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Why is it so difficult to predict the performance of non-conventional wells?

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Abstract

Non-conventional wells that include, horizontal, highly deviated and multilateral wells – often called designer wells – are becoming more and more common. Both analytical and numerical tools have been developed and continue to be developed for predicting their performance. Unfortunately, predictions made using these tools rarely match actual performance, except in cases where sufficient production data are available for history matching and the model used for making predictions is selected carefully. Even then the predictions are generally good only for a limited time. In this paper we explore reasons for our inability to make accurate predictions. We consider a case where a vertical well has been drilled and cored. Then, we generate twenty consistent geostatistical descriptions of permeability and porosity that are all constrained to the hard data obtained from the vertical well. Simulations with these realizations show large differences in production rate, WOR and GOR predictions as a result of variations in reservoir properties. It is also shown that the effect of well index (WI) on simulation results is large. Furthermore, for the example considered, analytical models for critical rate and productivity calculations were found to be of limited practical use.

Introduction

In a recent talk at Stanford University Edward Teller was asked what had changed in science over the past 60 years or so since he immigrated to the U.S. He responded by saying that "then we believed that everything could be predicted, now we know that future can only be predicted in a probabilistic sense." While Teller was talking about physics, his remarks are equally valid for other areas of science and engineering.

In most cases the prediction of the aggregate effect of random events is sufficient for engineering purposes. For example pressure drop caused by the flow of gas in a pipeline is a consequence of the motion of individual molecules. While we cannot – nor do we want to – predict the behavior of individual molecules, we can predict everything of practical significance: pressure and temperature distribution, average velocity at every location, etc. In order to make such predictions we have to be able to describe our system, and its initial and boundary conditions. In the case of steady-state flow in a pipeline we must specify:

- pipe diameter, length, profile and roughness;
- initial state of fluid in the pipe; and
- interaction with the boundaries.

Even for this simple problem there are uncertainties. Heat transfer from the pipe to the surroundings will depend on the material in which the pipe is buried and the ambient conditions, which are never known precisely.

Wells drilled in petroleum reservoirs interact in a complex way with the reservoir. In order to predict their behavior we must be able to model multiphase flow in the well and the reservoir. In this problem there are many sources of uncertainties, some of these are explored in this paper. The most serious of these is the limited data about the reservoir itself.

As with everything else in nature, in the end the best we can hope to do is to predict the performance of horizontal wells only in a probabilistic sense and reduce the uncertainty to a manageable level. In a fascinating paper Beliveau (1995)[1] has analyzed the performance of 1,306 horizontal wells from 230 fields around the world. He shows that the productivity improvement factors (PIF) – defined as the initial stable oil or gas production rate of a horizontal well divided by the current production of an offsetting vertical well – have an approximately log-normal distribution because "most reservoir parameters are log-normally distributed about their mean." He shows that horizontal wells in conventional reservoirs have a mode (most likely) PIF of 2, a median of (50/50) 3 and an average (or mean) of 4. In heavy oil reservoirs the mode was about 5 and in fractured reservoir about 6. Beliveau also compared forecasts of well performance with actual results. Here he found that in a 13-well program in a North Sea field actual results were 14% higher than initial forecasts; however, the average of the absolute individual well errors was much higher at 43%. Only 8 of the 13 producers had actual results within ±50% of the forecasts. Furthermore the predicted ranking of wells was not preserved during their production phase. Beliveau[1] also summarizes Shell Canada's experience with 75 horizontal wells in several fields: Actual average results exceeded forecasts by about 20%; while the average absolute error (error bar) was almost 60%. Fewer than half the wells performed within ±50% of their forecasts. While Beliveau makes repeated reference to the importance of geological heterogeneity, he does not quantitatively investigate its effect on well performance.

In another study by Mullane et al. (1996)[2] performance of 29 horizontal wells was compared with predictions. While in this case the estimated oil rate was hit exactly, the average absolute error was 47%. Predictions of only about half the wells were within ±50% of actual performance. They used a "calibrated" version of Joshi's deliverability equation (Joshi, 1986)[3] to predict oil rate.

In published field scale evaluations, oil rate at a given drawdown appears to be the most common predicted quantity that is compared with field performance. In this paper we will show how more detailed well performance predictions differ with different geological descriptions constrained to the same data, different grid block sizes, and different methods of upscaling absolute permeability. Here we will consider time for which plateau production can be sustained, WOR and GOR. These factors are much more difficult to predict than fluid rate. In addition we will show the effect of techniques used for modeling wells in simulators. In particular we see the effect of the well index and the pressure drop in the well. Finally we will compare analytical and numerical results for water cresting into a horizontal well and well productivity.

What is Needed for Predicting Performance

Predicting the performance of non-conventional (including horizontal wells) or conventional wells requires that we be able to model transient multiphase flows in systems consisting of one or more connected petroleum reservoirs and several wells, that are produced under specified constraints on pressures or rates imposed on individual wells or groups of wells. In order to predict the performance of a well in such complex systems we must be able to

- describe each reservoir (geometry, permeability and porosity distribution);
- describe each well (profile, completion details and the internal condition of the well ;
- model the artificial lift system used in the field;
- model multiphase, multicomponent flows in heterogeneous porous rocks;
- adequately characterize reservoir fluids, and mixtures of reservoir fluids and any fluids that are injected into the reservoir;
- model changes in fluid properties with changes in pressure and temperature (PVT models);
- model the influx of fluids into wells as result of drawdown along wells;
- model multiphase, multicomponent flow in wells; and
- specify the initial state (saturations and pressures) and the boundary conditions (water influx from aquifers) of each reservoir.

None of the above requirements is ever fully met and yet we must make predictions. Furthermore, three-phase, multicomponent flow modeling requires many of assumptions and simplifications that may not be always justified. The job of the engineer is to understand the sources of uncertainty and make the best possible predictions to provide guidance to management in making decisions to meet overall corporate objectives. Assessment of uncertainty associated with predictions can be used to associate risk with each option.

Models of various degrees of sophistication may be available or possible. But the level of sophistication must be balanced with (Aziz 1989, 1995)[4,5]:

- available resources,
- available information, and
- the objective of the predictions.

It would be ridiculous to try to model the whole reservoir by modeling the flow in individual pores of a network that represents the reservoir. Yet a pore network model of a small portion of the reservoir may provide very useful information about the average behavior of a network of pores, that is represented in reservoir engineering through absolute and relative permeabilities and porosities. This is why our interest spans models of various kinds and complexity – from models for flow in a single pore to full-field models.

In the remainder of this paper we will show how performance predictions are affected by major sources of uncertainty. We will restrict our discussion to predicting the performance of a single horizontal well. First we will discuss the effect on well performance predictions of reservoir description and how it is used in simulators. Next we will show the effect of uncertainty associated with some of the assumptions made in models used for predicting horizontal well performance.

Reservoir Description and Simulation Grid

It is generally acknowledged that lack of knowledge about reservoir heterogeneity is a major cause of the "error bars" associated with performance predictions. Here we will consider a hypothetical example of a horizontal well that is based on data from a real reservoir. The drainage volume associated with the well is 10,000×5,000×100 ft.

We will assume that a single vertical well has been drilled.

With information from this well and other sources a stochastic model is constructed to produce multiple permeability and porosity images of the drainage volume.

