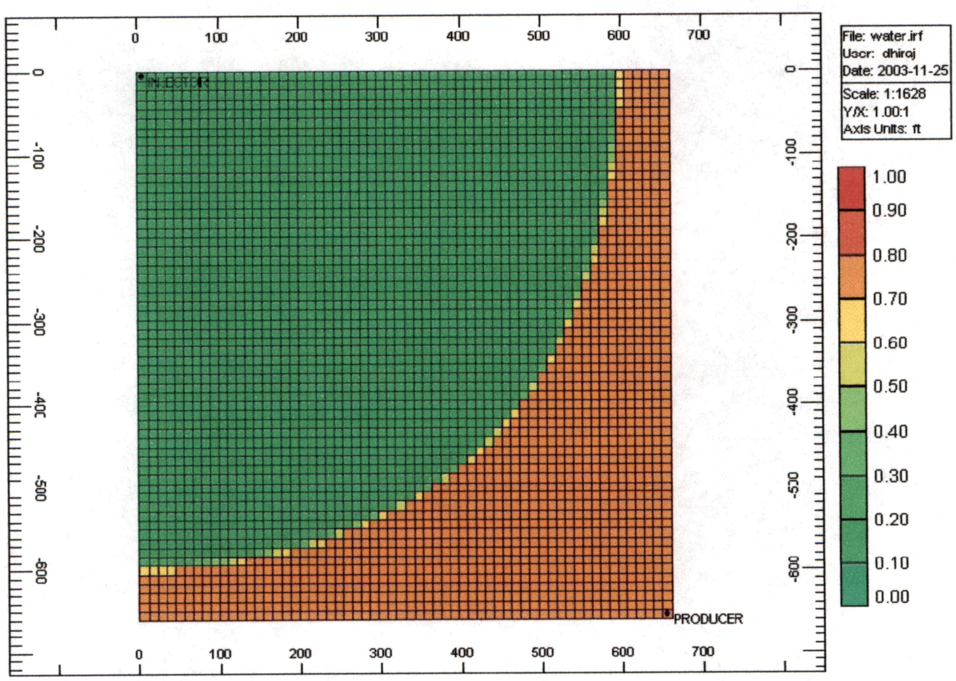

Figure 10. Oil Saturation at 4000 days (fraction).

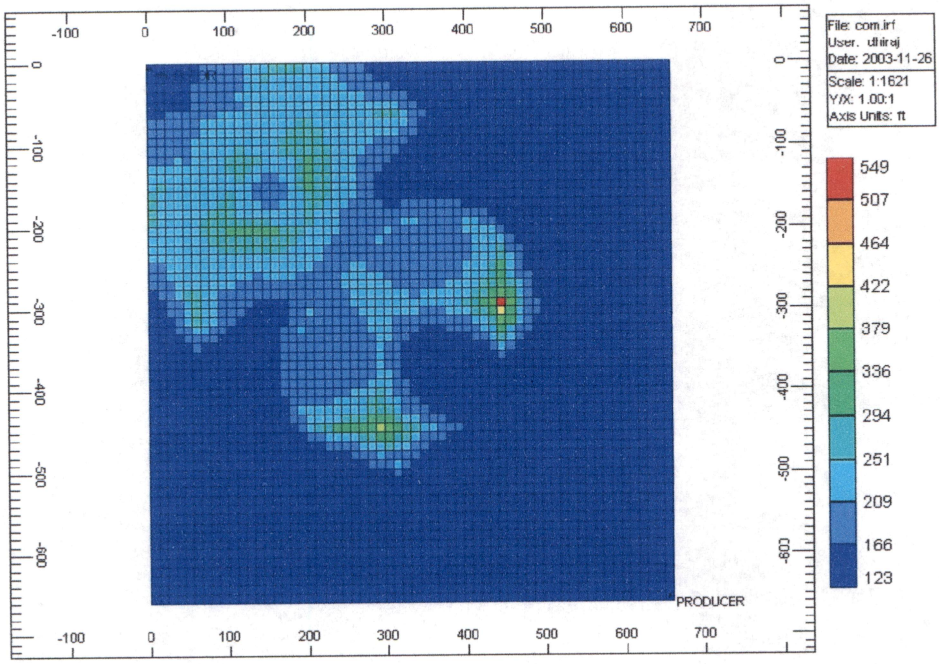

Figure 29. Temperature map at 2000 days (°F).

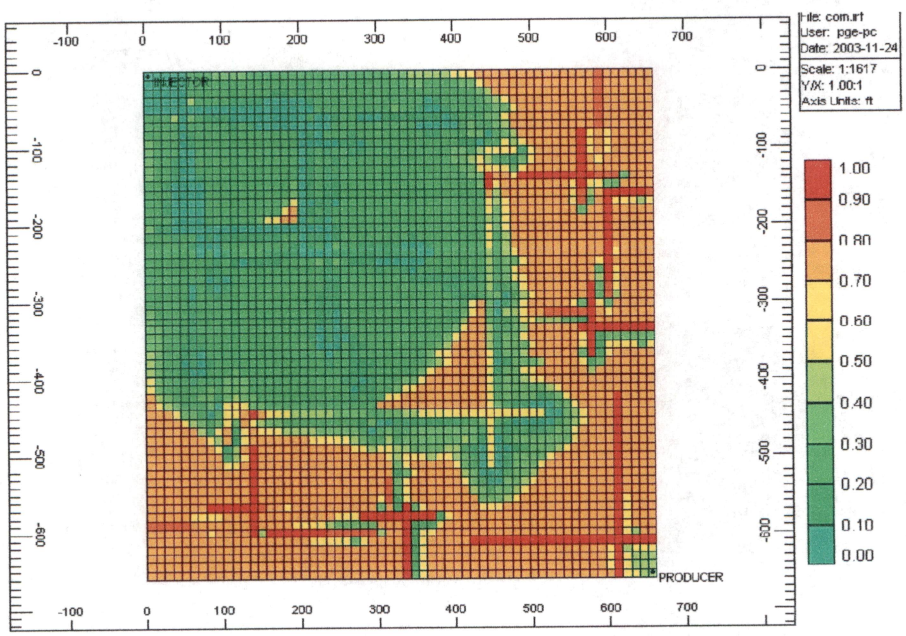

Figure 30. Oil Saturation at 100 days (just before breakthrough) (fraction).

