THE EFFECT OF RESERVOIR HETEROGENEITY ON PREDICTED WATERFLOOD PERFORMANCE IN THE DODSLAND FIELD

M.R. CARLSON

this article begins on the next page ☞

INDEX

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The Effect of Reservoir Heterogeneity on Predicted Waterflood Performance in the Dodsland Field

M.R. CARLSON
Applied Reservoir Engineering & Evaluation Ltd.

Abstract

Predicted waterflood performance in the Dodsland Viking field has not occurred. Previous study identified that the effects of hydraulic fractures must be taken into account in order to predict performance. The revised predictions are still somewhat optimistic when compared to actual production. The previous work has been extended to account for reservoir layering.

Core data has been used to provide a quantitative analysis. Due to extreme permeability contrasts, it is difficult to simulate large ranges in formation permeability as separate layers. Hearn type relative permeability curves were therefore used.

With high reservoir heterogeneity, waterflood response may consist only of a levelling of production. This prediction is consistent with actual well performance observed. The methodology used and its limitations are discussed. Additionally, the effects of well spacing and fracture extension are presented. This work has important economic implications for existing and planned waterfloods:

1. Wells which are producing below their economic limit, awaiting predicted waterflood response, can be shut-in. This was used to implement substantial reductions in operating costs.
2. More realistic estimates of waterflood response in highly stratified reservoirs can be made by using core data and Dykstra-Parson ratios prior to implementation.

Introduction

Outline

This paper summarizes a study originally made for an individual unit. Although the results are more broadly applicable, the outline follows the historical development, under the following headings:

a. Geological Description
b. Production Performance
c. Model Construction
d. Reservoir Modelling
e. Conclusions

This work is an extension of work done previously by Carlson and Andrews[1]. Although this paper has been written on a stand-alone basis, further background data may be found in the previous paper.

Background

The Dodsland field, located in south-west Saskatchewan, was first discovered in 1953. The location of the field is shown in Figure 1. Light oil (36° API) production is obtained from the Cretaceous aged Viking sandstone.

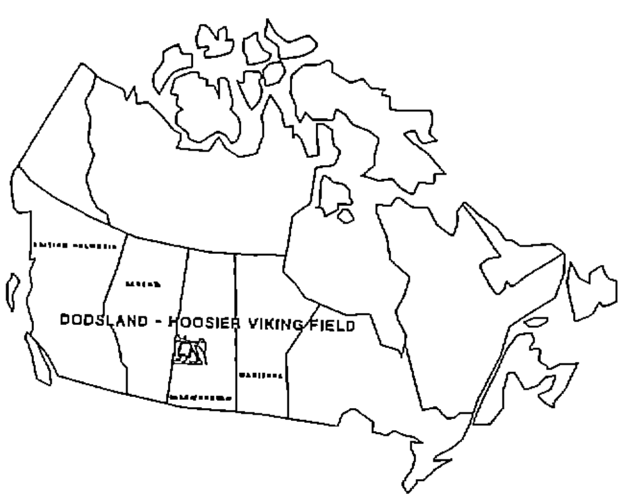

FIGURE 1: Location of Dodsland field.

Delineation of the field occurred rapidly during the 1950's. Unitization and waterflooding followed in the mid 1960's. A resurgence in development occurred in the late 1970's and early 1980's due to high oil prices. Development in the mid 1980's was also fuelled by attractive government incentives.

Geological Description

Lithology

The Viking consists of an interbedded shale and sandstone. The sandstone is a poor quality reservoir rock; however, its shallow drilling depth and large area have permitted extensive development.

The lithology has been described in detail by Tooth et al.[2] The sandstone portions typically consist of sublitharenates which locally grade into siltstones of similar composition. Porosity is intergranular with significant amounts of micro-porosity associated with clay mineral assemblages. Cementing by silica, siderite, pyrite and kaolinite is poor.

The more productive areas of the reservoir are comprised of 4.6 to 7.6 m (15 to 25 ft.) thick sandstones with discrete shaly partings. In the less productive areas, the shale partings are dense and the pay consists of thin lenses of sandstone. This layering does not show directly on well logs, since it is so fine. The sandstone appears to be dirty or has a high gamma-ray reading in the cleaner sands. Identifying this layering depends on visual examination.

The clay minerals have a strong effect on reservoir

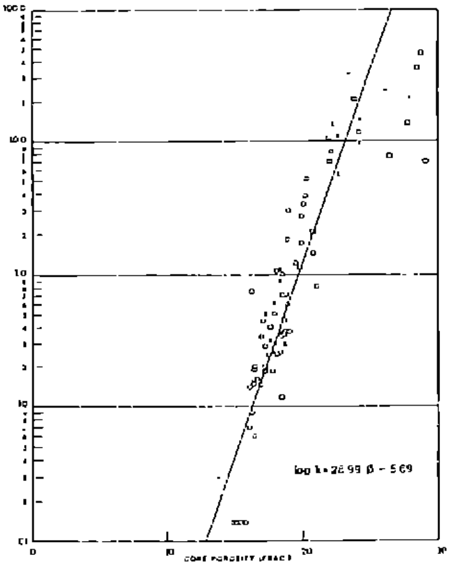

FIGURE 2: Core permeability vs. core porosity.

performance:

1. The amount and type of porosity is controlled by shale content.
2. Permeability is controlled by the amount and type of clay.
3. The clays are water sensitive.
4. Vertical permeability is restricted by the shale partings.

Imbricate Members

W.E. Evans[1], by detailed log correlation, has identified separate overlapping members. Several sequences of fining down sands are evident within each individual well. Although the Viking sand is areally extensive, the "blanket sand" model is far from reality.