The synthetic reservoir data was fashioned after a fluvial sandstone reservoir with a 70% net-to-gross ratio. Sequential indicator simulation was used to construct a sandstone/shale lithofacies model. An indicator variogram with a vertical range of 10 ft. and an isotropic horizontal range of 100 ft. was considered. This resulted in shales that generally extend over less than 100×100×10 ft. Porosity and permeability in the shales was set to 0.1 and 1.0 mD. The sandstone porosity model was created by sequential Gaussian simulation with a normal scores variogram with a vertical range of 10 ft. and an isotropic horizontal range of 2,500 ft. Sequential Gaussian simulation with the collocated cokriging option in GSLIB (Deutsch and Journel, 1992)[6] was used for the permeability model. The normal scores of porosity were correlated with permeability with a correlation of 0.7. The normal scores variogram of permeability had a vertical range of 3.33 ft. and an isotropic horizontal range of 1,500 ft. The data representing a vertical well that goes through the heel of the horizontal well was extracted from an initial unconditional geostatistical realization. The lithofacies, porosity and permeability data from this vertical well were honored in all twenty geostatistical models. The geostatistical parameters for all realizations are identical and the images appear to be similar. For the medium grid the mean shale fraction is 0.311 (std. dev. of 0.007), mean porosity 0.261 (std. dev. of 0.003), and mean horizontal permeability 430.04 (std. dev. 5.71). The horizontal well is aligned along the X-axis and placed in the middle of the drainage volume.

All stochastic images were constrained to the same permeability and porosity at the location of the vertical well and are created on a 100×50×30 grid (150,000 uniform grid blocks, each block is 100×100×3.33 ft) which is considered to be the *fine* grid in this study. For the purposes of simulation we have created two sets of upscaled images of the fine grid: a 20×10×10 *medium* grid (500×500×10 ft blocks), and a 10×5×5 *coarse* grid (1,000×1000×20 ft blocks).

The grid is nearly uniform in all cases. The upscaling from the *fine* grid to the other two grids was done using two commonly used methods:

- numerical single phase flow matching in each of the three directions for each upscaled block and the *fine* grid blocks contained in that block (referred to as *medium-f* and *coarse-f*), and
- power law averaging (referred to as *medium-p* and *coarse-p*).

Histograms of horizontal and vertical permeability for all three scales are shown in Figure 1. The first of the flow based upscaled realizations was used to estimate the power law averaging exponent for the horizontal and vertical directions. Exponents of 0.71 and 0.02 were obtained for the horizontal and vertical directions for the *medium* grid, and 0.73 and -0.18 for the *coarse* grid. This gives a total of 100 images to process (20 *fine* grid, 40 *medium* grid and 40 *coarse* grid).

Figures 2 through 5 show XZ (vertical permeability) and XY (horizontal permeability) slices going through the horizontal well for four selected realizations. These figures compare fine grid descriptions with corresponding upscaled images for the flow based (*medium-f* and *coarse-f*) and power averaging (*medium-p*) methods. These images were selected because they showed extreme behavior during performance predictions.

In addition to the grid blocks generated by this process, a layer of homogeneous grid blocks with huge pore voltumes (25 x 10^{12} cubic feet) were added to the top and bottom of the reservoir to simulate a large gas cap and a large aquifer. All other data (also extracted from a real field study) are shown in Table 1.

The single 2,000 ft horizontal well nearly located in the middle of the drainage volume is produced at a rate of 5,000 barrels per day with a minimum bottom-hole pressure of 1,500 psia. The results for oil production rate, GOR and WOR for the *medium-f* grid are shown in Figures 6 to 8. Based on these and other results, a single realization (identified on figures showing results) was selected as the base case. Figure 9 compares production rates predicted for this base cases by*fine*, *medium-f*, *medium-p*, *coarse-f* and *coarse-p* grids. Figures 10 and 11 provide corresponding results for GOR and WOR. Because of the large computational time required, it was not possible to process all of the fine grid images. Results of all of the simulations are summarized in Table 2. Here values of maximum, minimum, mean, and spread (maximum-minimum) are presented for:

1. Cumulative oil production during the plateau period (when the oil rate is constant at 5,000 barrels per day),
2. Time for the oil rate to drop to 3,000 barrels per day (40% of the specified rate),
3. GOR at 6,000 days,
4. WOR at 6,000 days. and
5. Bottomhole pressure at 2,000 days.

We have also performed simulations for the base case at the *medium* grid by using the upscaled geological description from the corresponding *coarse* grid. This was done to see the effect of grid block size (discretization errors). The results for this case are referred to as *medium-f-c* and they are compared with other cases on Figures 9 to 11.

These results show that the oil rate is more sensitive to upscaling than to gridblock size. However, GOR and WOR are highly sensitive to both the block size and upscaling. This is confirmed by other work (not reported here) where we have found that cresting calculations require very fine grids. It is also clear that the geological description has a huge influence on results. In particular, we see that the spread in results decreases as reservoir parameters are upscaled to coarser and coarser grids, and power law averaging reduces the spread as compared to flow based upscaling. The spread in predictions based on just 20 stochastic images is huge and it is likely to increase as more images are processed. The other interesting observation is that a smaller spread does not necessarily mean lower uncertainty. In other words, the distribution of uncertainty generated by repeated flow simulations may not span the *true* or *full* uncertainty because of the assumptions made in the stochastic model and/or the method used for upscaling. In the example discussed here, the flow based upscaling (considered to be the more reliable method) gives a bigger spread in results than simpler power law averaging. Neither of the two upscaling methods is exact.

Influence of Model Assumptions

Well Models. All simulators use simplified models to relate the wellblock pressure to the pressure of the well in that block. Here we will show the effect of using an inappropriate well model. The sources of uncertainty in the well model are: saturation gradients that cause the effective phase permeabilities for the well region to be different from the corresponding values for the well grid block, effective absolute permeabilities for the well region may be different from the average values for the block, the effective block radius (r_o) may be in error because default procedures in simulators are based on assumptions that are more suitable for typical vertical wells than for horizontal wells, and the effective skin may not be known. All of these factors are not likely to cause the well index to increase or decrease by a factor of more than 5 times the default value. We have done simulations by changing the well index by a factor of 5, 0.2, 1.2 and 0.8. As expected the oil production rate, GOR, WOR are all highly sensitive to the WI. The effect of changes in WI on production rate and GOR for the base case *medium-f* grid are shown in Figure 12.

Effect of Wellbore Pressure Drop on Well Performance. Another factor in well modeling that is often ignored is the pressure drop in the well. This is only important in cases where the reservoir permeability is high and the drawdown is small. We have used a high pipe roughness of 1 mm in the *medium-f* grid base case to see the effect of well pressure drop on results. The pressure drop calculation method is the homogeneous (no-slip) model in the Eclipse (1995)[8] simulator. These two values of roughness cause a pressure drop in the well at 6,000 days that is approximately 18% of drawdown. The maximum reduction in oil rate is about 12% when friction is included over when friction is ignored. Clearly not as major a factor in this case as reservoir heterogeneties. The greatest effect of wellbore pressure drop is on GOR. While in the homogeneous case the wellbore pressure drop causes the gas to breakthrough earlier than when this pressure drop is ignored, the behavior for the base case is opposite.

