PROCEEDINGS, Thirty-Sixth Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, January 31 - February 2, 2011
SGP-TR-191

ANALYSIS OF COMPLEX RESERVOIR GEOMETRIES AND COMPLETION USING DYNAMICAL CHARACTERIZATION

Héctor Pulido[1,2], Guadalupe Galicia-Munoz[1], Alex R. Valdes-Perez[1] & Felipe Díaz-Garcia[1]

1. Universidad Nacional Autónoma de México, Ciudad Universitaria, México, D.F.
2. Petróleos Mexicanos, Av. Marina Nacional No. 329 Col Petróleos Mexicanos, México, D.F.
E-mail: hector.carlos.pulido@pemex.com

ABSTRACT

Complex reservoir geometries can influence the results obtained from transient-production-decline analysis. For naturally fractured reservoirs, it is common to observe linear-flow geometries and limited drainage areas. In some cases, these results are inconsistent with the expected geological, structural, and depositional character of the reservoir. Complex reservoir geometries and flow conditions such as liquid loading can contribute to this phenomenon.

Single numerical simulation with well test models cases will be used to generate the control data sets to demonstrate these effects. This paper presents seven cases showing the effects of complex reservoir flow conditions on the results obtained from production analysis with well testing.

INTRODUCTION

Production analysis is commonly used to evaluate completion efficiency and effective drainage area of producing wells. The methodology is a type-curve-matching methodology. *Flowing bottomhole pressures and production rates are treated as a long-term production/drawdown test*, providing an estimate of *effective drainage area, flow capacity, and fracture half-length* through type-curve analysis.

This methodology, originally was presented for a single-layer reservoir, is applied to layered systems by assuming average properties the productive zones. Production-analysis methodologists are suited for the analysis of tight gas reservoirs.

Naturally fractured reservoirs typically in transient flow for an extended period of time, and therefore daily pressure and rate data can be used to analyze transient behavior of the reservoir around the producer. Wells in naturally fractured reservoirs typically drain a limited area and often experience linear flow for an extended period of time after completion.

SIMULATION

Single numerical simulation cases were constructed to develop production and pressure profiles use for the analysis. The base case for this analysis was a fracture-stimulated radial-flow model.

The reservoir geometry for the single layer cases was a square, and for the multilayer case, the top layer was a high-permeability channel. Production rate from the models was controlled by a 350-psi constant tubing pressure with a 10,000 bpd maximum flow rate limit.

The base case was run for 2 years.

BASE CASE

Sedimentary environments indicate the importance of the productive formation and provide structural information as well; it is possible to forecast their behavior, the lithostratigraphic units which allow identifying the existence of each one of the layers. It also provides information about existing faults and fractures.

Based on all the information available from sedimentary environments, it is possible to build the structural geology at the well location and at al regional level. Facies which intersects a well indicates the structural position of the well. Structural position of the formations can be determined based on relative density of the fluids.

Relative production rhythms (regarding to a base flow rate); the analysis of the sealed layers allows knowing the structural part of the layers.

The base case represents a well producing from the center of a 40-acre square reservoir. Logarithmic gridding was used in the simulation cases to capture the transient flow in the reservoir and eliminate numerical dispersion. The results of this case demonstrate the ability of the production analysis methodology to match simulation results.

Fig. 1 is the type- curve match for this case. It should be noted that the match assumes an *infinite conductivity fracture* and that an acceptable match also was obtained by use of a *finite-conductivity model* with a 200-tf fracture half-length X_f, and a 75-md-ft *fracture conductivity.*

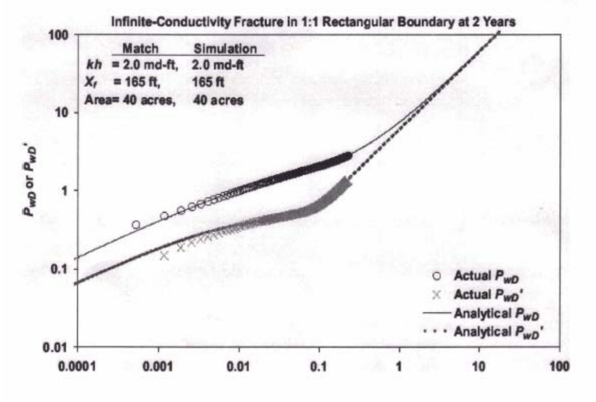

Fig. 1. Base case production analysis results.

CASE 1

This case incorporates stress dependent permeability into the base case. In this case, as the cell-block pressure is reduced, the effective permeability is reduced as a function of increasing stress.

The stress-vs.-permeability data used for this case were obtained trough laboratory experiments and are a typical for stress-sensitive reservoirs. The effect of increasing stress on the reservoir *flow capacity, fracture half-length, flow geometry, and effective drainage area was examined trough production analysis.*

When a well is placed on production in this kind of environment, the reservoir flow capacity decreases as pressure depletes in reservoir, resulting in an increase in net stress in the reservoir rock.

