Deliverability Of Gas-Condensate Reservoirs—Field Experiences and Prediction Techniques

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Introduction

Predicting and assuring well deliverability often are important concerns when developing gas-condensate reservoirs. Many gas-condensate projects are in deep, hot, low-permeability reservoirs for which well costs are a significant part of the project economics. It is well known that the deliverability of gas-condensate wells can be impaired by the formation of a condensate bank once the bottomhole pressure drops below the dewpoint. This paper outlines the five steps—appropriate laboratory measurements, fitting laboratory data to relative permeability models, use of spreadsheet tools, single-well models, full-field models (FFMs)—to predict deliverability loss caused by condensate banking. It then discusses integrated laboratory/simulation field studies used to validate these steps. Finally, options to improve well deliverability are explored.

Gas Condensate and Banking

Typically, gas-condensate reservoirs are single-phase gas in the reservoir at discovery, but yield small amounts of oil at the surface (approximately 10 to 300 STB/MMscf). They have a composition consisting largely of methane and small fractions of intermediate and heavy ends (typically, approximately 87% C_1, 9% $C_{2\text{–}6}$, and 4% C_{7+}). The temperatures encountered in these reservoirs (200 to 400°F) are higher than the critical temperature of the fluid, but lower than the maximum temperature extent of its two-phase region. As **Fig. 1** shows, the gas is extracted, the pressure declines isothermally, and at the dewpoint, the first droplets of liquid formed from the heavier hydrocarbon components appear.

A gas-condensate system is also characterized by a liquid-condensation curve such as that shown in **Fig. 2.** A lean system may have a yield of approximately 10 STB/MMscf (2% maximum condensate), and a rich system could yield as much as 300 STB/MMscf (20% condensate).

When the flowing bottomhole pressure falls below the dewpoint of the reservoir fluid, liquid condensate builds up (condensate banking) near the wellbore, as shown in **Fig. 3.** This buildup of liquid reduces the gas relative permeability and can cause well-productivity loss greater than 50%, which is well documented in industry literature.

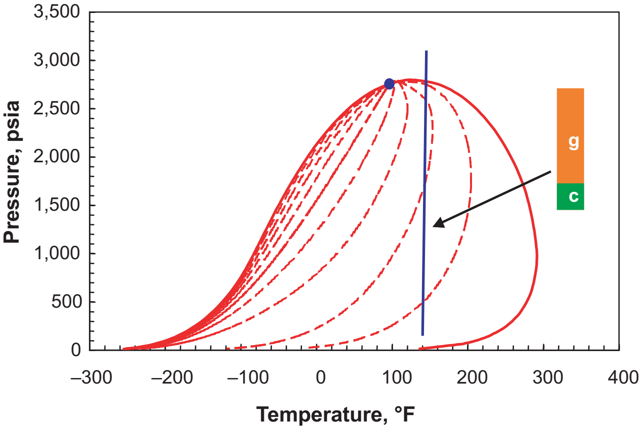

Fig. 1—Phase diagram of gas-condensate system: g=gas and c=condensate.

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Predicting Deliverability Loss Caused by Condensate Banking

Predicting the deliverability loss that is caused by condensate banking requires the following.

Appropriate Laboratory Measurements. Several reservoir-condition experiments have been documented to measure gas-condensate relative permeability. Some found similar behavior of model and reservoir fluids, whereas others noted differences. Investigators have observed improved relative permeabilities with reduced interfacial tension, higher velocities, and higher trapping numbers. Other methods have been reported that measure the key relation defining pseudosteady-state flow in gas-condensate wells without the need for saturation measurements.