Structure

Underlying the Viking formation are the Prairie Evaporites. Solution collapse has resulted in a complex series of oil and gas fields. These structures are quite large areally and are quite broad In the areas under study, which are located well away from the gas-oil contacts, there is limited structural effect on production within an individual waterflood pattern.

Core Analysis

To contain drilling costs, relatively few cores were taken. Data from a number of wells was combined, as shown in Figure 2. This figure shows core porosity vs. core permeability. The slope on this graph is extremely steep. There are large variations in permeability for very small changes in porosity. As discussed earlier, permeability and porosity are most strongly affected by clay contents.

Quantitative Permeability Variation

It has been found empirically that if log core permeability is plotted on log normal probability paper then a straight line is obtained. The slope of this line is described by the Dykstra-Parsons coefficient as follows:

$$V = \frac{k_{50} - k_{84.1}}{k_{50}}$$

Most reservoirs exhibit a Dykstra-Parsons ratio between a range of 0.5 to 0.9. The larger number represents more severe layering.

Dodsland core data was plotted as shown in Figure 3. This data shows a high permeability variation with a Dykstra-Parsons coefficient of 0.92.

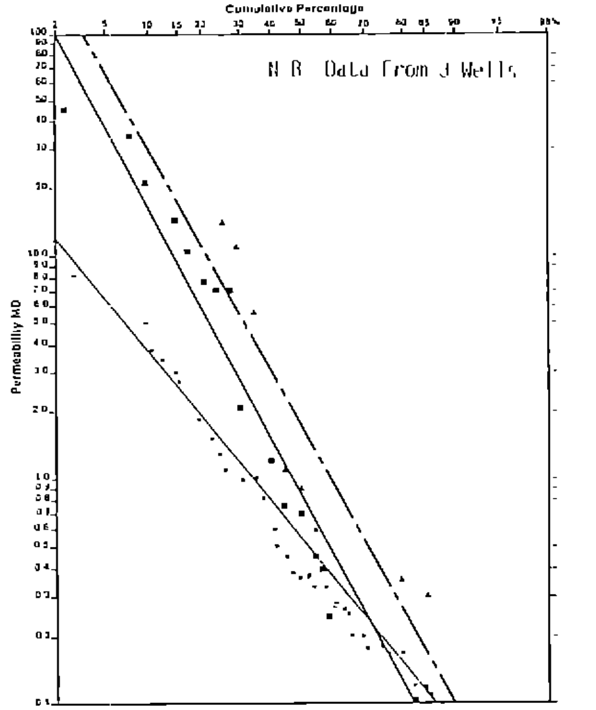

FIGURE 3: Log core permeability vs. log normal probability.

Geological Summary

1. The geology of the reservoir is moderately complex. The accumulation of oil and gas is controlled by overlapping imbricate members and a collapse structure.
2. Due to a low energy depositional environment, the reservoir is of poor overall quality. As a result the wells must be hydraulically fractured.
3. There are a number of items that suggest strong permeability variation (or layering) in this reservoir:
   a. Multiple imbricate members—production is obtained from a series of sands rather than from an individual sand,
   b. Interbedded shale and sandstone lithology, and
   c. Core data indicates that large permeability variations result from small changes in porosity.
4. Dykstra Parsons coefficients can be used to quantitatively compare this reservoir

Production Performance

Production Profiles

Based on economic evaluation experience in the area, a distinct period of flush production is seen, which is typical of low permeability formations. Production decreases rapidly during the first year in a hyperbolic shape. After two years the wells decline exponentially.

Most Dodsland wells show erratic production data. This is typical of low productivity wells, where it is difficult to get frequent test data economically. To dampen out these variations, production can be averaged. When this process is applied to a moderate number of wells, a characteristic pattern is obtained, as shown in Figure 4.

Extended Primary Production

The best examples of extended primary production are in the eastern portion of the Dodsland field, since the western portion was placed on waterflood. The eastern area, which is of lower reservoir quality, was originally drilled during the 1960's on 64 ha (160 acre) spacing. Production from these wells has sometimes

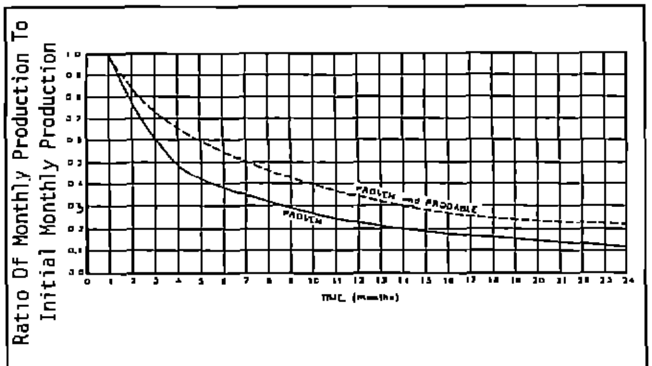

FIGURE 4: Typical Dodsland oil production profile.

been considered to be representative of primary production performance, regardless of spacing, due to the low overall permeability of the Viking.

Hydraulic Fractures

Since the reservoir is of poor quality, successful development required that all wells be hydraulically fractured. Treatments of 23,000 to 32,000 kg (50,000 to 70,000 lbs.) of sand were typically used. Due to the importance of the fracture treatments, they were simulated numerically[1]. Fracture lengths of approximately 76 to 91 m (250 to 300 ft.) from well to wingtip were generated

Ideally pressure transient analysis could be used to verify these dimensions. However, buildups are very difficult to obtain on pumping wells. The reservoir is tight and extensive shut-in times are required to get a full analysis. With low production rates extended shut-ins are hard to justify. No suitable well test analysis has been found by the author. Therefore, the data from the fracture simulator was used as input for the reservoir simulator.

