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A Compartmented Simulation System for Gas Reservoir Evaluation With Application to Fluvial Deposits in the Frio Formation, South Texas

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ABSTRACT

We present comparisons of simulations of performance histories for wells in highly compartmented, fluvial gas reservoirs generated by very precise finite element models and a much simpler multi-compartment material balance model. These comparisons validate the capability of this simple compartment model for the evaluation of compartmented reservoirs. Specifically we show that history matching of well performance with this simple model provides excellent estimates for directly drained pore volumes, supporting secondary pore volumes and inter-compartment transmissibilities.

INTRODUCTION AND GEOLOGIC BACKGROUND

Reservoir heterogeneity is well recognized as a factor limiting recovery in oil and gas reservoirs. Simulation techniques for characterizing reservoir variability have appeared recently in the literature. Stewart and Whaballa[1] have shown that a material balance simulator can be used with pressure histories from well tests in compartmented oil reservoirs to identify geological configurations. Hower and Collins[2] introduced a material balance model for a two-compartment gas reservoir, in which the compartments are coupled by a low permeability barrier. This was shown to provide a technique for identifying compartment structure through history matching field pressure data. Furthermore, these authors presented a rigorous criterion which specifies when observed shut-in pressures are representative of average reservoir pressures. This criterion is necessary for the application of the compartment model to gas reservoir analysis. A further study by Lord and Collins[3] generalized the compartment model so that a gas reservoir is represented by any number of permeable compartments with communication between compartment pairs through low permeability barriers. This numerical simulation system provides for very general specification of well operation. It allows the user to match observed pressure histories by specifying historical rate data or match well rate histories by specifying well production pressure histories. This simulator has been shown to be very effective in history matching field data with resulting estimates of primary and secondary drained pore volumes.

References and illustrations at end of paper.

The study presented here was designed to demonstrate that the compartment model is capable of describing drained pore volumes in diverse reservoir configurations. The reservoir configuration of particular interest is that which would represent the fluvial depositional system of the middle Frio Formation (Oligocene in age) of the South Texas Gulf Coast (Galloway[4], Kerr and Jirik[5]). Gas reservoirs in these fluvial deposits are largely developed in sandstones of the channel-fill facies; reservoirs are also developed in sandstones of the splay facies. The channel-fill facies is divided into three subfacies based on texture and sedimentary structures (Kerr and Jirik[5], Kerr, et al[6]): (1) the lower channel-fill subfacies, composed of mudstone intraclast pebble to granule sandy conglomerate and/or large-scale trough cross-stratified medium- to fine-grained sandstone; (2) the middle channel-fill subfacies, composed of subhorizontal parallel-stratified and ripple-laminated, fine- to very fine-grained sandstone with lateral accretion surfaces and chute-channel-fill deposits; and (3) the upper channel-fill subfacies, composed of muddy sandstone grading up to sandy mudstone with poorly developed parallel stratification.

The lower and middle channel-fill subfacies are the principal reservoir rocks. For much of the middle Frio, permeability to air is controlled by an intergranular pore system with a high degree of spatial correlation related to stratification

(Kerr, et al[7]). Permeability to air in upper channel-fill sandstones is two-orders of magnitude less than that in lower and middle channel-fill sandstones with no spatial correlation observed (Kerr, et al[7]). The magnitude of permeability, however, is strongly affected by framework composition and subsequent diagenesis (Grigsby and Kerr[8]). Permeability reduction in the upper channel-fill sandstones is in part related to early infiltration of fines, through bioturbation and soil-forming processes and calcite cementation which together reduce pore volume and obstruct pore throats (Kerr, et al[7]). Mudstones of the upper channel-fill subfacies have measured permeability to air, at surface conditions, of 0.01 md or less.

The architectural arrangement of middle Frio Formation fluvial sandstones has important implications for potential reservoir compartmentalization. Three scales of architectural elements, as described by Kerr[9] and Kerr, et al[6], are readily identifiable in the subsurface. (1) Lateral accretion bar deposits are the principal channel-filling element. In general, these deposits occur as net-sand isopach thick sites staggered from one side to the other in each discrete levee-confined channel system; distance between centers of thick isopach areas is about 2,500 feet (Figure 1). (2) An individual levee-confined channel system with its attendant splays, is the larger scale architectural element (a discrete genetic interval of Kerr and Jirik[5]). (3) The stacking pattern of middle Frio fluvial systems forms a continuum from lateral stacked, exemplified in Figure 1, where sandstones bodies contact one another or are vertically separated by only a few feet of mudstone, to vertically stacked, where substantial thicknesses of floodplain mudstones separate sandstones (Kerr and Jirik[5]).

