Epic

Newsletter

Winter 2001/2002

Full-Field Modeling Using Streamline-Based Simulation: 4 Case Histories

Introduction

Until now streamline-based flow simulation was limited in its application to reservoir engineering. Recent advances in streamline-based flow simulators have overcome many of these limitations. Streamline-based simulators are now fully 3D and account for multiphase gravity, fluid mobility and compressibility effects. Changing well conditions due to rate changes, infill drilling, producer-injector conversions, and well abandonments are also accounted for.

With advances in streamline (SL) methods, the technique is becoming a standard tool to assist in the modeling and forecasting of field cases. Published case studies using SL simulators are now appearing from a variety of sources. This article briefly discusses streamline methods, and then presents four large field-scale history matches that have been conducted by EPIC.

The Streamline Simulation Method

The SL simulation method solves a 3D problem by converting it into a series of 1D problems, each solved along a streamline. Unlike finite difference (FD) simulation, SL simulation relies on transporting fluids along a dynamically changing streamline-based flow grid, as opposed to a fixed underlying Cartesian grid. The result is that large time step sizes can be taken without numerical instabilities giving the streamline method a near linear scaling in terms of CPU efficiency versus model size. SL simulators can be 1 to 2 orders of magnitude faster than FD methods for very large models. Table 1 below lists some studies that used SL simulation. Note the relative speed regarding run times and the large numbers of grid blocks used in the models.

For a detailed discussion and a list of additional references describing SL methods see: Batycky, R.P., Blunt, M.J., and Thiele, M.R.: "A 3D Field Scale Streamline-Based Reservoir Simulator," SPE Reservoir Engineering (November 1997) 246-254.

Co.	Type	History (# yrs)	#cells (thous)	#wells	Runtime (hrs)	History Match (months)
Epic	W.F-Light oil	45	89	88	1<	1
Epic	W.F-Heavy oil	15	105	105	1<	2
Epic	W.F-Heavy oil	37	150	156	1<	1
Other	W.F/Misc.	38	450	700	NA	NA
Other	W.F	25	164	115	NA	NA

Table 1

Epic's Dennis Beliveau Honored by SPE

Dennis Beliveau, Vice President, Epic Consulting Services Ltd. received the "Reservoir Engineering Award" at the Annual SPE Convention held in New Orleans in October of 2001. Dennis was honored for his expertise and significant contributions to waterflooding; advanced reservoir characterization, especially in naturally fractured and carbonate reservoirs; reservoir surveillance; the use of horizontal wells; and the study of risk and uncertainty. Dennis is also author of numerous reservoir engineering papers, including "Honey, I Shrunk the Pores". Dennis received the JPT Best Paper of 1995 Award for his paper entitled "Heterogeneity, Geostatistics, Horizontal Wells, and Blackjack Poker".

Streamline Simulation Within Reservoir Modeling

Reservoir engineers have a suite of tools available to model reservoirs, ranging from simple analogy methods to full field simulation. The tool chosen depends upon the availability of data, amount of time allotted, and accuracy of outcome required. As shown in Figure 1, SL simulation is part of the high-end modeling domain where a significant amount of data and data preparation is required, final answers are detailed, and a high degree of confidence is achieved from the tools' predictive abilities.

(Continued on page 2)

inside . . .

Full-Field Modeling Using Streamline-Based Simulation: 4 Case Histories . . . continued

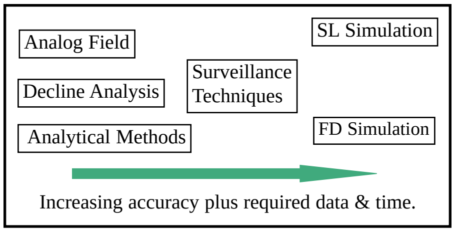

Figure 1: Evaluation Methods

It is important to understand that no single simulation technique can be applied to all cases. SL simulation is well suited to the solution of very large models that are dominated by convective displacement processes (i.e. waterflood, miscible flood and WAG) where PVT behavior is only a weak function of pressure (quasi-incompressible). Generally a criteria we use for SL simulation is to have a cumulative voidage replacement ratio of VRR>0.9 and water drive/waterflood drive index >0.8. Our experience has shown that many waterfloods are well suited for SL simulation.