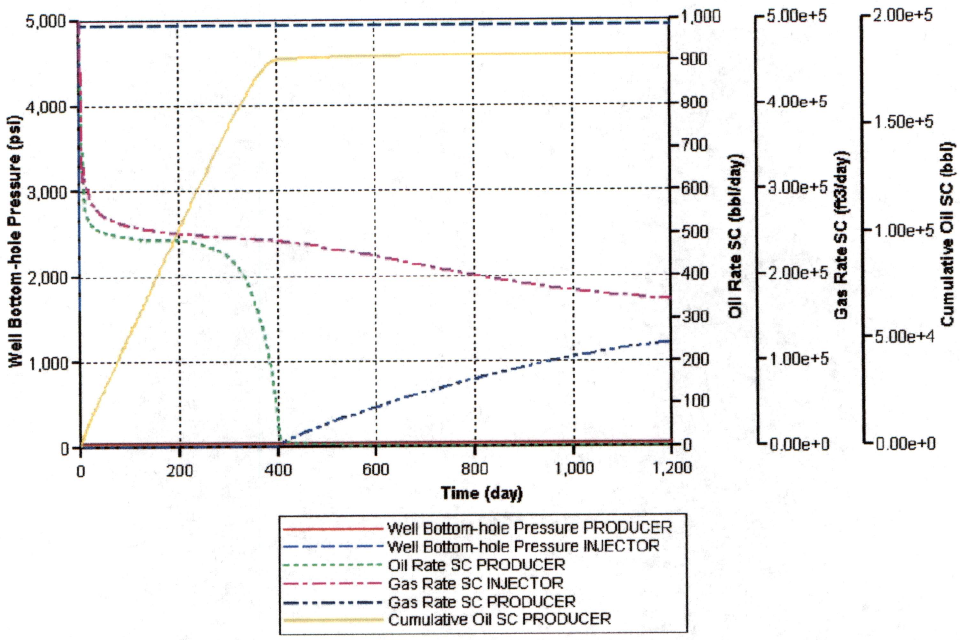

Figure 11. Homogeneous airflood.

