Performance of Multiple Horizontal Well Laterals in Low- to Medium-Permeability Reservoirs

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Summary

A generalized semianalytical productivity model, accounting for any well and reservoir configuration has been constructed and presented recently. The model allows for the production or injection prediction of any well (vertical, horizontal, deviated) and reservoir configurations in both isotropic and anisotropic media. Partially completed wells can also be simulated. A concern in modern reservoir management is the potential desirability of multiple horizontal laterals, frequently emanating from the same vertical well. Once pseudosteady state is reached, the productivity index differences among various well configurations are diminished. Thus, multiple laterals in higher-permeability formations, draining an assigned "box," may not offer incremental benefits. However, at early time and under transient conditions in low- to medium-permeability reservoirs, the relative productivity improvements provided by multiple laterals may result in sufficient incremental benefits to warrant their drilling. This paper presents a series of parametric studies for a range of reservoir permeabilities and permeability anisotropies for various multiple well configurations. The desirability or lack thereof for these configurations is demonstrated.

Introduction

A comprehensive multi- and single-well productivity or injectivity prediction model was introduced recently that allows arbitrary positioning of the well(s) in anisotropic formations.[1] Such a flexible and generalized model can be used to study several plausible scenarios, especially the economic attractiveness of drilling multiple horizontal wells, which in some cases may be multiple laterals configured from the same wellbore.

Clearly, multiple wells (vertical or horizontal) in the same drainage area will interfere with each other. This interference will be felt earlier in higher-permeability formations, and the relative economic attractiveness of the multi-well configurations may begin to diminish early. The lower the reservoir permeability, the later the interference will be felt. However, the absolute value of the productivity differences between various configurations may be much larger, albeit diminishing with time, in the larger-permeability cases.

The Economides *et al.*[1] solution technique obtains dimensionless pressures for a point source of unit length within a no-flow boundary "box." Using a line source with uniform flux, they integrate the solution for the point source along any arbitrary well trajectory. Careful switching of early- and late-time semianalytical solutions allows very accurate calculations of the composite dimensionless pressure of any well(s) configuration. These generalized solutions encompass early-time transient responses, all geometric and permeability interactions, and, very importantly for the purpose of this paper, late-time pseudosteady-state conditions.

Once the productivity with time of any well configuration is compared with a base case (i.e., a vertical well or single horizontal well), economic comparisons can be done readily. Discounted incremental benefits can be judged against the incremental cost of drilling, completing, and stimulating any alternative multiwell configuration. The aim of this paper is to compare such productivities for typical low-to-moderate permeability reservoirs. This is an issue of great interest in modern reservoir development.

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Production Model

Salient points of the generalized productivity index model are summarized below. The productivity index, J, is given (in oilfield units) by

$$J = \frac{q}{\overline{p} - p_{wf}} = \frac{\overline{k} x_e}{887.22\ B\mu\left(p_D + \frac{x_e}{2\pi L}\sum s\right)}, \quad \ldots\ldots\ldots\ (1)$$

where $\overline{p}$ is the reservoir pressure, p_D is the calculated dimensionless pressure, and $\overline{k}$ is the average reservoir permeability $\left(\sqrt[3]{k_x k_y k_z}\right)$. Σs is the summation of all damage and pseudoskin factors. Dimensioned calculations are done on the basis of the reservoir length, x_e; L is the horizontal well length.

In the tradition of several other works,[2-4] the 3D p_D is decomposed into one 2D and one 1D part following the transition to pseudosteady state,

$$p_D = \frac{x_e C_H}{4\pi h} + \frac{x_e}{2\pi L} s_x, \quad \ldots\ldots\ldots\ (2)$$

where C_H is a "shape" factor characteristic of well and reservoir configurations in the horizontal plane and s_x is the skin accounting for vertical effects.

