A QUICK-LOOK SIMULATION STUDY ON THE FULL FIELD MODEL OF THE JATIBARANG VOLCANICS

by

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ABSTRACT

A full field simulation study was carried out on the Jatibarang Formation volcanics reservoir in the Jatibarang field. A model developed during a study carried out by LEMIGAS in 1988, up-dated to incorporate current analyses on logs and well tests, was used. The study revealed that the building blocks of the old model need revising to include more up-to-date analyses of the available data and our current understanding of the reservoir. Owing to initial limitations on time and available information, many fundamental changes had to be carried out on the model after the data had been input in order to match the production profile. These and subsequent changes have resulted in a model that is difficult to justify using recent geological and engineering understanding of the reservoir. Although this study was limited by available resources and time, it does provide adequate evidence for the need of a review, and pointers for the direction of future work.

There are indications that a large portion of the reserves in Jatibarang is inaccessible or inefficiently produced. There is a potential for improving the recovery process. It is suggested that different production scenarios be explored and the ideas tested using an up-dated finer grid multi-layer model. Techniques like horizontal drilling and fracturing suggested for improving oil recovery in Jatibarang and can be tested on fine grid 3D section simulation studies on the field. Recommendations are included to act as a guide to the evolution of an updated full field model for Jatibarang using current scientific techniques.

I. INTRODUCTION

A. Previous work

Single well modelling work done recently on three wells in Jatibarang (Thawer et al. 1992) combined with log analyses using current techniques reveals that the previously used flow parameters in the model developed by LEMIGAS in 1988 need to be revised. The recent work yielded more realistic values for fracture permeability and the matrix/fracture flow coupling factor σ than those inferred in the previous study using conventional techniques (LEMIGAS report for PERTAMINA UEP-III, 1988). Results from the single well models indicate a fracture permeability in the range of 20mD to 150mD. Fracture porosity was between 0.03% to 0.12% and σ (also known as the matrix shape factor), was inferred to be between 1 and 14. The old Jatibarang model used fracture permeabilities of the order of 1000mD and a σ value of 0.00001; the implication of this is that there are less than ten large cracks of a significant width across the whole of the field, somehow connecting all the wells. The resulting model can be made to history match the production data and will represent the volumetrics at the well-head; however, it seems very unlikely that such an approach could model the physics of the flow process within the reservoir correctly. The major constraint at the time seems to have been the absence of enough information on fractures. Under such circumstances it may be more reasonable to assume that no fractures are present and tune the matrix permeability to account for additional flow from fractures in a usual single porosity model.

B. Current study

The current study has used some recent data on fractures to build a dual porosity dual permeability model which approximates the reservoir description as known currently, and attempts have been made to history match the fieldwide total production data approximately. The pressure and water cuts have been matched keeping the well control on the oil production rate. No attempt has been made to history match the gas/oil ratio or the individual wells in the field. This was deemed unnecessary since the new models are only approximations of current data from a small section of the field, extended to the whole field. Sufficient experience has been gained through this small study to indicate the need for a fuller data review.

C. Background

The Jatibarang field is situated 30 km to the northwest of Cirebon in West Java (Fig. 1). Volcanic tuffs and lavas of the Jatibarang Formation form the major producing zone (Fig. 2). The volcanics reservoir occupies a culmination on a major east-west trending anticline and is bounded by two major faults to the east and west (Fig. 3). Oil and solution gas are produced from the volcanics zone. Most of the wells producing from the volcanics are barefoot completions, commonly producing from over 100m of open hole.

Flow in the reservoir is thought to occur via natural fractures. Fractures, solution vugs, and primary microporosity have been observed in core samples. The fractures and vugs can be approximated using the Kazemi representation of a cube or slab model. This approximation can represent the fracture volume and model the primary recovery process only. Secondary/tertiary flow processes, where displacement of one phase by another is described by relative permeability curves for fractures, depend on the geometry of the flow paths. To represent the tortuosity of the actual fracture/vug flow paths and include inaccessible dead-ends in some vugs these relative permeability curves should be amended to include residual saturations which are non-zero, and their shapes changed to account for phenomena such as numerical dispersion and coning, in the same way as pseudo-curves are generated from matrix relative permeability curves. In a full study on the field these pseudo curves should be generated through the Intera PSEUDO package after the usual 2D cross-sectional studies and coning studies. In the limited scope of the current study these pseudos evolved through history matching.

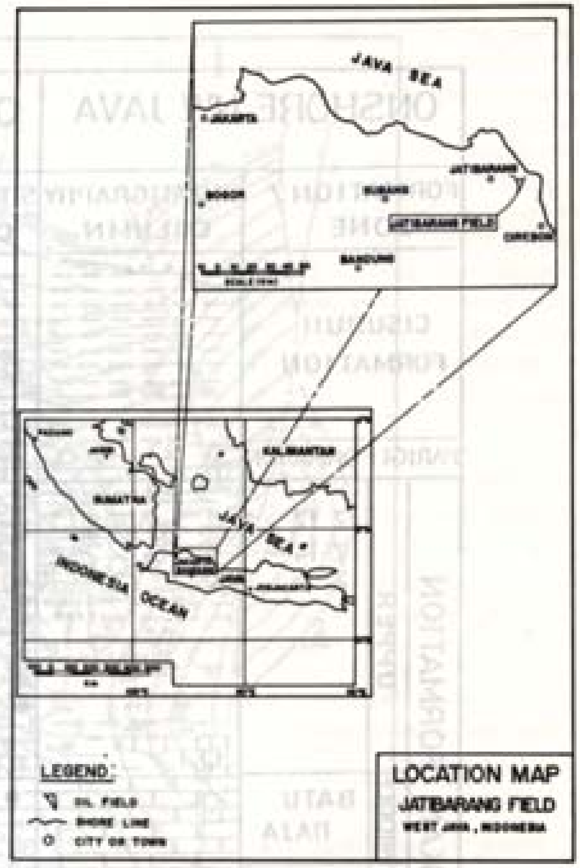

Figure 1 (from Nutt and Jujur Sirait, 1987)