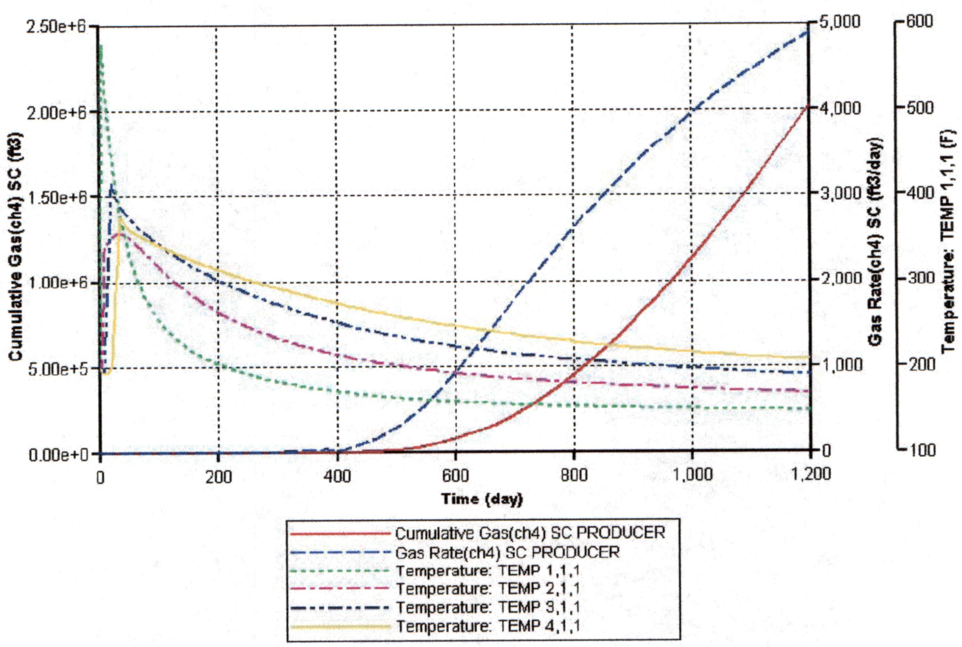

Figure 12. Homogeneous airflood

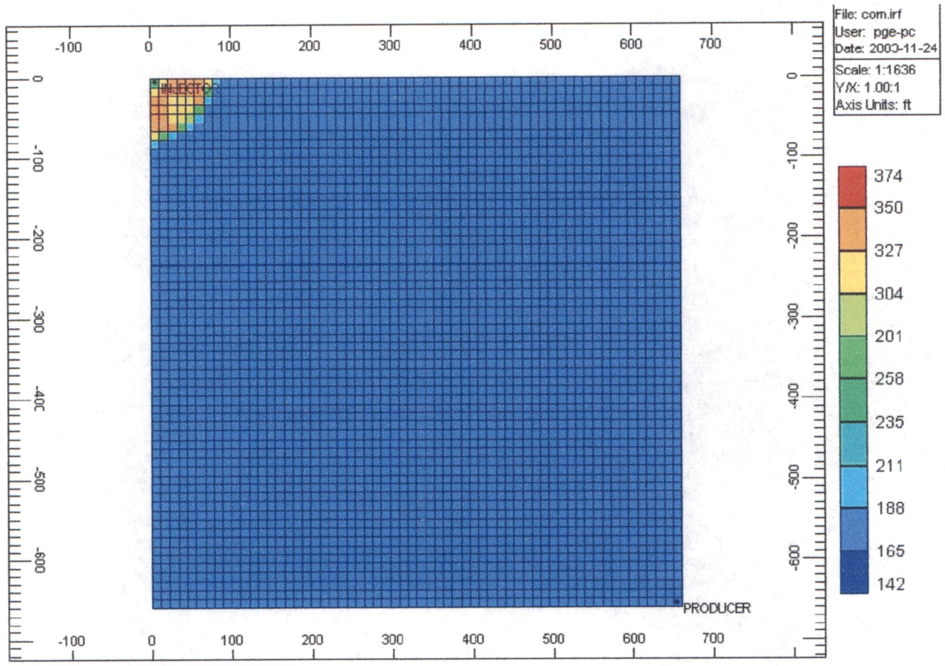

Figure 13. Temperature map at 100 days (°F).

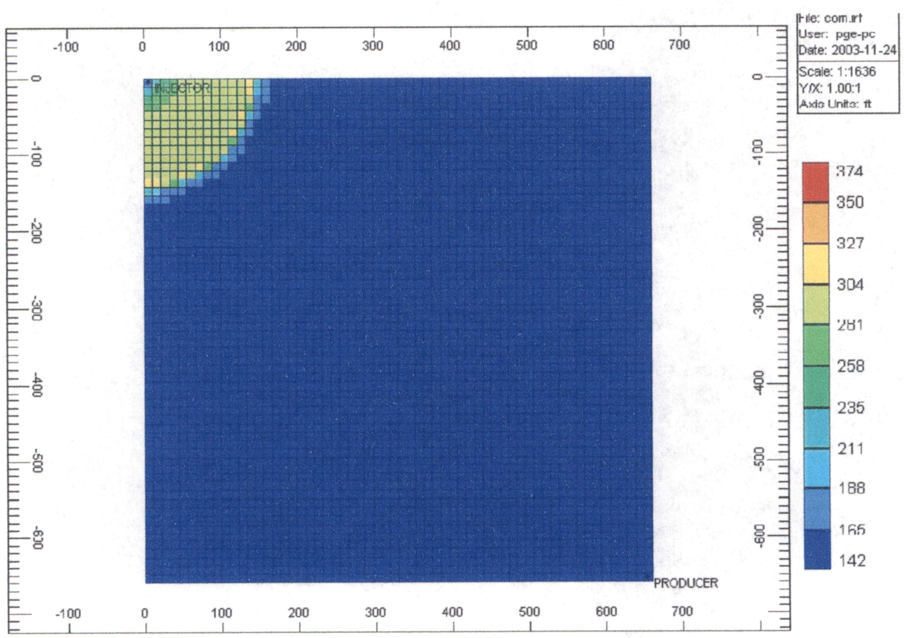

Figure 14. Temperature map at 400 days (°F).

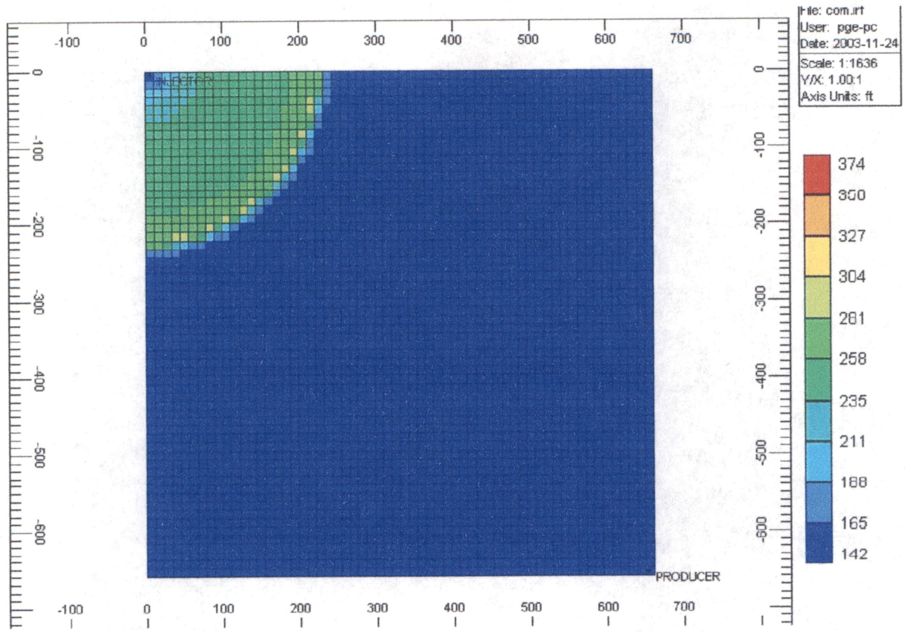

Figure 15. Temperature map at 1200 days (°F).