At first, only the near well region is affected by the pressure decrease. As the drainage area increases with time, there is a corresponding decrease in pressure within the drainage area. Because of the nature of the rock, there is a corresponding decrease in permeability. This is typically noted as a decrease in *flow capacity* over time. The effect is not a result of a change in the flow geometry within the reservoir. The effect, when modeled using production analysis results, is a longer *fracture half-length* as a result of the initial improvement in the dimensionless *fracture conductivity.*

As expected, the overall flow capacity was reduced in the reservoir, and the effective drainage was less for the same 2-year production life. After 30 years of production, the apparent drainage area obtained from the analysis increased to 34 acres. The stress-dependent nature of this reservoir results in a false depletion stem. In this case, production analysis did show the reduced reservoir *flow capacity* and did not suggest that a reduced fracture length caused the reduced production rate.

CASE 2

This case is a *two-layer* reservoir with the top layer having a 20-md-ft *flow capacity* producing from a 466 ft wide by 1,320 ft long channel. The drainage area of the upper layer is 14 acres, with a 2, 8 length-to-width ratio. The bottom layer has properties identical to the base case, with 2.0-md-ft flow capacity, a 40-acre drainage area, and a 1.0 length to- width ratio. Both layers have a 200-ftgridded fracture with a 75-md-ft *fracture conductivity.* After 2 years of production, the match clearly shows that the reservoir flow geometry is dominated by the *high-permeability upper zone.* Fig. 2 shows the type curve match for this case.

A second model was constructed with the channel having a 2.0-md-ft *flow capacity* and the bottom zone having the higher *flow capacity*. In this case, the type-curve match was obtained with and 1.0 aspect ratio and a 27-acre *effective drainage area.*

The low effective drainage area for these cases is a result of treating the two-layer channel/blanket sand as a single zone with an 80-ft net thickness (model net pay at the completion). When the actual geometry is not known, assuming a common geometry for both sands results in an inaccurate estimate of drainage area. However, the resulting drainage-volume estimate obtained from the analysis matches the simulated volume.

The actual reservoir geometry can be determined if the individual-zone rates are known through time.

It has been shown that in some cases, treating non commingled zones as a single sand with average properties can extend the time to reach pseudo steady state significantly.

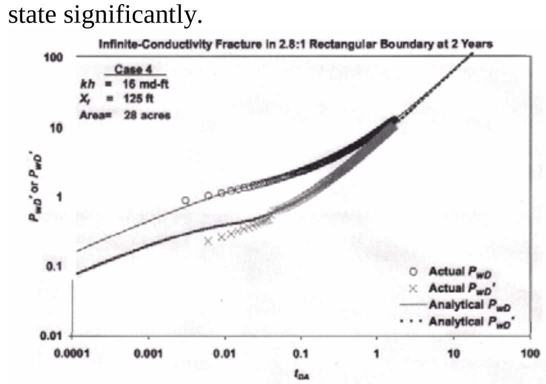

Fig. 2. Case 2: Production analysis results.

CASE 3

It is focuses on hydraulic-fracture cleanup. The base model was used for this case, and the cleanup time in the simulation was 60 days. The conductivity of the fracture was set equal to the formation conductivity at Day 1. Hydraulic fracture cleanup has a distinct type-curve response.

Fig. 3. Is the type-curve match for this case. Note the negative slope in the early-time data and the fact that the resulting match shows much less fracture half-length than the base case. This result may be one of the most logical explanations for the short fracture lengths obtained from production analysis. After stimulation of a oil well with a liquid fracturing fluid, the

conductivity and effective fracture length with respect to oil is zero.

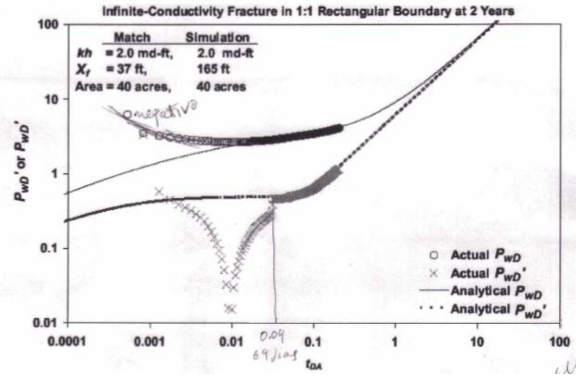

Fig. 3. Case 3: Production analysis results.

Oil saturated fracture length increases with improving conductivity as desaturation occurs during cleanup. The fracture length estimated depends entirely on the degree of cleanup accomplished at the time when the flow is observed, and in this case, at dimensionless time based on area, t_{DA} of approximately 0.04 (after 69 days of production). It is important to note that the fracture conductivity after 60 days was equal to the base-case conductivity of 75 md-ft.

