A DODSLAND - HOOSIER VIKING WATERFLOOD PREDICTION

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A Dodsland-Hoosier Viking waterflood prediction

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ABSTRACT

A waterflood prediction study has been developed for the Dodsland Viking field in Saskatchewan. This study demonstrates the importance of the geological description used to account for fieldwide variations in PVT properties. The methodology identifies the significance of local wellbore effects (hydraulic fracture stimulations). The use of a modern simulator, which is fully implicit and uses improved Orthomin-type matrix solvers, enables modelling of this problem where older technology fails. Finally, the results are compared against actual offset production performance and models which do not account for local wellbore effects.

Introduction

The Dodsland-Hoosier Viking field was discovered in 1953. Its location in southwestern Saskatchewan is shown in Figure 1. The field consists of a complex series of oil and gas pools, as depicted in Figure 2. Development occurred rapidly during the late 1950s, followed by unitization and subsequent waterfloods. A resurgence of development occurred during the early 1980s in response to government incentives.

The Kiyiu Lake Voluntary Unit No. 1 was developed in 1983 and 1984. A waterflood was planned and government approval obtained during 1985. However, the dramatic dip in oil prices in early 1986 delayed implementation of the project. A detailed re-evaluation was commissioned by J.C. International Petroleum Ltd. to more closely evaluate waterflood economics under the more severe economic conditions of 1988.

Geology

The geology of the field was comprehensively documented in a paper by W.E. Evans[1]. Two main factors control the occurrence of oil and gas: (1) the separate linear sandstone bodies, which overlap; and, (2) the structure, which is controlled by underlying solution collapse and post depositional compaction.

Figure 3 shows the axes of the overlapping members and Figure 4 displays the stratigraphic relationship of the sandstone bodies. Cross sections through the centre of the members (Fig. 5) demonstrate how both of the above factors resulted in a system of oil and gas accumulations shown earlier in Figure 2.

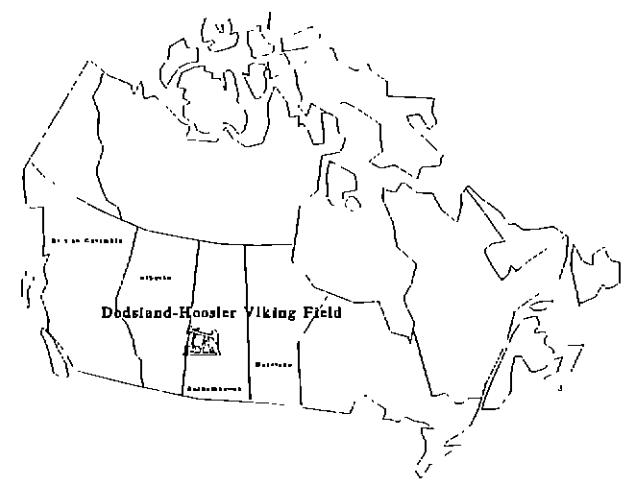

FIGURE 1. Map of Canada showing location of the Dodsland-Hoosier Field.

The lithology of the field has been studied in detail by Tooth *et al.*[2]. The vast majority of the reservoir rock consists of finely interlaminated sands, siltstone, and shales. These laminations are typically 13 mm (0.5 in.) thick. Core analysis, from wells near the study area, had porosities ranging from 16% to 24% and permeabilities ranging from 0.1 mD to 40.0 mD. The average porosity and permeability was 20.7% and 6.3 mD, respectively. A basal chert conglomerate is also found in some members, but is not thought to be present in significant amounts within the study area. Overall, the Viking formation in this field is of poor quality.

Production Characteristics

Production from such a low permeability reservoir required hydraulic fracture stimulation. These treatments, coupled with the low permeability of the reservoir, results in a characteristic production profile. Economic evaluations have been conducted for a number of

Keywords: Simulation, Waterflood, Dodsland, Viking, Hydraulic fractures.

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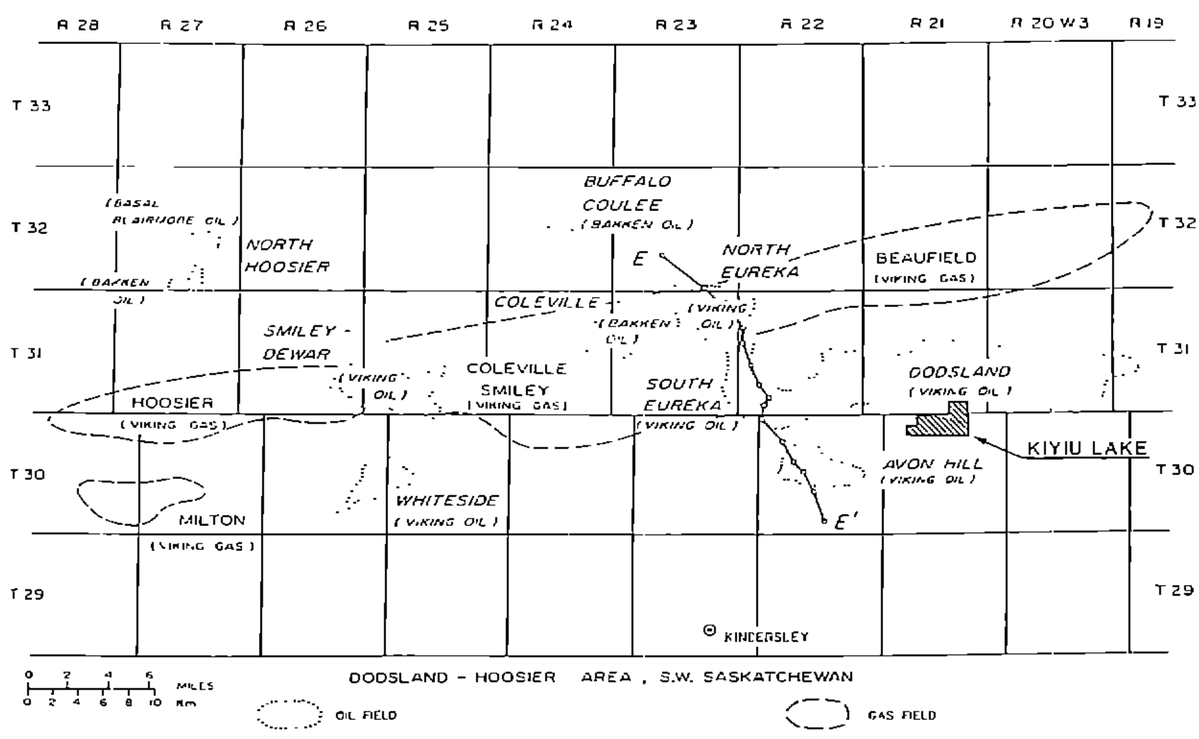