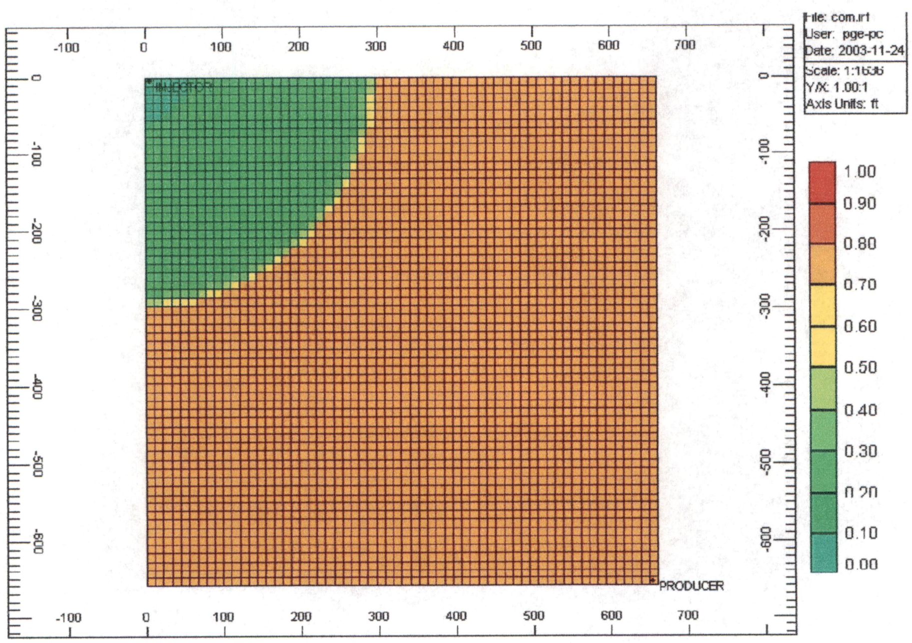

Figure 16. Saturation at 50 days (fraction).

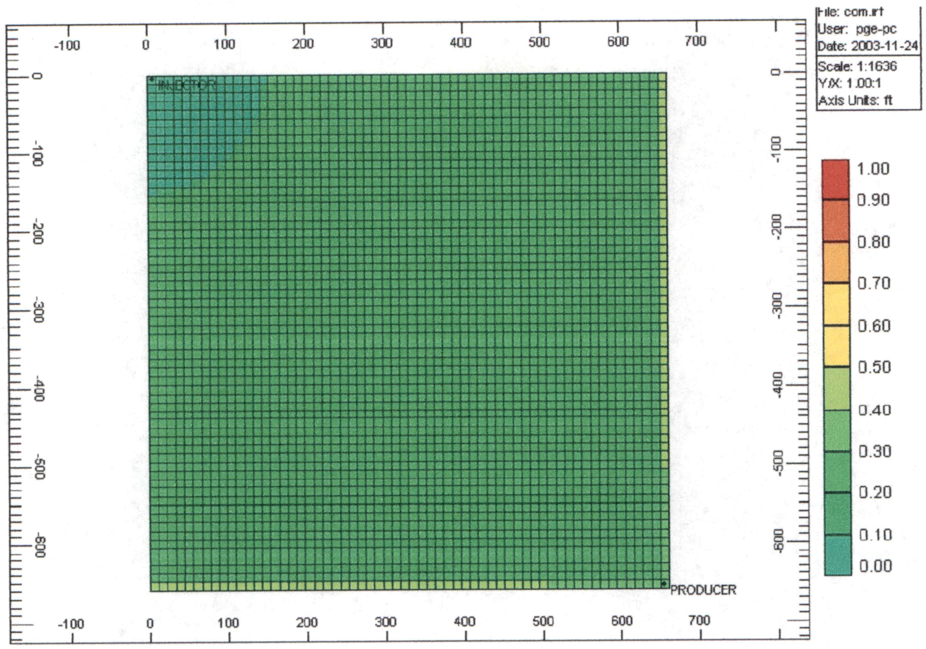

Figure 17. Saturation at 400 days (breakthrough).

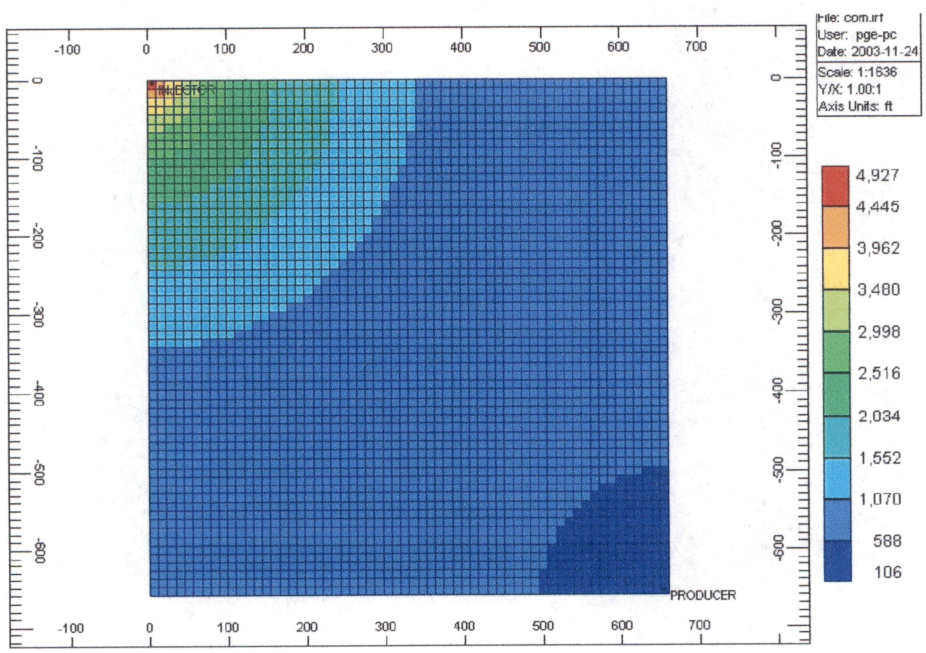

Figure 18. Pressure map at 100 days (psi).