The expression for this skin effect is (modified from the expression given by Kuchuk *et al.*[4])

$$s_x = \ln\left(\frac{h}{2\pi r_w}\right) - \frac{h}{6L} + s_e. \quad \ldots\ldots\ldots\ (3)$$

Finally, s_e, describing vertical eccentricity effects is

$$s_e = \frac{h}{L}\left[\frac{2z_w}{h} - \frac{1}{2}\left(\frac{2z_w}{h}\right)^2 - \frac{1}{2}\right] - \ln\left[\sin\left(\frac{\pi z_w}{h}\right)\right]. \quad \ldots\ldots\ (4)$$

The latter is negligible if the well(s) is (are) placed largely at the vertical middle of the reservoir.

Permeability anisotropy transformations for both the well(s) and the dimensions of the reservoir are done first, and the transformed variables are used for calculations. A complete list of these transformations is contained in Ref. 1.

Case Studies for Production Prediction

A series of parametric studies is done with several plausible configurations of single- and multiple-lateral horizontal wells. For these studies three permeabilities are used ($k_x =$ 0.1, 1, and 10 md). The subscripted k_x suggests a permeability along the x_e dimension. (This is not necessary, of course. Any principal permeability axes can be used whether or not they coincide with reservoir boundaries.) The vertical permeability, k_z, for these studies is taken always as 0.1 k_x, which is a reasonable assumption for sandstone reservoirs. Three permeabilities in the y_e direction are used: $k_y = k_x$, 0.1 k_x, and 0.01 k_x.

For all three horizontal-to-horizontal permeability anisotropies, four configurations are used.

1. A 2,000-ft horizontal well along k_y.
2. A 2,000-ft horizontal well along k_x (for $k_x = k_y$ this case is unnecessary).
3. A "cross" configuration of four laterals that form the equivalent of two 2,000-ft wells intersecting orthogonally at the reservoir middle.
4. A "star" configuration with eight laterals (i.e., the equivalent of four 2,000-ft wells intersecting at 45° angles at the reservoir center).

(Note: Any arbitrary configuration can be studied with the model.)

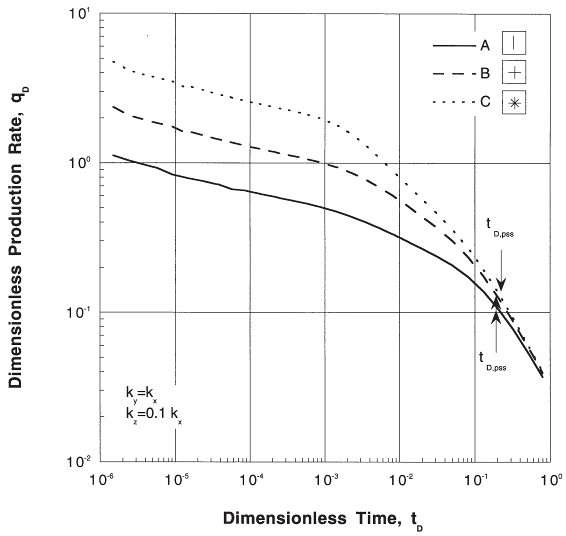

Fig. 1—Dimensionless production rate vs. dimensionless time for horizontal-to-horizontal permeability isotropy (Cases A through C).

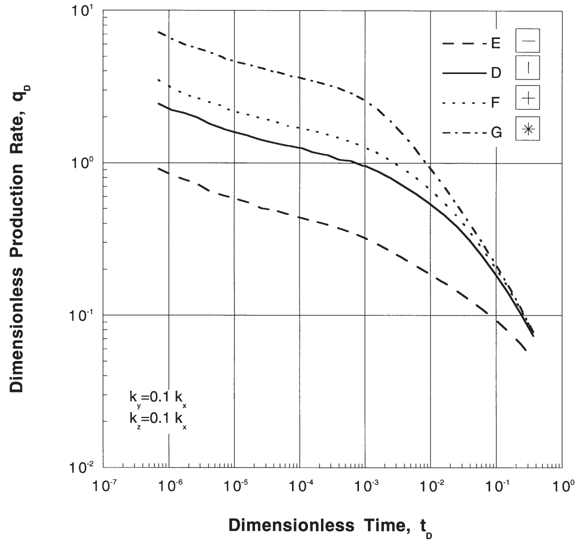

Fig. 2—Dimensionless production rate vs. dimensionless time for horizontal-to-horizontal permeability anisotropy, $k_y = 0.1\ k_x$ (Cases D through G).