II. NUMERICAL MODEL

The model in the current study was based on the model developed by LEMIGAS in 1988. Initially only σ (from the Kazemi equation) and fracture permeabilities were changed. However, it soon became apparent that this was not enough. The old model had been tuned in many other respects beyond reasonable limits to match the production data. For example the net pay was reduced to be an quarter of what is clearly observed from log analysis data across the field. There is no evidence to suggest that the reservoir formation with significant porosity is as small as is portrayed in the old model. The previous σ was 0.00001,

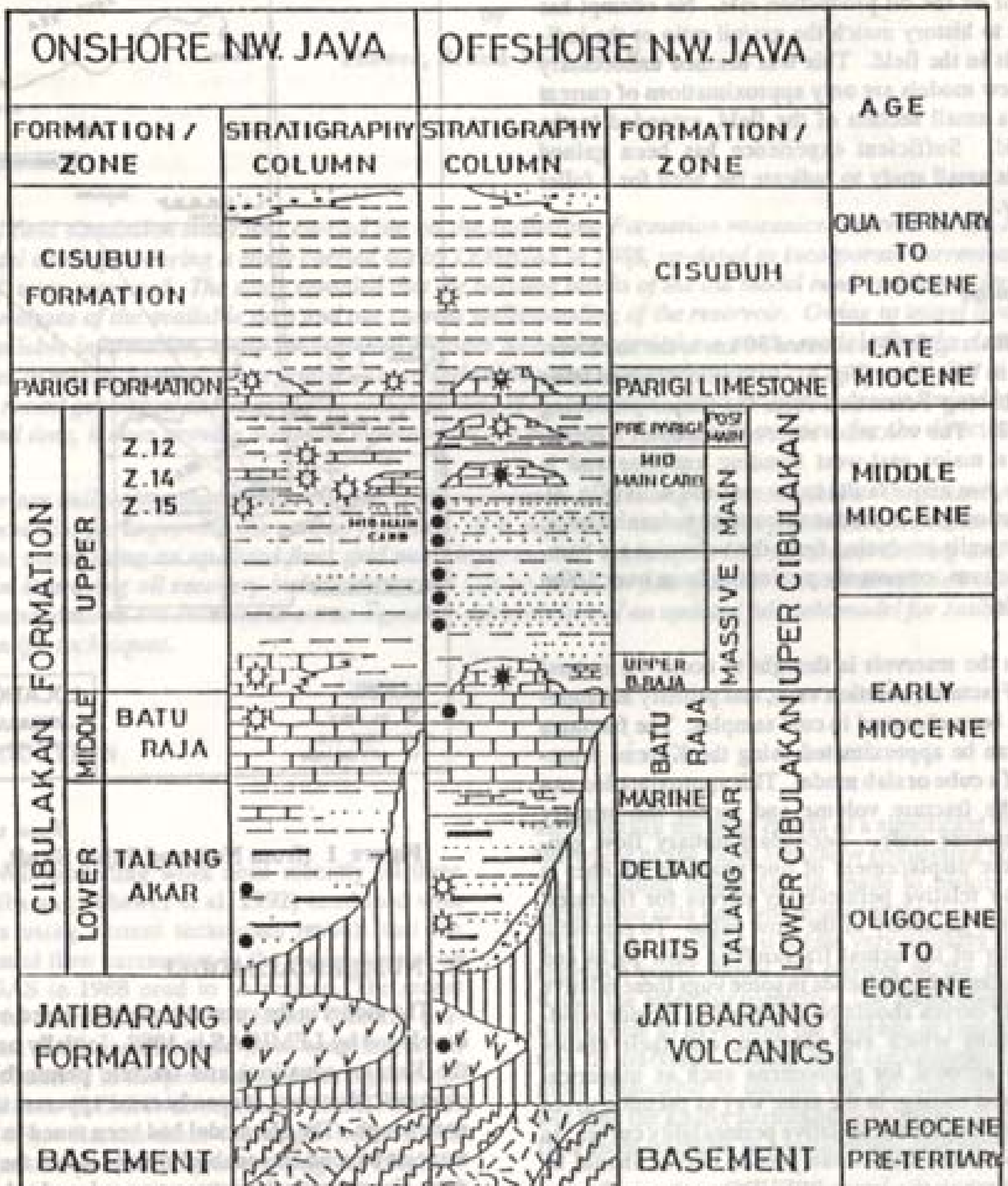

Figure 2. Stratigraphy of the NW Java basin (from Soewono and Setyoko, 1987)