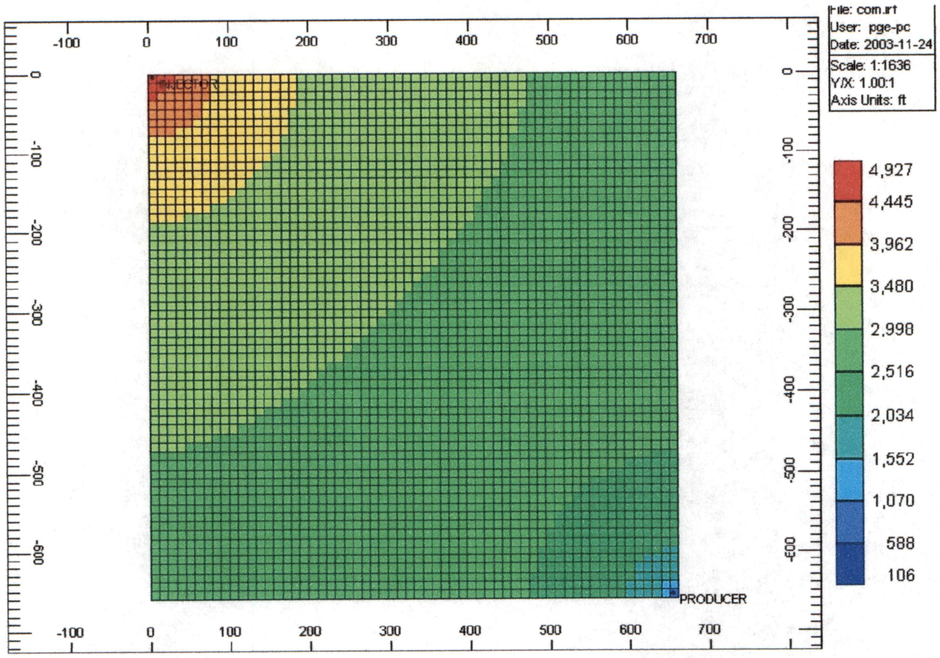

Figure 19. Pressure map at 1200 days (psi).

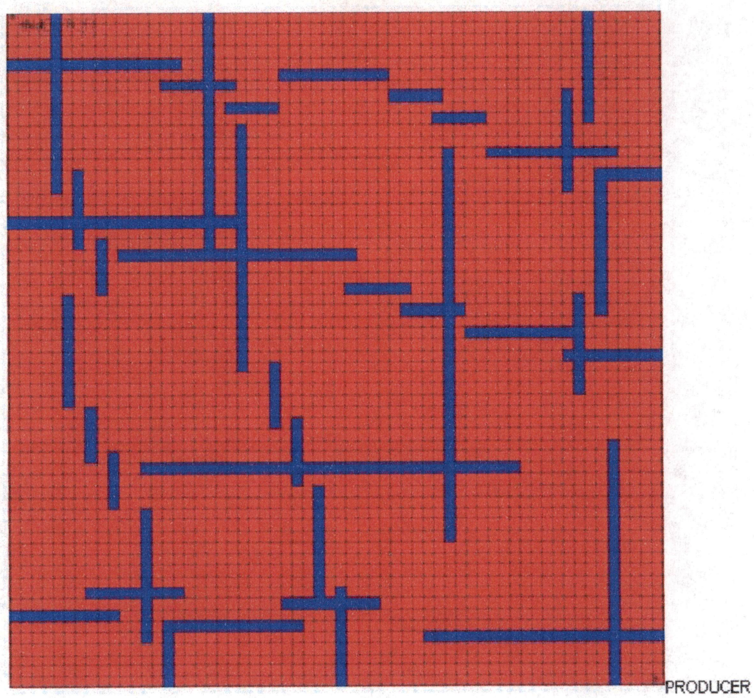

Figure 20. Discrete Fracture System.

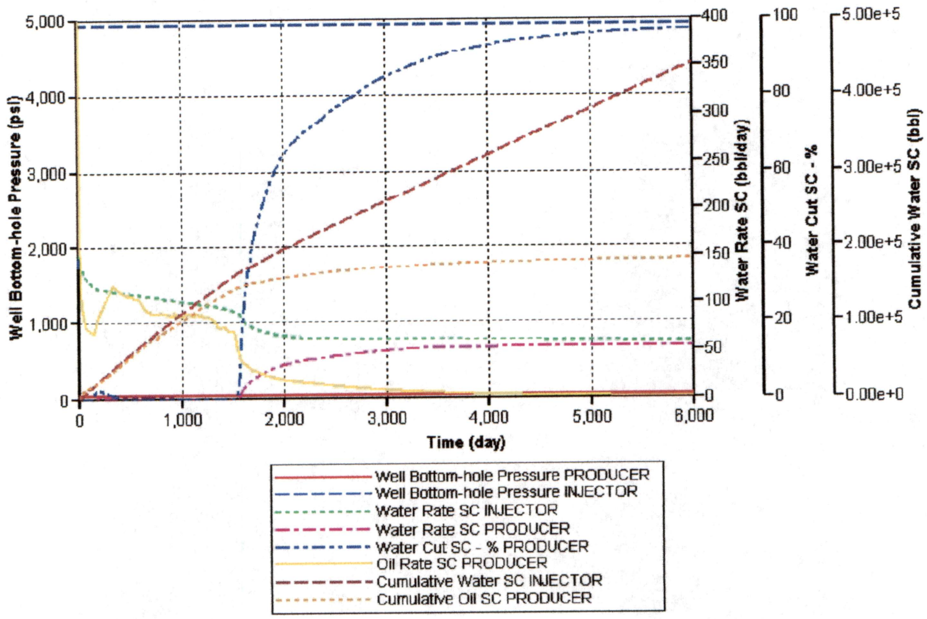

Figure 21. Discrete Fracture waterflood.