Paleo Stress

The orientation of the hydraulic fractures is controlled by the residual stresses in the earth[4]. Adams and Bell[5] have documented fracture trends, as shown in Figure 5. Fractures in the Dodsland area will trend east-west.

Existing Waterfloods

Most of the Dodsland field was put on waterflood during the later part of the 1960's. There is considerable existing production data to analyse. These waterfloods were implemented simultaneously with extensive infill drilling programs (to 16 ha or 40 acre spacing). This has made it difficult to distinguish, on a unit-wide basis, how much production resulted from infill drilling and how much production increase resulted from waterflood response.

It was therefore necessary to review production on a well-by-well basis. Few of the existing wells show a discernable production increase after the implementation of waterflood. Performance can only be described as poor. The only positive indication of waterflood response has been a reduction in produced GOR's to near solution gas oil ratios.

Fresh Water Injection

Fresh water, from the Belly River formation, was originally used for injection. In the early 1980's, it was proven that the Viking was damaged by fresh water. The newer waterfloods, implemented in the 1980's, injected a mixture of saline Deadwood and Belly River waters to prevent clay swelling and migration problems.

Due to the low permeability and formation damage, high injection pressures were required in the older waterfloods.

Production Performance Summary

1. Production data is erratic, which makes modelling of individual wells difficult. Averaging produces good quality data which can be used as the basis for modelling.
2. There is rarely an indication on individual well production plots of an increase in oil production due to waterflooding.
3. Reductions in produced GOR's are the only indicators of waterflood response.
4. The dimensions of fracture treatments are relatively well known, based on numerical modelling of hydraulic fracture treatments.

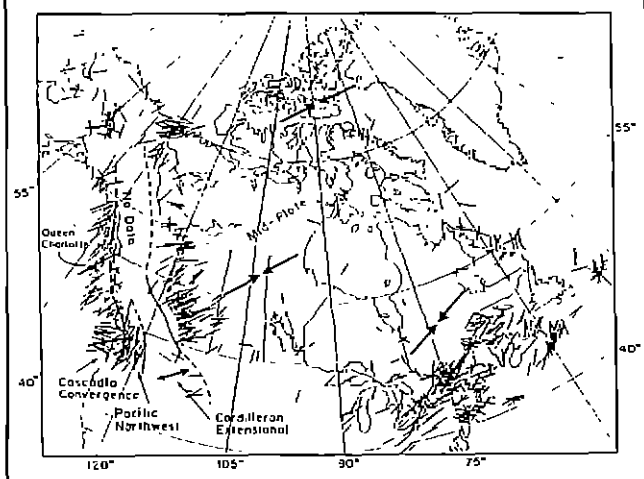

FIGURE 5: Fracture orientations controlled by paleo stress.

Model Construction

Type Modelling

A type model approach was taken in this study, for the following reasons:

1. To include the effects of the hydraulic fractures. Previous experience has shown that this has a profound effect on production response. This is really an indirect requirement, since fractures could be included in an areal model. However, the size of the model would become so large as to require extensive computing facilities and time.
2. To allow the effects of layering to be included. Classic waterflooding techniques, such as those developed by Stiles have shown the effects of layering are critical to accurately predict waterflood performance. As above, this is really an indirect requirement: the constraint is the size of the simulation grid.
3. To keep history matching to a manageable level. The unit on which this work was initially done had a considerable number of wells. Although a unit of this size can be modelled, the cost of history matching so many wells would not be supported by a field that produces at marginal rates.

Grid Construction

Grid design is a compromise between greater accuracy achieved by using smaller grid block sizes and the amount of time that is required to solve the problem. It is not possible to analytically determine the amount of error produced by a grid. This must be determined by grid sensitivities.

Initially a very fine grid, as shown in Figure 6a, was used. This grid was used as a base case for developing a coarser grid.

Grid Properties

A net pay of 1.2 m (4.0 ft.) was used. The zone thickness from logs averages 2.75 to 4 m (9 to 13 ft.) It is customary in the area to reduce the pay from logs by one half since the sandstone is layered with alternating shale and sandstone.

Porosity was input using an average value of 19%.

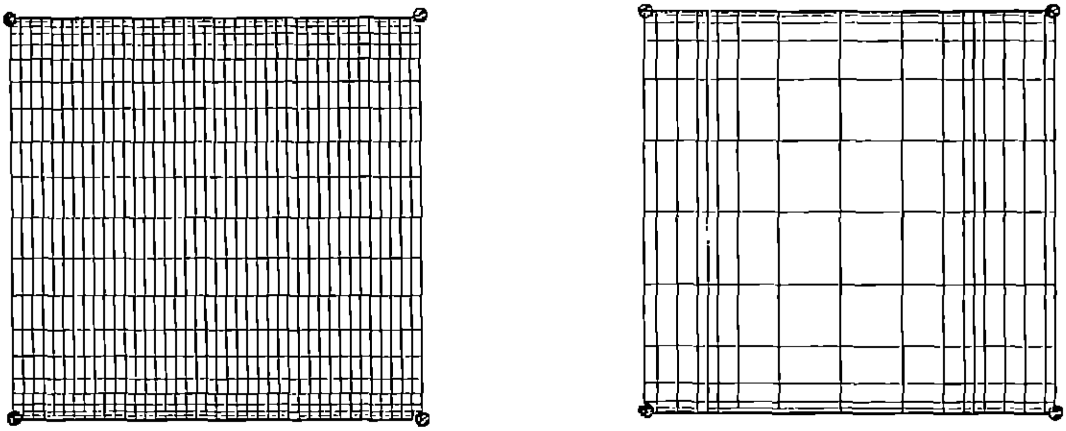

FIGURE 6: Fine simulation grid (a) and coarse grid (b).