Analytical Cresting Models. Often analytical models are used to assess the tendency of water and gas to crest into a horizontal well. This is done because the simulation of cresting requires very fine grids. The analytical cresting models are based on assumptions that are generally different from those in simulation studies or real fields. Also, analytical models can only produce critical rates or time for breakthrough, not the behavior for super-critical rates. Arbabi and Fayers (1995)[7] have shown that different semi-analytical models presented in the literature can produce results for critical rates that are different by a factor of 24. They have proposed a new model that produces essentially the same results as careful simulations that mimic the assumptions in the analytical model. Here we present an example where we have used the technique developed by Arbabi and Fayers (1995)[7] to calculate the critical rate for our problem, under the assumption of steady-state, using average permeabilities of 433 mD in the horizontal direction and 14 mD in the vertical direction. The optimum well location, defined as the location that gives the same critical rate for both the gas and water interfaces, is predicted to be about 30 ft from the gas/oil contact with a critical oil rate of about 68 barrels per day. Theory shows that for the no-flow boundaries used in simulation, there is no critical rate. Simulations with a rate of 50 barrels per day (critical rate of the well in the middle of the reservoir) show that indeed this is true, but the gas and water breakthroughs occur after 3,000 years for the "optimum" well location, and when the well is located in the middle of the reservoir water breakthrough occurs at about 1,800 years and gas at about 4,300 years. As expected, when the simulations are done with *medium-f* grid breakthroughs occur earlier. We have also done simulations with the production rate of 5,000 barrels per day and the two well locations. Again, as expected, moving the well to the 30 ft location delays water breakthrough and reduces gas breakthrough times. The overall conclusion from this part of our work is that critical cresting rate solutions available in the literature have limited practical utility, because real situations normally have different boundary conditions and furthermore economical production rates are usually much higher than critical rates.

Productivity Models. The most common approach used to compare the performance of horizontal and vertical wells is the use of single phase analytical solutions for steady-state or pseudo steady-state flow in homogeneous media. The most popular of these is Joshi's equation.[2,3] Since our problem does not reach steady-state it is not appropriate to directly use Joshi's equation. A more general transient analytical model based on the work of Babu and Odeh[9] is used here with infinite conductivity in the well. In Figure 13 we compare analytical and simulation results. As expected the agreement between the numerical and analytical models for the single phase case is excellent. However, for the three-phase case (with the gas cap and the aquifer included) the simulation results (homogeneous properties, *medium* grid) are very different from the single phase results. The PI's calculated for various situations are given in Table 3. The PI depends on the model (analytical or numerical, boundary conditions, single or multiphase flow) used and the conditions in the reservoir (transient, pseudo steady-state, steady-state). These results clearly show the inappropriateness of using a steady-state analytical model for predicting horizontal well performance. Furthermore, we observe that the results are very different when pressure support is provided by the gas and water zones.

Other Factors

Not all sources of errors or uncertainty have been investigated in this paper. Some of the other factors that may influence predictions but were not considered in our study are mentioned below:

1. Exact location of the well and the condition of the wellbore are often not known precisely.
2. Net-to-gross ratio, pore volumes and hydrocarbon volumes were all fixed.
3. Aquifer and gas cap sizes were fixed.
4. Influence of other wells in the field was not considered.
5. A very simple no-slip model for multiphase flow in the horizontal well was used.
6. Wellbore hydraulic calculations during multiphase flow in the well can be in error. In this study well pressure constrained at the well heel.
7. Only two upscaling techniques for absolute permeability were considered.
8. Relative permeabilities were not upscaled.
9. Grid alignment with the well can be a serious problem in multiple well studies.
10. The reservoir was assumed to not have any fractures.
11. A black-oil fluid description was used.

Concluding Remarks

The greatest source of uncertainty is reservoir description and how it is used in simulators. Integration of data through geostatistical techniques leads to multiple descriptions that all honor available data. The reality is never known. The only way to reduce this uncertainty is to use more data from geological studies, formation evaluation, high resolution seismic, well tests and production history to constrain stochastic images.

Even with a perfect knowledge about reservoir geology, current models cannot do routine simulations at a fine enough scale. Furthermore, we normally don't know what scale is fine enough. Upscaling introduces errors and masks some of the physical phenomenon that we are trying to model. The scale at which upscaling is robust is not known and it is probably smaller in most cases than the scale actually used for predicting performance. Uncertainties in the well index (WI) can cause errors in predictions that are of the same magnitude as those caused by reservoir heterogeneities.

Simplified semi-analytical models for cresting behavior and productivity predictions can be very misleading.

Acknowledgments

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Table 1—Summary of Rock and Fluid Properties Used

Initial pressure, P_i, at GOC	2294 psia
Rock compressibility, at P_i	1.2E-5 $psia^{-1}$
Oil viscosity	1.3-1.5 cP
Gas viscosity	0.016-0.020 cP
Connate water saturation	0.07
Critical gas saturation	0.10
Residual oil sat. to water	0.25
Residual oil sat. to oil	0.07
Capillary pressure	None

Table 2—Summary of Simulation Results

	Cumulative Oil Production (plateau period) MMSTB	Time to Reach Oil Rate of 3,000 STB/Day Days	GOR at 6000 Days MSCF/STB	WOR at 6000 Days	WBHP at 2000 Days Psia	
Maximum	30.94	9726	384	7.44	2109	Coarse Grid flow based
Minimum	7.40	3753	74	0.89	1500	
Mean	18.09	6363	168	1.96	1823	
Spread	23.54	5973	310	6.55	609	
Maximum	34.35	9706	426	8.23	2159	Medium Grid flow based
Minimum	6.95	2618	67	1.23	1500	
Mean	18.20	5948	213	3.10	1856	
Spread	27.40	7088	359	7.10	659	
Maximum	22.97	7565	488	7.62	2036	Coarse Grid power averaged
Minimum	7.16	3382	186	2.21	1500	
Mean	13.84	4922	293	4.00	1764	
Spread	15.81	4183	302	5.41	536	
Maximum	23.61	8275	806	11.13	2118	Medium Grid power averaged
Minimum	7.41	2601	172	3.59	1500	
Mean	12.76	4467	426	6.90	1730	
Spread	16.20	5674	634	7.54	818	

Table 3—PI's Calculated from Various Methods

Method & Problem	PI (STB/Day/psi) 100 Days	1,400 Days	4,000 Days
Babu and Odeh, 1-phase (Transient)	68.7*	67.5	+
Simulation, 1-phase (Transient)	65.3*	63.9	+
Joshi, 1-phase (Steady State)	18.9*	18.9	+
Simulation, 3-phase (Homogeneous Case)	139.7*	15.2*	3.7