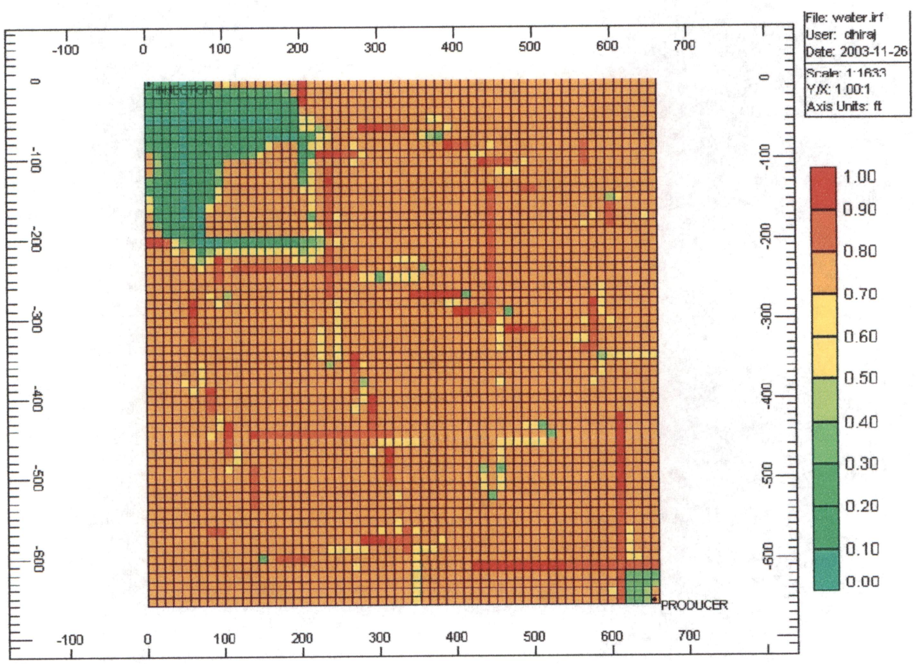

Figure 22. Oil Saturation at 100 days (fraction).

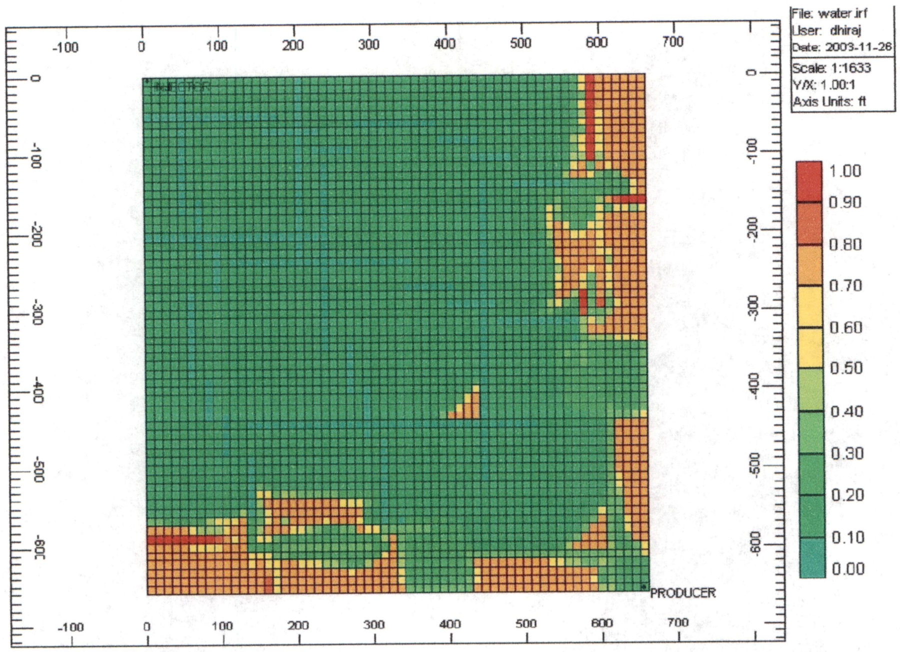

Figure 23. Oil Saturation at 1600 days (breakthrough).

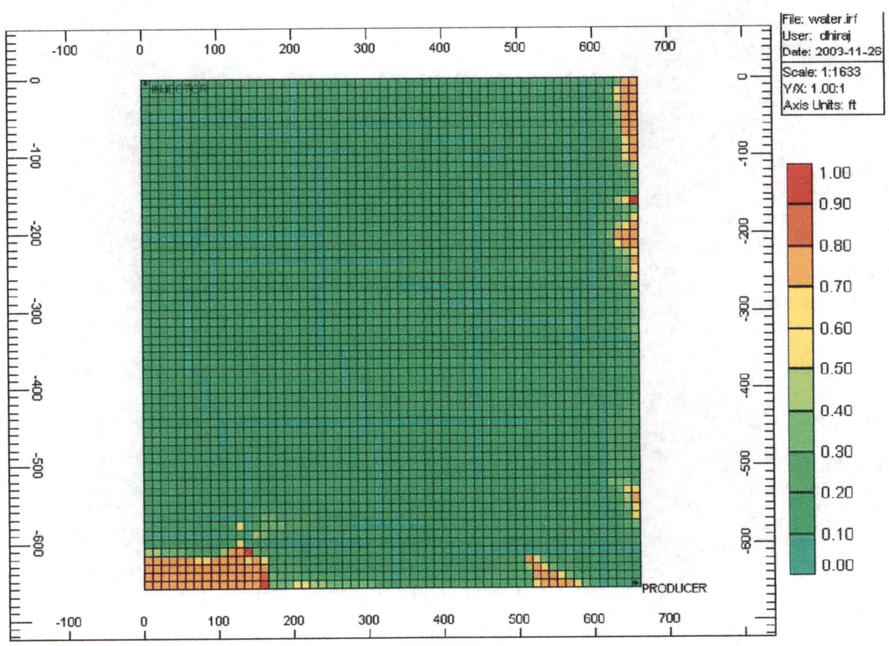

Figure 24. Oil Saturation at 6000 days (fraction).