MODEL DESCRIPTIONS

Production based on these architectural elements is simulated in a detailed physical representation of the reservoir by means of a finite element simulator. Details of this finite element simulation system are given by Kocberber and Collins[10]. Well performance histories generated by these numerical experiments are then history-matched using the compartment model. Pore volumes determined in parameter assignments to achieve these matches are found to be in excellent agreement with actual pore volumes of the detailed finite element models.

The compartment model reservoir realization consists of a number of compartments which operate in a tank-like manner. A compartment is in flow communication with other compartments through low permeability barriers. Each compartment is completely described by its pore volume and each inter-compartment barrier is characterized solely by its transmissibility, KA/L, where K is the barrier permeability, A is the area normal to the flow direction through the barrier and L is the length of the flow path through the barrier. Gas PVT properties are correlated to reservoir temperature and gas gravity. Wells have either rate specified or wellbore pressure specified histories with operation dynamic in time. For pressure specification, a pseudo steady state inflow performance equation[11] relates average compartment pressure, flowing wellbore pressure and well rate. Finally, the initial pressure must be specified. With the above information, the compartment model simulation system performs a material balance for each compartment over time with flow across barriers modeled as linear Darcy flow. The simulator reports the pressure history for each compartment and the production history for each well and each compartment. A mathematical description of the simulator is given by Lord and Collins[3].

The compartment model computes histories for average compartment pressures. Therefore, history matching requires field measured shut-in pressures to be representative of average compartment pressure. A criterion defining this condition is given by Hower and Collins[2]. Application of this criterion under normal well pressure testing procedures (24 hour shut-in) shows that shut-in pressures are representative of average reservoir pressures when permeability is much greater than 5 md. For reservoir permeability much less than 5 md, the 24-hour shut-in pressures are significantly below average pressures and extended shut-in periods would be required. Thus, application of the compartment model simulator is appropriate for intermediate to high permeability reservoirs while it is not an appropriate tool for low permeability reservoirs.

An idealized single well, two compartment reservoir system is shown in Figure 2. Normally, initial pressure at completion is known and reservoir temperature and gas gravity are also known. If the production history of a well is specified, then the reservoir drainage behavior is completely determined by the pore volume of the primary drained compartment, the pore volume of the secondary supporting compartment, and the barrier transmissibility. If adequate shut-in pressure data are available, the compartment model allows a history match of the observed shut-in pressures for a specified rate history of the well by adjustment of these three reservoir parameters. If the pressure data are sparse or unreliable, a further history match procedure is available. Knowing the operating wellbore pressure history and the production rate history, a match for the production rate history can be made by adjustment of the same three reservoir parameters together with the two well inflow performance parameters. Any available shut-in pressure data should also be honored during this history match. This procedure is demonstrated in one study in this paper.

The power of the compartment model simulator is the simplicity of the reservoir description. No information is required concerning the compartment geometry or properties other than pore volume. Flow between compartments is determined by the barrier transmissibility. The history match process determines these parameters, thus describing gross reservoir response and identifying potential secondary gas reserves. Further, once the history match has identified reservoir and well performance parameters, the simulator can predict future drainage and resulting recovery efficiency.

INTRA-CHANNEL HETEROGENEITY STUDY

The intra-channel heterogeneity study simulates compartmentalization between lateral accretion bar deposits within a single channel. Figures 3 and 4 present an idealized geometric model of architectural element dimensions, net sands isopachs and permeability units for a typical middle Frio fluvial channel system. Regions between the lateral accretion bars and between the bars and the channel boundary are mostly filled with mudstone; the mudstone has very low permeability and for modeling purposed is assumed impermeable. The lower 1 to 5 foot in thickness across the area between bars is modeled having a low permeability (upper channel-fill subfacies sandstones). For modeling purposes, the bulk of the lateral accretion bar deposits (lower and middle channel-fill subfacies) are simplified to an interval with a single permeability value (values K_1 and K_2 combined, Figure 4). The range of permeability is 10 to 100 md; if the compartment model simulation successfully matches shut-in pressures at the low permeability, then it should prove equally successful for the high permeability. Therefore, the bar (lower + middle channel-fill subfacies) was assigned a permeability of 10 md.