+ no oil production at the fixed well bottom hole pressure of 1500 psi

* oil production at constant rate of 5000 STB/Day

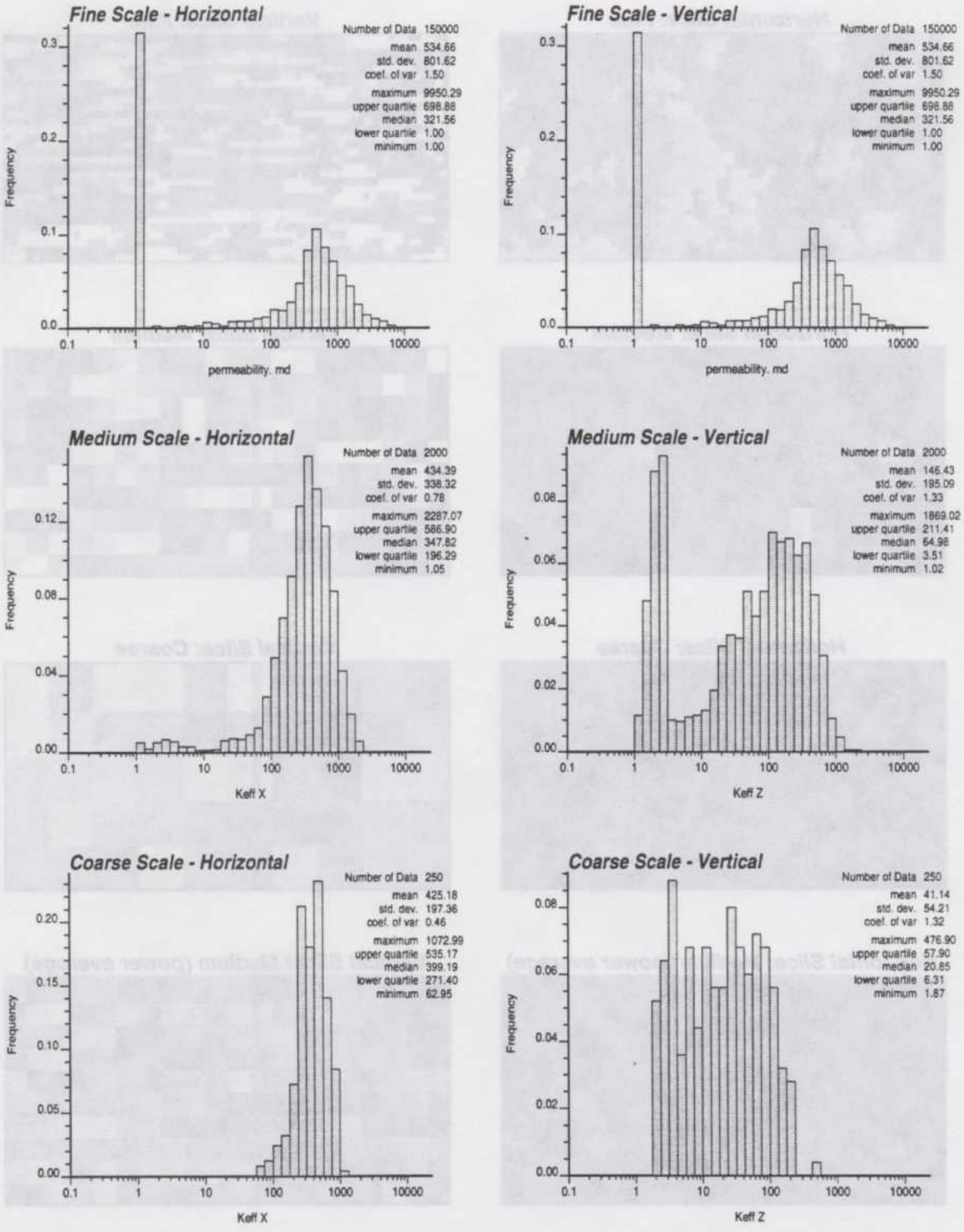

Fig. 1–Histograms of horizontal and vertical permeability for fine, medium, and coarse resolutions. A fixed multiplier of 0.1 is applied to the vertical permeability data in the simulations.

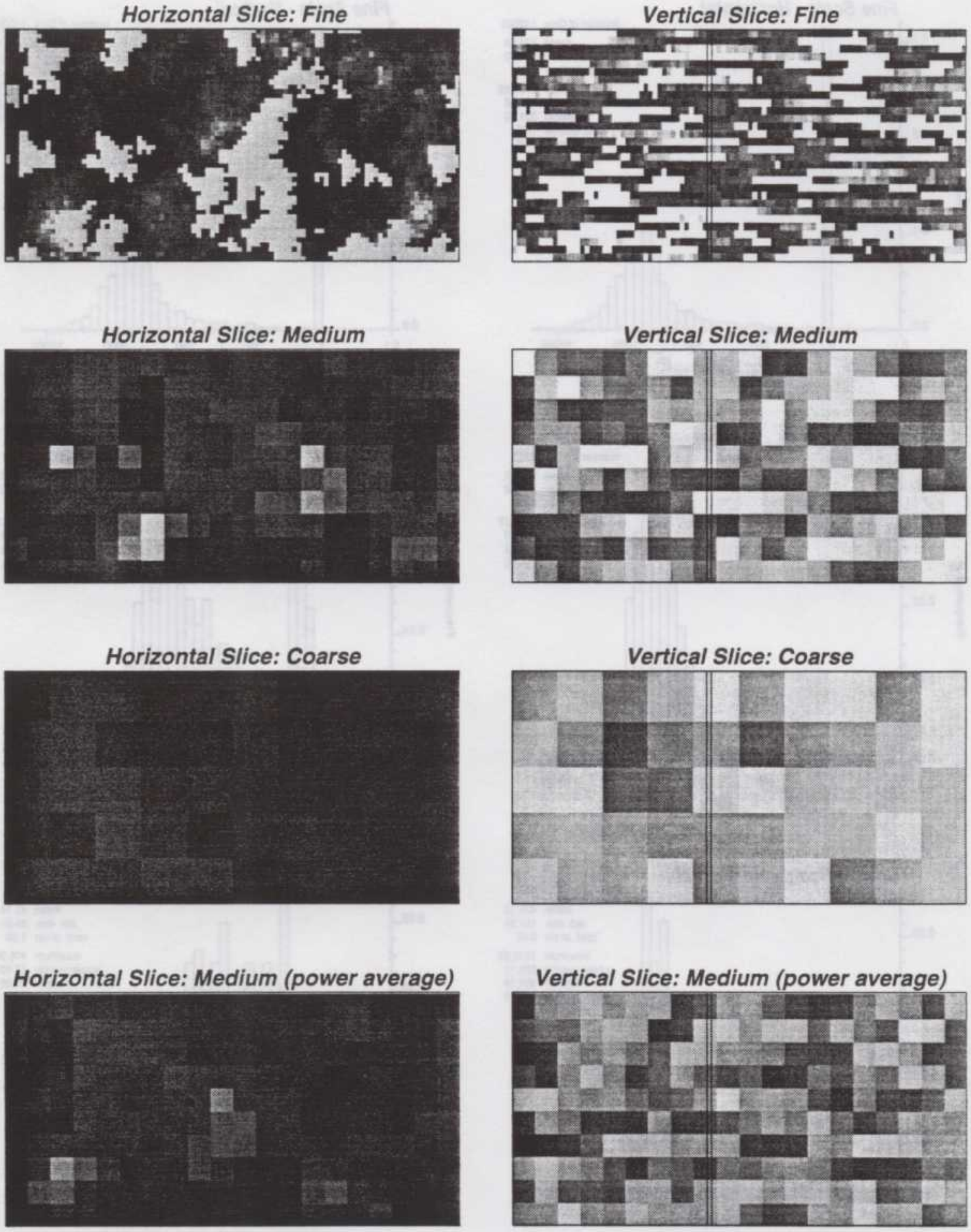

Fig. 2–Horizontal and vertical permeability maps of realization 3 for *fine*, *medium-f*, *coarse-f*, and *medium-p* grids. Slices are for the plane of the well.