Permeability was estimated from core data, offset experience, and pressure buildup analysis. Core data from the unit wells indicates an average air permeability of 8.5 mD. The liquid permeability was adjusted to be 4.25 mD. Pressure buildups indicate permeabilities from 1 to 4 mD. These tests are not the best, due to the low permeability, but once again are the most accurate data available. A final value of 3.75 mD was used, representing a minor reduction in core values for overburden effects, to match pressure buildup analysis.

No capillary pressure data was available. The data used is from correlations and offsetting reservoirs.

Hearn Type Relative Permeability Curves

Although pseudo relative permeability curves are typically generated by history matching, they may also be generated analytically as described by Dake[6]. Hearn type relative permeability curves[7] for stratified waterflooding were used.

There are a number of assumptions which are invoked by using this technique:

1. That there is no vertical communication. This is probably a realistic assumption for Dodsland, in view of the interbedded nature of the reservoir. The true vertical communication is likely very poor.
2. That gravity and capillary forces are negligible relative to viscous effects. This concerns the presence of a water-oil contact within the zone thickness. There are normally two tests for this, an analytical estimate by Coats[7] comparing vertical forces to horizontal forces, and the thickness of the capillary pressure curve compared to zone thickness. A 4 ft. zone thickness is small in comparison to the height of the capillary transition zone.
3. That displacement within layers is piston-like. Thus, the water saturation in each layer is either the connate water saturation or 1 - Sor, although Buckley-Leverett theory shows this may not be the case. However, the relative permeability for this zone is strongly water wet. The viscosity of the water is 1.55 cp at bottom hole temperature and pressure and the oil viscosity is 2.65 cp at the bubble point. Hence, a favourable mobility ratio exists (in field terms) and the displacement within the reservoir is relatively efficient. Figure 7 is a fractional flow diagram for the field. The average water saturation, behind the flood front at breakthrough, is approximately 69%. This is 96% of the movable oil, which is as close to a "piston-like" assumption as can be reasonably expected. Thus, the actual field displacement will be somewhat less efficient and water breakthrough will be slightly ahead of the Hearn type relative permeability curves used in the simulation.
4. That the potential within the injector and the producer is the same for all layers (or that there is a negligible vertical potential gradient). In reservoir terms the difference in potential across 1.2 m (4 ft.) of net pay is trivial for any combination of fluids.
5. That the fluids are incompressible. Although this is not perfectly true, it is a reasonable assumption. This matter is discussed by Lake[8] in detail (see Section 5-3).
6. The same oil-water relative permeabilities apply to each layer. This is somewhat difficult to quantify. The data has been derived from another reservoir located in Alberta. Although both are from the Viking, there may be differences. Data from this reservoir is presented in Figure 8 and shows reasonable consistency, particularly on a Kro/Krw basis. There is undoubtedly some variation with reservoir quality.

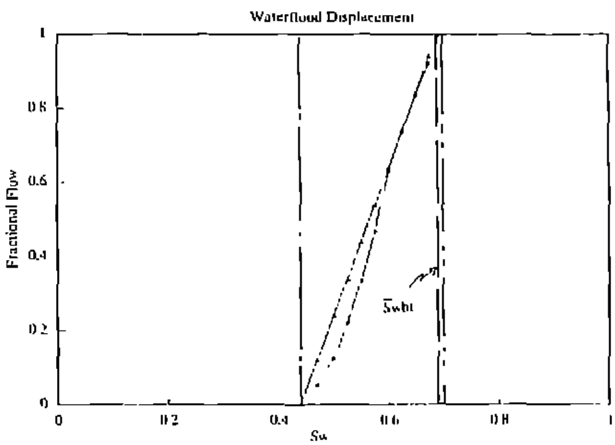

FIGURE 7: Fractional flow curve—Dodsland relative permeability and fluid properties.

Initial Gas Saturation

One question that frequently arises is the effect of a gas saturation, from primary production, at the beginning of waterflooding. The effect of the gas saturation is discussed qualitatively and practically by Slider[9] in Chapter 9 of his book. The matter is solved with elegance by Lake[8] in Section 5-7 of his book. Both show that the gas is so mobile that it is rapidly displaced ahead of the water-oil shock front and hence has little effect on the water-oil displacement (but may substantially affect the time for the reservoir to re-pressure). Therefore, from a three phase flow / relative permeability perspective, modifying only the water-oil relative permeability is correct.

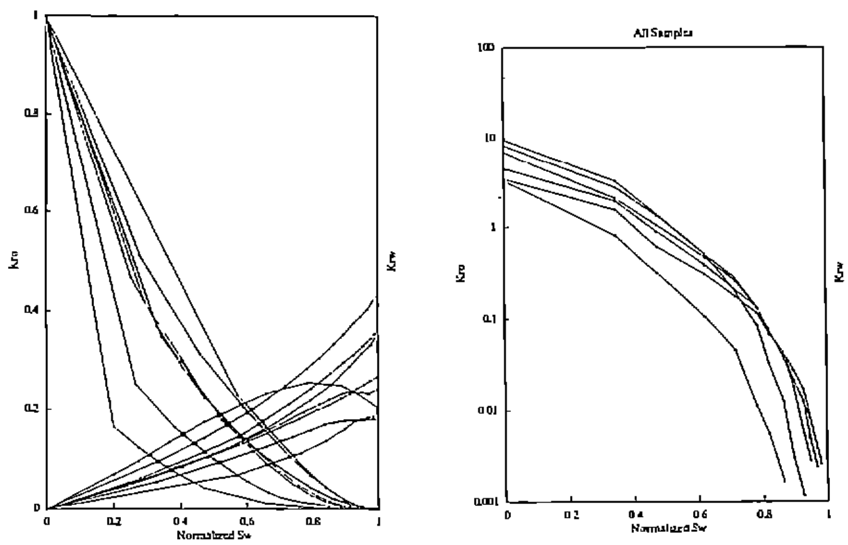

FIGURE 8: Normalized water-oil relative permeability (a) and normalized Kro/Krg (b).