Figure 5 is a 2-dimensional representation of the channel system. The cross-section in Figure 5 shows the point bars represented by high permeability sandstones while the barrier is represented by a thin layer of low permeability sandstones overlain by impermeable mudstone. The reservoir dimensions are shown in Figure 5. The well was produced at fixed wellbore pressure to an economic rate limit of 100 Mcf/d. The upper channel-fill barrier properties were adjusted so that at the end of production a pressure difference of approximately 1500 psi existed between the production well and the offset well, labeled as observation well 1 in Figure 5. Pressure differences at offset well completions of this magnitude have been observed in the field.

Values used in this study for sand permeability, porosity and thickness, for both the upper and lower channel-fill are summarized in Table 1. Reservoir temperature was 162°F and gas gravity was 0.65. Well production was maintained by a flowing well pressure of 200 psi with 24 hour shut-in periods at intervals of cumulative production of approximately 0.5 Bcf.

This reservoir system and well operation history were modeled by finite element simulation. The finite element grid is shown in Figure 5, where local grid refinement corresponds to regions of high pressure gradient. The simulated shut-in well pressures, together with the pressures at the two observation wells, are shown as P/Z versus cumulative production in Figure 6.

This complex reservoir system with known production history and pressure response was then modeled with the compartmented reservoir simulator. The reservoir was conceptualized as two compartments with production from the first compartment and supporting flow across a permeable barrier from a secondary compartment. Using the rate history from the finite element simulation as input, the compartment model generated the pressure history shown in Figure 6. This match to the finite element data was obtained by adjustment of the two compartment pore volumes and barrier transmissibility with the resulting values:

primary drained pore volume	=	8.0 MMcf
secondary pore volume	=	25.0 MMcf
barrier transmissibility	=	4.67 md-ft.

From the reservoir geometry and porosity the actual pore volumes of the reservoir realization yield 8 MMcf for the primary pore volume and 24.7 MMcf for all pore volume outside of the primary volume. The barrier adjacent to the primary drained volume is approximately 8000 feet long,1000 feet across, and 1 foot high with a permeability of 0.5 md. This gives a barrier transmissibility estimate

$$KA/L = 0.5 \times 8000 \times 1/1000 = 4.0 \text{ md-ft.}$$

The compartment model results are in excellent agreement with the actual channel sand reservoir realization. Also of interest, the recovery efficiency at abandonment is 42% of OGIP. This would suggest that in an actual field case significant secondary gas reserves (2.8 Bcf) exist and further study, such as pressure interference tests or seismic survey, could target infill drilling or recompletion sites.

INTER-CHANNEL HETEROGENEITY STUDY

A second study considered a uniform channel deposit sandstone with a younger channel system partially down-cut into an older channel deposit. This produced two vertically configured compartments, with communication through the interface between the two channel system. Such an interface may be extensive in area but typically consists of low permeability shale. A possible realization for such a reservoir configuration is shown in Figure 7.

This reservoir realization consists of two vertically arranged homogeneous sandstone compartments. Communication between the two compartments is through a low permeability sand or mud in the interface between the two compartments. Both channel sands had properties assigned as:

$$Kh = 100 \text{ md-ft}$$
$$\phi h = 0.606 \text{ ft}$$

while the interface barrier was characterized by

$$K/L = 0.8 \times 10^{-6} \text{ md/ft}$$

The reservoir temperature was 162°F with a gas gravity of 0.65. The reservoir had an initial pressure 2550 psi. The two production wells were operated at a flowing well pressure of 200 psi until economic abandonment at a rate of 100 Mcf/d. The barrier K/L, as given above, was selected so that at abandonment of the producing wells the pressure at the observation well was 1000 psi. A finite element simulation generated the rate history shown in Figure 8.