FIGURE 2. Map of oil and gap pools in the Dodsland-Hoosier Field W.E. Evans, 1970, reprinted by permission of AAPG.

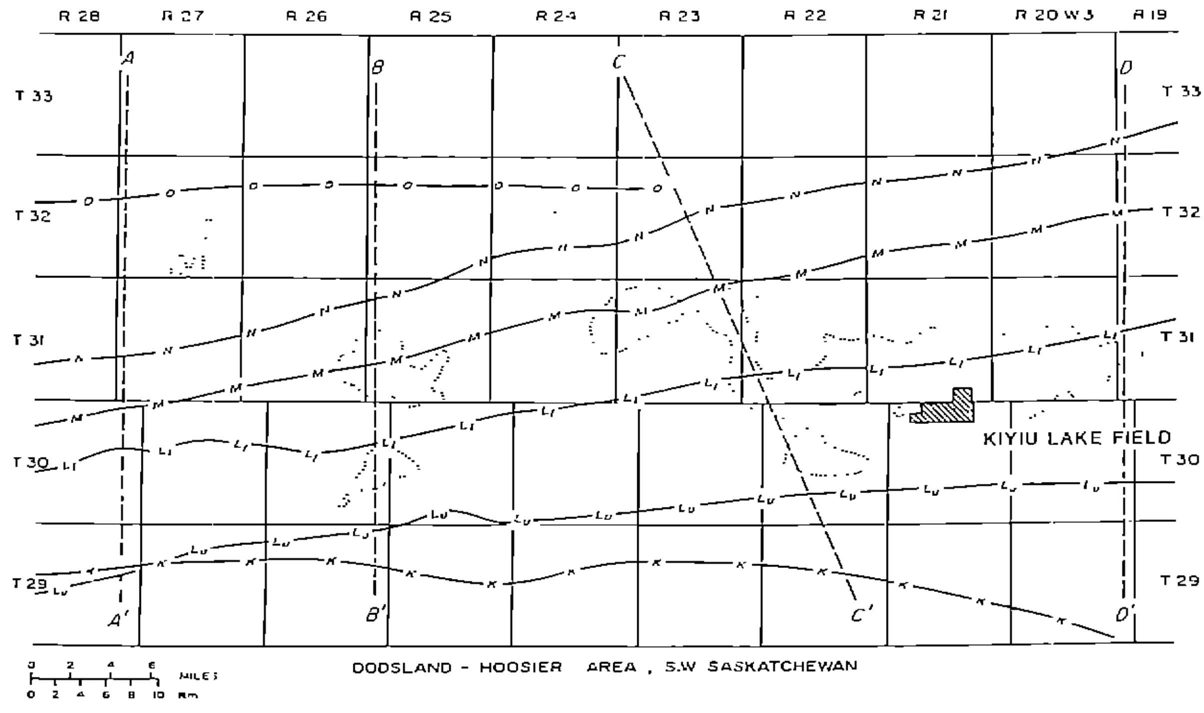


FIGURE 3. Map showing the location of the axes of imbricate sand bodies W.E. Evans, 1970, reprinted by permission of AAPG.

companies with substantial production from this field. Reserves are determined using type curves, an example of which is shown in Figure 6. A production forecast for an individual well is determined by multiplying the initial production rate by the normalized rates. After two years an exponential decline is used.

New Data

On the basis of limited primary production data and no waterflood history, a portion of the Unit shown cross-hatched in Figure 7 was simulated in 1985[3]. Subsequently more data was acquired:

(a) Production data indicated effects from an offsetting waterflood. The previous study area, which assumed no flow boundaries, would have to be altered substantially.

(b) Pressure information was now available. These measurements supported interference along the northern edge of the Unit, but were in general, substantially lower than anticipated.