Figs. 1 through 3 contain the dimensionless rate, q_D, and dimensionless time, t_D, for the three horizontal-to-horizontal permeability anisotropies. If pseudosteady state emerges within the time range of the calculations, the corresponding time is marked.

The dimensionless time and dimensionless rate are defined as

$$t_D = 0.000264 \frac{\bar{k}t}{\phi \mu c_t x_e^2}, \quad (5)$$

and

$$q_D = \frac{887.22 q B \mu}{\bar{k} x_e \Delta p}. \quad (6)$$

Suppose that a reservoir has $k_x = 2$ md, $k_y = 2$ md, and $k_z = 0.2$ md. Porosity, viscosity, total compressibility, and formation volume factor are 0.15, 2 cp, 3×10^{-5} psi^{-1}, and 1.2 res bbl/STB, respectively. Using Fig. 1 for $x_e = 3{,}000$ ft and $L = 2{,}000$ ft (for which the figure was constructed), the expected production rate after 2 months, for example, can be calculated for the three well configurations.

From Eq. 5, using $\bar{k} = 0.93$ md and substituting all variables, $t_D = 4.36 \times 10^{-3}$. From Fig. 1, q_D is 0.38 for the single horizontal well, 0.73 for the cross configuration, and 1.21 for the star configuration. From Eq. 6, the production rates are 251, 480 and 790 STB/D, respectively (using $\Delta p = 500$ psi).

For the case of horizontal-to-horizontal permeability isotropy, **Figs. 4 and 5** present the respective real-time cumulative production ratios for the cross (Case B) and star (Case C) configurations vs. the base case of a single 2,000-ft horizontal well (Case A). **Table 1** gives the general reservoir variables that were used. The times for initiation of pseudosteady state are also marked. Production rates and cumulative productions for the various well configurations and permeability anisotropies are given in **Table 2.**

Figs. 4 and 5 show the major impact of permeability on the cumulative production ratio. For low reservoir permeability, this ratio is maintained at a high level for a considerable time. For example, Fig. 5 shows that after about 1 year (8.76×10^3 hours), the cumulative production ratio of the star configuration compared with the single horizontal well case is still about 4 (for $k_x = 0.1$ md). For $k_x = 10$ md and after about the same time, the cumulative production ratio rapidly approaches unity. While the absolute values of the respective cumulative productions are obviously important, Figs. 4 and 5 and Table 2 can provide insights into the desirability or lack thereof of multiple laterals.

Fig. 6 contains the actual production rate declines for the three configurations in the isotropic medium and for the three permeability values of k_x. For the higher permeability ($k_x = 10$ md), after 1 year and few months (1.45×10^4 hours), the decline is very steep, reflecting reservoir depletion. In fact, the production rate crosses

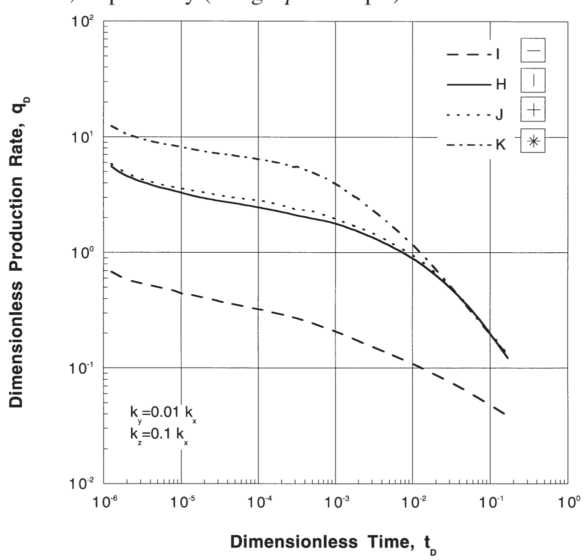

Fig. 3—Dimensionless production rate vs. dimensionless time for horizontal-to-horizontal permeability anisotropy, $k_y = 0.01\ k_x$ (Cases H through K).