With only these well production data and the one final pressure at the observation well the compartment model was used to estimate the drained pore volumes and barrier transmissibility. In this study the actual flowing wellbore pressure history is known. The compartment model was configured as a single well in one compartment of a two compartment system. The single well rate represents the combined rates of the two wells in the finite element simulation. The history matching process requires adjusting the two compartment pore volumes, the barrier transmissibility and the Darcy inflow performance coefficient for the well so that the observed rate history is matched together with the final pressure in the unproduced supporting compartment. The resulting rate and pressure matches are shown in Figures 8 and 9, respectively.

The parameters resulting from this match were:

primary pore volume	=	20 MMcf
secondary pore volume	=	17 MMcf
barrier transmissibility	=	8.0 md-ft
Darcy coefficient	=	55000 psi /cp/Mcf/d

The actual pore volume was 18.2 MMcf in each of the produced and secondary channel sands. The compartment model history match estimates both of these volumes to within 10%. The barrier transmissibility in the finite element model was:

$$(K/L)A = 0.8 \times 10^{-6} \times 3000 \times 3000 = 7.2 \text{ md-ft}$$

and the compartment model history match fixes this barrier transmissibility to within 11%.

It is significant that in this inter-channel study, the compartment model yields good estimates of drained volumes and barrier transmissibility while employing very limited production data.

DUAL PERMEABILITY RESERVOIR STUDY

In Lord and Collins[3] a compartment model study considered the Wardner 80T well, completed in the Frio F-39 reservoir, Stratton field, Kleberg County, Texas. The production history of the Wardner 80T indicated a compartmented reservoir with significant untapped secondary gas reserves. Also, the compartment model predicted a pressure in the secondary compartment which was confirmed in an offset well, the Wardner 182D. This demonstrated that the Wardner 182D well tapped a partially drained secondary compartment indicated by the analysis of the Wardner 80T production history.

However, the Wardner 182D completion proved unproductive and was abandoned. Further, the conventionally drawn net sand map in Lord and Collins[3] of the F-39 reservoir shows the well pair in communication through a continuous reservoir sand of approximately 20 feet at the Wardner 80T decreasing to about 10 feet at the Wardner 182D. Clearly this isopach map was not adequate in defining reservoir heterogeneity and reservoir productivity.

This example suggests that significant secondary gas may exist near a productive well, but the secondary compartments may not prove commercially productive.

This phenomenon is not unique to this well pair. Other well pairs have shown similar behavior. This behavior can be accounted for when a high permeability sand is in direct communication with an extensive muddy, low permeability sand. Production from the high permeability sand will experience pressure support very similar to a compartmented reservoir, but an offset well, completed in the low permeability sand, will have low productivity.

A numerical study was made to verify and quantify this behavior. Such a dual permeability reservoir system is shown in Figure 10, with a well located in the high permeability sand. Figure 10 shows the grid used in the finite element simulation with local refinement across the permeability discontinuity. The well is produced at a constant flowing pressure of 200 psi. Pressure profiles along the section of symmetry, A-A', through the wellbore are shown in Figure 11 at four periods during the production history. The produced compartment experiences secondary supporting flow from the low permeability region of the reservoir. However, the low permeability region is not tank-like in that it operates at a very non-uniform pressure. The finite element simulation included four 24-hour shut-in periods. These pressures are shown in Figure 12 where P/Z is plotted versus cumulative production. A compartment model history match to the pressures generated by the finite element model, using the actual rate history, yields the match shown in Figure 12. This match is obtained with the parameters:

primary pore volume	=	16 MMcf
secondary pore volume	=	13 MMcf
barrier transmissibility	=	47 md-ft.

The primary pore volume for the finite element simulation is the pore volume included in the high permeability region and the secondary pore volume is that included in the low permeability region. A comparison of pore volumes predicted by the compartment model with the actual reservoir volumes is given in Table 2.

The compartment model estimate of barrier transmissibility, KA/L, given above, can be combined with the cross-sectional area, A, of the barrier to give

$$\text{barrier } K/L = 1/850 \text{ md/ft.}$$

Hence a 1 md barrier would be 850 feet thick. The compartment model simulates the dual permeability reservoir as two high permeability compartments separated by a low permeability barrier. However, the compartment model estimates the drained pore volumes with reasonable precision even though pressure in an offset well completion located in the low permeability region of the reservoir could differ significantly from the average compartment pressure predicted by the compartment model.