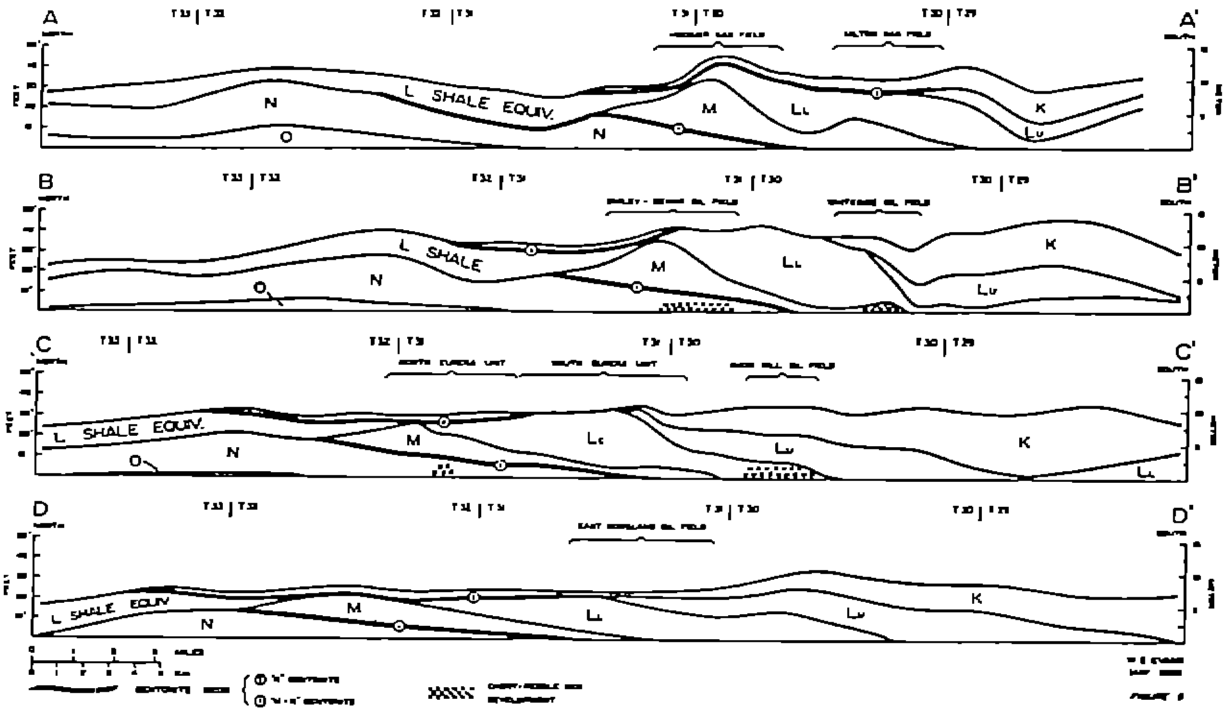


FIGURE 4. Cross sections (Fig. 3) across Dodsland-Hoosier Field showing imbricate relationship of members W.E. Evans, 1970, reprinted by permission of AAPG.

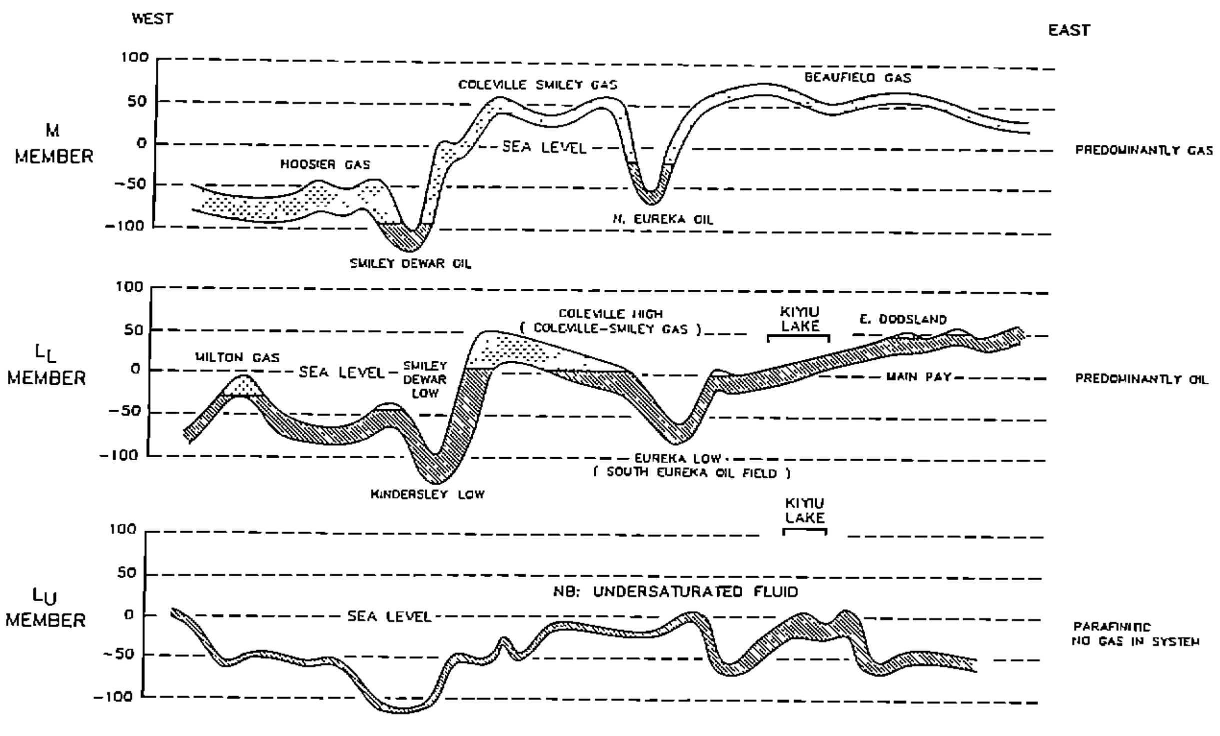


FIGURE 5. Cross sections through axes (Fig. 3) of imbricate sandstone bodies showing structural relationship of oil and gas accumulations.