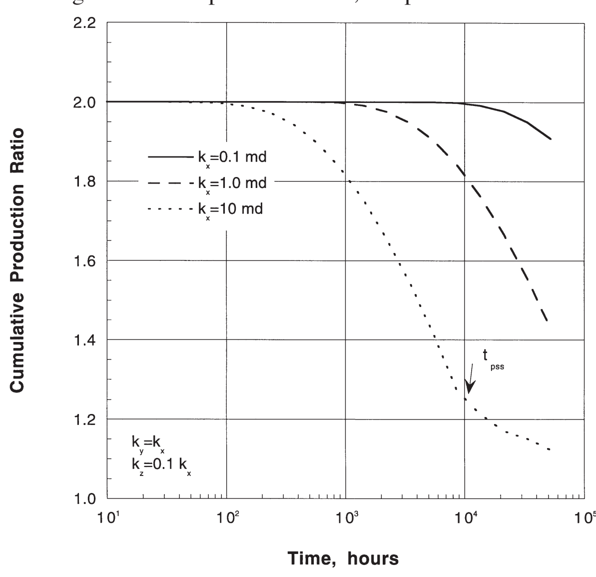

Fig. 4—Cumulative production ratio for real time for the cross configuration, $k_y = k_x$ (Case B).

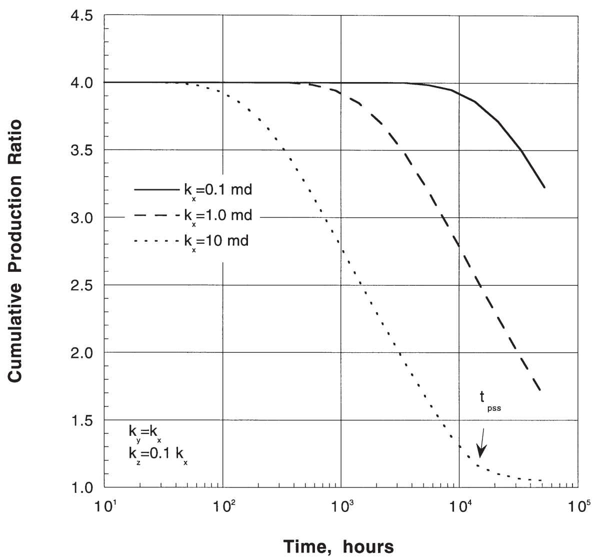

Fig. 5—Cumulative production ratio for real time for the star configuration, $k_y = k_x$ (Case C).

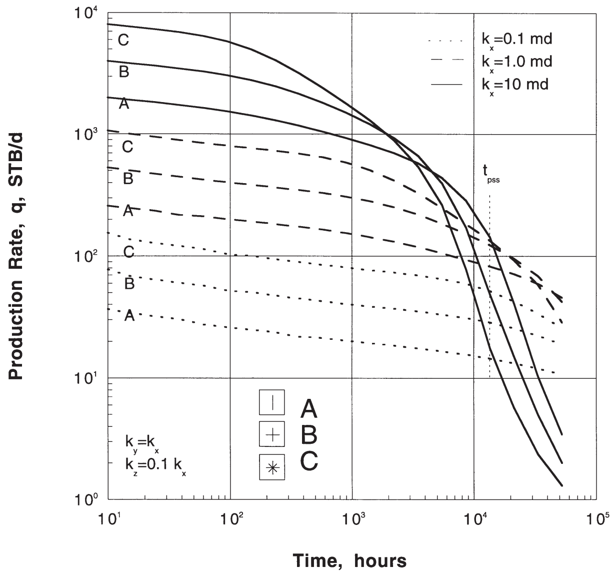

Fig. 6—Production rate for horizontal-to-horizontal permeability isotropy, $k_y = k_x$ (Cases A through C).

over for the higher-permeability case, and the star configuration produces less than the cross configuration, which also produces less than the single horizontal well case.