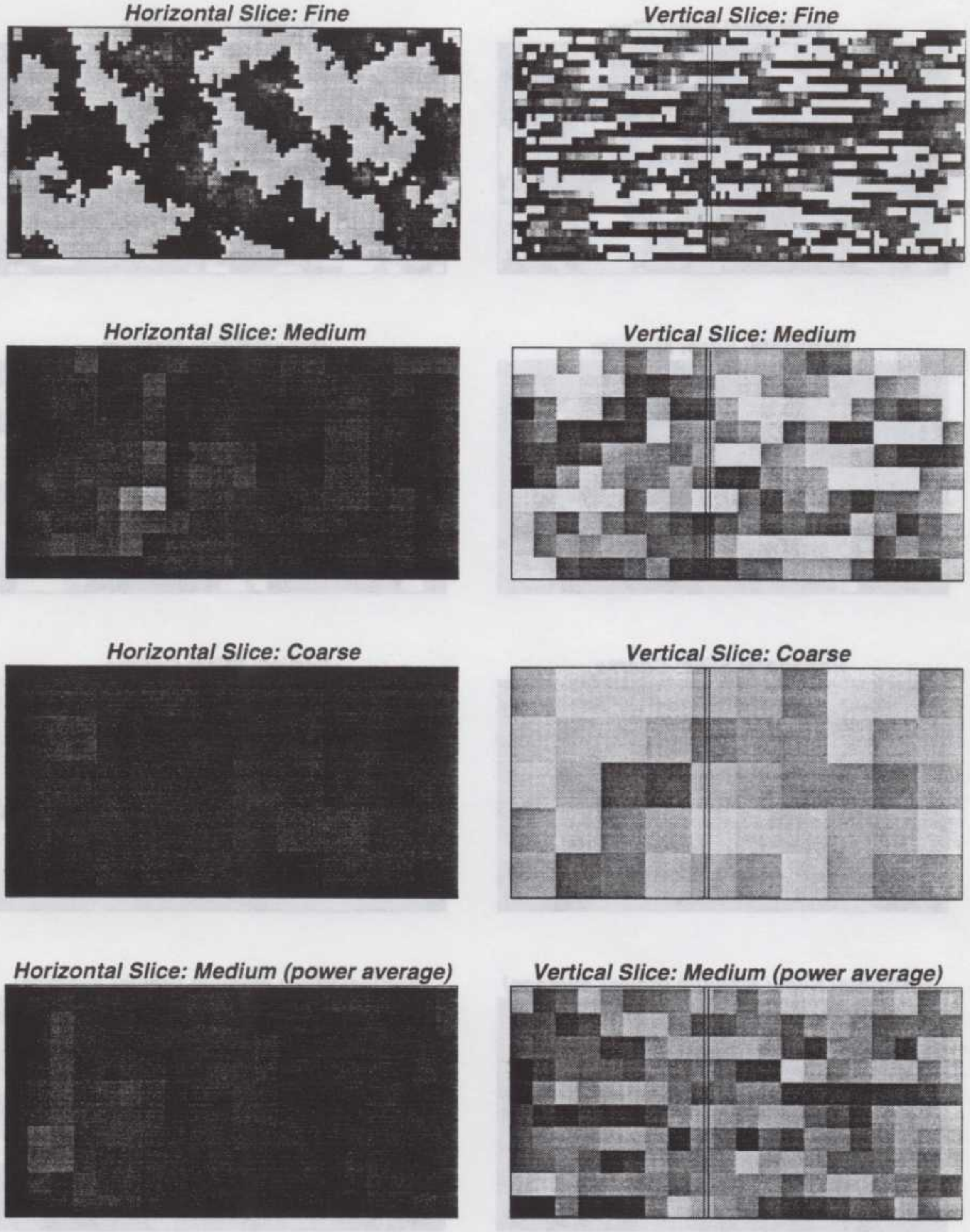

Fig. 3–Horizontal and vertical permeability maps of realization 9 for *fine*, *medium-f*, *coarse-f*, and *medium-p* grids. Slices are for the plane of the well.

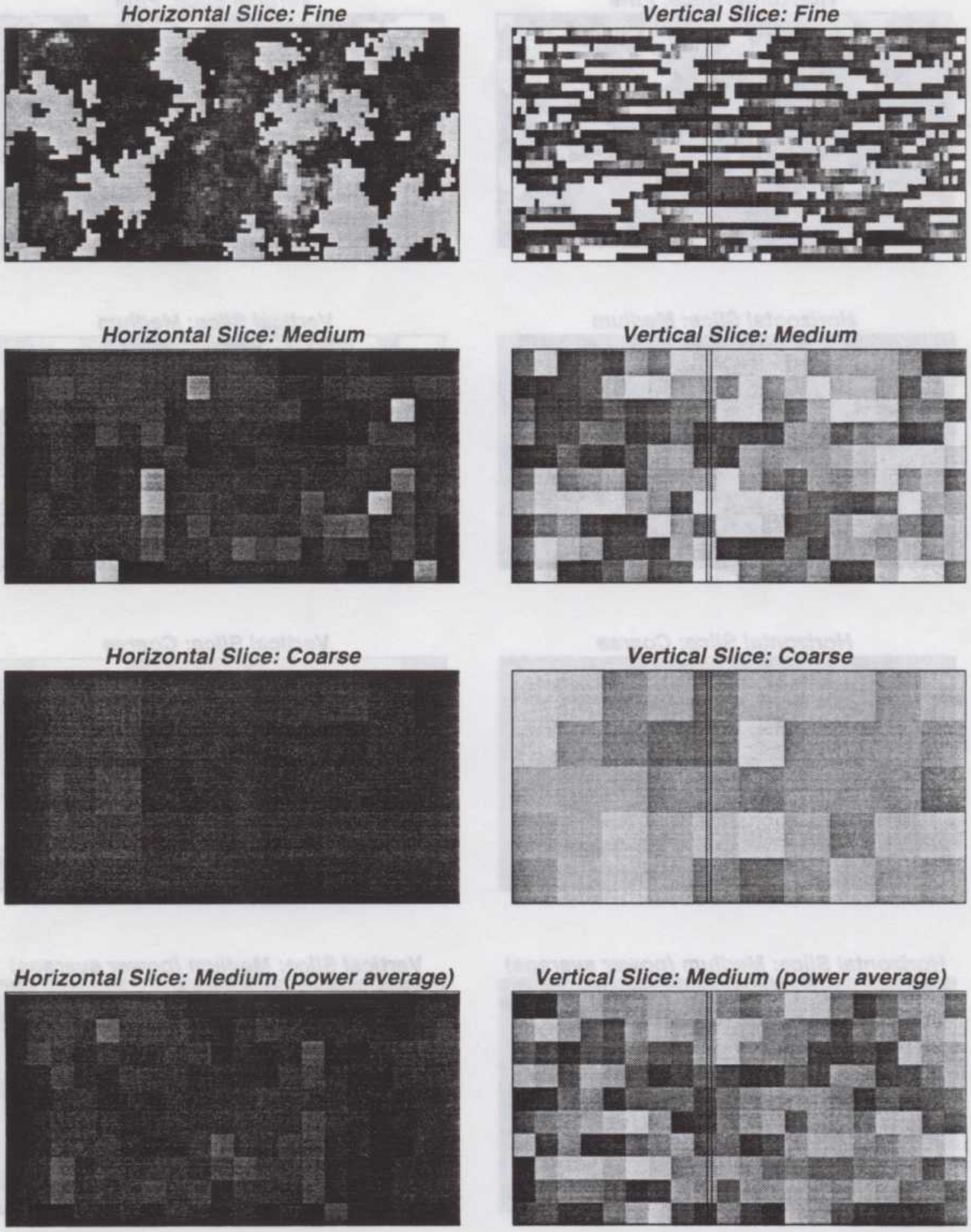

Fig. 4–Horizontal and vertical permeability maps of realization 12 for *fine*, *medium-f*, *coarse-f*, and *medium-p* grids. Slices are for the plane of the well.