On the other hand, FD simulation is well suited to small models where complex surface modeling is required or the details of fluid physics such as high compressibility (live-oils, condensates), capillary effects and relative permeability hysteresis are important. The decision is really, ***1) how much geological detail and how large of an area do you want to model? versus 2) how important is the flow physics?*** Of primary consideration in achieving an accurate field solution is the ability to model the entire field as opposed to a portion of the field. The large number of wells in a full-field model dictates the minimum grid size, and therefore the number of grid blocks, which are typically in the order of 100,000+ active cells. For models of this size, SL simulation is at least one order of magnitude faster.

Why Streamline-Based Simulation is Successful

Our experience indicates that the first reason SL simulation is effective in many field cases is that the inclusion of a large areal extent, and offset wells, is absolutely critical to understanding/modeling flood performance in a study area.Including all wells removes the uncertainty associated with outer boundary conditions.

The second advantage of SL simulation is visualization and quantification of the injector-producer relationship. Streamlines give direct information about which areas of the reservoir affect any particular well (see Figure 7 from Case History “C”). One can rapidly converge to a history match based on quantitative data from a SL simulation rather than blindly adjusting grid properties based on the engineer’s judgment of flow.

The third reason why streamline technology is successful is that well pressure constraints are not a limiting factor for incompressible systems. This allows for convection of water and oil in the reservoir according to measured total well rates. This yields a rapid solution to the transport problem.

In most conventional FD simulations the history match work flow is as follows:

1. The global pressure history match (material balance), followed by
2. The transport history match portion (i.e., watercut profile) and
3. Well tuning (matching drawdown pressures).

Unfortunately it is often hard to decouple the history matching stages, and well constraints may dominate the two initial stages. This can result in a big work slowdown especially in large simulation models with long well histories and high well counts.

The stringent adherence to this workflow process, with FD simulators, requires the solution of the inflow, or well productivity, problem before the larger scale material balance or transport problem can be resolved. This approach is often misleading and usually inefficient because the lesser-known parameters (e.g. wellbore skin, effective kh, lateral and vertical connectivity, drawdown, etc.) are being modified to match known parameters, such as produced volumes and flow rates. The streamline approach is more intuitive in that the known voidage displacement and transport problem is solved initially, providing a more accurate portrayal of the ‘big picture’ before fine-tuning unknown parameters on a smaller scale. In other words, SL simulation allows easy decoupling of the history match problem.

The fourth and perhaps most important reason why SL simulation is successful is simply that a larger number of grid cells allows for better areal and vertical resolution.

Field Studies

Field A

The first case study is an example of a high permeability sandstone reservoir that consists of two major sand units commonly referred to as the “upper” and “lower” units. The average porosity and permeability of the upper sand is 30% and 2000 md, respectively. Porosity and permeability in the lower unit is slightly lower. This is a heavy oil reservoir with an insitu oil viscosity of 600 cp at initial conditions. There are 119 wells of which 27 are injectors. The total number of grid blocks were 247,500.

(Continued on bottom of page 3

Full-Field Modeling Using Streamline-Based Simulation: 4 Case Histories . . . continued

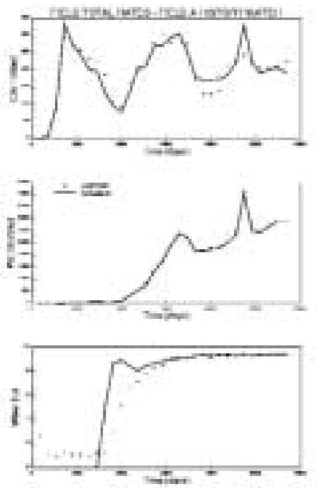

Figure 2: Streamline simulation: History Match Results

SL simulation was performed using the incompressible option in 3DSL. This is suitable when simulating reservoir performance that is dominated by voidage replacement as opposed to a depletion drive mechanism. Field A exhibited a cumulative voidage replacement ratio close to unity. The primary objective of the SL simulation is to match the water cut and oil rate profile. As observed in Figure 2, an excellent match was obtained between the historical data and simulated results.

In general, it was found that the highest water saturation exists in the bottom of each sand unit. Although the density difference between oil and water phases is only about 5%, gravity has a large impact on water movement because of high mobility and relatively high vertical permeability (i.e., even with a low kv/kh ratio). Because of the unfavorable mobility ratio, water generally under-rides oil when pushed laterally through a reservoir. This is witnessed in the saturation plots of the Upper and Lower sand.