Comparing the base case of a single horizontal well (Case A) with the cross configuration (Case B) from Fig. 6 or Table 2 for the 0.1 md case and after 2 years, for example, the production rates are 13.8 and 26.9 STB/D, respectively, while the corresponding cumulative productions are 1.18×10^4 and 2.33×10^4 STB, respectively. However, for the 1 md case, the production rates are 76.5 and 109 STB/D, respectively, and cumulative productions are 7.41×10^4 and 1.26×10^5 STB, respectively.

The question is whether the incremental revenues discounted to the time of drilling can outweigh the additional costs for the laterals. Table 2 provides sufficient information for this issue, addressing well configurations, permeability anisotropies, and well directions.

To understand this point, consider a simple calculation. For 0.1 md, the incremental cumulative production from Case B compared with Case A is 6.45×10^3, 5.10×10^3, and 4.40×10^3 STB for 1, 2, and 3 years, respectively. Comparing Case C with Case A, incremental production is 1.90×10^4, 1.36×10^4, and 1.05×10^4 STB for the same times. Assuming \$15/STB oil and a 25% time value of money, the 3-year net present value (NPV) of incremental revenues over a single horizontal well are \$160,000 and \$439,000 for the cross and star configurations, respectively. If the incremental drilling costs are less than these amounts, then the more complex configurations are warranted.

For the 1-md case, corresponding 3-year incremental NPV's are \$658,000 and \$1,250,000, respectively. For the 10-md case the 3-year incremental NPV's are \$580,000 and \$447,000, respectively. These results suggest that the incremental benefits of the complex configurations (Cases B and C) over the base case (Case A) are reduced considerably for higher permeabilities. More importantly, drilling more laterals would result in a lower NPV of the incremental revenue, suggesting that additional drilling costs would be highly undesirable.

TABLE 1—GENERAL RESERVOIR VARIABLES FOR CASE STUDIES

Reservoir dimension, x_e, ft	3,000
Reservoir dimension, y_e, ft	3,000
Reservoir thickness, h, ft	100
Porosity, ϕ, %	15
Oil viscosity, μ, cp	2
Oil formation volume factor, B_o, bbl/STB	1.2
Total compressibility, c_t, psi^{-1}	3×10^{-5}

Figs. 7 through 9 are the cumulative production ratios of a single horizontal well drilled in the k_x direction (Case E) and the cross (Case F) and star (Case G) configurations vs. a single horizontal well drilled along k_y (Case D) in an anisotropic formation where $k_y = 0.1\ k_x$. The results are also in Table 2. Comparing this permeability anisotropic case with the isotropic case, the production from a horizontal well drilled normal to the maximum permeability (Case D) is roughly comparable with that of the horizontal well in the isotropic case (Case A). From Table 2, for $k_x = 1$ md, the production rates are 71.5 and 76.5 STB/D, respectively, at the 2-year mark. However, the production rate drops to 26.3 STB/D if the well is drilled in the entirely wrong direction (Case E). **Fig. 10** contains the rate declines for the four configurations in the same formation, again showing the crossover in the high permeability case.

Finally, **Fig. 11** contains the rate declines for the two, 2,000-ft horizontal wells, one drilled along k_y and the other along k_x in formations where $k_y = 0.01\ k_x$. Again three k_x values, 0.1, 1, and 10 md, are used. The difference in the flow rates is considerable. For $k_x = 10$ md after 1 year, the well drilled normal to k_x (the larger permeability, Case H) is 227 STB/D compared with 53 STB/D from the well drilled normal to k_y ($= 0.01\ k_x$, Case I). The results are in Table 2 also.

