



Streamline-Based Reservoir Simulation – How it can help you!

The use of streamlines is receiving increasing attention in the reservoir simulation world. Streamline-based simulators can now properly account for true 3D displacements, multi-phase gravity effects, and changing well conditions. A streamline simulator can routinely generate million-gridblock flow simulations, or rank multiple earth models. But how can this new tool help the reservoir engineer in his daily work?

Streamsim Technologies believes that a streamline-based simulator —such as StreamSim’s simulator 3DSL — is a complementary tool to existing conventional simulators, because streamlines can provide reservoir flow information that conventional simulators cannot. In this article we demonstrate the application of 3DSL as a surveillance tool by way of a simple example and illustrate how reservoir flow patterns, by visualization of streamline paths, calculation of well drainage volumes, and calculation of well allocation factors, allow to better understand production behavior of a field.

For simplicity we consider a 2D 100x100 heterogeneous gridblock model with 1 water injector and 5 producers. The streamlines and water saturation distribution after 2000 days injection are shown

	I1	I2	I3	I4
P1	63%	12%	2%	23%
P2			60%	40%
P3				100%
P4		79%	21%	
P5		58%	42%	

Table 1a: Well allocation factors for producers.

	P1	P2	P3	P4	P5
I1	100%				
I2	22%			63%	14%
I3	3%	74%		14%	9%
I4	30%	40%	30%		

Table 1b: Well allocation factors for injectors.

in Fig. 1a. The usefulness of streamlines stems from the fact that in addition to providing a visual image of the local flow distribution, streamlines can also provide: 1) The porevolume drained by all streamlines flowing to a particular well (well pore volumes); and 2) the percentage of flow in a well due to any other well in the field (well allocation factors).

For the first 2000 days, producer P1 rep-

resents 60% of the total field production rate, yet only drains 22% of the total pore volume. In contrast, P3 represents 4% of the total field production rate but drains almost 50% of the total pore volume. Along with %-drainage volumes, the streamlines locate where these drainage volumes are. Figure 1b shows the drainage volume of each producer in a

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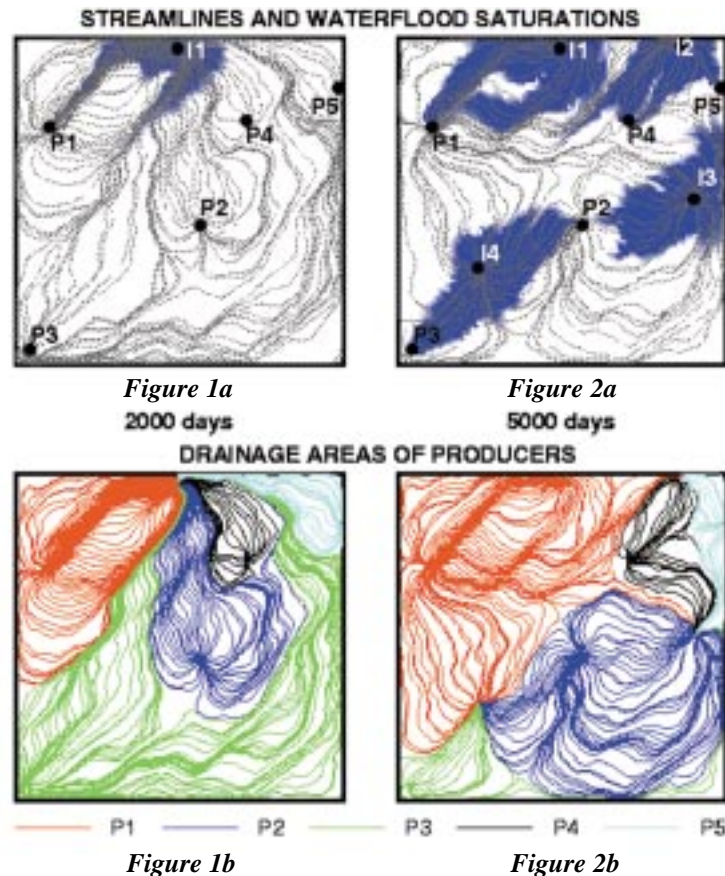
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different color. For example, one can see exactly how far away producer P3 is draining reserves from. This type of information can only be generated using a streamline-based simulator like 3DSL — merely having rate production information, as would be provided by a conventional simulator, could not provide these additional details about the flow behavior of the reservoir.

At 2000 days, 3 infill injectors are activated to support the original 5 producers. The streamlines and water saturation existing at 5000 days are shown in Fig. 2a. What happened to the well pore volumes? Figure 2b shows that the drainage volume for producer P3 has gone from 50% to 10% of the total pore volume, although producer P3 production rate increased from 4% to 8% of the total field production volume. Producers P1 and P2 together now drain 80% of the reservoir while producing 69% of the total field production.