(c) Recent gas oil ratio (GOR) measurements were substantially below the level recorded during the early production history. Measurement problems had been identified and corrected. The new GORs were also supported by data from direct offsets. These GORs were lower than the solution gas GOR accepted for the area.

A serious change in approach was required. A new study area should be chosen to eliminate boundary effects. It was necessary to determine why the pressures and GORs were lower than predicted. The producing GORs and PVT properties were examined first.

PVT Properties

Discussions with the operator and personnel with extensive experience in the area[4], resulted in the areal map of GORs shown in Figure 8. The producing GOR changes considerably. This gave

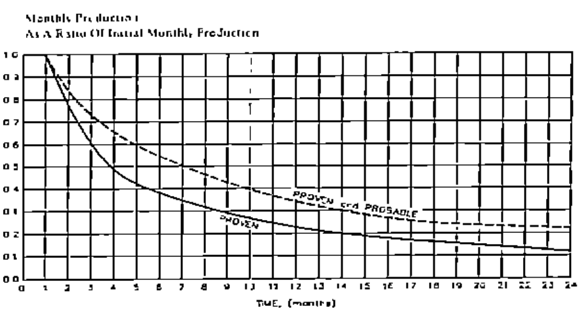


FIGURE 6. Evaluation type curves used for estimating reserves in the Dodsland-Hoosier Viking Field.

confidence that the available PVT data was not representative of the oil being produced from the subject Unit. The producing GORs could only be obtained from an undersaturated oil. This result was somewhat surprising because the field apparently consisted of a series of oil and gas pools in communication.

The use of an undersaturated fluid results in a rapid initial pressure drop during primary depletion. This offered hope in explaining the lower than anticipated reservoir pressures and the rapid initial production declines observed.

Geological Correlation

Analysis of the cross section developed from Evans' paper for the entire field showed that the "Lu" member, which corresponds to the imbricate sandstone body from which Unit production was obtained, did not have any gas pools. Further to this, the member thickens from west to east, which was opposite to the trend seen in other members. These factors suggested that the "Lu" member had a different geological source. The southeastern part of the field was also prone to paraffin problems, which correlated to the general position of the "Lu" member. With these geological differences, a different fluid and PVT data for the Unit seemed plausible.

Operations

The early production performance from the Unit was highly erratic. The wells were directionally drilled from pads since the surface leases were located in an intermittent lake. Initially, hydraulic pumps had been used for production. These pumps proved to be unreliable and most were subsequently replaced. From a modelling perspective erratic data is more difficult to use in history matching.

Average Well Results

Due to the erratic production, it was decided to model an "average well". PVT properties were adjusted using Standing's correlations, to be representative of the Unit area. The previous areal model was used since a representative range of wells were covered. Production was modelled using a bottomhole pressure control. Output production was averaged for the seven wells to produce an "average well" production curve.

The results are shown in Figure 9. The calculated oil rates are similar to the actual rate and declines observed. The predicted reservoir pressure, however, did not decline to the levels determined from the recent pressure surveys. The modelled GORs increased rapidly once the bubble point pressure had been reached and were substantially higher than the current (accurate) GOR measurements.

This mismatch could not be easily resolved. A systematic review of all data indicated that the effect of hydraulic fractures, which had not been included in the model, was potentially significant.

Hydraulic Fractures

Hydraulic fracture design was studied in the Dodsland-Hoosier Viking field, using a 3-D hydraulic fracture treatment simulator[5]. A typical treatment in the Dodsland area results in a fracture length

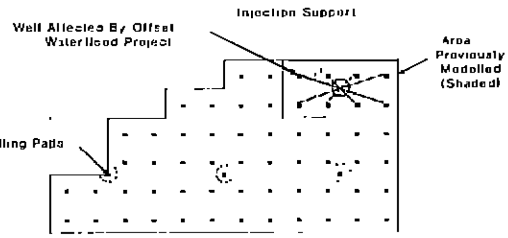


FIGURE 7. Detail map of the Kiyiu Lake voluntary Unit No. 1.

from well to wingtip of 95 m (250 ft to 300 ft). This represents nearly one third of the 16 ha (40 acre) production spacing unit (PSU). There could be a substantial deviation from a radial flow pattern.

The complexity of including hydraulic fractures in a simulation strongly suggested the use of a type model, utilizing an element of symmetry. Because a single well would be modelled, the use of the evaluation type curves seemed a logical basis for history matching.

Modelling Hydraulically Fractured Wells

Direct modelling of hydraulic fractures, with a conventional reservoir simulator, is a difficult problem. The scope of this paper is not sufficient to comprehensively cover this subject. This was a consulting project — where the most direct line of solution is used. Nevertheless a difficult problem was solved which had not been covered in the literature. Some general comments on the problem, the types of models and techniques which can be used are therefore in order.