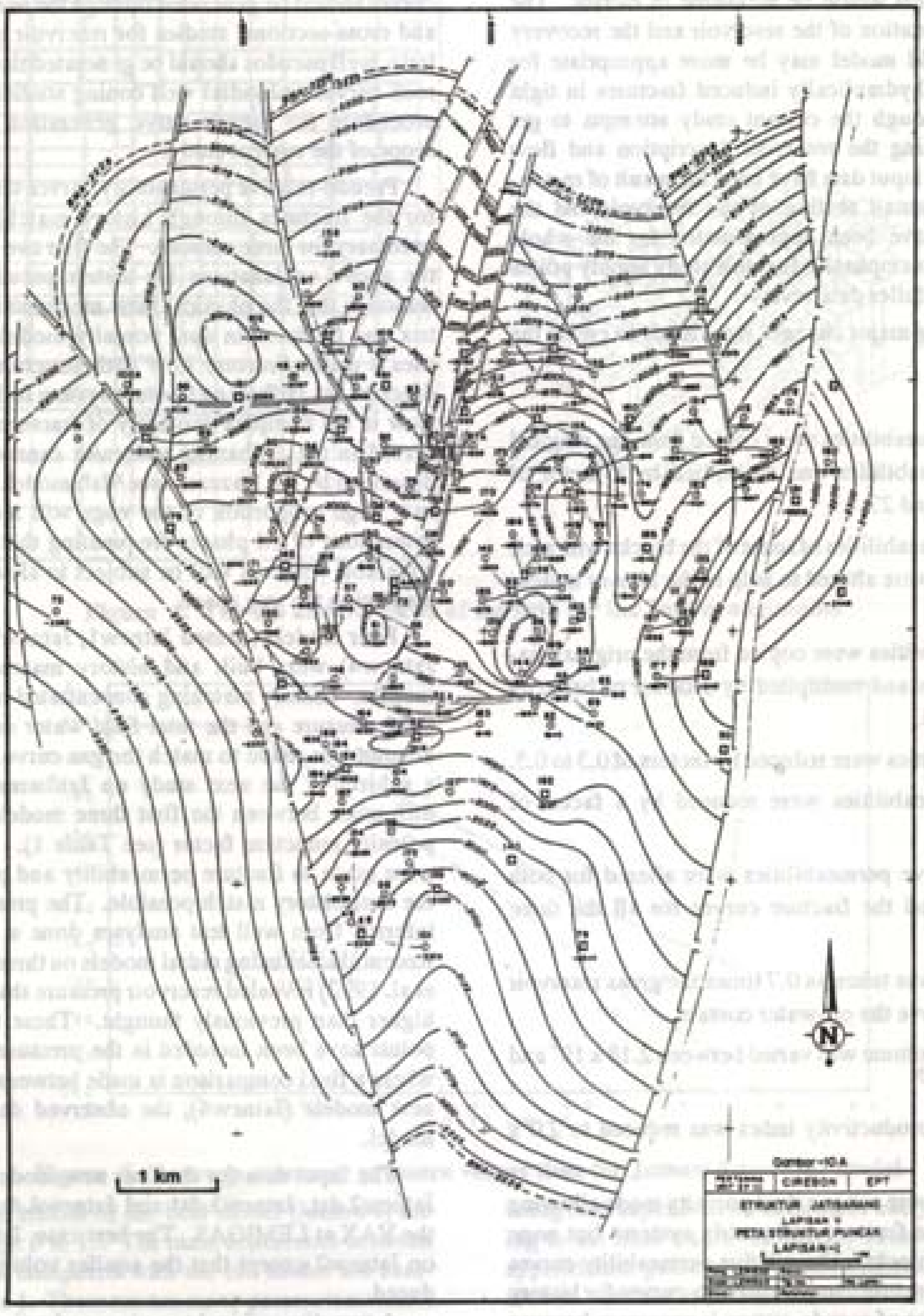

Figure 3. Top Jatibarang formation volcanics structure map (LEMIGAS, 1988)

implying an inter-fracture distance of 1095m; this coupled with fracture porosities of about 1%, would imply fracture widths that would be measured in metres. The physical representation of the reservoir and the recovery process in the old model may be more appropriate for modelling large hydraulically induced fractures in tight formation. Although the current study attempts to get closer to modelling the reservoir description and flow mechanisms, the input data have been the result of re-analysis of a very small section of the reservoir and the interpretations have been approximated for the whole field. We wish to emphasise that this study simply points to the need for a fuller data review.

The following major changes were made to create the current models:

1. $\sigma = 3$.
2. Fracture permeabilities were copied from the original matrix permeabilities and multiplied by a factor of between 15 and 27.
3. Fracture permeabilities of some of the blocks with well connections were altered to help in the history matching.
4. Fracture porosities were copied from the original matrix porosities and multiplied by a factor of between 0.05 and 0.06.
4. Matrix porosities were reduced by factors of 0.3 to 0.5.
5. Matrix permeabilities were reduced by a factor of 0.001.
6. Pseudo-relative permeabilities were altered for both the matrix and the fracture curves for all the three phases.
7. The net pay was taken as 0.7 times the gross reservoir thickness above the oil-water contact.
8. The aquifer volume was varied between 2.13×10^9 and 4.26×10^9 m^3.
9. The aquifer productivity index was reduced to 2.0×10^3

The models were run in a dual porosity mode allowing flow between the fracture and matrix systems but none between matrix blocks. The relative permeability curves for the matrix were tuned to give pseudo-curves for history matching. The use of pseudo-curves is necessary because the old model for Jatibarang is a single layer coarse grid model and numerical dispersion and gas/water coning need to be corrected for. In a full study these pseudo curves should be generated through the use of rock curves and cross-sectional studies for reservoir pseudos. Similarly, well pseudos should be generated through the use of rock curves and radial well coning studies. The detailed procedure for pseudo-curve generation is beyond the scope of the current study.

Pseudo-relative permeability curves were also derived for the fractures through history matching. This was necessary for three reasons. The first two are identical to the above explanations for matrix pseudos. The third reason is that the physical flow mechanism between matrix and fractures in dual porosity models on ECLIPSE uses a matrix/fracture flow path structure that does not describe the Jatibarang fracture system fully. Three phase flow in the complex geometry of fractures and vugs observed in the Jatibarang volcanics cannot be accurately described by the Kazemi cube/slab model. The dead ends in a large proportion of the vugs will result in residual saturations of all phases frequenting that space, and recoverable reserves will be subject to slow matrix influx displacing the vug space.

Four models (named Jatnew1, Jatnew2, Jatnew3 and Jatnew4) were built and history matched within two months. History matching concentrated on matching the field pressure and the total field water cuts. Very little attempt was made to match the gas curve. This could be a subject of the next study on Jatibarang. The major difference between the first three models is the matrix porosity reduction factor (see Table 1). Minor changes were made to fracture permeability and porosity to give the best history match possible. The pressure data were inferred from well test analyses done a long time ago. Recent studies using radial models on three wells (Thawer et al. 1992) revealed reservoir pressure that was generally higher than previously thought. These three new data points have been included in the pressure graph (Fig. 5) where a final comparison is made between the best of the new models (Jatnew4), the observed data and the old model.

The input data for the four new models Jatnew1.dat, Jatnew2.dat, Jatnew3.dat and Jatnew4.dat are stored on the VAX at LEMIGAS. The best case, Jatnew4, is based on Jatnew2 except that the aquifer volume has been reduced.