In addition to pore volumes, 3DSL provides a matrix of well allocation factors at each time step. The allocation factors for each producer after infill drilling are illustrated in TABLE 1a. Similarly, the allocation factors for each injector are illustrated in TABLE 1b. Consider the additional information well allocation make available: producer P1 is seeing support from all injectors, with most of its production rate (63%) due to injector I1. Similarly, injector I3 supports 4 producers with 74% of its rate supporting producer P2. From the well locations, it is obvious that producer P3 is wholly supported by injector I4. Interestingly, Table 2b says that injector I1 only supports producer P1 even though proximity to P2 and P3 would suggest support to these wells too.

The most useful application of well allocation factors is in helping the reservoir engineer balance well patterns. Flow information such as the above allocation factors are not possible to produce from conventional simulation technologies and represent data unavailable to the reservoir



100 x 100 Heterogeneous Waterflood Results Using 3DSL

engineer until now.

Although simple, the example used here illustrates that fluid flow can be much more complicated than our intuition might lead us to believe or what conventional simulation methods provide. Having additional flow information such as that generated by 3DSL can be invaluable to the reservoir engineer and will allow better and more optimal field recovery management.

For more information on streamline-based reservoir simulation and 3DSL please visit www.streamsim.com. ■

Inverted Decline Curve Analysis

Determining Reservoir Quality & Permeability

Today's Reservoir Engineer is always looking for simple accurate tools that yield a good understanding of a reservoir and tie reservoir parameters to a production profile. Recently, Epic used a technique known as "Inverted Decline Curve analysis (IDC) to assist in the reservoir characterization of a tight-gas reservoir. IDC is an analytical technique⁸, which takes the iso-slope theory one step further by quantifying permeability. Included below is a discussion on the iso-slope method followed by a description of the IDC technique and how it can be used in determining reservoir characteristics.

Theory

The early time production of tight gas reservoirs, where hydraulic fracturing is prevalent, can be readily analyzed to assess both reservoir quality and how efficiently the fractures were placed. The theory behind "Iso-slopes" is well established and has been described by Cinco-Ley and Samaniego-V.,³ Thompson,⁴ and others.^{5,6} These authors discuss the possible flow regimes that may be present at various times in the life of a vertically fractured well. The five flow regimes include (1) fracture linear flow, where all flow occurs within the fracture in the direction of the wellbore; (2) bilinear flow, a combination of fracture linear flow and formation linear flow, (3) formation linear flow, where flow is from the formation, normal to the fracture face, (4) elliptical flow, the transition stage between linear and pseudo-radial flow, and finally (5) pseudo-radial flow, where fluid flow from the reservoir approaches the well from all directions.

D.B. Neal and M.A. Mian⁷ developed a linear equation based on the equation that describes production from a vertically fractured gas well during the linear flow period;

$$q_D = p_{pD} / \sqrt{\pi t_D}$$

Their analysis assumes a homogeneous infinite-acting gas reservoir intersected by a fully penetrating vertical fracture. After

treating the viscosity/compressibility product as a constant the equation simplifies to;

$$1/q_t = m\sqrt{t} + s$$

where m is a constant defined as;

$$m = p_{sc} \sqrt{\pi T} / 2T_{sc} \Delta P_p \sqrt{\mu c} \sqrt{k \phi h x_f}$$

The variation in the slope, from well to well in a particular reservoir, would be attributable to changes in the term $1/\sqrt{k \phi h x_f}$. As in many tight gas reservoirs, the variation in porosity is small compared to the changes in kh. In addition, fracture treatments for a particular field are usually standardized, yielding similar fracture half-lengths. As a result, the difference in observed slopes between wells in a particular area can often be primarily attributed to variations in the term $1/\sqrt{k h}$.

By plotting $1/q$ against time (in months), for each well, the relative quality of the reservoir can be determined from the slope of the linear flow portion. The relative fracture half length can be determined by the length of the straight line trend and the rate change as a result of skin can be derived from the intercept.

Field Results

Almost all the wells included in the study exhibited formation linear flow characteristics throughout their production history. One well in particular appeared to deviate from the straight line, suggesting either a poorly placed fracture, a smaller fracture length or production interference from another well. This well has however been recompleted and, as observed from the updated plot, has shown a consistent (i.e., linear) flow trend since the recompletion. There doesn't appear to be any need for fracture placement optimization in the field.