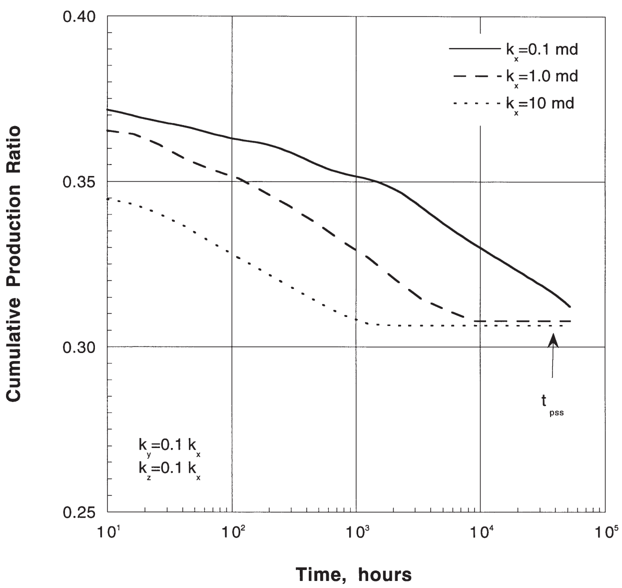

Fig. 7—Cumulative production ratio for real time for the single horizontal well drilled in the k_x direction, $k_y = 0.1\ k_x$ (Case E).

TABLE 2—PRODUCTION RATES AND CUMULATIVE PRODUCTIONS FOR THE VARIOUS CONFIGURATIONS AND ANISOTROPIES								
CASES	YEARS	k_x = 0.1 md		k_x = 1.0 md		k_x = 10 md		Configurations
		q	N_p	q	N_p	q	N_p	
		STB/D	STB	STB/D	STB	STB/D	STB	
A	1	15.54	6,466	93.33	43,917	282.99	213,936	$k_y = k_x$
	2	13.83	11,752	76.46	74,130	90.98	272,097	$k_z = 0.1\ k_x$
	3	12.73	16,551	66.14	99,697	28.41	291,945	
B	1	30.90	12,919	152.21	80,742	169.56	271,532	$k_y = k_x$
	2	26.93	23,308	109.17	126,424	22.50	314,990	$k_z = 0.1\ k_x$
	3	24.15	32,506	84.71	160,749	9.07	338,656	
C	1	59.04	25,498	183.18	126,390	76.84	292,658	$k_y = k_x$
	2	46.97	44,341	112.78	176,878	10.05	312,912	$k_z = 0.1\ k_x$
	3	38.92	59,665	78.55	210,370	3.50	315,301	
D	1	15.56	6,338	91.30	43,716	240.26	193,800	$k_y = 0.1\ k_x$
	2	13.92	11,641	71.54	72,538	103.93	249,540	$k_z = 0.1\ k_x$
	3	12.86	16,478	59.57	95,941	49.64	275,533	
E	1	5.29	2,226	31.54	14,869	151.59	81,342	$k_y = 0.1\ k_x$
	2	4.68	4,020	26.28	25,173	109.84	127,132	$k_z = 0.1\ k_x$
	3	4.30	5,642	23.37	34,109	85.25	161,668	
F	1	20.80	8,660	114.48	56,935	225.37	221,011	$k_y = 0.1\ k_x$
	2	18.44	15,714	84.90	91,965	80.13	268,806	$k_z = 0.1\ k_x$
	3	16.84	22,079	67.60	119,051	32.30	287,665	
G	1	43.28	18,287	156.71	100,495	149.23	256,064	$k_y = 0.1\ k_x$
	2	36.38	32,545	95.31	143,393	45.65	285,673	$k_z = 0.1\ k_x$
	3	31.30	44,668	66.93	171,851	16.02	295,926	
H	1	14.78	6,649	93.25	44,049	226.85	193,816	$k_y = 0.01\ k_x$
	2	13.30	11,631	72.60	73,375	90.29	244,283	$k_z = 0.1\ k_x$
	3	13.02	16,404	60.17	97,063	42.66	266,835	
I	1	1.93	834	10.91	5,284	53.15	28,213	$k_y = 0.01\ k_x$
	2	1.68	1,481	9.02	8,831	40.70	44,749	$k_z = 0.1\ k_x$
	3	1.53	2,059	8.01	11,897	34.01	58,102	
J	1	16.75	7,138	101.53	48,428	224.19	204,189	$k_y = 0.01\ k_x$
	2	15.52	13,001	77.28	79,983	84.39	252,803	$k_z = 0.1\ k_x$
	3	14.22	18,370	63.08	105,002	37.94	273,481	
K	1	38.50	16,344	148.62	92,378	143.49	241,259	$k_y = 0.01\ k_x$
	2	33.00	29,197	91.47	133,356	49.59	271,061	$k_z = 0.1\ k_x$
	3	28.61	40,246	64.36	160,696	22.34	283,238	