CASE 4

This case presents the results of liquid loading. In tight gas reservoirs, liquid loading historically has been viewed as a mechanical problem that effectively is placing an additional backpressure on the formation.

However, experience has suggested that liquid-loading results in a false depletion stem in production type-curve analysis. This work set out to address the cause of this phenomenon. This study approached the problem in a stepwise fashion. The first step was to determine if ignoring the additional backpressure caused by the liquid standing over the perforations would cause an early depletion stem.

The second step was to incorporate the effects of spontaneous imbibitions during flowing conditions into the model. This process was approximated by allowing small amounts of water to drop out during production.

Effectively, the near-wellbore region has slightly increasing water saturation with time during production. In conjunction with this study, laboratory experiments were conducted to determine if the process could be modeled physically.

The results of the laboratory experiments showed that if water was allowed to stand in or above the perforations, the effective gas permeability was reduced by as much as 75% of its original value.

These results were transformed into a relative permeability curve that was used in the simulation runs modeling this effect.

CASE 4A

Assumes a static liquid column is present but not accounted for when calculating flowing bottom hole pressure for the analysis. This case shows that backpressure alone does not account for field observations. The reservoir flow capacity and the fracture half-length are less than the actual values in the simulator because the incorrect bottom hole flowing pressure is accounted for as reduced completion efficiency. However, the effective drainage area and shape are correct.

Assumes a static liquid column is present but not accounted for when calculating flowing bottom hole pressure for the analysis. This case shows that backpressure alone does not account for field observations.

The reservoir flow capacity and the effective x_f are less than the actual values in the simulator because the incorrect bottom hole flowing pressure is accounted for as reduced completion efficiency. However, the effective drainage area and shape are correct.

CASE 4B

Assumes a static liquid column is present causing imbibitions during the production life of the well.

Liquid fills the near-wellbore fracture and matrix.

Fig. 4 presents the type curve match for this case, where the relative permeability in both the hydraulic incorporate the effects of spontaneous imbibition during flowing conditions into the model.

This process was approximated by allowing small amounts of water to drop out during production.

Effectively, the near-wellbore region has slightly increasing water saturation with time during.

CONCLUSIONS

The primary porosity composed by the matrix and microfractures that contain the fluid presented low capacity flow.

The model show changes in lithology, petrophysical parameters such as: high porosity in limestone very fractured for a calcareous limestone generating good permeability, high contrast in the pressure and temperature (top =85 C and botton 100 C). Exist heavy oil with changes very strong in viscosity with the temperature, changing the hydraulic diffusivty coefficient. In the top of the reservoir exist several horst and graben. Generating geometries complex.

REFERENCES

Agarwal, R.G., Carter, R.D., y Pollock, C.B.: "Evaluation and Prediction of Performance of Low Permeability Gas Wells Stimulated by Massive Hydraulic Fracturing," Paper SPE 6838, presentado en the 52nd Annual Fall Technical Conference and Exhibition, SPE of AIME, Denver, Colorado, del 9 al 12 de Octubre de 1977. Presentado también en JPT, en marzo de 1979, 362.

Andrews, L., “Special functions of mathematics for engineers”, 2da edición, SPIE, 1998.

Barker, B., y Ramey, H.J., JR.; "Transient Flow to Finite Conductivity Vertical Fractures", Paper SPE 7489, presentado en el 53rd Annual Fall Technical Conference and Exhibition, SPE of AIME, Houston, Texas, del 1 al 3 de octubre de 1978.

Bostic, N.J., Agarwal, R.G. y Carter, R.D.: "Combined Analysis of Postfracturing Performance and Pressure Buildup Data for Evaluating MHF Gas Wells," JPT, octubre de 1980, 1711.

Clark, K.K.: “Transient Pressure Testing of Fractured Water Injection Wells” JPT, junio de 1968, 639-643; Trans., AIME, 243.

Cinco Ley, H.: “Well-Test Analysis for Naturally Fractured Reservoirs”, Distinguished Author Series, JPT, enero de 1996.

Cinco Ley, H. y Samaniego-V., F.: "Effect of Wellbore Storage and Damage on the Transient Pressure Behavior of Vertically Fractured Wells," Paper SPE 6752, presentado en el 52nd Annual Fall Technical Conference and Exhibition, AIME, Denver, Colorado, del 9 al 12 de octubre de 1977.

Cinco Ley, H. y Samaniego-V., F.: "Determination of the orientation of a Finite Conductivity Vertical Fracture by Transient Pressure Analysis," Paper SPE 6750, presentado en el 52nd Annual Fall Technical Conference and Exhibition, SPE del AIME, Denver, Colorado, del 9 al 12 de octubre de, 1977.