The most comprehensive data set would be reservoir-condition gas-condensate relative permeability measurements conducted for the various preserved rock types and encompassing the range of flow velocities and pressures in the near-well region. These tests are very difficult to conduct. An approximation that was found useful, and is believed appropriate, is to conduct pseudosteady-state experiments

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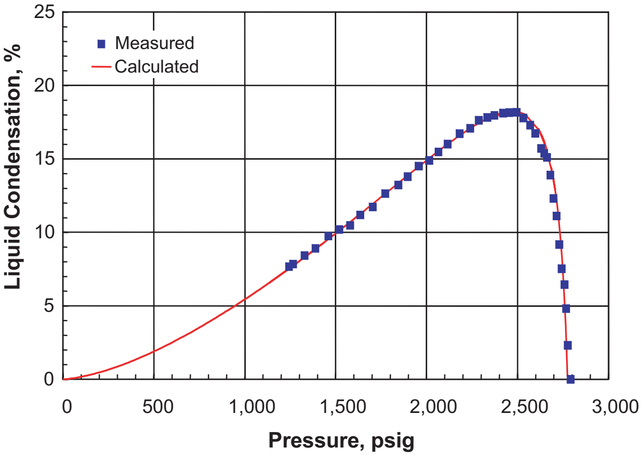

Fig. 2—Liquid-condensation curve.

(Whitson et al. 1999) with carefully designed synthetic fluids (Kalaydjian et al. 1996) that allow the experiments to be conducted at lower temperatures without the need for saturation measurements.

Synthetic-Fluid Design. In a study described in Silpngarmlers et al. (2005), the synthetic fluid (97.8% C_1, 2.1% n-C_{10}, and 0.1% n-C_{20}) was designed with the primary objective of matching the liquid condensation (V_{ro}), viscosity ratio (μ_g/μ_o), and interfacial tension (IFT) of the reservoir gas condensate (79% C_1, 15% $C_{2\text{–}6}$, 7% C_{7+}) while operating the corefloods at a much lower temperature (120°F) than the reservoir temperature (290°F). **Fig. 4** shows that the match was very good.

Experimental Design. Whitson et al. (1999) demonstrated that $k_{rg}=f(k_{rg}/k_{ro}, N_c)$ is the underlying relative permeability relationship determining well deliverability of gas-condensate reservoirs. The experiments were designed to define $k_{rg}=f(k_{rg}/k_{ro})$ for the range of k_{rg}/k_{ro} values and capillary numbers, N_c, expected near the well. The range of k_{rg}/k_{ro} near the well can be calculated from $k_{rg}/k_{ro}=(1/V_{ro}-1)\times(\mu_g/\mu_o)$, where V_{ro} is the relative oil volume from a constant-composition expansion and μ_g/μ_o is the ratio of the gas and oil viscosities of the steady-state-flowing phases in the near-wellbore region. **Fig. 5** shows typical ranges.

A high-pressure core-flow apparatus is shown in **Fig. 6.** A storage cylinder (II) contains the equilibrium synthetic gas. The pump (I) supplies this gas from the cylinder to the inlet of the core (IV) by flashing it across the upstream backpressure regulator (III). The upstream backpressure regulator is held at the reservoir pressure, and the downstream backpressure regulator (V) is set to the bottomhole pressure, thus resulting in two-phase condensate flow across the core. Varying the pressure of the cylinder regulates the mixture flowing from this system from a rich (initial) fluid to a leaner fluid. The pressure drop and the flow rate are noted after steady-state conditions are achieved, typically after approximately 10 to 15 pore volumes. Then, the pump rate is changed and the test is repeated at a different capillary number. The result is

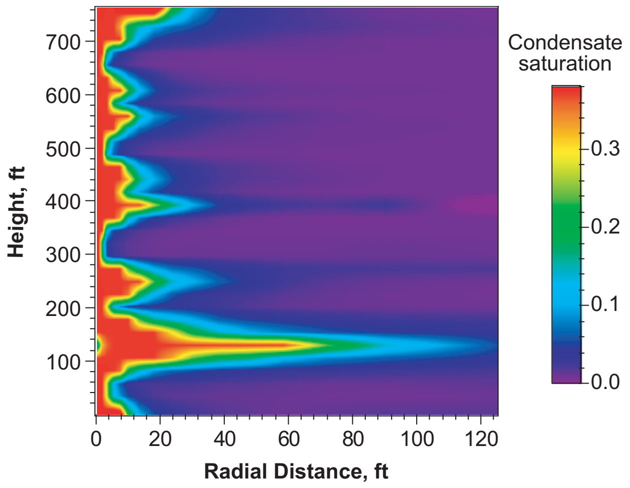

Fig. 3—Buildup of condensate near a well.