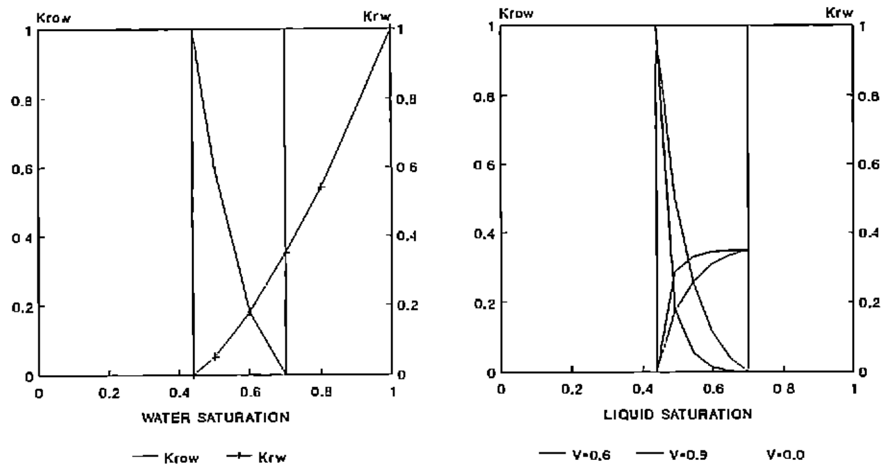

FIGURE 9: Rock relative permeability curve (a) and Hearn type pseudo relative permeability curves (b).

Relative Permeability Curves

The curves were calculated by arbitrarily assigning five layers. The permeability of the layers was then assigned by positioning a line on a log core permeability vs. log normal probability paper with Dykstra-Parsons slopes of 0.6, 0.8 and 0.9. Permeability was taken from the graph (at the 0.10, 0.30, 0.50, 0.70 and 0.90 cumulative per cent points) and input in Table 1 for the five layers. The calculations were done using a spreadsheet.

The effects are shown in Figure 9. The relative permeability to water is strongly increased and the relative permeability to oil is decreased. The utilization of Hearn type relative permeability curves is the most important difference between this and previous modelling.

Multiple Layers

An attempt was made at a multi-layer (3D) simulation. The layer properties were input as described in the preceding section (see Table 1, V=0.9). The time requirements for this case were enormous. The variation in layer permeabilities from hundreds of milli-Darcies to fractions of a milli-Darcy is very severe. This variation in transmissibility is too high for a problem which is already difficult by virtue of the presence of a frac. For this reason, the use of Hearn type relative permeability was necessary.

Model Construction Summary

1. Type modelling was the preferred approach in this reservoir to keep grids to reasonable proportions.
2. The use of multiple layers leads to impractically long simulation times.

TABLE 1: Pseudo relative permeability curve calculations.

Dykstra - Parsons Co-Efficient = 0.900

Sw	fraction (or h)	perm.	h*k	Krw	So	Krow
0.440	0.000	0.560	1.000			
0.492	0.800	70.000	56.000	0.287	0.508	0.160
0.544	0.800	10.700	8.560	0.331	0.456	0.055
0.596	0.800	3.500	2.800	0.345	0.404	0.014
0.648	0.800	1.000	0.800	0.349	0.352	0.002
0.700	0.800	0.170	0.136	0.350	0.300	0.000
		total height		4.000		
		total kh		68.296		
		average k		17.074		

3. Hearn type relative permeability curves were used in a single layer grid to more efficiently model the effects of layering.

Reservoir Modelling

Grid Refinement

The grid was coarsened, as shown in Figure 6b, and test runs made for comparison. The results of the two runs are presented in Table 2. Note that the new grid sensitivities are improved over those used in the original study by Carlson and Andrews. The new comparisons are made between waterflood cases. These figures

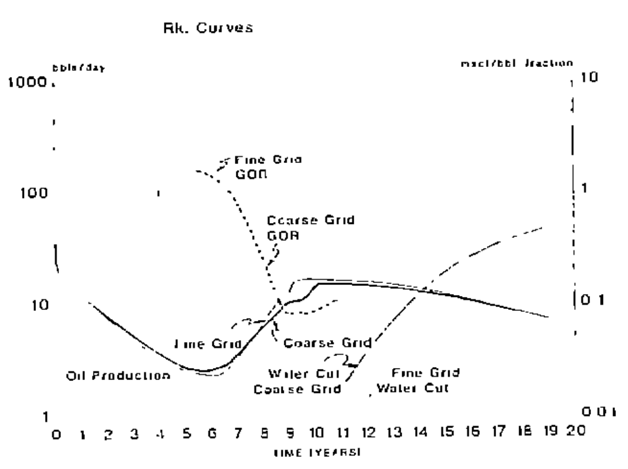

FIGURE 10: Comparison between fine and coarse grid waterflood predictions.

indicate that the numerical errors are of the order of 2.45 (4.80 - 2.35)% on primary production and up to 11.47 (4.8 - 6.67)% on waterflood.