A two dimensional top view and a three dimensional representation of the grid are presented in Fig. 4. The

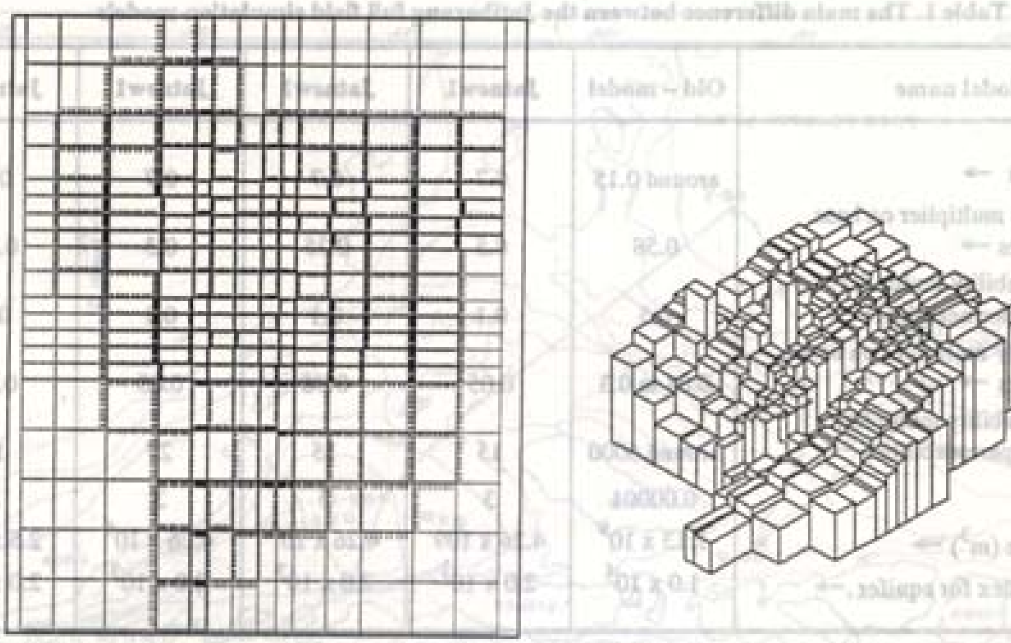

Figure 4. Top 2D and 3D views of the grid for the Jatibarang model

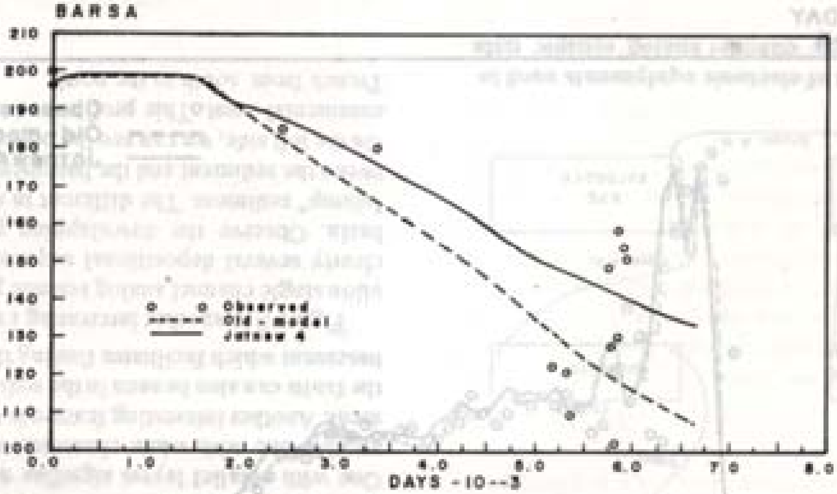

Figure 5. Average reservoir pressure versus time for Jatnew 4 and Old-model

history matched results of the best model (Jatnew4) are presented in Figs. 5 to 13. The main differences between the new models compared with the old model are summarised in Table 1. There are too many parameters within a reservoir model to allow an accurate, brief, comparison in a table. The complexity is compounded by the changes being interdependent on each other and jointly contributing to the final result. However, Table 1 does act as an approximate guide to the major differences between the models. It should be noted that the matrix and fracture pseudo relative permeability curves in the new models are very different from those used in the old model.

Table 1. The main difference between the Jatibarang full field simulation models

Model name	Old – model	Jatnew1	Jatnew1	Jatnew1	Jatnew1
DZNET = DZ x →	around 0.15	0.7	0.7	0.7	0.7
Matrix porosity multiplier on base matrix porosities →	0.58	0.5	0.35	0.3	0.35
Matrix permeability multiplier on base matrix permeabilities →	0.5	0.1	0.1	0.1	0.1
Fracture porosity multiplier on base matrix porosities →	0.01 to 0.3	0.05	0.06	0.05	0.06
Fracture permeability multiplier on base matrix permeabilities →	around 6000	15	15	27	15
σ →	0.00001	3	3	3	3
Aquifer volume (m^3) →	2.13×10^9	4.26 x 109	4.26×10^9	4.26×10^9	2.5×10^9
Productivity index for aquifer →	1.0×10^4	2.0×10^3	2.0×10^3	2.0×10^3	2.0×10^3

Note : The table is only an approximate guide to the major defferences between the models. Psedu relative permeability curves have also been changed for matrix and fracture systems.