Settari[6] indicates modelling of a hydraulic fracture for multiphase flow, with a reservoir simulator requires:

(a) A highly stable, implicit type model; and

(b) that the open fracture be approximated by an arbitrarily small thickness, and a sufficiently high transmissibility. Stability problems can be encountered if too high a transmissibility is used.

Examples of successful modelling are reported in References 7 through 9, and cover compressible (i.e. gaseous) systems.

Older Technology

Experimental runs were made with an older model, which had been used for the previous areal study. This simulator had been a successful "workhorse" for many years. Typical of some older black oil models, two methods of solution were available: (1) IMPES (Implicit Pressure Explicit Saturations), and (2) S.S. (Sequential Solve) Method.

The IMPES formulation is limited in that it will become unstable for practical timesteps when rapid changes in pressures and saturations occur. The sequential solve method solves for pressures and gas saturations simultaneously and then solves for water saturations, either implicitly or explicitly. Although more stable than an IMPES formulation, the S.S. method does not conserve mass in all phases, which can lead to material balance errors[10].

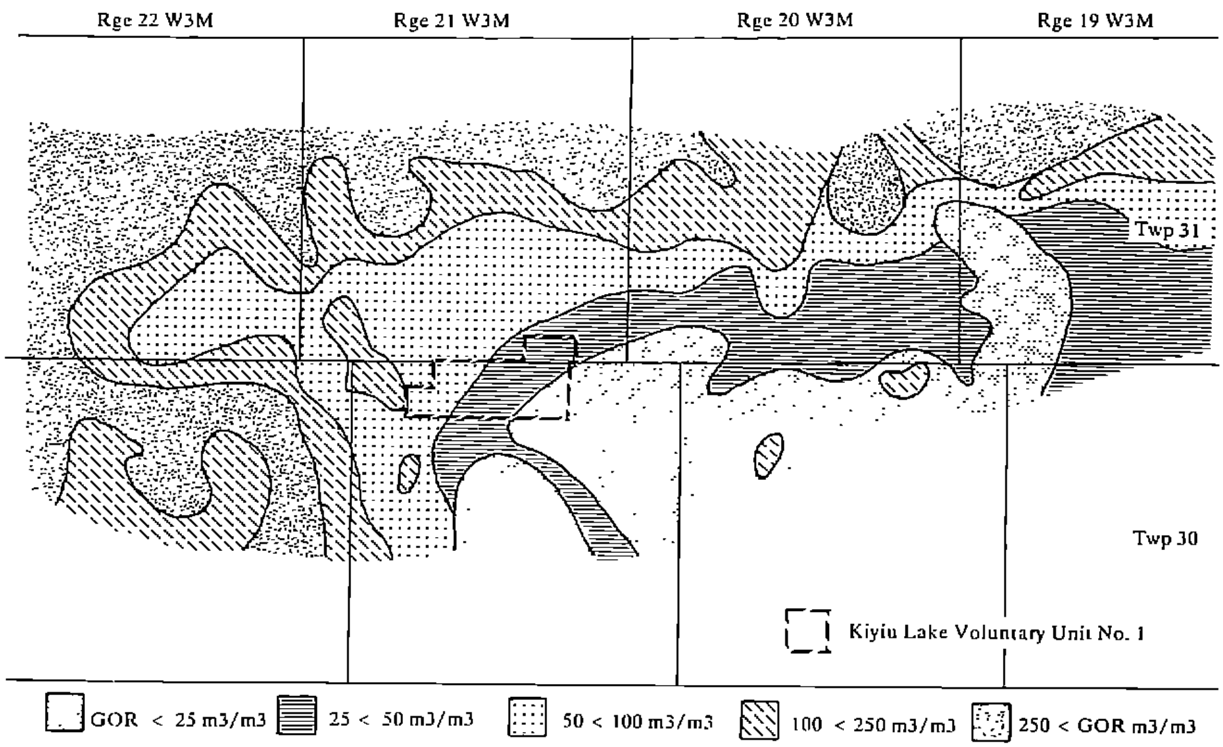
A number of runs quickly confirmed that the convergent flow and transmissibility contrasts in this study could not be simulated with the older model.

Alternatives

Specialty fracture simulators, which usually include treatment design, were available. However, the simulator available in-house had not been extended to model three-phase multiwell patterns. This capability would be necessary for waterflood predictions.

Another alternative was to represent fractures by a series of sources (injection well) and sinks (producing well). Experiments were made in studies relating to other parts of the field, although no conclusive results were obtained[11]. This method assumes that the storage and pressure drop in the fracture is negligible.

It was decided to attempt direct modelling of a hydraulic fracture using one of the newer fully implicit simulators.



FIUGRE 8. Map showing areal GOR variation in the Dodsland-Hoosier Viking Field.

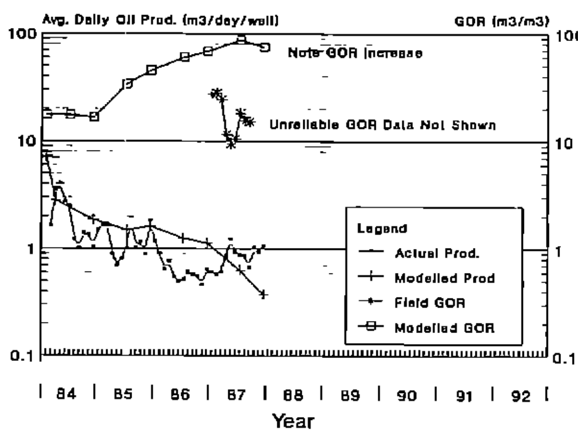


FIGURE 9. History match plot for "average well".