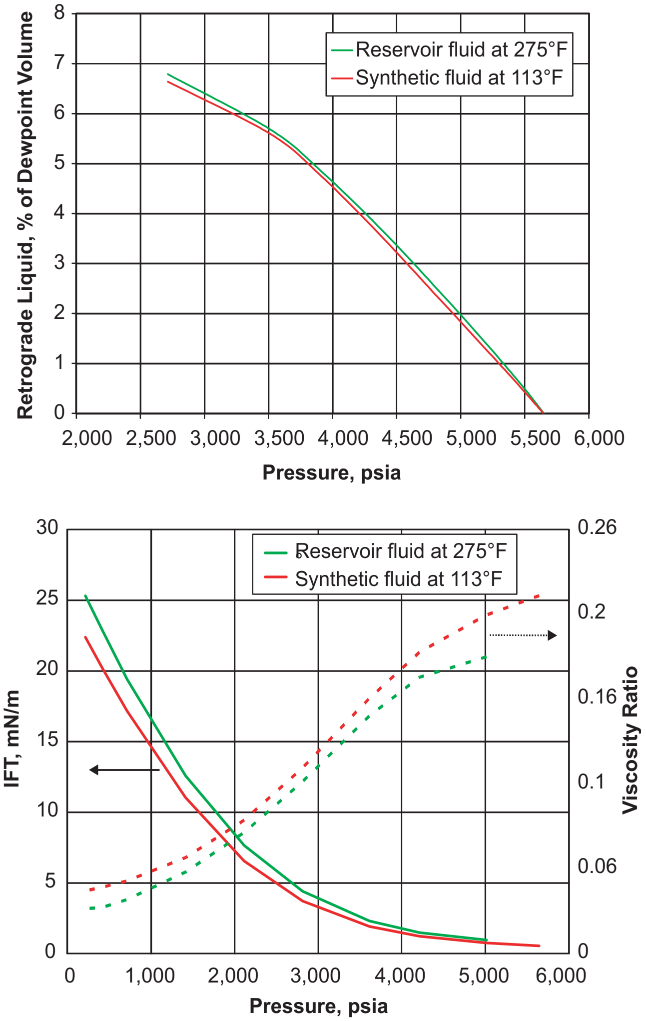

Fig. 4—Comparison of synthetic and reservoir fluids. Top: liquid volume fraction; bottom: IFT and viscosity.

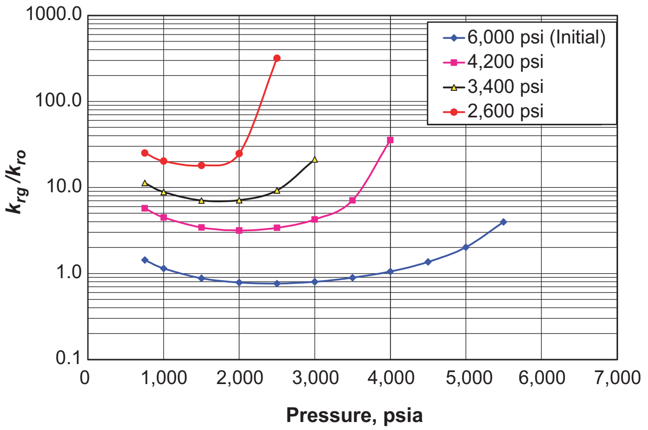

Fig. 5—k_{rg}/k_{ro} as a function of bottomhole pressure.

a variation in k_{rg} with N_c at a fixed k_{rg}/k_{ro}. The gas in the cylinder then is bled off until the pressure in the tank drops to a lower reservoir pressure, and the procedure is repeated to yield the same data at a different k_{rg}/k_{ro} value.