Streamlines were greatly influenced by the modeled geological scenarios. Modifying the vertical transmissibility changes the dynamics of water underriding oil and also changes the connectivity between pressure sources (i.e., injectors) and pressure sinks (i.e., producers) when perforation intervals are staggered vertically. The streamlines may therefore be concentrated in different areas, between some wells, thereby altering focal points of some subsequent changes, required to optimize the history match.

Field B is similar to Field A in that the modeled sandstone layers have an overlying conglomerate although, in this case, more continuous. Also, the underlying sandstone intervals have much lower permeability (one or two orders of magnitude lower). The conglomerate only contains about 10% of the OOIP however has permeability in the 1.0 Darcy range and therefore acts as the primary conduit for water movement. The layers are also quite stratified and vertical permeability is limited (i.e., kv/kh < 0.01).

The five model layers therefore ultimately comprised of:

1) Conglomerate
2) Upper high perm sand (~ 100md)
3) Upper low perm sand
4) Lower high perm sand (~20 md)
5) Lower low perm sand

SL simulation is useful in this application because one can readily determine the origin of total liquids flowing into a producing well, at any given time. If the area has shown early depletion of mobile oil saturation it would suggest that the residual oil saturation is too high. Conversely if the area still has plenty of mobile oil yet, historically, the well should be watering out already, it would suggest the residual oil saturation is too low.

All 200+ wells were set to produce historical liquid production rates to honor total voidage displacement. Oil rates and the corresponding water-cut for each well could then be matched.

ResAssistTM, the graphical user interface to 3DSL, used to input data and review streamline output, was also used to modify the geology, as shown in Figure 3.

Figure 3 shows the preferential flow paths introduced in the Conglomerate (k > 10 Darcies).

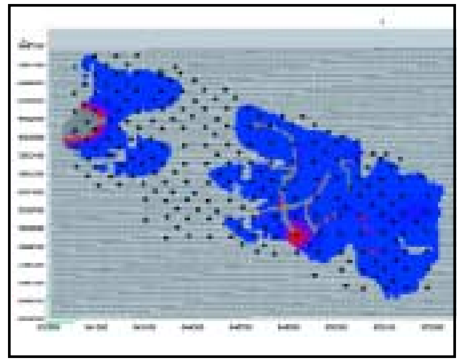

Figure 3: Conglomerate Permeability

Aside from the relatively few high permeability 'paths' in the two top layers, the permeability distribution is the same as reflected in input maps.

The final history match is shown with the Base Case forecast (i.e., with existing wells) in Figure 4. The simulated field oil production rate shows an excellent correlation with the historical oil production curve. Individual well history matches, particularly those of the high producing wells, were also very good.

After an acceptable history match was attained, forecast scenarios were run over a 30-year period. The conglomerate, is fully swept by the end of the history match period, and therefore not completed in forecast scenarios. Initially, 50 infill wells were modeled, including 14 injectors and 36 producers to continue developing the field with a reduced spacing, as was done in other parts of the field. Wells having cumulative oil production of less than 125 MBbls before producing a water volume of 2.5 MMBbls, were subsequently

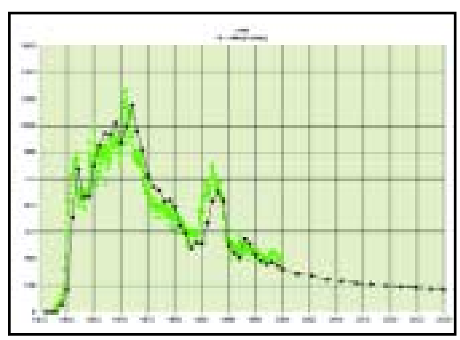

Figure 4: Base Case Forecast

(Continued on page 4)

Full-Field Modeling Using Streamline-Based Simulation: 4 Case Histories . . . continued

eliminated. The 'optimized' forecast, with two dozen additional producers, and half as many new injectors, is shown in Figure 5.