The results of this study quantify the compartmented reservoir behavior of a dual permeability type reservoir. The compartment model will effectively predict primary and secondary pore volumes, but estimates of the pressure distribution in a secondary compartment may be in error. In the dual permeability reservoir it is clear how the production of a well may indicate significant secondary gas, but attempted recovery of this gas through infill development can prove ineffective. This further emphasizes the fact that results of compartment model simulation require support from further engineering and geologic study.

CONCLUSIONS

The simulation studies in this paper were designed to represent geological configurations typical of the fluvial reservoirs found in the middle Frio Formation of the Texas gulf coast. An areal finite element gas reservoir simulator was used to generate synthetic "field" production data in such reservoirs. These synthetic well rates and pressure histories were then history matched by a material balance, tank-type compartmented reservoir simulator. The results show the compartment model simulator to be very effective in estimating drained and secondary support pore volumes for each of these reservoir configurations. A successful history match for the inter-channel model was achieved using only rate history and a single pressure observation at the end of production. Limitations of the compartment model in the case of the dual permeability reservoir showed that real secondary compartment pressures are not uniform, as in a tank, and will not be accurately represented by the compartment model simulator.

The studies presented are valuable benchmarks for the compartment model simulator. With insight from these studies better engineering interpretation of actual field behavior is possible. Simplicity of application is the power of the compartment model simulator; however, the results of the simulation system are not definitive in answering all questions necessary to formulate a successful infill development strategy for a mature gas field. The compartment model simulator does provide an effective tool for initial study and identification of reservoirs with potential for successful secondary infill development.

NOMENCLATURE

A = cross section area of barrier, ft^2
h = reservoir thickness, ft
K = permeability, md
L = barrier thickness, ft
P = average compartment pressure, psi
q = gas flow rate, Mcf/d
V = pore volume, ft^3
Z = gas compressibility factor
ϕ = porosity, fraction

Subscripts

wf = well, flowing conditions

ACKNOWLEDGEMENTS

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Table 1
Channel Sand Properties of Middle Frio Formations

	Permeability (md)	Porosity Model	Thickness (ft)
Lower Channel Sand	10	.2	10
Upper Channel Sand	.5	.05	1

Table 2
Pore Volume Comparisons

	Finite Element	Compartment Model	Difference
Primary Pore Volume (MMcf)	14.8	16	8%
Secondary Pore Volume (MMcf)	13.2	13	-2%

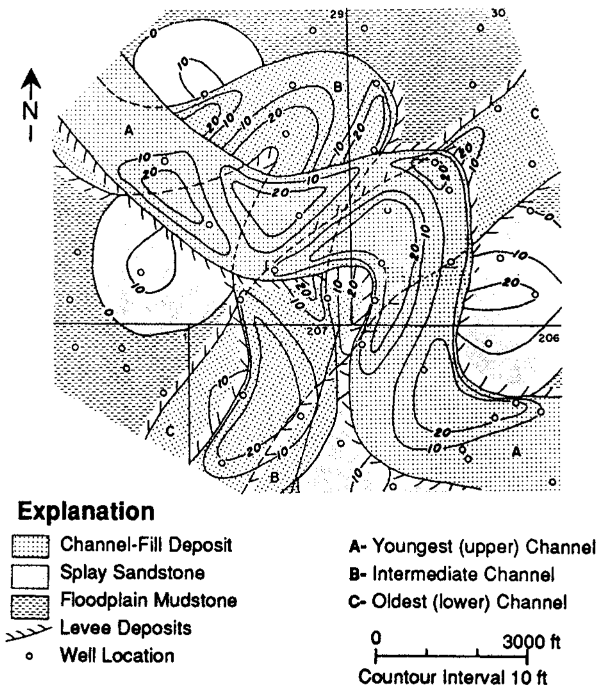


Figure 1.
Facies and net-sand isopach map of the C18 reservoir (Stratton field).