The results from these two runs are also compared in Figure 10. The primary portions of these runs overlay, however, the water breakthrough on the coarser grid occurs much earlier. This represents numerical dispersion. Most of the differences occur at low water cuts and are thus not as important as the graph might initially suggest. The timing of water breakthrough is normally important in establishing a history match and some loss of accuracy has been accepted. The saving in run time, from 159.65 to 11.12 minutes is very significant. The coarser grid was used for the balance of the study.

Primary Production

Primary production was modelled prior to proceeding with waterflood predictions as shown in Figure 11a. The initial rate for the second month of production was 1.9 m³/d (12 B/d). The classical Dodsland area flush production is seen before stabilizing to an exponential decline. The exponential decline is 21.7%, which was slightly higher than the actual field values for the unit studied. Final recovery, at a final rate of 0.8 m³/d (0.5 B/d) was 2,509 m³ (15,780 Bbl).

Effects of Spacing

As discussed earlier, a number of wells in the Dodsland area were drilled during the 1960's on large spacings. The production decline from these wells was used to a greater or lesser extent to predict the performance of wells drilled in more recent years. Figure 11b shows the results for the same run only on 64 ha (160 acre) spacing. The decline slows to an exponential decline rate of 8.5% per annum. The cumulative recovery after 16 years was 5,078 m³ (31,940 bbls). Extrapolating to 20.8 years resulted in a recovery of 5,552 m³ (36,809 bbls). This was compared to actual well performance (on wells from the 1960's) of 4,647 m³ (29,228 bbls). This is 79% of the simulator prediction. Since infill wells had been drilled during the 1980's, this model is likely fairly accurate.

Note that the GOR shows an initial rise, then stabilizes at slightly above the solution gas GOR. The GOR's increase less quickly than on 16 ha (40 acre) spacing.

The ultimate recovery has been compared as follows:

16 ha (40 acres):	2,137 m³/well (13,440 bbls/well)
4 wells:	8,547 m³ (53,760 bbls)
64 ha (160 acres).	6,310 m³/well (39,691 bbls/well)

Based on these figures, infill drilling to 16 ha (40 acres) clearly increases recovery.

TABLE 2: Grid refinement test.

		Fine	Coarse	Difference
Pore Volume	(RB)	233,041	244,781	+4 78%
OOIP	(Mstb)	120,830	126,919	+4 80%
Primary Recovery (t=1463 0)	(Mstb)	12,591	13 038	+3 40%
Recovery Factor	(per cent)	10 42	10 27	
Pressure	(psia)	489	501	+2 35%
Waterflood Recovery (t=694.75)	(Mstb)	38,895	37,421	-3 93%
Pressure	(psia)	907	901	-0 67%
Water Produced	(Mstb)	43,758	42,242	-3 59%
Water Injected	(Mstb)	48	45	-6 67%
Gas Produced	(Mscf)	12,583	12,457	-1 01%
Run Time	(Minutes)	159.65	11 12	-93 0%

Waterflood Predictions

A five spot water injection pattern was modelled for a uniform reservoir. The 'top right' and 'top left' wells were placed on injection after four years of primary production. Note that the oil rates respond very slowly. Oil production levels for three to four years and does not peak until 11 years after the start of injection. Water breakthrough does not begin until after 14 years. The GOR does not respond for two years, after which it decreases rapidly to near the solution gas oil ratio

Layering Sensitivities

Sensitivities were run based on Dykstra-Parson ratios of V = 0.6, 0.8 and 0.9. In each run the peak oil response becomes pro-

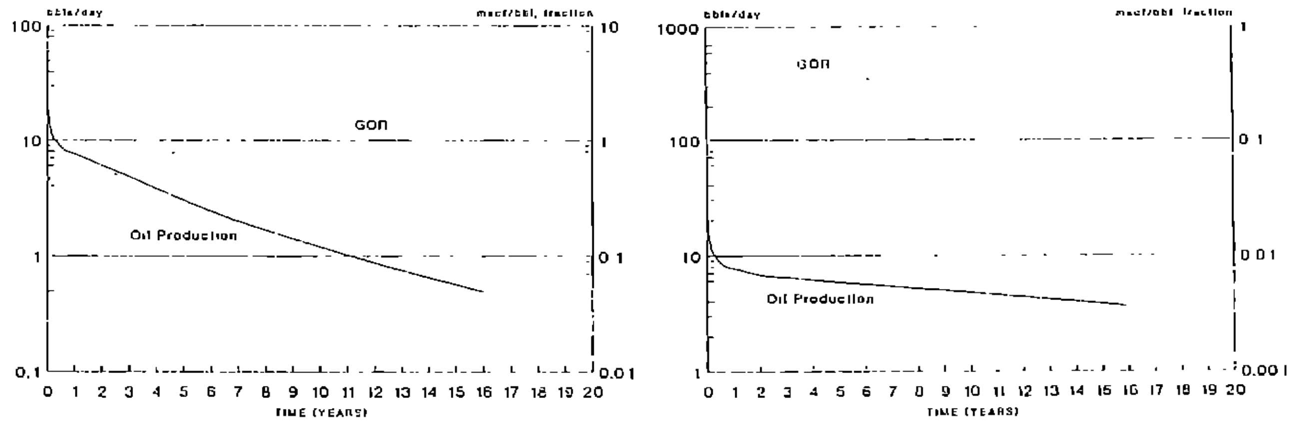

FIGURE 11: Primary production on (a) 40 acre spacing and (b) 160 acre spacing.