Cinco Ley, H. y Samaniego-V., F. y Domínguez, N.: "Transient Pressure Behavior of a Well with a Finite-Conductivity Vertical Fracture," SPE Paper 6014, 51st Fall Meeting, SPE of AIME, New Orleans, del 3 al 6 de octubre de 1976. Presentado también en SPE J. (Agosto de 1978), 253.

Cinco Ley, H. y Samaniego-V., F.:: "Transient Pressure Analysis for Fractured Wells," Paper SPE 7490, presentado en el 53rd Annual Fall Technical Conference and Exhibition, AIME, Houston, Texas, del 1 al 3 de octubre de 1978. Presentado también en JPT, en septiembre de 1981m 1749.

Dyes, A.B., Kemp, C.E., y Caudle, B.H.: "Effects of Fractures on Sweep-Out Pattern," Trans.,AIME (1958), 213, 245.

Galicia, M., S., 2009: Geomecánica aplicada a Yacimientos Naturalmente Fracturados para la Determinación de Compresibilidad de la Formación. Tesis de Licenciatura, Facultad de Ingeniería, UNAM.

Gringarten, A. C. y Ramey, H.J., Jr., 1973: "The Use of Source and Green's Functions in Solving Unsteady Flow Problems in Reservoirs," SPE J., oct., 285-296; Trans. ,AIME Vol. 255.

Gringaten, A. C., Ramey, H.J., Jr., y Raghavan, R.: "Unsteady State Pressure Distributions Created by a Well with a Single Infinite Conductivity Vertical Fracture," SPE J., agosto de 1974, 347.

Gringaten, A. C., Ramey, H.J., Jr.: "Unsteady-State Pressure Distribution Created by a Well with a Single Horizontal Fracture, Partial Penetration or Restricted Entry," -SPE J., agosto de 1974, 413.

Guppy, K. H., Cinco Ley, y Ramey, Jr.: Effect of Non-Darcy Flow on the Constant Pressure Production of Fractured Wells. Paper SPE 9344, presented in the Annual Fall Technical Conference and Exhibition, SPE of AIME, Dallas, Texas, sept. 1980, presentado también en SPE J., en junio de 1981, 390.

Mao, M. L., “Performance of Vertically-Fractured Wells with a Finite-Conductivity Fracture,” Tesis de doctorado, Stanford University, Stanford, California, mayo de 1977.

McGuire, W.J., y Sikora, V.J.: "The Effect of Vertical Fractures on Well Productivity," Trans., AIME 1960, 219, 401.

Morales Germán Gabriela, “Caracterización del sistema matriz-fractura para flujo transitorio y pseudoestacionario para tamaño múltiple de bloque”, Tesis de Licenciatura, Facultad de Ingeniería, UNAM, 2009.

Muskat, M.: “Flow of Homogeneous Fluids Through Porous Media”, McGraw-Hill Book Co., Inc., New York, 1937.

Prats, M.: "Effect of Vertical Fractures on Reservoir Behavior- Incompressible Fluid Case," SPE J., Junio de 1961, 105.

Pulido, H. Samaniego, F., Rivera, J., Diaz, F., Galicia, G., “Well Test Analysis for Naturally Fractured Reservoirs with Transient Interporosity Matrix, Microfractures and Fractures Flow”, presentado en la 31st Workshops on Geothermal Reservoir Engineering, Standford University, Standford, California, del 30 enero al 1 de febrero de 2006.

Raghavan, R., Uraiet, A., y Thomas, G.W.; "Vertical Fracture Height: Effect on Transient Flow Behavior," Paper SPE 6016, presentado en la 51st Annual Fall Technical Conference and Exhibition, SPE AIME, New Orleans, del 3 al 6 de octubre de 1976.

Raghavan, R.: "Pressure Behavior of Wells Intercepting Fractures," Proc., Invitational Well-Testing Symposium, Berkley, California, del 19 al 21 de octubre de 1977.

Russell, D.G., y Truitt, N.E.: "Transient Pressure Behavior In Vertically Fractured Reservoirs," JPT, octubre de 1964, 1159.

Sawyer, W.K., Locke, C. D., 1973: Simulation of a Finite-Capacity Vertical Fracture in a Gas Reservoir. Paper SPE 4593, presented en 48th Annual Fall Fleeting, SPE of AIME, Las Vegas, Nevada, del 30 de sept. 3 de octubre de 1973.

Scott, J. O., 1963: The Effect of Vertical Fractures on Transient Pressure Behavior of Wells. JPT, dec., 1365.

Van Poollen, H. K., Tinsley, J. M., and Saunders, C. D., 1958: "Hydraulic Fracturing: Fracture Flow Capacity vs. Well Productivity," Trans., AIME, 213, 91.

Warren, J. E., Y Root P.J., 1963: The Behavior of Naturally Fractured Reservoirs, Trans., AIME 426.