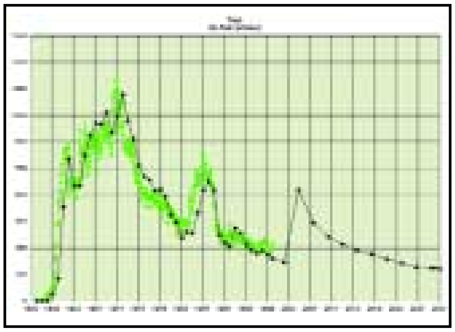

Figure 5: Optimized Waterflood Forecast

This case study showed how SL simulation could be used to more than double the field productivity and increase the ultimate recovery factor by more than 5%.

Field C, another heavy oil field example, consisted of approximately 150+ wells and 37 years of history. Again, a SL simulation was used to identify unswept portions of the waterflood. The oil/water viscosity ratio was approximately 180, the oil/water surface density ratio was approximately 0.9, the average Bo was 1.03 and the average Bw was 1.00. Lastly, water injection was implemented sufficiently early such that the field pressure has always been maintained above the bubble point.

The reservoir is comprised of 3 main sand bodies, each one in weak communication with the other. The top sand is long and thin with kv/kh=0.02, the middle sand is small and discontinuous with a kv/kh=0.1, and the bottom sand is large and areally extensive with kv/kh=0.02 and is connected to an underlying water-oil contact to the west (i.e., half of the layer). The simulation model consisted of a corner-point geometry grid with 150x375x12 cells, equal to 675,000 of which 156,000 cells are active. Model run-times were less than one hour per history match on a P3-700MHz computer.

A history match was achieved in about 15 iterations. Absolute permeability was adjusted based on streamline and well allocation factor data. A small adjustment was also made to the residual oil saturation of the relative permeability curves. The final overall field history match is shown in Figure 6. While a well-by-well history match is difficult to quantify with 150+ wells, we did note that 77% of producers having a cumulative oil production of 10,000+ sm3 were within +/-10% cumulative water production.

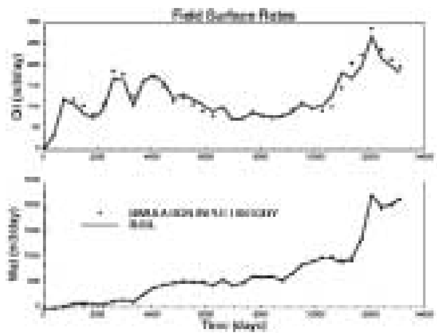

Figure 6: Field History Match

Several forecast runs were made for both infill locations and producer-injector conversions. Because the model was an incompressible system, infill and conversion wells could not be placed on BHP but, instead, were set to total surface liquid control. Infill rates were based on offset production liquid rates. Offset injection rates were increased accordingly. A similar adjustment was made when modeling conversions.

The simulations revealed the following;

1. The streamline distribution (Figure 7) clearly showed that there are no isolated reservoir regions and it would be difficult, if not impossible, to extract only a portion of the reservoir for flow simulation.

2. Although the density ratio was only 0.9, gravity under-ride was significant in this flood with higher water saturations seen in the bottom of each sand body.

3. The optimal recovery of bypassed oil was via producer-injector conversion rather than in-fill drilling. This was because a smaller incremental oil recovery was needed to justify conversions as opposed to infill wells.

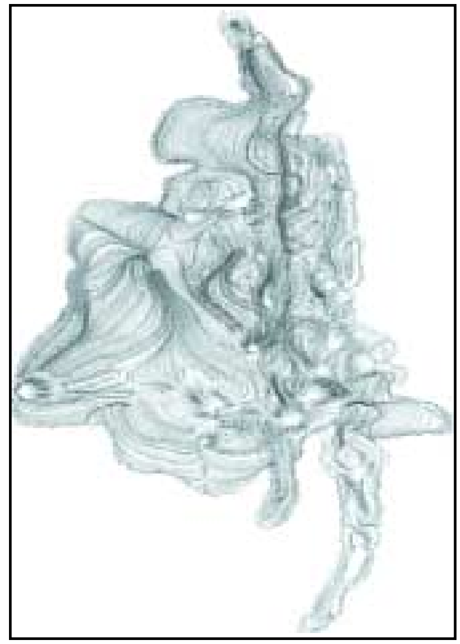

Figure 7: Field C Streamline Distribution

Field D

For commercial reasons, this study examined the potential to optimize a small sector (49 wells out of approximately two thousand) of a large field unnder waterflood. The mature field had been on production for 45 years and recovery was at 88% of its ultimate recovery (43% of OOIP), based on decline analysis. Strong indications of heterogeneity suggested that there may be unswept areas available as infill well targets, despite the fact that the current well spacing was approximately 50 acres/well.