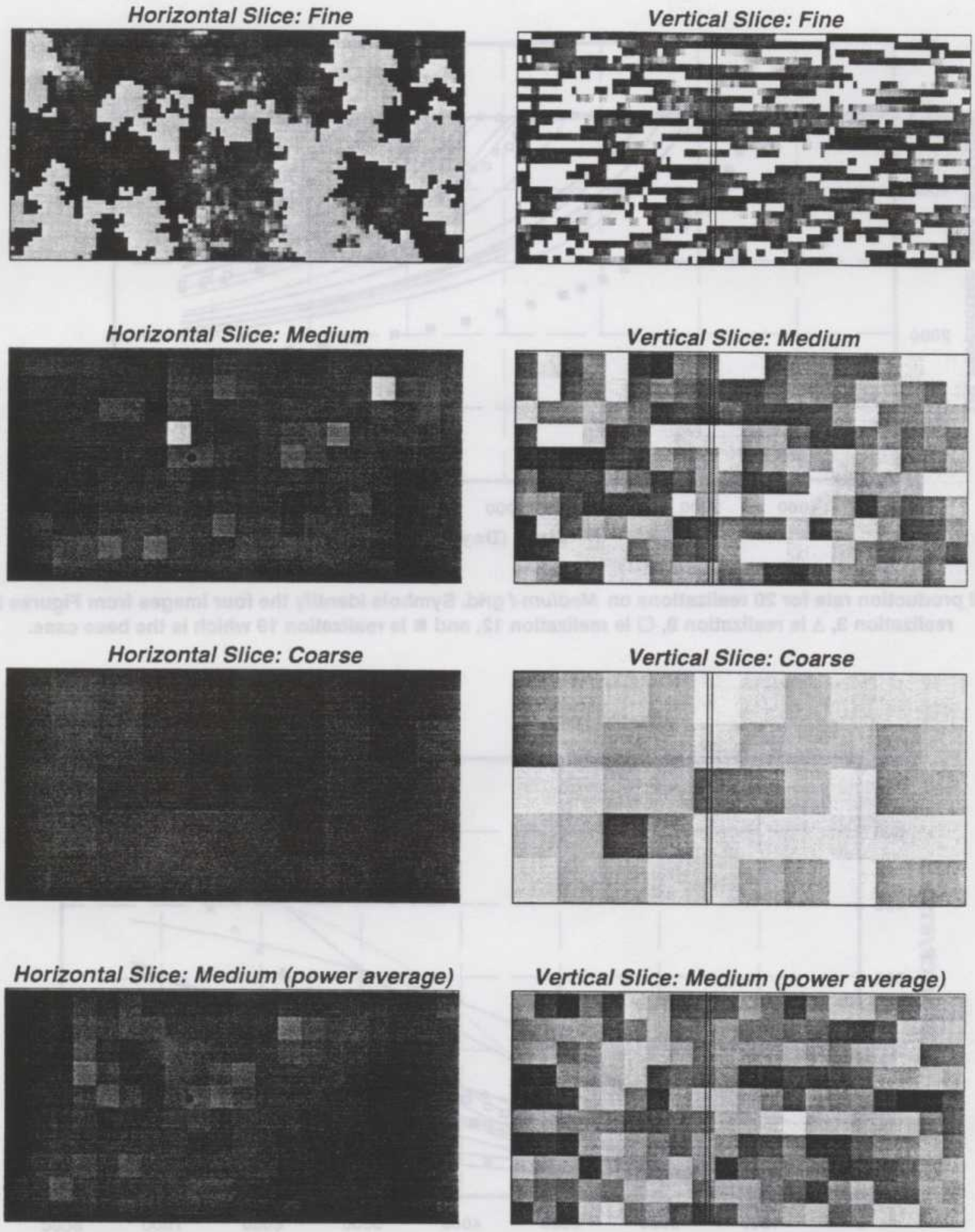

Fig. 5–Horizontal and vertical permeability maps of realization 19 (base case) for *fine*, *medium-f*, *coarse-f*, and *medium-p* grids. Slices are for the plane of the well

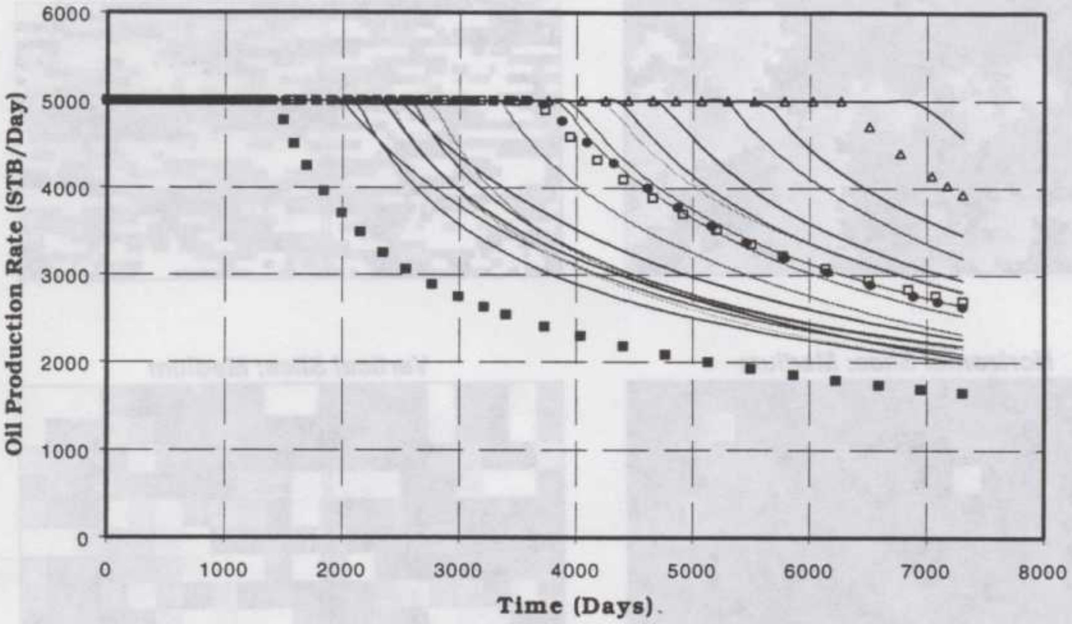

Fig. 6–Oil production rate for 20 realizations on *Medium-f* grid. Symbols identify the four images from Figures 2-5. - • is realization 3, Δ is realization 9, □ is realization 12, and ■ is realization 19 which is the base case.