When all slope values are mapped on an "iso-slope" map, it reveals useful information with respect to reservoir quality and the proximity of the Channel and Delta Front facies. Although the Fluvial facies, underlying the Delta Front, has a higher permeability, the associated smaller pay thickness yields an aggregate kh (for Delta Front + Fluvial) that is still considerably lower than that of the Channel facies. The

iso-slope map is therefore a good representation of where the Channel facies is located with respect to Delta Front and Fluvial facies. In fact iso-slope maps were relied upon to complete mapping of the various facies, particularly in the west end of the reservoir.

IDC Analysis

The inverted decline curve (IDC) is an analytical technique⁸, which takes the iso-slope theory one step further by quantifying permeability. The method uses a plot of the inverse of a well's producing rate ($1/q$) against the log of its producing time. The well's entire production history essentially becomes the equivalent of a very long drawdown test and therefore can be used to determine a permeability that is representative of radius of investigation that is comparable to the drainage radius. The method can also be used to determine if the well is damaged. Based on the relationship :

$$\frac{1}{q} = \frac{1637T}{(m(p_e) - m(p_{wf}))kh}$$

$$\left[\log(t) + \log\left(\frac{k}{\phi \mu c_i r_w}\right) - 3.2275 + 0.86859S \right]$$

where;

$1/q$ = well inverse day rate at constant BHP, day/mcf

T = temperature, degrees R

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Inverted Decline Curve Analysis . . . continued

Permeability Through IDC Analysis

$$\frac{1}{q_D} = \frac{1637T}{(m(p_e) - m(p_{wf}))kh} \left[\log(t) + \log\left(\frac{k}{\phi\mu c_i r_w}\right) - 3.2275 + 0.86859S \right]$$

Well 1007-14-57-19W5/90

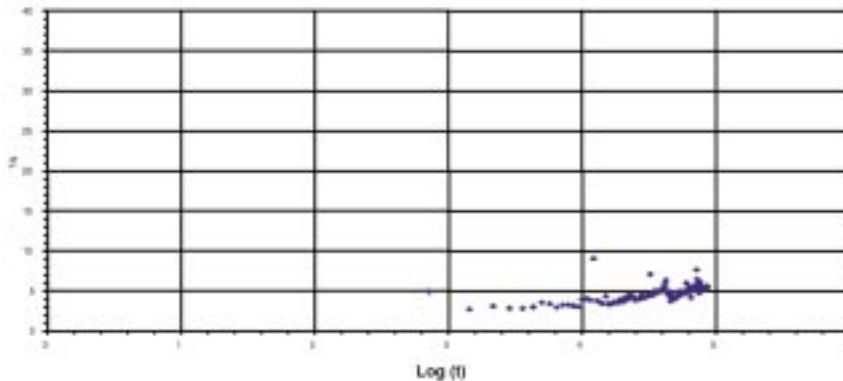


Figure 1

- k = permeability, mD
- h = net pay, ft
- φ = porosity
- μ = viscosity, cp
- c_i = compressibility, psi⁻¹
- m(p) = pseudo pressure, psi²/cp
- r_w = well bore radius, feet
- S = skin
- t = time (hours)

sured from core or well testing. This was found to be more prevalent in the reservoir studied where permeability in the near well-bore vicinity may be reflective of the higher quality Channel facies while permeability, representative of the total drainage radius (i.e., from long term IDC plots), includes poorer quality Delta Front - type rock.

CONCLUSION

The inverse decline curve method proved to be a useful and practical tool in helping to determine reservoir characterization in the formation. Epic has used this technique on five fields with success. Linear flow transient technology was used to accurately model the permeability distribution and complete the mapping of the various facies of the tight-gas reservoir.

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The permeability is determined from the slope of the 1/q versus log(t) plot (Figure 1). The permeabilities calculated from this method are listed in Table 1, and are compared with core, well test and simulation history matched values. The IDC and final history matched simulation values generally agree quite well.

An important point to note is that the IDC permeability can be as much as one order of magnitude lower than the permeability mea-

Table 1

Well	Core Permeability md	Well Test Permeability md	IDC Permeability md	Simulation Permeability md
11-11-57-20W5	.54			0.45
10-07-57-19W5	4.17		0.12	0.05
09-08-57-19W5	1.08		0.29	0.13
10-11-57-19W5	8.42		1.15	1.85
12-13-57-19W5	0.43	3.24	0.06	0.07
07-14-57-19W5	3.98	2.95	0.44	0.36
07-15-57-19W5	0.64	0.25	0.10	0.03
12-08-57-18W5	2.34	1.78	0.72	0.82
04-17-57-18W5	0.78	0.49	0.17	0.15
12-19-57-18W5	0.78	0.47	0.06	0.02

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- Horizontal Wells
- Coal Bed Methane

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