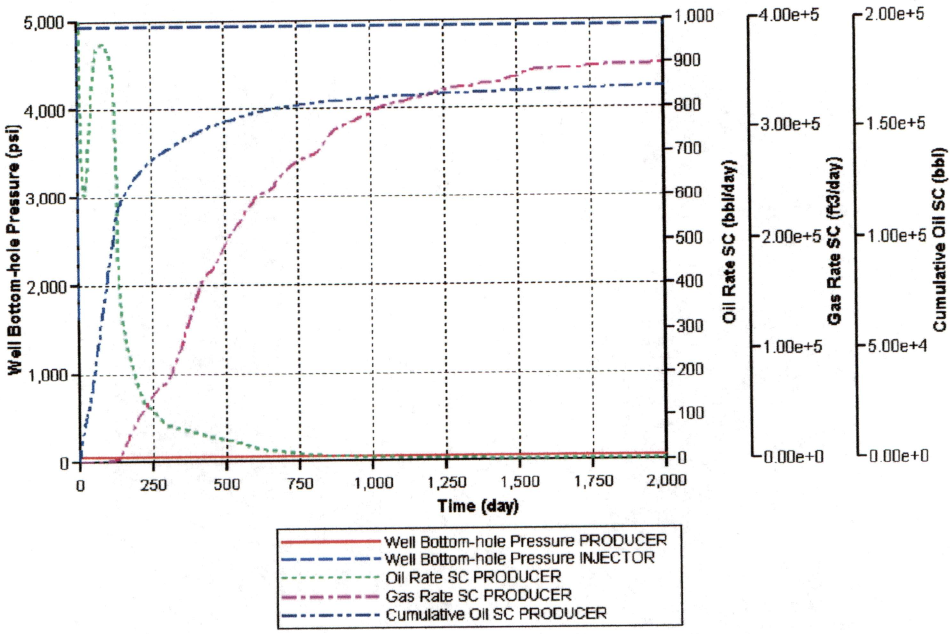

Figure 25. Discrete Fracture airflood.

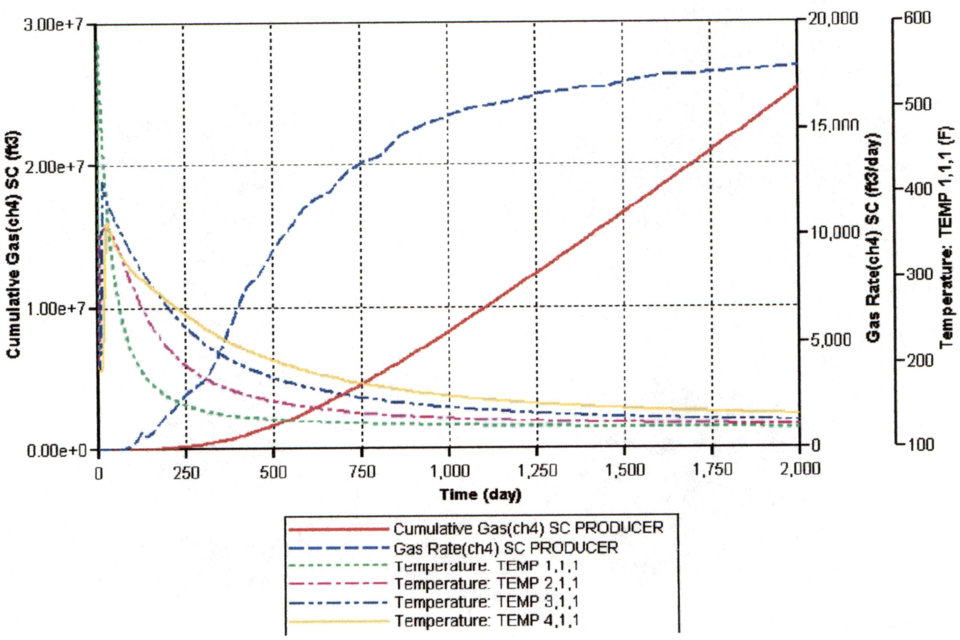

Figure 26. Discrete Fracture airflood.

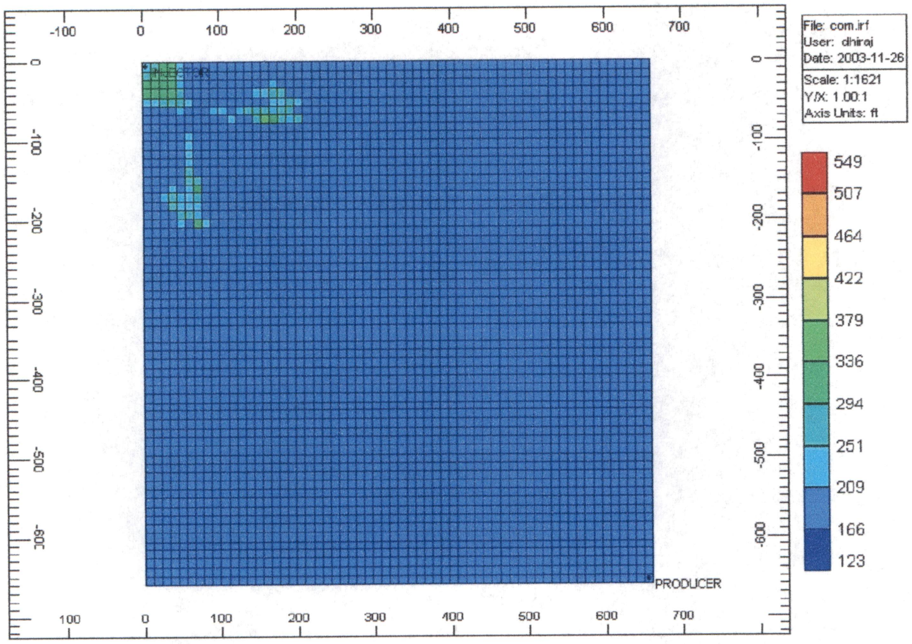

Figure 27. Temperature map at 100 days (°F).