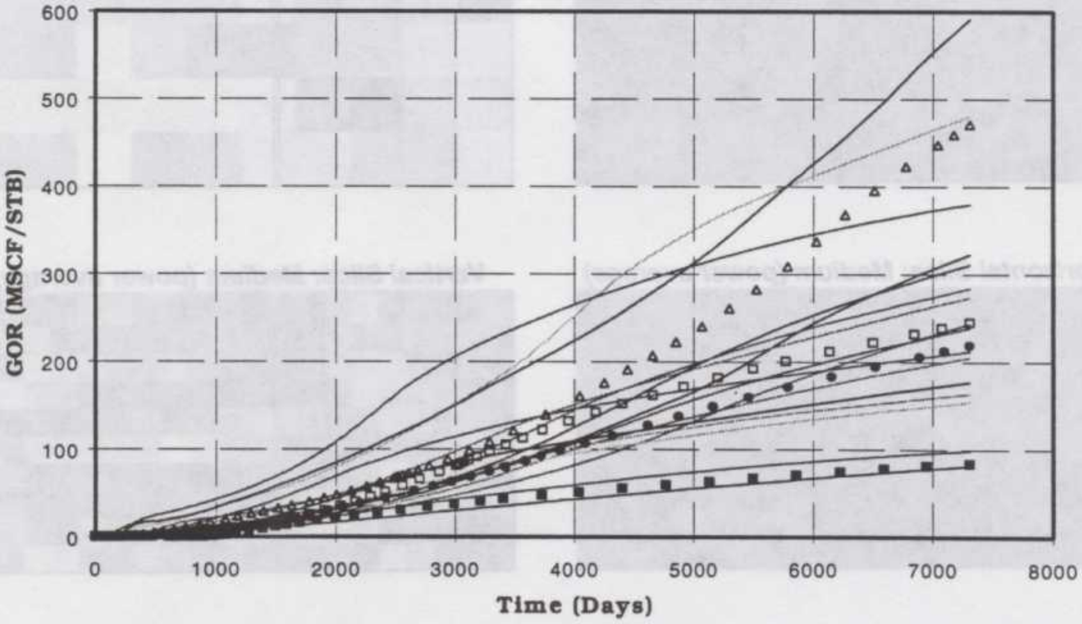

Fig. 7–Gas/Oil ratio (GOR) for 20 realizations on *Medium-f* grid. Symbols identify the four images from Figures 2-5. - • is realization 3, Δ is realization 9, □ is realization 12, and ■ is realization 19 which is the base case.

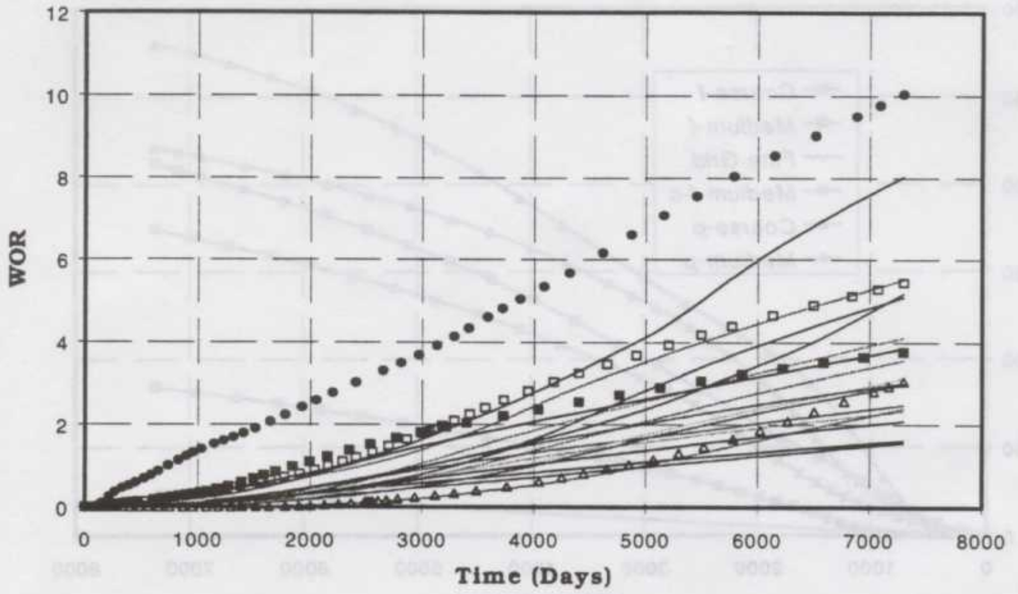

Fig. 8–Water/Oil ratio (WOR) for 20 realizations on *Medium-f* grid. Symbols identify the four images from Figures 2-5. - • is realization 3, △ is realization 9, □ is realization 12, and ■ is realization 19 which is the base case.

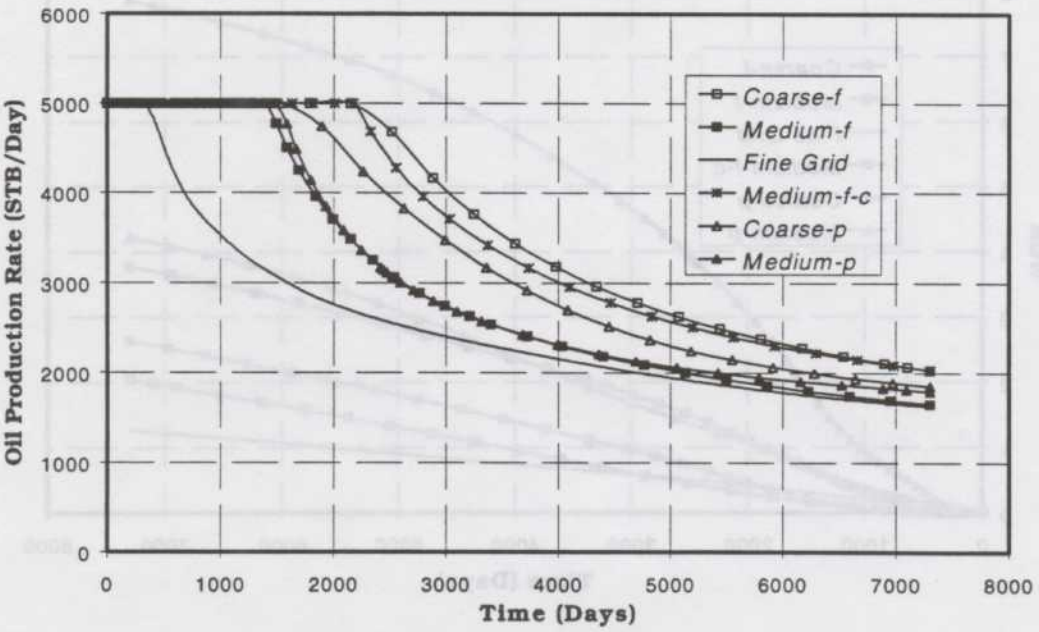

Fig. 9–Comparison of oil production rates from different grids for the base case (realization 19)

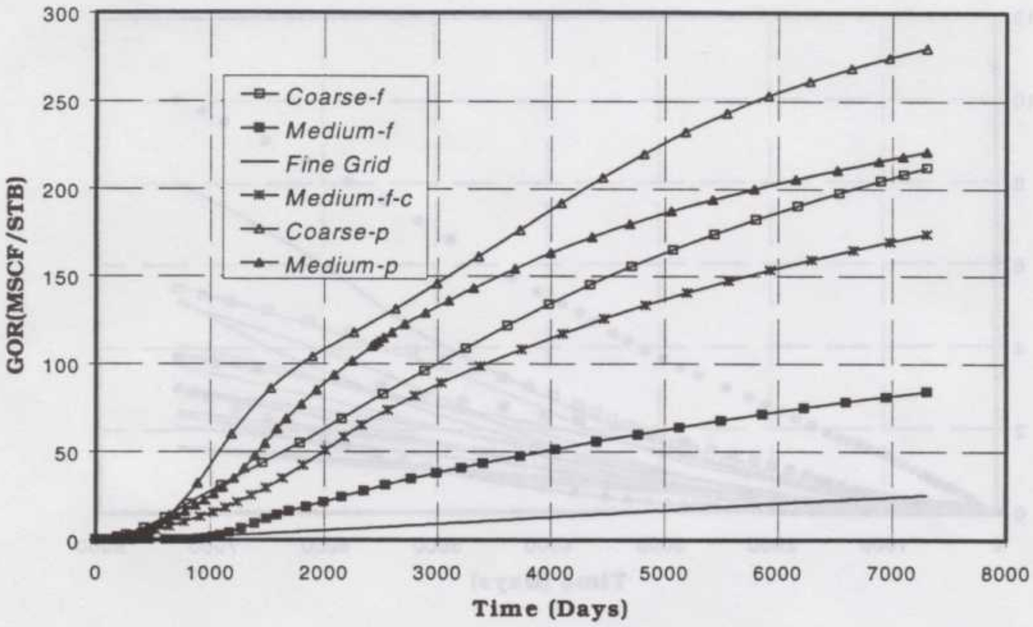

Fig. 10–Comparison of gas/oil ratio (GOR) from different grids for the base case (realization 19)