Typical experimental data from Silpngarmlers et al. (2005) are shown in **Fig. 7.**

Fitting Laboratory Data to Relative Permeability Models. The laboratory data are of the form $k_{rg}=f(k_{rg}/k_{ro}, N_c)$. This form of data can be fitted by use of models such as those of proposed by Whitson et al. (1999) and can be used for spreadsheet calculations. However, many conventional simulators require that the data be fitted to the form $k_{rg}=f(S_g, N_c)$. These can be done, for example, by use of the Heriott-Watt model (Henderson et al. 1998), U. of Texas model (Pope et al. 1998), and scaling models (Ayyalasomayajula et al. 2005).

The models require that the base "immiscible" relative permeability data be fitted, which can be difficult because it may be impossible to define an invariant low-capillary-number curve. In addition, the commonly used power-law functional forms used for relative permeability curves provide poor fits to the base curve, and more-flexible forms are needed.

Fig. 8 shows a typical fit to the data. Because laboratory data often are extrapolated, better models and fuller implementation and testing of existing models, along with adding measurements in the high-(k_{rg}/k_{ro}) and -capillary-number space of the existing database, will increase confidence in predictions.

Use of Spreadsheet Tools. Mott (2003) and others developed spreadsheet tools to evaluate well performance rapidly. The spreadsheet uses a material-balance model for reservoir depletion and a two-phase pseudopressure integral for well-inflow performance, and it can use laboratory data in the form $k_{rg}=f(k_{rg}/k_{ro}, N_c)$. The calculations are based on a modified black-oil formulation with homogeneous reservoir properties. Given the uncertainty and often lack of relevant laboratory measurements, it is recommend that such spreadsheet tools be used as the first step in understanding whether condensate banking will affect well deliverability significantly and whether detailed compositional simulation is warranted.

Fig. 9 shows the productivity-index (PI) prediction of Well 1 from the spreadsheet calculations at different minimum bottomhole pressures. Because of the effect of condensate blockage, the PI drops to as low as 15 Mscf/(psi-D), an 80% productivity loss.

Single-Well Models. If spreadsheet calculations indicate that condensate banking can affect deliverability significantly, and appropriate relative permeability and fluid-property data