The reservoir was comprised of a slightly higher permeability conglomerate (60 md, 9% porosity) overlaying two sand units of similar quality (30-40 md, 19% porosity). A shale barrier separates the two sands throughout the field. The oil is light with a gravity of 36 API and a viscosity of 0.64 cp. Due to the oil/water surface density ratio of 0.84, ten layers were used to capture the impact of gravity. The cornerpoint grid consisted of 137x68x10 gridblocks (93,160 cells). The kv/kh ratio

(Continued on page 5)

Full-Field Modeling Using Streamline-Based Simulation: 4 Case Histories . . . continued

used was 0.1. Thirty-one producers and eighteen injectors provided access to the reservoir.

Initial history match runs gave a reasonable match on half of the oil producers. Changes to the relative permeability showed that the match was relatively insensitive to this parameter, as could be expected for a light oil system with a favorable mobility ratio. Upon closer inspection, it was noted that the inner producers matched reasonably well, however the outer producers had insufficient water production. It was necessary to add an outer ring of injectors to match the water cuts within the sector, thereby increasing the well count to 80.

This course of action was also justified by examining the conformance plots. Rapid convergence on the history match for the 80 well pattern was achieved within 2-3 weeks (Figure 8).

Forecasts showed the remaining oil recovery could not be easily improved by water diversion. To speed up infill selection, the reservoir was populated with 25 potential locations. This was an effective way to pre-screen the complex interplay between remaining oil, permeability, offset well interference, injection patterns, well spacing, etc. Only five of the new infill wells dominated the performance. These five wells provided 68% of the entire pattern's remaining oil reserves, and doubled the remaining oil reserves.

This article is a synopsis of SPE66405. For more information, please download SPE66405 from our website.

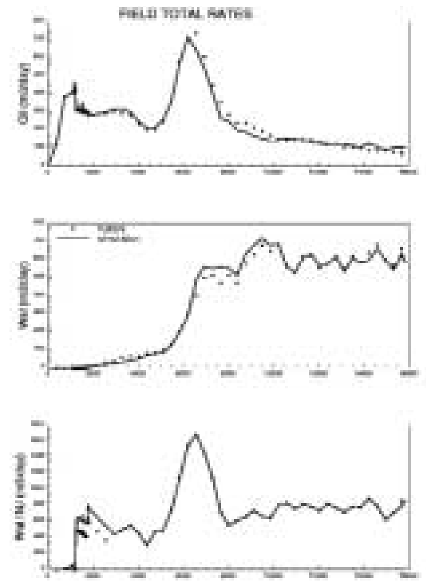

Figure 8: Field D History Match

Analysis of Production Data to Improve Characterization of Megascopic (Inter-well) Permeability

Gas recovery is impacted by a number of parameters (figure 1) that have a significant impact on the capital requirements and recovery (Figure 2). Recent work by Epic in a large integrated study helped assess interwell scale permeability and connectivity to determine field development plan requirements and future capital.

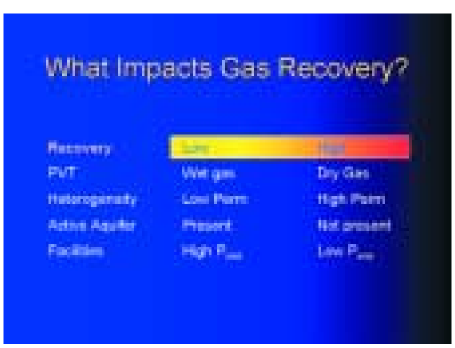

Figure 1 – What Impacts Gas recovery

Introduction

The performance of a gas well in a tight, heterogeneous fluvial sand is determined by reservoir quality, i.e kh or more specifically k (permeability), and sand body connectivity. An estimation of the permeability, which can vary by orders of magnitude, is necessary for assessing reservoir quality. In addition, adequate knowledge of the spatial distribution of permeability is critical in predicting reservoir depletion performance by any recovery process. This work shows how a comparison of effective/average permeability values at various scales reveals information about reservoir quality and connectivity.