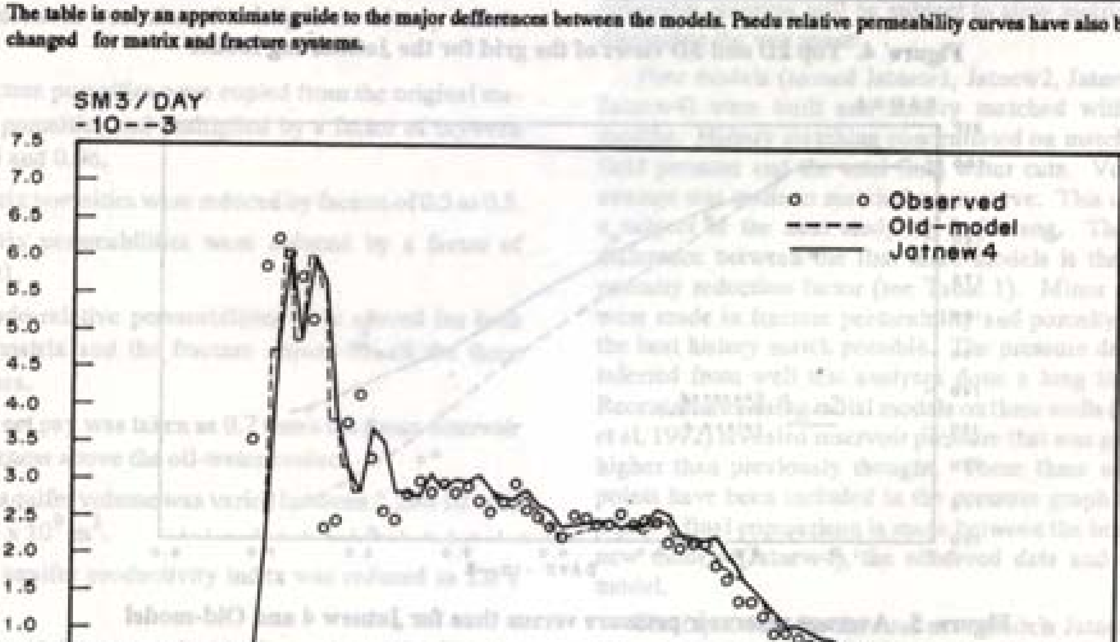

Figure 6. Oil production rate versus time for Jatnew4 and Old-model

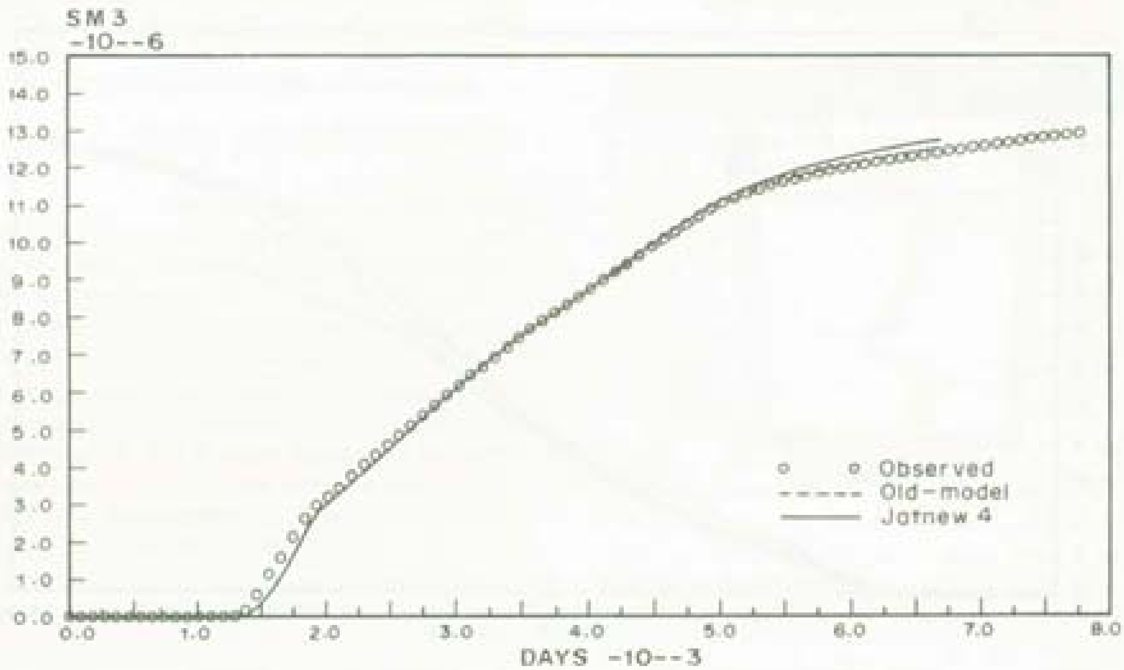

Figure 7. Oil total production versus time for Jatnew4 and Old-model

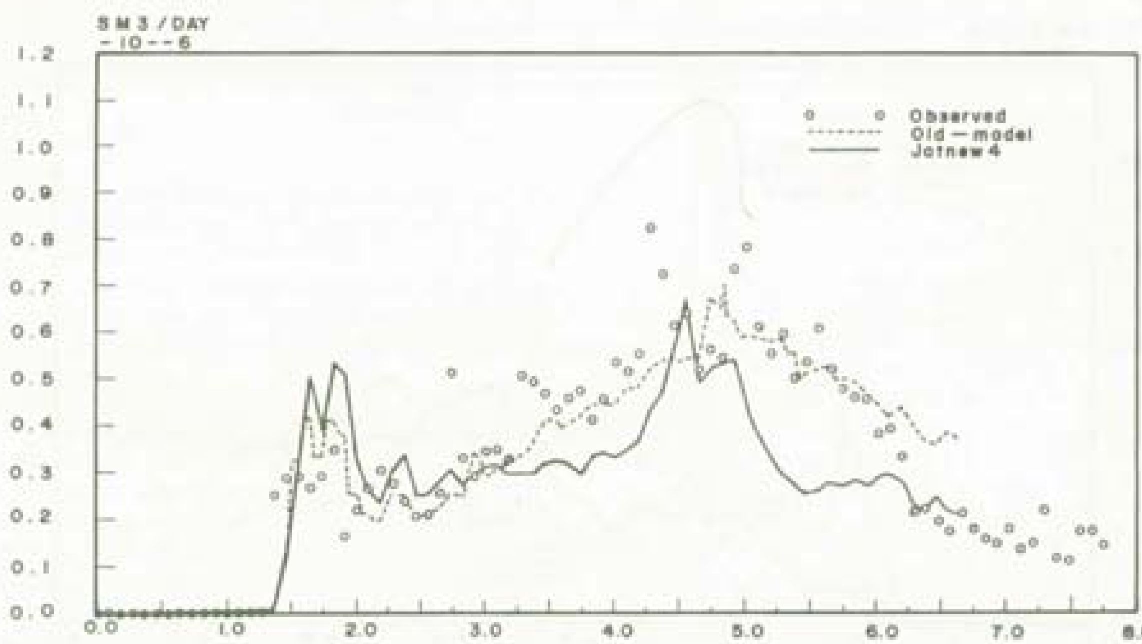

Figure 8. Gas production rate versus time for Jatnew4 and Old-model

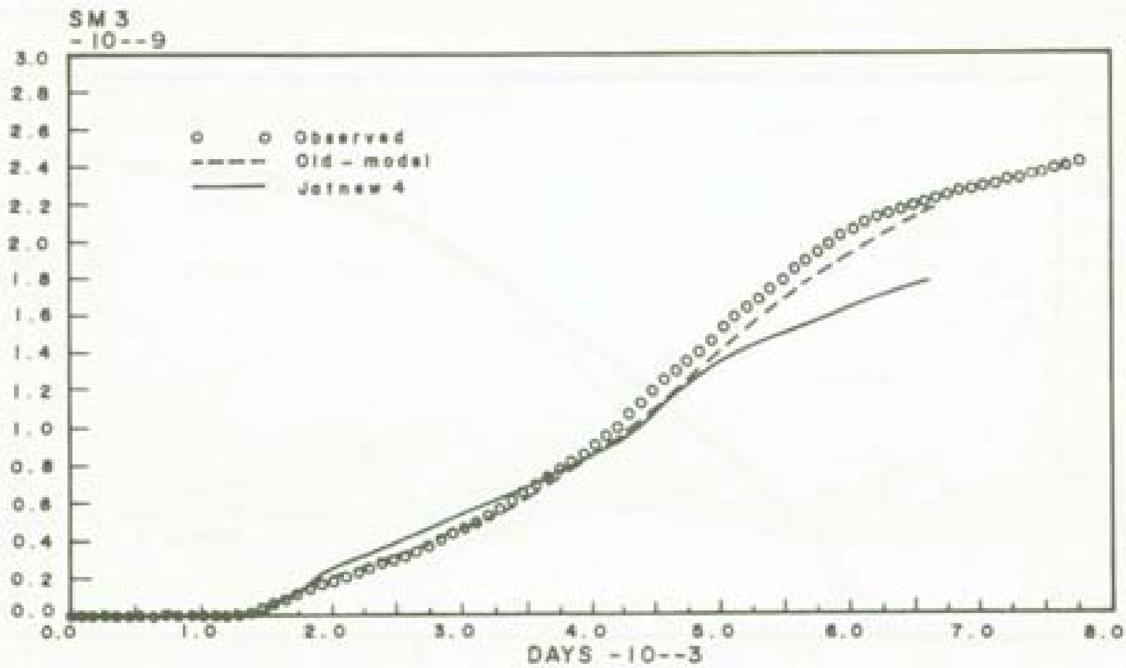

Figure 9. Gas production versus time for Jatnew4 and Old-model

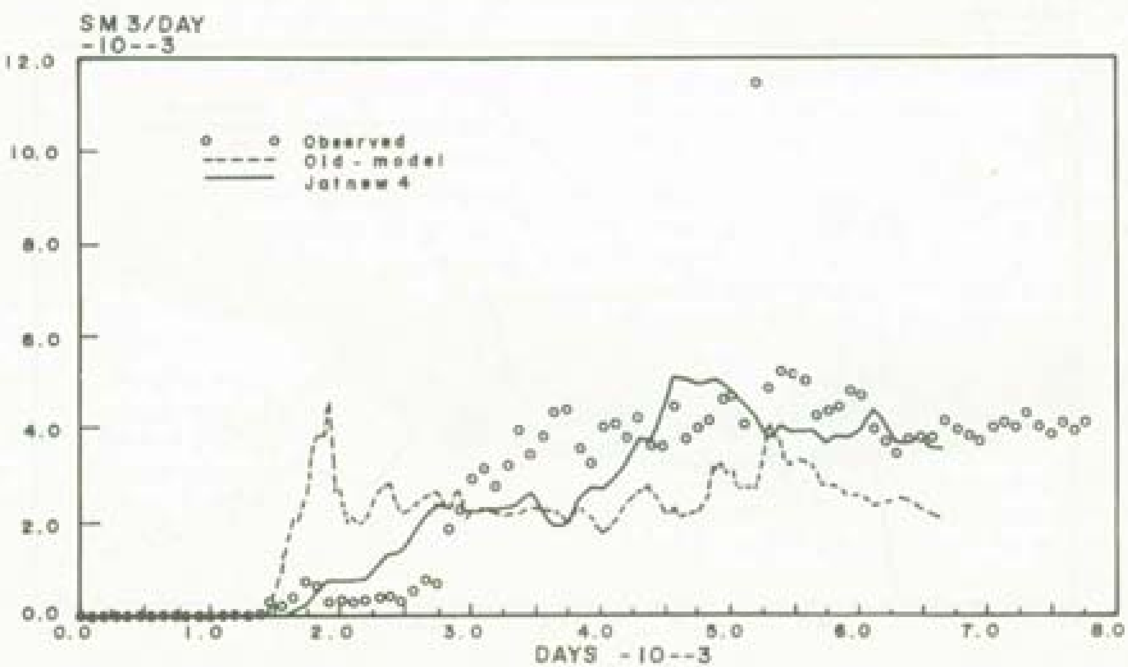

Figure 10. Water production rate versus time for Jatnew4 and Old-model

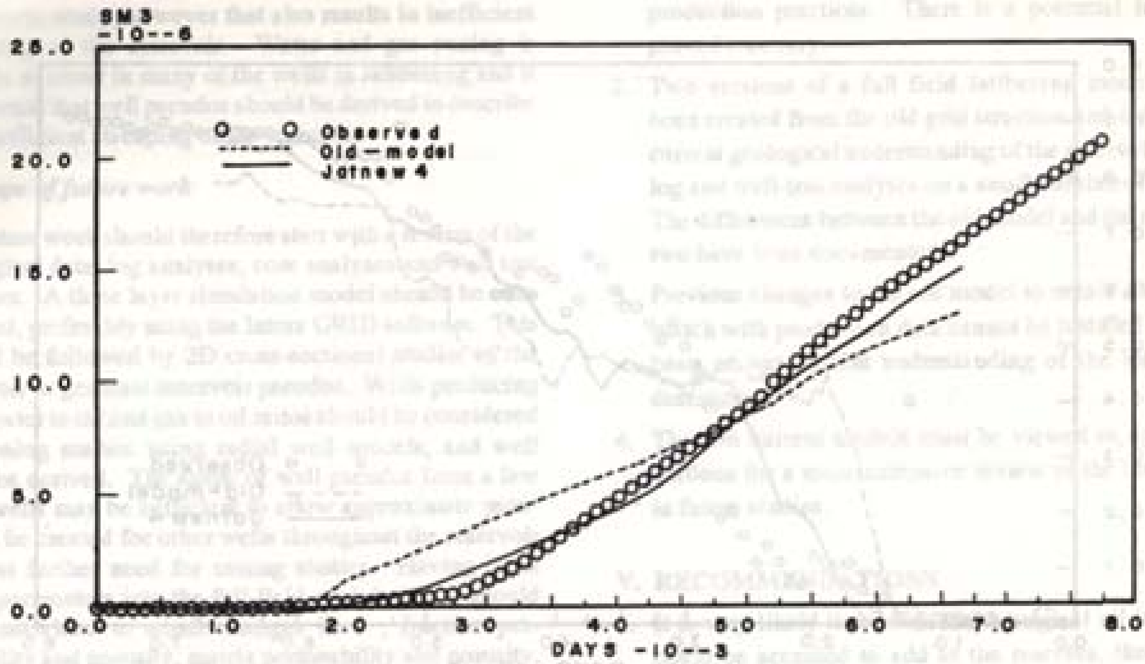

Figure 11. Water total production versus time for Jatnew4 and Old-model

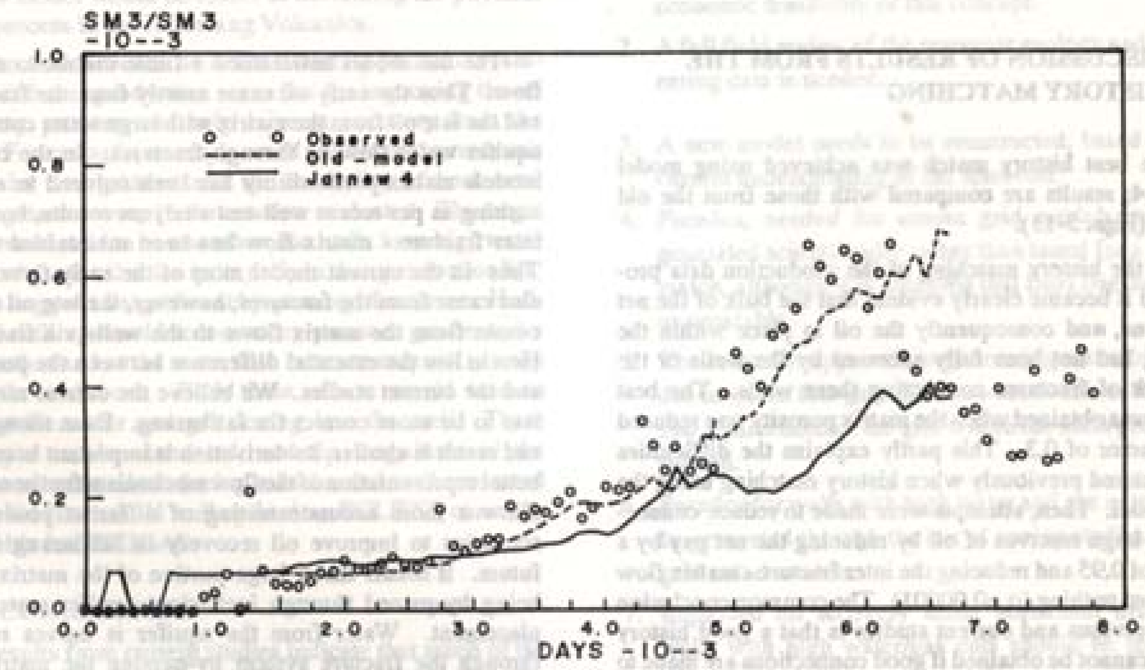

Figure 12. Gas/oil ratio versus time for Jatnew4 and Old-model

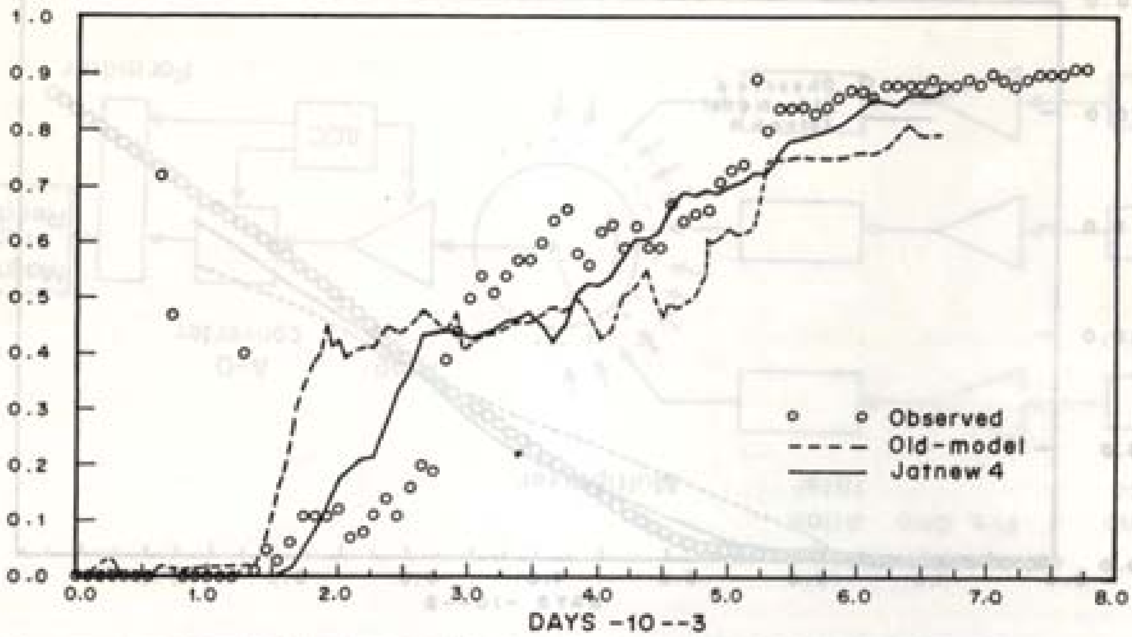

Figure 13. Water cut versus time for Jatnew4 and Old-model

III. DISCUSSION OF RESULTS FROM THE HISTORY MATCHING

The best history match was achieved using model Jatnew4; results are compared with those from the old model (Figs. 5-13).

As the history matching of the production data progressed it became clearly evident that the bulk of the net pay zone, and consequently the oil in place within the matrix, had not been fully accessed by the wells or the network of fractures connecting these wells. The best match was obtained when the matrix porosity was reduced by a factor of 0.3. This partly explains the difficulties encountered previously when history matching using the old model. Then, attempts were made to reduce connection to large reserves of oil by reducing the net pay by a factor of 0.95 and reducing the inter fracture - matrix flow to almost nothing (σ =0.00001). The common conclusion from previous and current studies is that a good history match cannot be obtained if good connections are made to all the available oil in the pore space within the matrix.