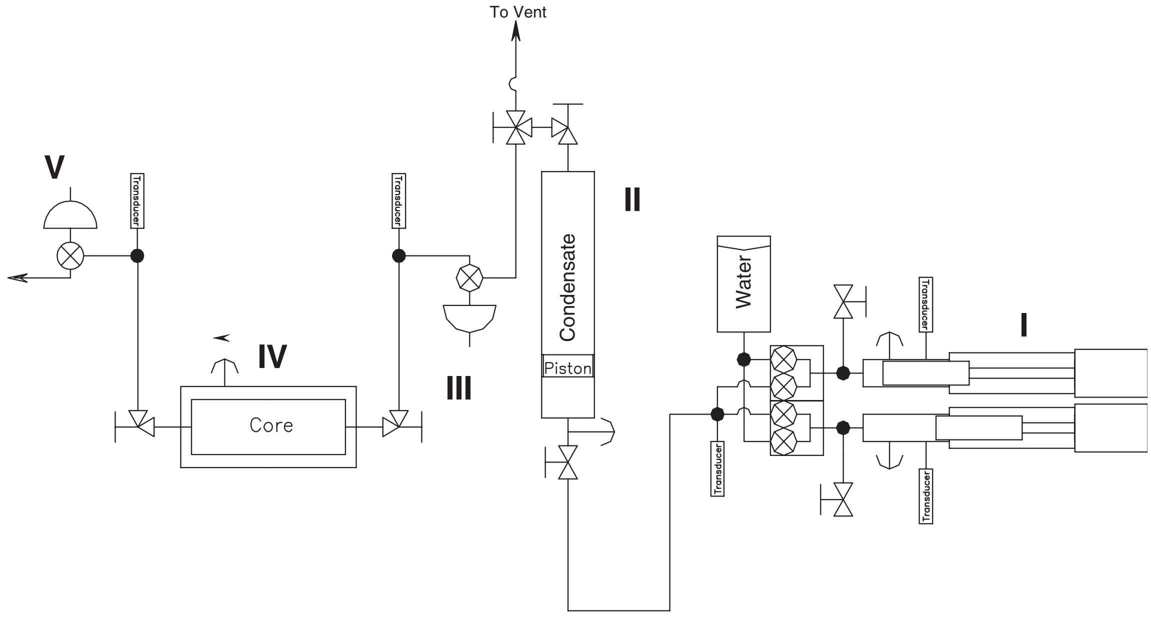

Fig. 6—Experiment schematic.

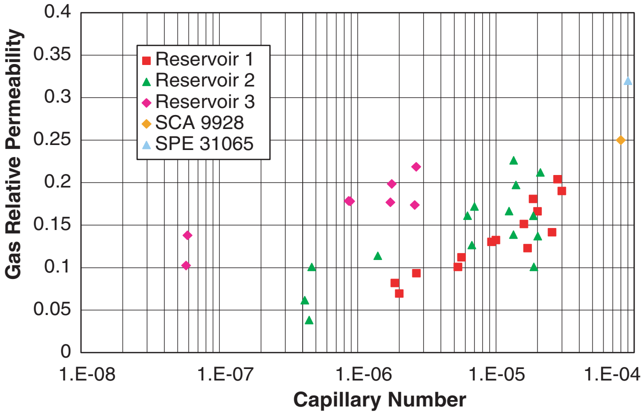

Fig. 7—k_{rg} as a function of capillary number for k_{rg}/k_{ro} of approximately 12.

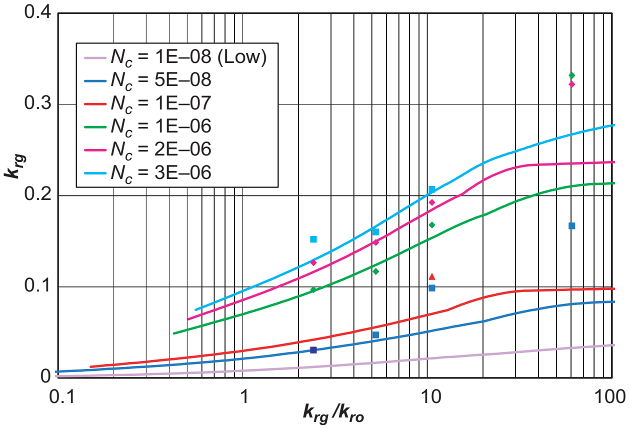

Fig. 8—Fit of experimental data.

are available, single-well compositional models such as that shown in **Fig. 10** are very useful tools to quantify the effect further. The advantage of single-well models over spreadsheet models is the ability to understand compositional effects, heterogeneity, differential depletion, and time-varying boundary conditions. The effect of condensate banking is captured by use of very-fine-scale (1-ft) grids near the well, with petrophysical properties extracted from the FFM. The FFM also provides the appropriate external-boundary conditions and the producing rules for each of the wells studied (Ayyalasomayajula et al. 2005).

FFMs. If spreadsheet and single-well models indicate that condensate banking can affect well deliverability significantly, then these effects can be captured in FFMs in three ways: PI multipliers, local grid refinement (LGR) around wells, or by use of the generalized pseudopressure (GPP) model.

Modeling often shows the PI reduction in a homogeneous system as a step change when the bottomhole pressure drops below the dewpoint and as a gradual change thereafter. Given the uncertainty in the input parameters and the resulting uncertainty in PI estimates, it may be sufficient to use a constant-PI multiplier for each layer in a well model. The composite effects of these layers can cause a multilayer well model to show a varying PI with time.