Conclusions

A state-of-the-art productivity index simulator has been used to investigate the effects of multiple-lateral configurations, permeability anisotropy, and well direction. Multiple laterals in low- to moderate-permeability reservoirs can maintain high production and cumulative production rates. In higher-permeability reservoirs the incremental benefits from multiple laterals are reduced. In some cases, the multiple laterals are counterproductive. In all cases, incremental benefits must be discounted and balanced against the incremental drilling and completion costs.

Nomenclature

B = formation volume factor, L^3/L^3, res bbl/STB
c_t = total compressibility, psi^{-1}
C_H = shape factor
h = reservoir thickness, L, ft
J = productivity index, L^2/m, STB/D-psi
k = permeability, L^2, md
$\bar{k}$ = average permeability, L^2, md
L = well length, L, ft
N_p = cumulative production, L^3, STB
$\bar{p}$ = average reservoir pressure, m/Lt^2, psi
p_{wf} = bottomhole flowing pressure, m/Lt^2, psi
q = flow rate, L^3/t, STB/D
r_w = wellbore radius, L, ft
t = time, t, hours
x_e = extent of drainage area in x direction, L, ft
y_e = extent of drainage area in y direction, L, ft
z_w = distance of well from middle of reservoir, L, ft
ϕ = porosity, fraction
μ = viscosity, m/Lt, cp

Subscripts

D = dimensionless
w = well

Acknowledgments

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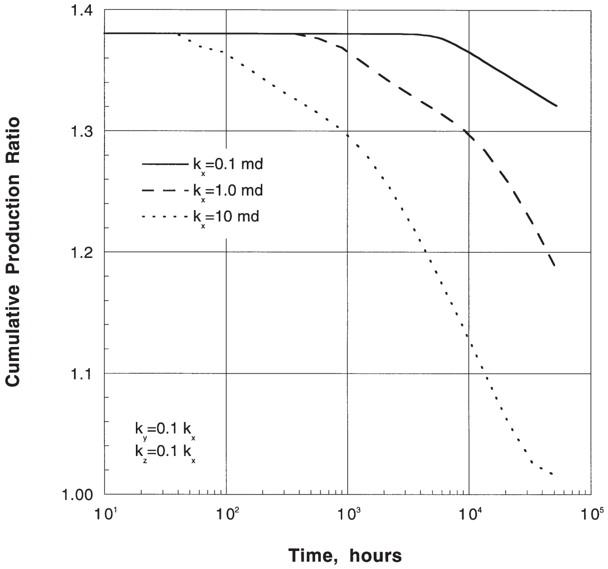

Fig. 8—Cumulative production ratio for real time for the cross configuration, $k_y = 0.1\ k_x$ (Case F).