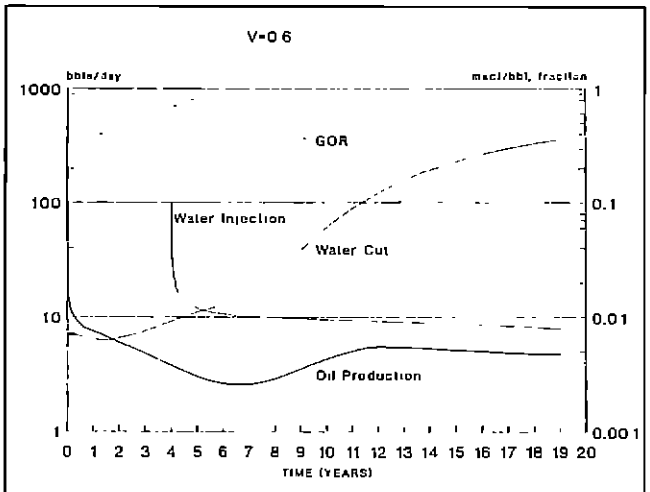

FIGURE 12a: Waterflood response Dykstra-Parsons ratio 0.6.

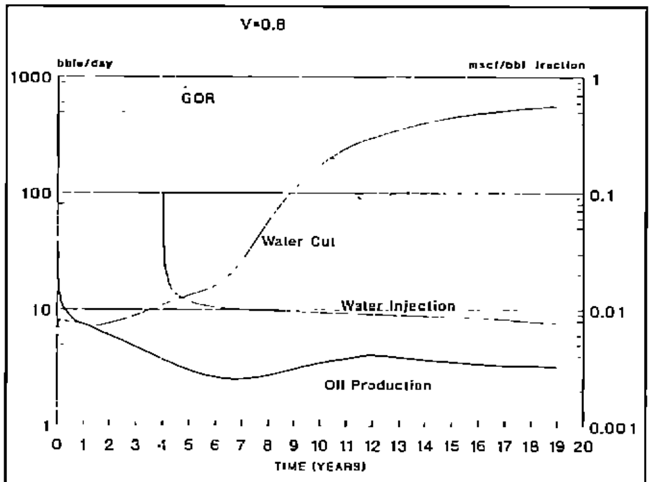

FIGURE 12b: Waterflood response Dykstra-Parsons ratio 0.8.

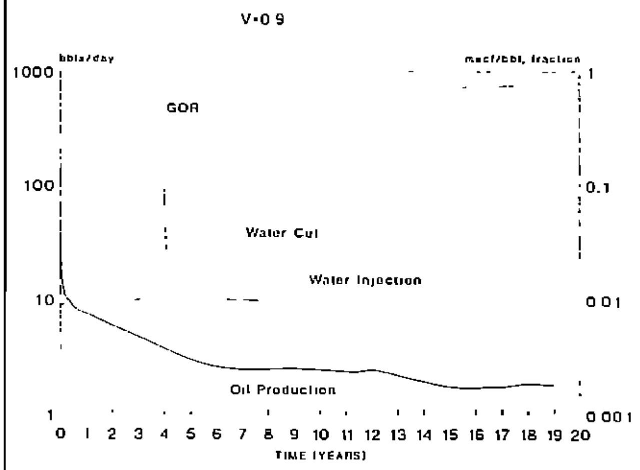

FIGURE 12c: Waterflood response Dykstra-Parsons ratio 0.9.

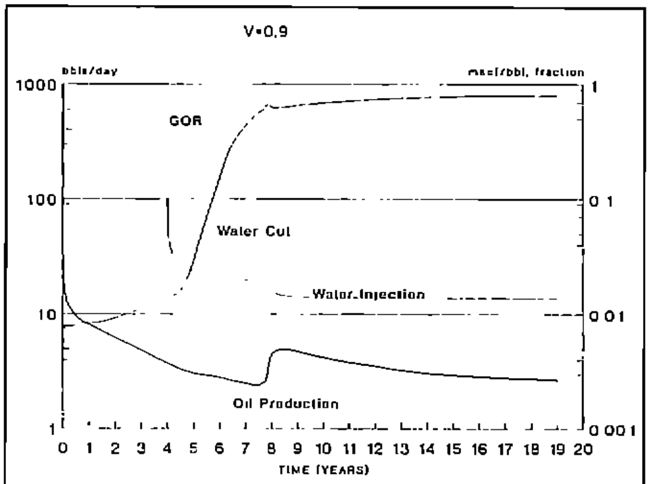

FIGURE 13: Waterflood prediction with fracture extension at high pressures.

gressively lower as summarized below and as shown in Figure 12a through Figure 12c:

V	Peak Rate m^3/d	Breakthrough 20 % wtr. cut yrs. waterflood
0.6	0.87	10.0
0.8	0.65	6.5
0.9	0.40	4.5

The peak rate declines rapidly when V is greater than 0.8. Water breakthrough is greatly accelerated by even moderate layering.

In the last case, with the most severe layering (V=0.9), waterflood performance consists of a reduction of the decline rate, to fairly low levels. Later on, the production resumes decline at about half the initial decline rate at approximately 12%. Note that the GOR in all cases decreases rapidly.

GOR Response

If the layering in the reservoir is severe, the above shows that no increase in oil production may occur. The only concrete indication of waterflood response is a decline in GOR, which the majority of Dodsland projects exhibit. For many waterfloods, in layered reservoirs, this will be the only definitive indicator of response.