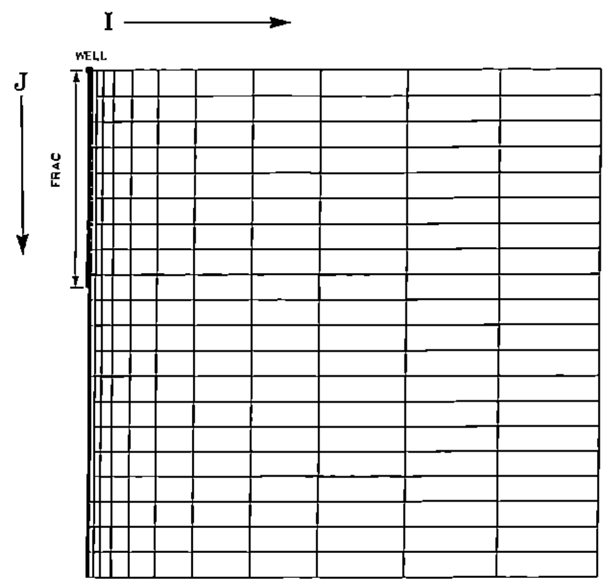


FIGURE 10. Grid utilized for type well, primary production and pressure build-up.

Representation of the Hydraulic Fracture

The fracture was initially modelled with a thickness of 3.05 cm (0.1 ft) and a length of 85 m (278.8 ft). Fracture properties were input based on a previous study, and hydraulic fracturing expertise[12] as: (1) a fracture permeability of 50 000 mD to 70 000 mD. This includes some damage to the fracture sand. This was determined by history matching post treatment production. Possible sources of damage were migrated fines and paraffin deposition (2) an approximate width ranging from 0.75 cm (0.3 in.) to 1.26 cm (0.5 in.) at the wellbore. The grid utilized is shown in Figure 10.

Orthomin Solver

Detailed discussions of matrix solvers is also beyond the scope of this paper. However, this problem is sufficiently difficult that the matrix solver has an important impact on the performance of a reservoir simulator. A few points are highlighted regarding the use of Orthomin type solvers:

(a) although this problem is not so large as to require this type of solver (a direct Gaussian type solve can be used), it serves to show that difficult problems can be solved; and,

(b) more generally, the power of the new solvers has permitted the development of large-scale fully implicit reservoir simulators.

Considerable literature exists on the mathematical formulation of Orthomin and Conjugate Gradient techniques. A selection of papers is outlined in References 13 to 21. The method is iterative and involves two main steps (after Thurnau[22]):

Preconditioning: An approximation of the solution matrix is made which is easily solved. A rigorous residual shift vector is then calculated.

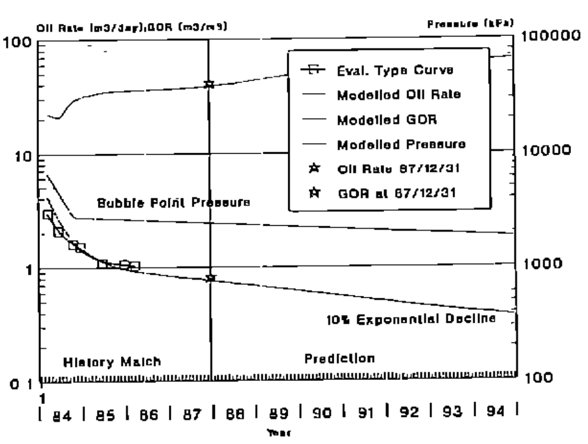


FIGURE 11. History match plot — type well model.

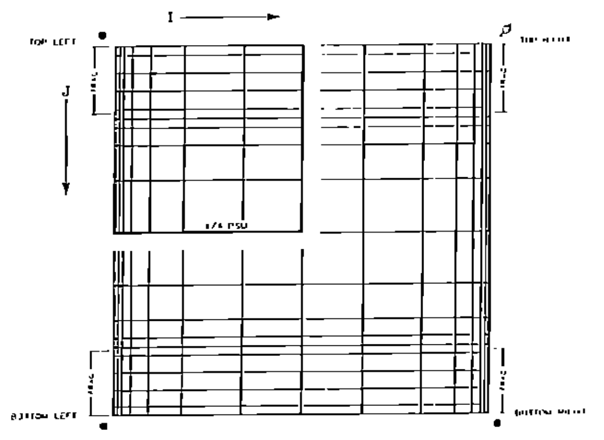


FIGURE 13. Grid utilized for waterflood predictions.

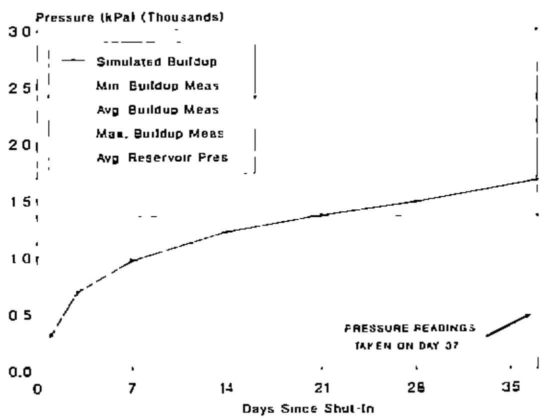


FIGURE 12. History match of pressure build-up for type well.