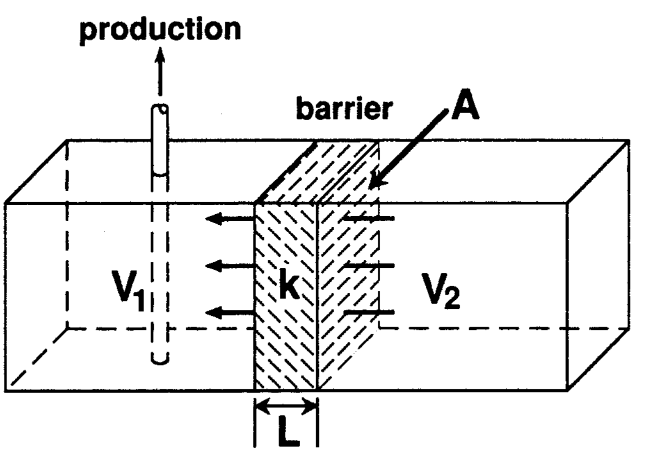


Figure 2
Idealized two compartment tank model with permeability barrier.

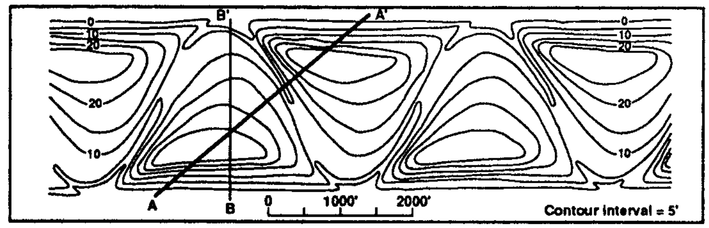
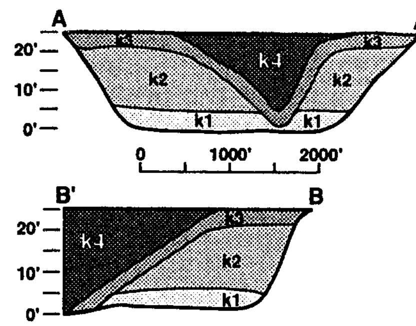


Figure 3
Net Sand Map, Middle Frio Formation Channel Model



	Subfacies	Permeability
k1	lower sand	high
k2	middle sand	intermediate
k3	upper sand	low
k4	upper mud	impermeable