LGR around wells is an alternative, but the LGR cells must be very small to resolve the condensate bank and the computing time may be prohibitive, especially if there are many wells. In addition, many FFMs are black oil, and capillary-number effects are not captured.

Barker (2005) reported on the use of the GPP option available in some full-field simulators. This option is based on the work of Fevang and Whitson (1996) and accounts for the variations in saturation and relative permeability within the gridblocks affected by condensate banking. Barker found that the GPP option sometimes does not work and recommends that this method always be checked by use of a fine-grid model.

Comparison With Field Performance

There have been many excellent laboratory studies on gas-condensate relative permeability, but integrated laboratory/simulation/field studies that compare systematic predictions to field performance are rare. Hence, there is still significant uncertainty in the extent and importance of condensate banking.

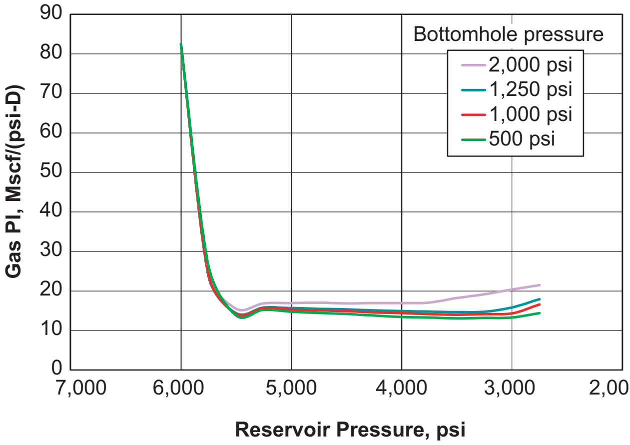

Fig. 9—Spreadsheet calculations of PI as reservoir pressure declines.

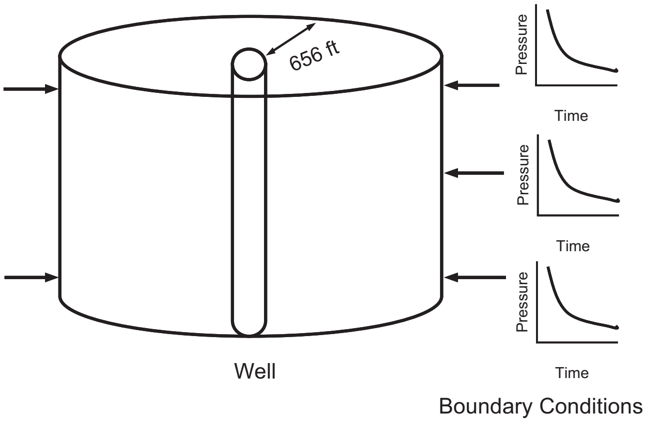

Fig. 10—Vertical-well radial model with time-varying external-boundary conditions for each layer.