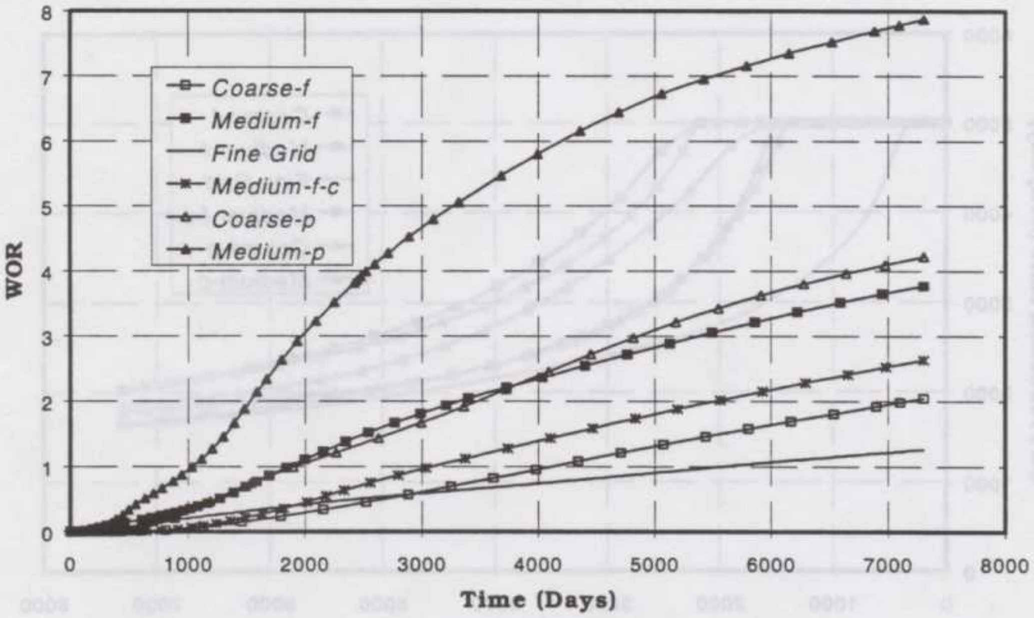

Fig. 11–Comparison of water/oil ratio (WOR) from different grids for the base case (realization 19)

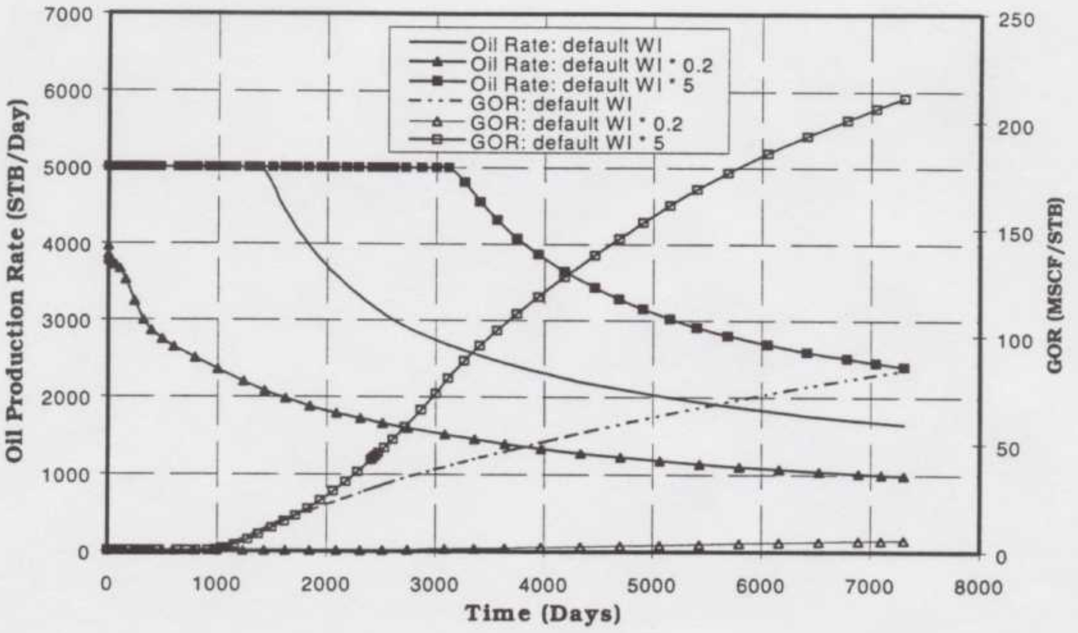

Fig. 12–Effect of well index (WI) on oil production rate and GOR for the base case (realization 19)

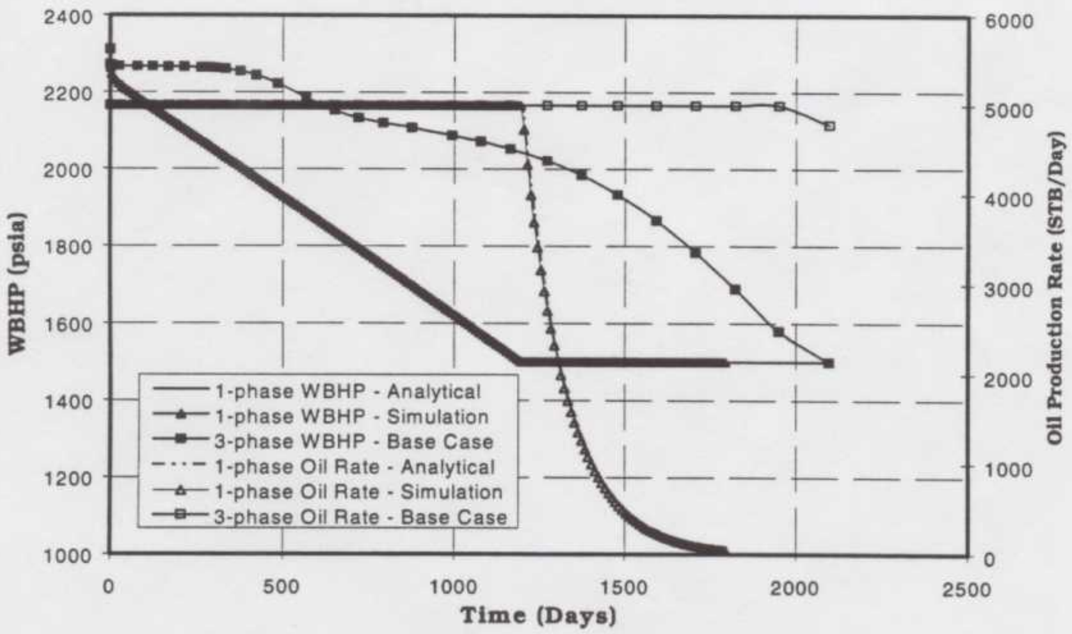

Fig. 13–Comparison between single phase (analytical and simulation) and three-phase *medium* grid simulation with homogeneous properties