Correctly measuring the magnitude and distribution of permeability in the reservoir is virtually impossible given that the core plug (or logs) samples perhaps a billionth of the reservoir, which may or may not be representative of the lateral heterogeneity away from the core/wellbore. Clearly the measurement of permeability is a highly scale and technique dependent problem.

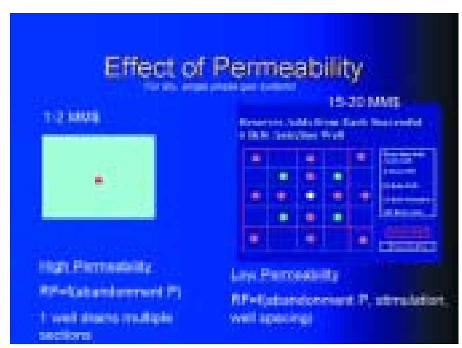

Figure 2 – Impact of Permeability

Figure 3 shows various measurement scales. Core measurements are microscopic measurements, while logs (macroscopic) and well-tests (mesoscopic) sample larger

(Continued on page 6)

Analysis of Production Data to Improve Characterization of Megascopic (Inter-well) Permeability . . . continued

volumes near the wellbore. Interwell or megascopic scale measurements are the most difficult to pin down, but are most important in terms of impact on production. Finally, there is the gigascopic scale at the reservoir or regional level. These concepts were applied to characterizing a multi-layered tight gas field in the Cooper Basin prior to conducting simulation studies with the objective of optimizing gas recovery.

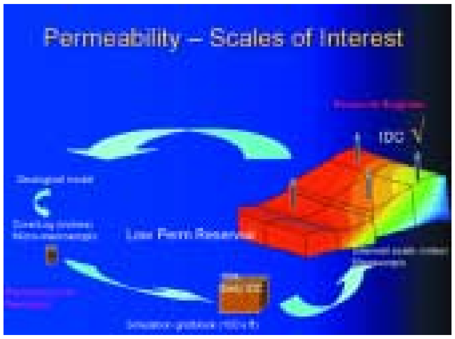

Figure 3 – Scales of Permeability Measurement

Micro/Macro-scopic Permeability

The smallest scale permeability measurements available are the core data. These measurements typically represent a cubic inch of rock-volume. Based on a comparison of these core plug measurements to log derived values, a robust relationship was developed to calculate permeability from a combination of sonic, resistivity, and gamma log values. By the nature of the logging measurements these log-derived permeability values typically represent tens of cubic feet of rock volume. The question was how do you take these core/log scale values and use them in a simulation of performance determined by megascopic (interwell) scale permeability?

Mesoscopic Scale

Whereas log scale values measure rock properties within a few feet of the wellbore, pressure transient tests measure average properties tens to hundreds of feet from the well. Well tests thus provide a convenient measurement of properties at an intermediate scale between log-core and field-scale values. Pressure transients provide another "scale" of measurement that can be used to test or "condition" the smaller-scale log-core values.

Analysis of Production Data to Infer Megascopic Insitu Reservoir Permeability

Production from a well provides a dynamic description of reservoir quality over its entire drainage area, and "brings another dimension to" the static description obtained from core plugs, logs, and well-tests. Furthermore, production data is more readily available than other sources of dynamic data (ie. pressure data). In reservoirs with significant production, integration of such data to better characterize the reservoir can lead to faster history matching in simulation models.

In contrast to conventional decline analysis, which is used primarily for reserves estimation and forecasting, advanced decline methods are used to infer reservoir properties. Our analysis relies on two methods, the 'Inverted Decline Curve' (IDC) and the 'Reciprocal Productivity Index' (RPI). Both techniques can be used to calculate the following:

1. Permeability

2. Skin

3. Fracture Length

4. Drainage Area

5. Ultimate Reserves

The key plot in each method is the modified Miller Dyes Hutchinson (MDH) plot, which compares the inverse of a well's producing rate (1/q) with the log of its producing time. The well's entire production history essentially becomes the equivalent of a very long drawdown test.

Three flow periods – pre-radial, radial and pseudo-steady state – are analyzable as shown in Figure 4. Our work focuses on the pre-radial and radial periods. The first linear trend on the IDC profile, following fracture transient performance, is used to determine reservoir kh and skin. Pseudo-steady state is represented by the upward curving portion of the IDC/RPI curve. This portion was not analysed in our work on multi-stacked, complex fluvial reservoirs since it could represent boundaries which may imply a lack of continuity/connectivity, well interference (especially in the connected, layer cake portion of the reservoir), poorer connectivity between channels or include the flow contribution of significantly lower permeability in splays.