Start of Waterflooding

The effects of starting the waterflood later were also investigated. Due to the advanced primary decline, there is a much higher gas saturation in the reservoir. The gas that has come out of solution must be compressed and displaced out of the reservoir, delaying waterflood response. This has a profound effect on waterflood economics, which depend on an increased oil rate to generate an economic rate of return.

Effects of Injecting Over Fracture Pressure

It is not possible to model fracture extension using a reservoir simulator. However, an upper limit can be calculated by doubling the fracture length of the injector and increasing the downhole injection pressure from 1,600 psi to 2,600 psi.

The effect is shown in Figure 13. There is a very short and rapid production increase followed by a production decline similar to primary production's decline.

Model Accuracy

The production prediction at high levels of heterogeneity shows some "wiggles" in the output. This represents numerical errors. Numerical stability is a function of the relative permeability curves. The use of pseudo relative permeability has increased the level of error since the grid refinement discussed earlier. The previous grid refinement indicated an accuracy on waterflooding of 11.5%. The current model would have an accuracy of roughly plus or minus 20%.

Grid sensitivities were not re-run. The model achieved its basic purpose in showing the effects of layering. In reality, the various input data (i.e., relative permeability curves, permeability, porosity, fracture length, etc.) are only approximately known or taken from analogous reservoirs. The accuracy of this data is less than plus or minus 20%.

Limitations

There are some further limitations in the idealized model that has been used and actual in situ conditions. There is probably some vertical (albeit limited) vertical communication.

More importantly, not all of the sand lenses are going to be continuous, as is assumed by the Hearn relative permeability curves. This has two implications:

1. The degree of connection around the well is probably slightly higher than was history matched. For this reason flush production is underestimated. The model was used to estimate infill well performance and initial performance is understated. There is no easy way of addressing this within a single layer model. The flush production is best estimated via analogy, i.e., infill performance from other parts of the field
2. Second, there is undoubtedly some areal heterogeneity that causes water to channel more directly between wells. Such accurate description is difficult, if not impossible, to obtain. Geostatistics has the potential to address this level of detail in reservoir description.

Modelling Summary

1. Grid sensitivities were used to generate a more efficient grid. The approximate accuracy is plus or minus 11.5%.
2. A reasonable model of primary production is obtained.
3. The early wells, on 64 ha (160 acre) spacing, give an optimistic indication of recovery on primary production.
4. Layering sensitivities indicate that at high levels of permeability variation waterflooding will result in only a levelling of production.
5. A decrease in GOR indicates that the reservoir is responding to waterflood, even if there is no increase in production.
6. Delaying waterflooding has a strong effect on how rapidly production response is seen. This is most significant from an economic perspective.
7. The effect of fracture extension will be a short rapid increase in oil production, followed by decline at rates which are similar to those seen on primary production.
8. The use of pseudo relative permeabilities decreases the accuracy of the simulator. However, the loss in accuracy is compensated for by accounting for layering, which is a critical parameter. Adequate accuracy is achieved for an engineering solution.
9. The current technique is not a completely accurate representation of the mechanics in the reservoir. However, it is the best available solution, without resorting to substantially more sophisticated techniques, such as geostatistical modelling.

Conclusions

It is believed that the final piece in the Dodsland waterflood puzzle has been put in place. With the severe layering or heterogeneity that exists, which has been quantified with a Dykstra-Parsons ratio, waterflood response will consist only of a levelling of oil production. The critical factors affecting waterflood response are:

1. The presence of hydraulic fractures, which results in a non-radial flow pattern in the reservoir.
2. The severe layering in the reservoir which diminishes waterflood response.

This study is essentially a post analysis of waterfloods that have been in place for a long time. For the unit studied it was possible to identify that there would not be a future increase in oil production due to waterflooding. With this information, it was possible to shut in a significant number of wells and still maintain the majority of production. This reduced overhead and thus improved the unit's profitability.

The results of this study may be used to more accurately predict the performance of new waterfloods. The key is in the geological analysis. Reservoirs prone to rapid breakthrough can be identified by the following:

1. A layered description—either due to multiple members or due to an interbedded lithology.
2. Extreme variation in core permeability for small changes in core porosity.
3. High slopes on log core permeability vs. log normal probability paper, or high Dykstra-Parsons coefficients.

From a modelling perspective the following is demonstrated:

1. That Hearn type pseudo relative permeability curves can be used to efficiently solve this type of problem.
2. Accounting for layering or heterogeneity is critical to achieve an engineering solution. Some assumptions are made which are not rigorously correct. However, these errors are smaller than the errors caused by not accounting for layering.
3. That Dykstra-Parsons co-efficients can be reasonably used as a tool in simulation.

This simulation technique has also been subsequently applied to other similar reservoirs in Alberta and Saskatchewan, both for resolving existing waterflood performance and predicting future performance.

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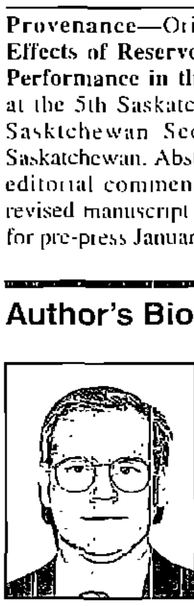
Author's Biography



Mike Carlson is president of Applied Reservoir Engineering & Evaluation Ltd. He was recently technical program chairman for the 1994 ATM and has authored a number of published papers. He has a B.App.Sci. in geological engineering (Toronto, 1979). Previously, Mike worked for Amoco, Home Oil and Scientific Software-Intercomp. His experience covers operations, completions, reservoir engineering, corporate reserves, log analysis and simulation. He has appeared as an expert witness in Alberta court and is a member of The Petroleum Society, APEGGA, CWLS, PJVA and SPE.