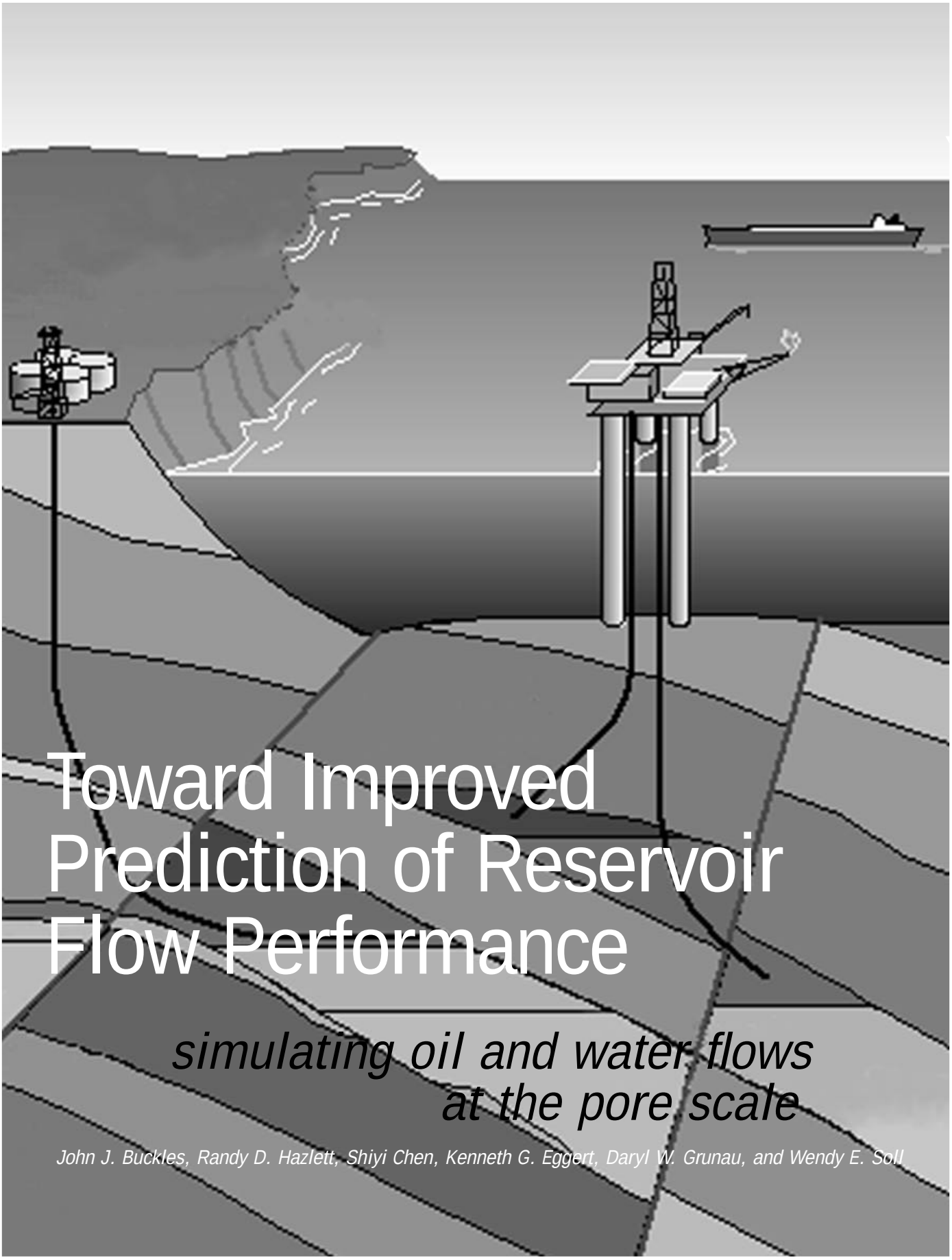


Toward Improved Prediction of Reservoir Flow Performance

simulating oil and water flows at the pore scale

John J. Buckles, Randy D. Hazlett, Shiyi Chen, Kenneth G. Eggert, Daryl W. Grunau, and Wendy E. Soll