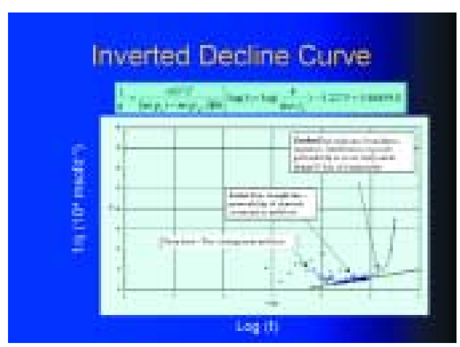

Figure 4 – The Inverted Decline Curve

(Continued on page 7)

Analysis of Production Data to Improve Characterization of Megascopic (Inter-well) Permeability . . . continued

The Link Between Micro/Macroscopic and Megascopic Permeability

A comparison of the microscopic/macroscopic permeability (average 400 md) to that obtained from IDC analysis (average 18 md) showed a difference of twenty-fold! The difference can be rationalized if one considers the scale of each measurement and the spatial ordering of the permeability.

Figure 5 shows the general concept behind permeability averaging which is required to extend the measured point source permeability spatially over the area of interest. For a layered medium where the flow direction is perpendicular to the layering (barrier scenario) the harmonic average applies, biasing the average permeability to the extreme low end of the distribution. At the other end of the spectrum, for a layered medium where the flow direction is parallel to the layering (layer cake scenario), the arithmetic average applies. For a two-dimensional medium consisting of random permeability values, with a relatively small spatial correlation, the geometric average applies, which is biased towards the medium and lower end of the permeability distribution. As indicated in Figure 5, the power exponents –1, 0, and 1, respectively, represent the harmonic, geometric and arithmetic average.

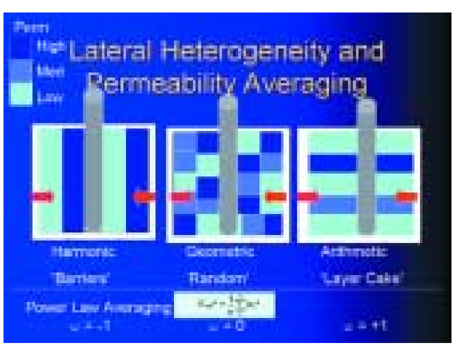

Figure 5 – Permeability Averaging Methods

For example, a hundred values of permeability (1,2,..100) can manifest as 50 (arithmetic), 38 (geometric) or 19 (harmonic) millidarcies depending on the arrangement/connectivity within the reservoir. It can be shown that for certain flow patterns the permeability average of a three dimensional medium of random permeability values is best represented by averaging with power exponent 0.3.

Implications for up-scaling of permeability values for 3D geological model

Based on the observation that the log-derived permeability values represent some lateral continuity, it was felt appropriate to populate the geo-model cells directly with log-derived permeability values (realizing they are representative of the logging scale ~ 10 ft3). Figure 6 shows a comparison for the kh value of the 1000 m by 1000 m cells in which a given well is located and the IDC value for these wells. The IDC kh values compare nicely to the final history matched model values. This confirms that the upscaling process employed was valid.

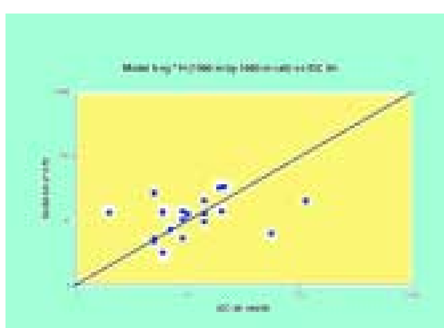

Figure 6 – Comparison of Upscaled Model Permeability to IDC Permeability

An estimate of each well's connectivity could also be obtained. For all wells in the study area the geometric, power exponent 0.3, and arithmetically averaged permeability values were calculated using the relative gas in-situ permeability values (krg). Although there is significant scatter for all three averaging cases, the power exponent 0.3 represented the IDC values best. Comparison on a per well basis of the power exponent 0.3 average permeability to the IDC permeability resulted in the observation that if the permeability at the well is better than the IDC permeability, it indicated that there was a degradation in the lateral continuity (i.e. the exponent was closer to 0 or -1). Conversely for wells where the IDC permeability value is greater than the 0.3 exponent average, the surrounding area has "better" permeability than the near wellbore area, or is more layer cake structured (i.e. the exponent was closer to 1).