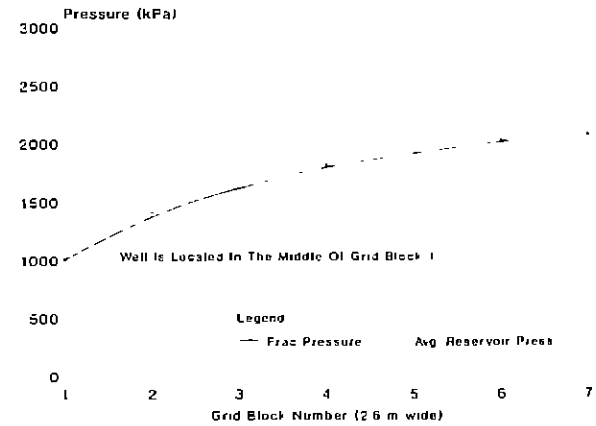


FIGURE 14. Graph showing pressure profile in hydraulic fracture time = 1733 days.

Orthogonalize: Successive iterations are corrected by using a least squares norm of previous solution vectors.

The second step is a powerful method, however, dramatic improvements are obtained by using the "right" preconditioner.

A number of different preconditioners are contained in the newer simulators. In some models, such as the one used in this study, the preconditioner may be specified using the "level of difficulty". In many cases the program will be hard wired or may choose a preconditioner for the problem automatically.

Default settings were used in this study. Subsequent work, utilizing other models, has shown that adjustments to make input solution tolerances tighter may be necessary for this type of problem. This study was completed utilizing a single layer. Multiple layer problems are more difficult.

Type Well Results

The results of the type well model are shown in Figure 11. Key points are:

(a) The predicted production profile is close to the evaluation type curves.

(b) The GOR response rises rapidly initially and then flattens out near the measured levels.

(c) The pressure drops rapidly to the bubble point, and then declines slowly. Pressures are close to the measured levels.

History match changes required to achieve this were: a slight reduction in porosity to 19%, a net pay of 1.22 m (4 ft) and a permeability of 8.5 mD. The parameters were judged to be well within acceptable limits.

Over-all, the results gained by including the fracture in the simulator were highly encouraging. Although the pressures were closer than predicted for the "average well", the degree to which the wells had built up was not fully accounted for.

Pressure Build-up

Adequate pressure build-ups are difficult to obtain in this field. All of the wells are on pump and build-ups are very slow due to the low permeability. The low production rates yield a low economic margin, which further discourages extended shut-ins. Analyzing pressure transients utilizing conventional methods has not proven practical.

The operator had, for the purposes of modelling, gone to extensive efforts to establish the reservoir pressure. The wells were shut-in, the pump and rods were pulled and the pressure monitored using surface gauges and sonologs. When the pressures appeared to have stabilized, a static gradient was run.

In order to check these pressures, the shut-ins were also simulated. Production was set to zero at the time of the build-up and the well-bore pressure plotted. These results are shown in Figure 12. The modelling suggests that a complete build-up had not yet occurred (after 35 days). The pressure predicted was close to the measured values.

Grid Refinement

The majority of the field was developed on an inverted nine-spot waterflood pattern. The existing grid was therefore expanded by four times to model a quarter of this pattern. Initial runs with this model were quite slow and a grid refinement was conducted. The resultant grid is shown in Figure 13. The numberof grid blocks for

TABLE 1. History match for type well (section 34)

Criteria	Units	Actual	Model	Variation
Initial rate	m³/day	3.13	3.48	11.2%
Rate at 4.75 years	m³/day	0.81	0.76	(5.9)%
Cum. Prod. @ 4.75 years	m³	1439.3	1589.9	10.5%
Decline rate	per cent p.a.	8.1	10.0	11.8%
Expected reserve	m³	3871.7	3666.9	(5.3)%
Stabilized GOR	m³/m³	40.7	34.7	(8.6)%
Well pressure, 37 days B.U.	kPa	1696	1482	(12.6)%

TABLE 2. Waterflood prediction compared to offset performance

Characteristic	Units	Expected	Model
Primary reserve	m³/ha	175-500	172
Waterflood reserve	m³/ha	340-740	310
Waterflood reserve/ primary reserve	ratio	2.0	1.8
Waterflood decline	per cent p.a.	11.2	12.5
Water injection rate	m³/day	9.1	7.6

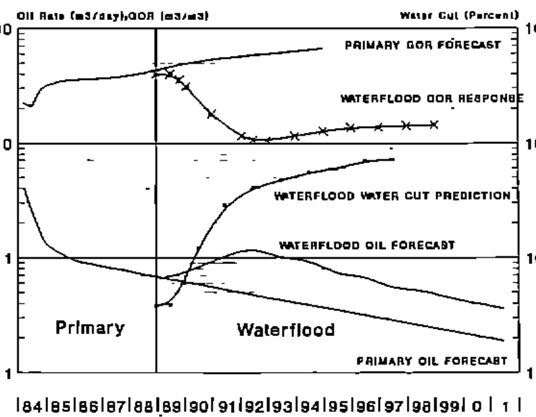


FIGURE 15. Prediction results for inverted nine-spot producer (note — three producers in Fig. 13 averaged).

the quarter PSU was reduced from 18*20 to 11*9. This resulted in only a 2% difference in pressures predicted and roughly a quarter of the run time previously required.