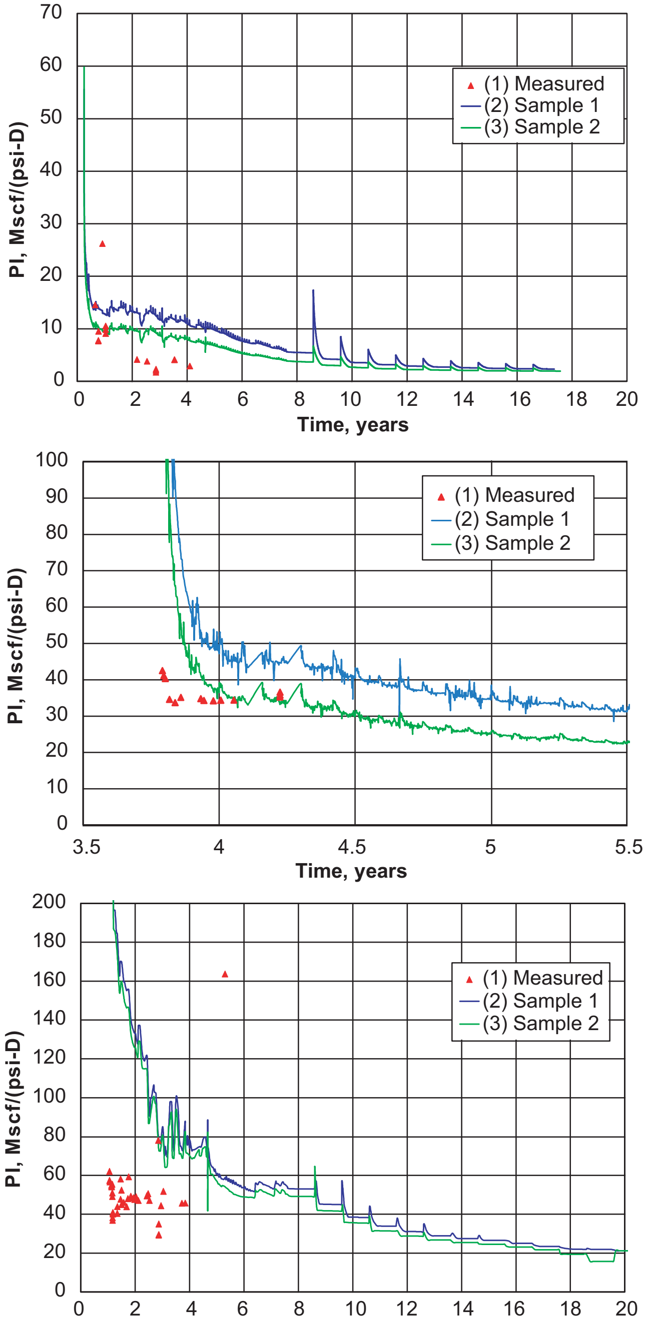

Fig. 11—Comparison of measured and predicted PI for three wells in a low-permeability gas-condensate reservoir.

A careful and comprehensive evaluation of deliverability of several wells in a low-permeability gas-condensate reservoir was made and reported in Ayyalasomayajula et al. (2005) and Silpngarmlers et al. (2005). This sandstone reservoir has permeability of approximately 10 md, porosity of approximately 10%, and condensate yield of approximately 50 bbl/MMscf. The performance of the wells was predicted reasonably. The approach consists of the following steps.

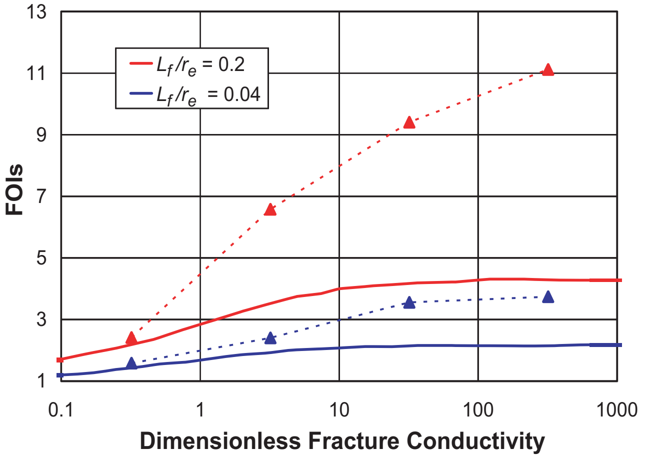

Fig. 12—FOIs for dry gas (solid lines) and a lean gas condensate (symbols, dashed lines).

1. Carefully select core samples that cover the range of expected responses.
2. Design fluid systems that mimic reservoir fluids but at lower temperatures.
3. Acquire appropriate relative permeability measurements $k_{rg}=f(k_{rg}/k_{ro}, N_c)$ for a range of flow conditions.
4. Fit these data to several different relative permeability models for use in reservoir simulators.
5. Use analytical spreadsheet tools to calculate deliverability.
6. Perform detailed single-well compositional models with realistic geology and boundary conditions extracted from FFMs honoring complex producing rules and differential depletion.
7. Compare the prediction to four wells: three vertical and one inclined.