Figure 4
Cross-Section Permeability Distribution in Point Bar Streambed

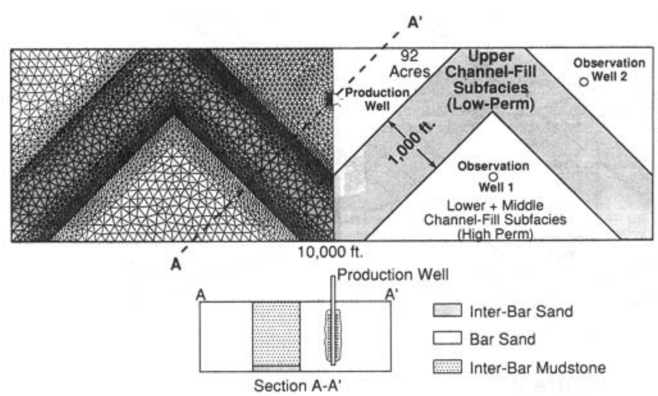


Figure 5
Intra-Channel (Point Bar) Heterogeneity Evaluation

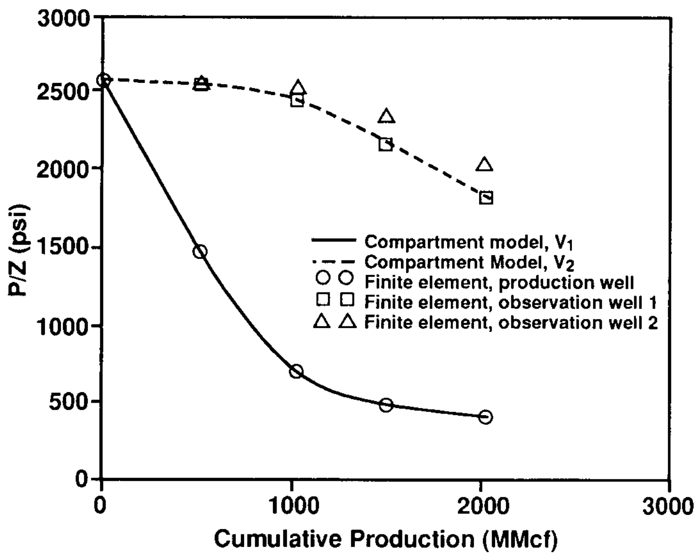


Figure 6
Pressure Histroy Match for Intra-Channel Heterogeneity Study

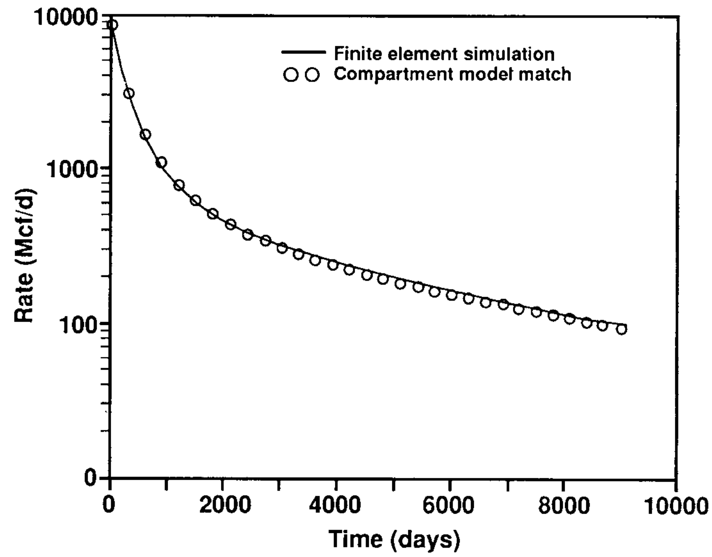


Figure 8
Inter-Channel Heterogeneity Rate History Match

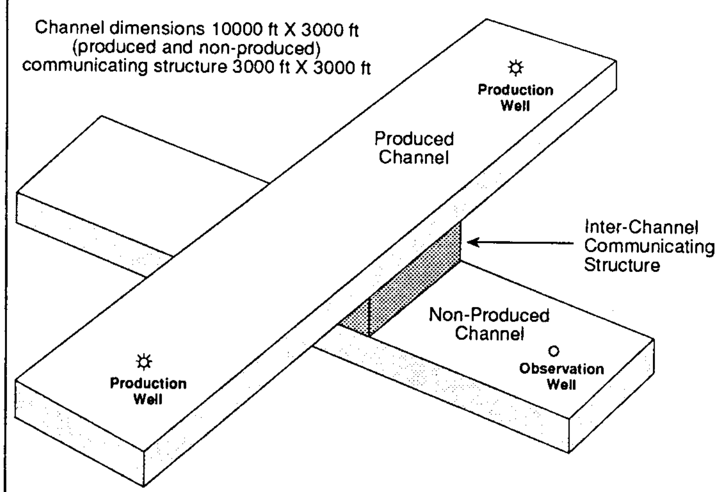


Figure 7
Inter-Channel Heterogeneity Evaluation