The increased grid block dimensions of the frac in the new grid demonstrates that storage volume in the fracture is not significant. The pressure profile in the fracture at time = 1733 days, on primary production, is shown in Figure 12. As one would expect, there is a pressure drop in the frac. Returning to the alternative techniques discussed earlier; it would be difficult to have used the sources/sinks method, since a pressure profile would have to be assumed *a priori*.

Waterflood Prediction

Water was injected in the "top right" well shown in Figure 13. A maximum bottomhole pressure of 12 500 kPa (1815 psi) was used based on injection pressure limitations set by the government. The prediction is shown in Figure 15. Note that production from all three producers was averaged and is displayed on a per well basis. The response to waterflood in this pool is characterized by:

(a) a peak oil rate that occurs after five years of injection;

(b) initial water breakthrough in two years where a watercut of 20% is attained;

(c) a slow decrease in GORs which returns to initial levels after 3 years of injection;

(d) an exponential decline, after the oil production peak of 12.5% per annum; and,

(e) an ultimate recovery of 32.8% of OOIP for waterflood. The primary recovery modelled was 18.2%.

Stability

The limits of stability were tested in this problem. Difficulties were experienced with water injection, and pressures around the bubble point. On the type well evaluation, which predicted primary production and pressure build-ups, the material balance deteriorated for short periods to 1.0134 and 0.9995 for oil and water, respectively.

The waterflood predictions proved to be the most difficult. On the initial runs, at the start of injection, material balances were 1.0117, 0.9658, and 1.5434 for oil, gas, and water, respectively. To improve this a number of steps were taken: a short shut-in time was implemented for injector conversion, injection rates were increased gradually over 15 days, and a fixed timestep length of 10 days was specified when water breakthrough was occurring in the producing wells. The material balance improved, at the worst timestep during water breakthrough at the producers, to 1.0294, 0.9992 and 1.0000 for oil, gas and water, respectively. Curiously, the results of the two runs described were virtually identical for history match purposes (less than 5% difference).

It should be pointed out that for a stable formulation, the errors introduced in previous timesteps must decrease with time. Also, after disturbances such as passing through the bubble point and the start of injection, the material balances consistently improved. The production curves show no sign of oscillation. (Note that there is some stair stepping apparent on the graphs at low production rates — this is due to output rounding). The material balance error is also dependent on the method of calculation. A highly sensitive indicator was used.

Rigorous investigation of stability would require a major time investment. The approach utilized was pragmatic: how close was the history match and were the predictions consistent with engineering judgment.

Prediction Checks

Considerable offsetting performance existed for comparison. Offsetting waterfloods had been installed in the 1960s. Unfortunately, multiple episodes of infill drilling had masked any examples of performance which would allow direct comparison. The input data was checked extensively against observed data and government reserves statistics[23]. Table 1 summarizes this review. Table 2 compares the performances expected from a review of offsetting units, taking into account reservoir quality variation, and the results from the model. The area review is shown in Table 3. Based on the above, it was felt that a match on all parameters had been obtained to within ±15%.

Radial Flow Models

Waterflood predictions from radial/areal models resulted in substantially more optimistic predictions. This is based on previous studies in this and other units, as well as from offset operators (government applications). The peak rate is higher, occurs more rapidly, and results in substantially higher recoveries. Typically, recovery estimated based on radial flow is 50% higher than that obtained with the model described in this paper.

Conclusions

1. The geological description of the reservoir was critical in rationalizing fluid property variations in the field.

2. Near wellbore effects, i.e. hydraulic fractures, must be included to simulate wells in the Dodsland Hoosier Viking Field.

3. The latest simulators have substantially more capability and were required to model this problem.

4. This study demonstrates the application of simulation techniques such as: grid refinement, use of elements of symmetry, data screening, and simulation for use in build-up analysis.

5. A wide range of input was required for this study. The following areas of expertise were utilized: geological, production engineering, completions — hydraulic fracturing, and evaluations.

TABLE 3. Performance summary of offsetting units

Unit	SEM OOIP E3M3	Primary Rf E3M3 %	W.F. Rf E3M3 %	Well Spacing Ha. Primary W.F.	Areal Recovery m³/ha Primary W.F.	Waterflood Rf Primary Rf ratio	W.F. Decline per cent p.a.	Wtr. Inj. Rates m³/da7 per well	Comments
Eagle Lake	12,725	1,985 9.8%	3,000 23.6%	32/16	526/795	2 4	15	13.0	Best part of field
Gleneath	9,546	1,279 12.6%	2,073 30.1%	32/16	425/688	2.3	12	9.7	Best part of field
Gleneath South	397	62 15.6%	91 22.9%	16/16	481/729	2.0	—	3.5	Spacing consistent
Eureka South	6,811	650 9.5%	1,600 23.5%	32/16	427/1050	2.6	9.8	25.0	Eureka struct. low
Eureka North	6,709	440 6.6%	1,280 19.1%	32/16	261/—	2.9	—	—	Gassy in North
	6,709	660 9.8%	1,280 19.1	16/16	392/682	1.9	8.0	—	Eureka struct. low
East Dodsland	24,431	1,200 4.9%	— —	16/16	176/—	—	—	9.6	Early to determine WF response
North Dodsland	7,253	334 4.5%	650 9.0%	16/16	175/340	2.0	—	8 7	No GOR response
Whiteside	2,668	267	580	16/16	220/478	2.0	—	14.5	No GOR response
		100%	21.7%						

Acknowledgments

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