Fig. 11 compares the PI prediction with measured values. The measured productivity reduction of the wells was found to be in the range of 80%, the majority of which occurred in the initial phases of production. Samples 1 and 2 represent the uncertainty in relative permeability input. There are significant other uncertainties including difficulty in defining initial single-phase PI because the reservoir was at the dewpoint pressure. Therefore, it appeared that a reasonable prediction of the performance was made, but an unresolved issue is that the predicted rate of PI decline is slower than that observed in the field.

Improving Deliverability

Deliverability can be improved by use of fracturing, chemical treatments, and huff ’n’ puff gas injection. Though there are sporadic reports on the use of various techniques in gas-condensate reservoirs with limited and short-term success, it is difficult to find details. Fracturing may not yield expected results if the design does not consider that the fracture may load up with liquid condensate and that the condensate bank in the reservoir will reshape around the fracture. Most chemical injection and huff ’n’ puff projects will have only short-term results because the bank will form. Simulations show that a well-designed huff ’n’ puff CO_2 injection (late in the field life with large slugs) can provide enough incremental PI to be economic in some cases.

Hydraulic Fracturing. Predicting productivity improvement by fracturing in gas-condensate wells is not as well understood as in dry-gas systems. This lack of understanding is the result of the effects of condensate banking and liquid loading in the fracture. Good laboratory data and understanding of the complex multiphase-flow physics are required. Industry literature discusses the use of hydraulic fracturing to restore well productivity to single-phase values, sensitivity studies, optimization of fracture parameters, and some field examples.

Measured laboratory and actual field data were used along with very finely gridded compositional models with all the relevant physics to improve the understanding of fracture performance of gas-condensate wells. **Fig. 12** shows that the fold of increase (FOI) ratio of (PI after fracturing)/(initial PI) in gas-condensate wells is very different from that in dry-gas wells. FOI in gas-condensate wells is also a function of time and depends on gas composition.

Chemical Treatments. Some literature reports on the use of chemicals to reduce the impairment effects of condensate buildup around the well. Use of solvents such as methanol can improve deliverability but is not a long-term solution because the condensate bank will reform. Fahes and Firoozabadi (2005) attempted to solve this problem by altering the wettability in the near-well region to allow the condensate to flow easier, thus reducing the saturation of the condensate bank. Kumar et al. (2006) conducted reservoir-condition gas-condensate flow tests to study the effect of various fluorosurfactants on wettability as well as on the changes in the critical parameter $k_{rg}=f(k_{rg}/k_{ro}, N_c)$ that determines the effect on well deliverability. Chemicals were found that work well, and simulations showed that this process could be economic. Planning for field trials is under way.

Conclusions

Recent developments have provided practical laboratory techniques and modeling approaches to predict deliverability of gas-condensate reservoirs. A five-step approach—appropriate laboratory measurements, fitting laboratory data to relative permeability models, use of spreadsheet tools, single-well models, and FFMs—can predict deliverability loss caused by condensate banking reasonably.

Continued extensive testing of existing relative permeability models and more measurements in the high-(k_{rg}/k_{ro}) and -capillary-number region will increase confidence in predictions. Productivity improvement by fracturing in gas-condensate wells is not as well understood as in dry-gas systems and could benefit from additional work. Chemical treatments to change wettability and improve deliverability are in the laboratory phase, and field trials are still needed to evaluate their effectiveness.

Nomenclature

f = function
k_{rg} = gas relative permeability
k_{ro} = oil relative permeability
L_f = fracture half-length
N_c = capillary number
r_e = radius to external boundary
S_g = gas saturation
V_{ro} = oil relative volume (liquid condensation)
μ_g/μ_o = gas-/oil-viscosity ratio

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