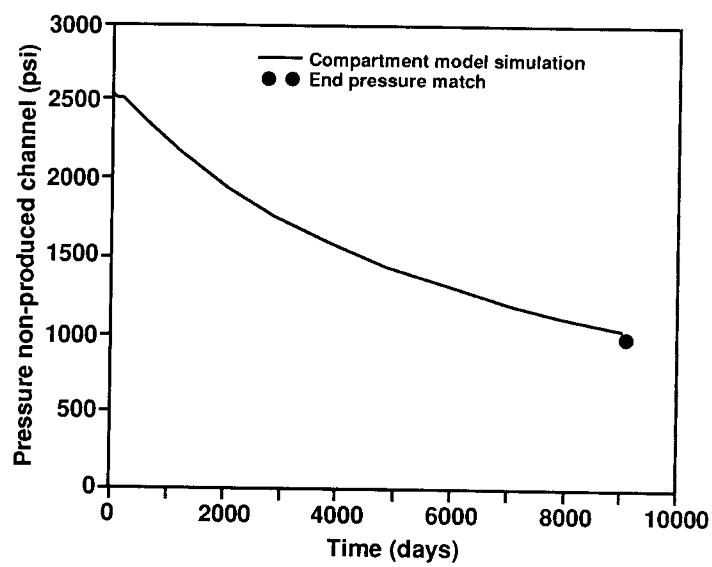


Figure 9
Inter-Channel Heterogeneity Pressure History Match

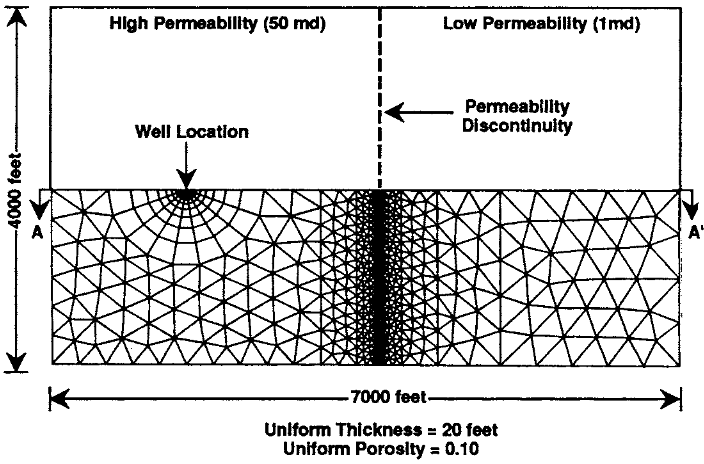


Figure 10
Dual Permeability Reservoir Geometry with Finite Element Grid (Symmetry about section A-A')

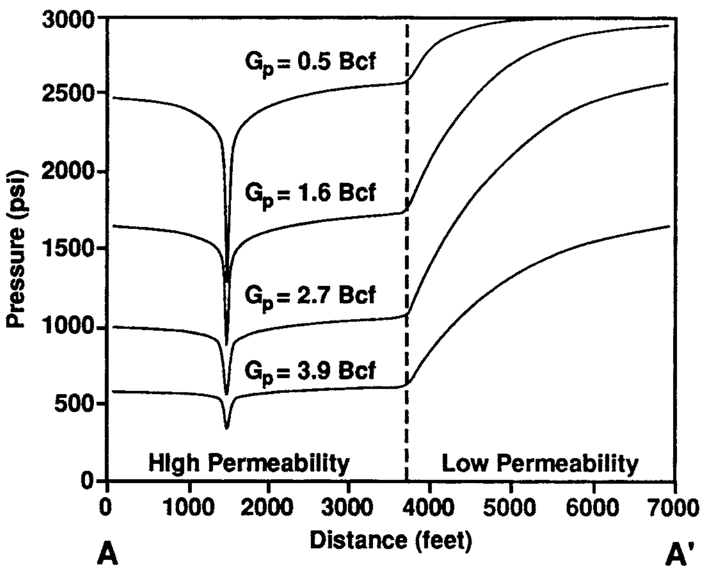


Figure 11
Dual Permeability Reservoir Pressure Profile History: Finite Element Model (Pressure Along Section A-A')

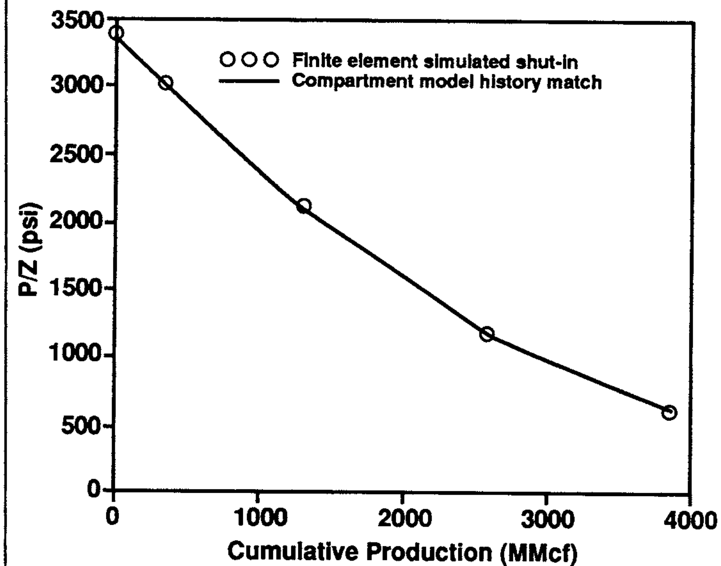


Figure 12
Dual Permeability Pressure History Match