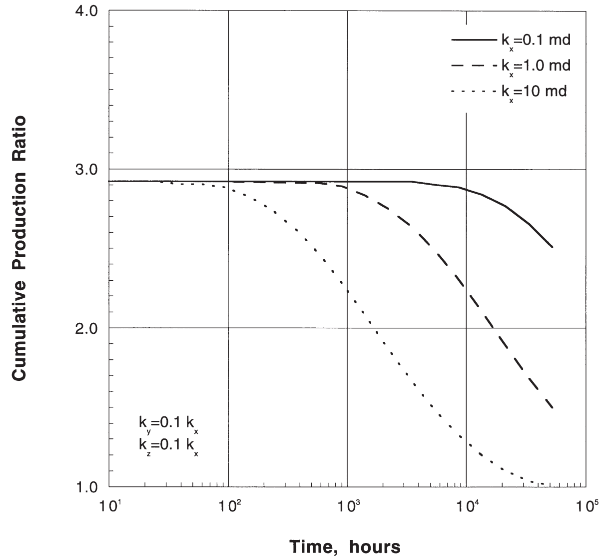

Fig. 9—Cumulative production ratio for real time for the star configuration, $k_y = 0.1\ k_x$ (Case G).

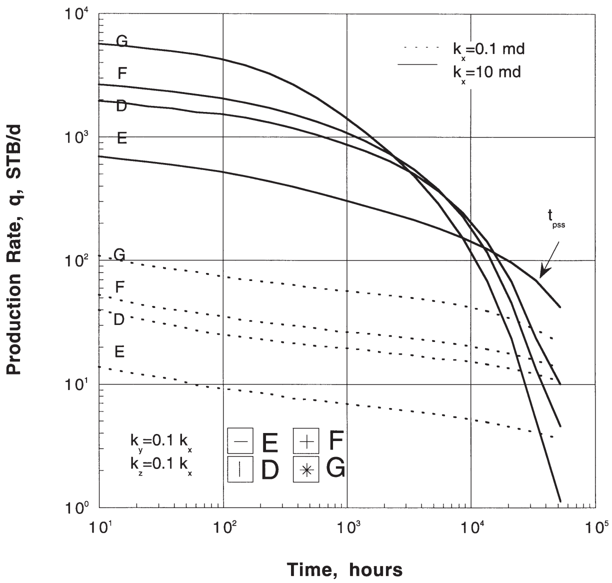

Fig. 10—Production rate for horizontal-to-horizontal permeability anisotropy, $k_y = 0.1\ k_x$ (Cases D through G).

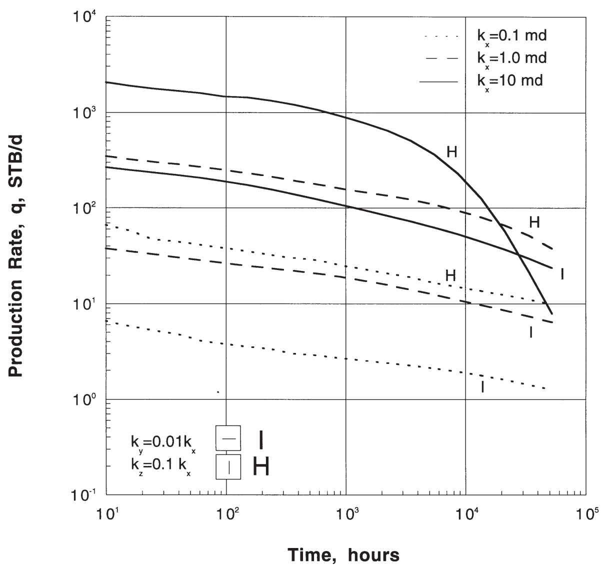

Fig. 11—Production rate for two horizontal wells, one drilled along k_y and the other along k_x in a formation where $k_y = 0.01\ k_x$.

SI Metric Conversion Factors

bbl	× 1.589 873	E − 01 = m^3
cp	× 1.0*	E − 03 = Pa·s
ft	× 3.048*	E − 01 = m
md	× 9.869 233	E − 04 = μm^2
psi	× 6.894 757	E + 00 = kPa
psi^{-1}	× 1.450 377	E − 01 = kPa^{-1}

*Conversion factor is exact.

SPERE

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