(Continued on page 8)

Analysis of Production Data to Improve Characterization of Megascopic (Inter-well) Permeability . . . continued

Comparison of Well Test and IDC Permeabilities in a Tight Gas, Heterogeneous Environment

It's tempting to ask why one should go through an analysis of the production data when well test analysis is available. Although both IDC and well test analysis can yield estimates of megascopic permeability in high permeability reservoirs, the usefulness of the IDC permeability is more pronounced in low permeability heterogeneous reservoirs. In these reservoirs, the 4 - 5 day buildup period, typically used, has a short radius of investigation and is highly influenced by the wellbore heterogeneities such as hydraulic fracture or high permeability streaks of limited areal extent.

For the near wellbore scale, pressure transient analysis is an appropriate measurement tool. However in the tight gas reservoirs encountered, the radius of investigation for a one millidarcy reservoir using a radial flow model, is approximately 500 feet in a 96 hour buildup. Identifying the correct semilog straight line can be difficult even with current type curve analysis techniques. Furthermore, wellbore heterogeneities such as hydraulic fractures and high permeability hot streaks can influence the apparent measured kh. High permeability layers or permeability streaks dominate the pressure buildup response initially, although low permeability layers contribute in the latter stages. For our reservoir, the beginning of a second straight line on the Horner plot which would provide an estimate of the bulk permeability, would occur at approximately 14,000 hours (almost two years).

In contrast, use of IDC/RPI analysis of long term production in a tight gas reservoir that has produced 10 Bcf/well, for example, would investigate an approximate minimum radius of 3100 feet, for a radial case, to 5100 feet, for a channel belt system assumed to be 3000 feet wide.

	IDC	RPI	Well Test Analysis
Kh md-ft	19	17	92
Pre-frac skin	-3.8	-5.6	3.0
Post-frac skin	-5.3	-6.0	-2.7

Table 1: Permeability Measurement Comparisons

Table 1 shows the (average) results obtained by each of the methods for the 11 wells with PTA tests.

The kh from IDC/RPI is lower than well test analysis by a factor of 5. However, the IDC/RPI skins are more negative than those from well tests. Another interesting result is the negative skin obtained from IDC/RPI analysis prior to hydraulic fracturing. This apparent discrepancy was resolved by reviewing the available core permeability measurements for the study area (two of the four wells tested and four other untested wells), which showed the pervasive existence of high permeability streaks. These streaks act as pseudo fractures and show up as negative skin or an apparent wellbore enhancement relative to the megascopic permeability on the IDC/RPI plots. Well tests reported the high permeability streaks primarily as kh within the radius of investigation.

Since the wells typically contain 50 - 100 ft of net pay (and 150 - 300 ft of gross pay), the low kh (15-20 md-ft) from IDC/RPI analysis shows that the effective permeability is in the sub-millidarcy range. This information is not readily apparent from core or well test measurements, which indicate higher permeabilities.

Conclusions

1. Improvement in the inter-well megascopic representation of permeability is possible when using IDC/RPI techniques.

2. The comparison of permeability values determined at various scales allows classifying to some extent the spatial distribution of permeability in the area investigated by the IDC technique.

3. During the process of building a 3D geo-science model, plug scale permeability values are, in various steps, upscaled to large simulation blocks. To re-affirm the validity of these upscaling processes, it is very useful to compare the various permeability averages from core,log, and welltest data with values obtained from the IDC/RPI analysis and the upscaled values in such a simulation model.

4. Well test permeabilities can be misleading in low permeability, heterogeneous environments.

This article is a synopsis of SPE 59761 "Analysis of Production Data to Improve Characterization of In-situ Megascopic Reservoir Permeability" by S. Chugh, J.Herweijer & F.Kuppe. For more information, please download SPE59761 from our website.

Epic wishes to thank the following for their contributions to this newsletter.

Richard Baker
Shelin Chugh
Dennis Beliveau
Frank Kuppe
Greg Osiowy
Bette Harding