The old model maintained a finite matrix to matrix flow. Thus the early oil came mostly from the fractures and the late oil from the matrix with large water cuts from aquifer water flowing through fractures. In the current models matrix permeability has been reduced to almost nothing as per recent well-test analyses results, however inter fracture - matrix flow has been maintained via σ. Thus in the current model most of the early flow of oil also came from the fractures; however, the late oil which comes from the matrix flows to the wells via fractures. Herein lies the essential difference between the previous and the current studies. We believe the current mechanism to be more correct for Jatibarang. Even though the end result is similar, its derivation is important because a better representation of the flow mechanism for the oil will allow a more accurate testing of different production scenarios to improve oil recovery in Jatibarang in the future. It seems that a large portion of the matrix oil is being by-passed through inefficient aquifer water displacement. Water from the aquifer is moves rapidly through the fracture system by-passing the matrix oil. Water and gas coning in wells has not been addressed in the current study; however that also results in inefficient sweeping of the reservoir. Water and gas coning is thought to occur in many of the wells in Jatibarang and it is essential that well pseudos should be derived to describe this inefficient sweeping of the reservoir.

A. Scope of future work

Future work should therefore start with a review of the geological data, log analyses, core analyses and well test analyses. A three layer simulation model should be constructed, preferably using the Intera GRID software. This should be followed by 2D cross-sectional studies of the reservoir to generate reservoir pseudos. Wells producing high water to oil and gas to oil ratios should be considered for coning studies using radial well models, and well pseudos derived. The shape of well pseudos from a few such wells may be sufficient to allow approximate pseudos to be created for other wells throughout the reservoir without further need for coning studies. Having input these parameters into the full field model, tuning should be constrained to small changes in σ , fracture permeability and porosity, matrix permeability and porosity. These parameters need to be tuned because the information on them is limited to a small area of the reservoir. Such a model would be closer to describing the physical flow process in the Jatibarang Volcanics.

The model could also act as a starting point for evaluating different production scenarios for improving the oil recovery process, and help increase recovery from the field. For example, a sample small section of the reservoir could be fine gridded and the feasibility of horizontal drilling on recovery in that section evaluated. The target area would need to be one where the wells have high water cuts and gas to oil ratios quite early in their production life; which suggests a significant by-passing of reserves. Horizontal drilling would reduce steep pressure gradients for production and at the same time increase reservoir sweep near the well-bore. Both these effects would tend to reduce the water and gas coning into the well. These concepts can be simulated, and the magnitude of the improvement on introducing a horizontal well evaluated using the 'horizontal well option' on ECLIPSE currently available in LEMIGAS.

IV. CONCLUSIONS