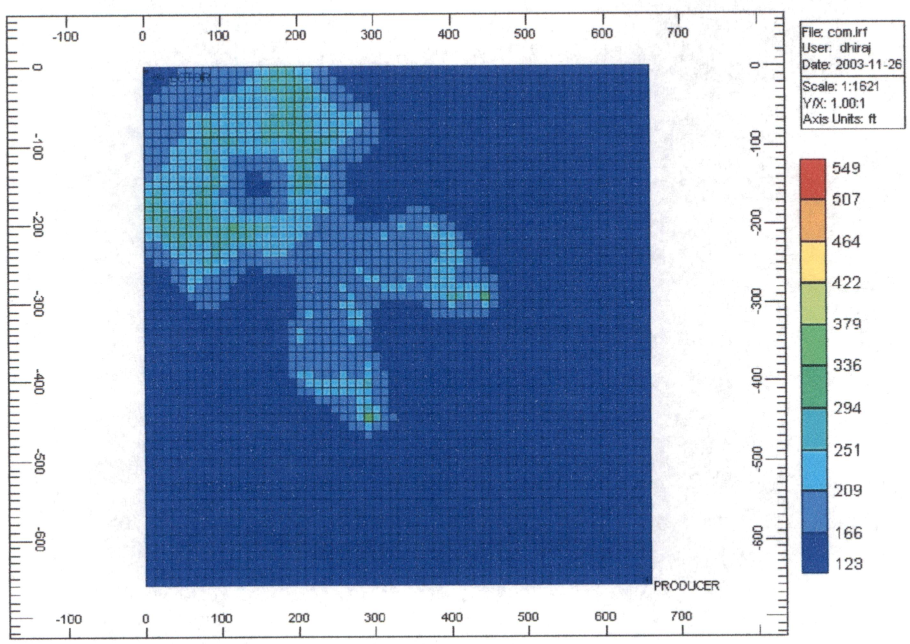

Figure 28. Temperature map at 100 days (°F).

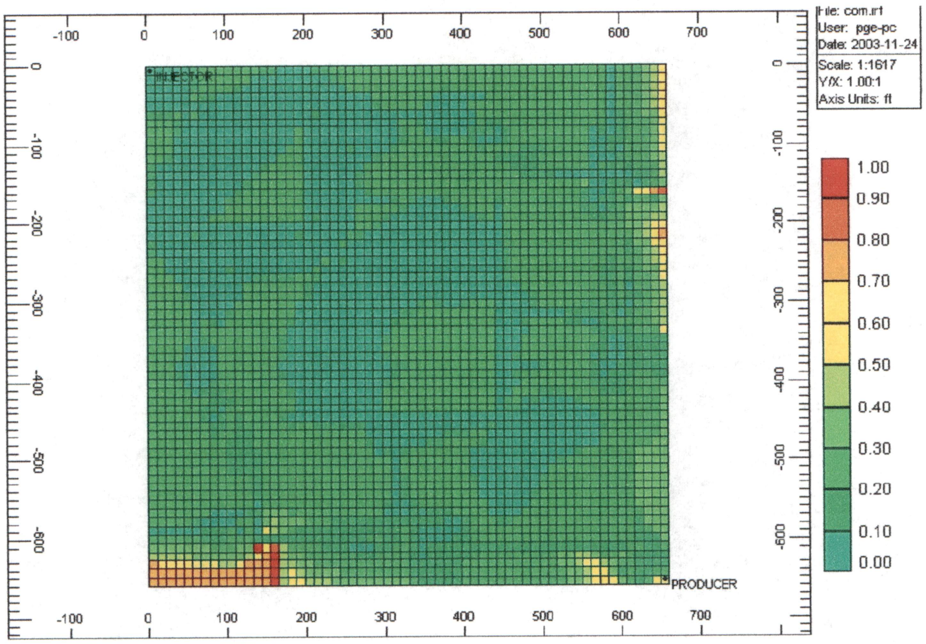

Figure 31. Oil Saturation at 2000 days (fraction).

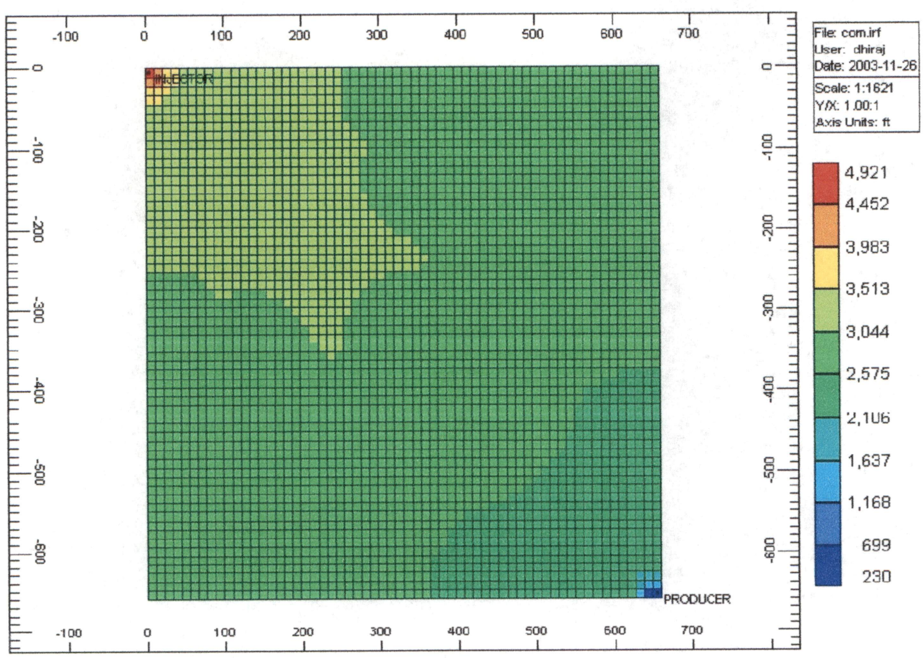

Figure 32. Reservoir Pressure map at 2000 days (psi).