1. Results from current studies indicate that much of the reservoir bulk porosity is inaccessible through current production practices. There is a potential for improved recovery.
2. Two versions of a full field Jatibarang model have been created from the old grid structure and using the current geological understanding of the reservoir from log and well-test analyses on a small number of wells. The differences between the old model and the current two have been documented.
3. Previous changes to the old model to obtain a history match with production data cannot be justified on the basis of our current understanding of the reservoir description.
4. The two current models must be viewed as approximations for a more extensive review of the reservoir in future studies.

V. RECOMMENDATIONS

1. It is very likely that more of the original oil in place could be accessed to add to the reserves, through a combination of horizontal drilling and fracturing. A finer grid, multi-layer model is needed to test the economic feasibility of this concept.
2. A full field review of the reservoir geology and engineering data is needed.
3. A new model needs to be constructed, based on our current understanding of the reservoir.
4. Pseudos, needed for coarse grid models, must be generated scientifically rather than tuned for a history match, although it is accepted that final fine-tuning is unavoidable.
5. The scientific approach to generating reservoir pseudos involves fine grid 2D cross-sectional studies in X and Y directions of the grid within the main producing section.
6. Pseudos for wells with high water and gas cuts should be generated through the use of coning studies on fine grid radial models.
7. Improved oil recovery using horizontal drilling in wells with high water/gas cuts should be tested on three dimensional sector models.

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