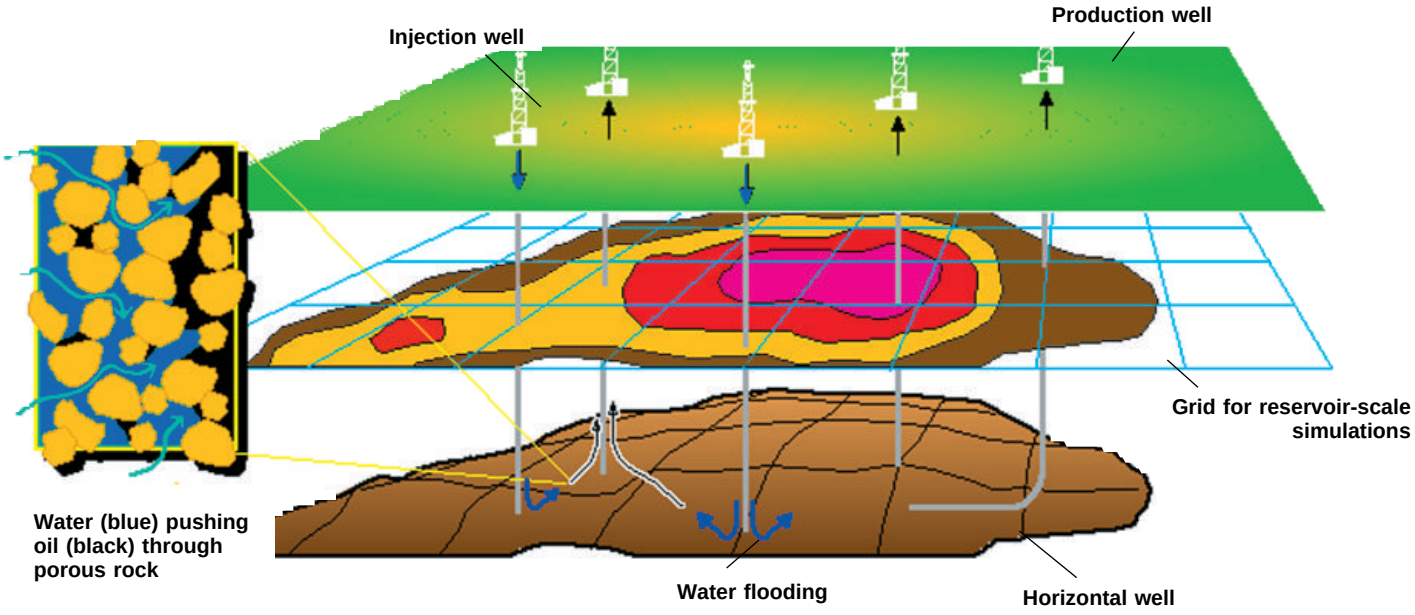


Figure 1. A Modern Oil-Recovery Project

This illustration of a modern oil-recovery project shows both production wells (black arrows indicate hydrocarbons) and injection wells (blue arrows indicate water) drilled into oil-bearing strata deep beneath the Earth's surface. The enlargement at left shows the porous network in the oil-bearing rock. Water (blue) that has been injected under pressure into the reservoir is displacing oil (black). The regular planar grid between the surface and the reservoir represents in two dimensions the rectangular-block geometry used in bulk flow simulations of reservoir performance. Plotted on the grid are lines of constant altitude in the top layer of the reservoir, which is not parallel to the surface but rather has hills and valleys. Bulk-flow simulations of reservoir-flow performance are an important ingredient in the decision of whether to invest in major recovery projects. Improved prediction of bulk-flow parameters through understanding the physics at the pore scale is the goal of the lattice-Boltzmann simulations of multiphase flow through porous media.

In today's world oil market, economic production of oil and gas resources requires carefully engineered recovery projects of increasing technical complexity and sophistication. Hydrocarbons do not reside in cavernous pools awaiting discovery. Rather they are found—sometimes at enormous depths—within the confines of tiny pores in rock. Although the pores may be interconnected, the resulting pathways still present a significant resistance to the flow of oil toward a well drilled into the hydrocarbon-bearing strata. In addition, since water resides in some of the pores, hydrocarbons and water are recovered simultaneously at the well-head. Thus, even when large amounts of oil are known to be in a reservoir, often only a relatively small fraction of it can be recovered with conventional pumping technology. The most common method of enhancing oil recovery, which accounts for much of the oil production in the U.S., is the injection of water at strategic locations to displace the oil toward the production wells.

Modern recovery projects of the type depicted in Figure 1 require very large capital investments. A single off-shore well drilled to a depth of 15,000 feet can cost up to $100 million. To be successful, a project must have a sizable hydrocarbon target, the promise of extracting oil or gas at a sufficiently high rate, a strategy for water separation and disposal, and a scheme for transportation to a refinery. As exploration efforts are driven to more remote environments, the infrastructure costs for hydrocarbon production escalate. Large potential returns are inevitably accompanied by large monetary risk.

Obviously, economic analysis must be performed before deciding whether a particular investment should be made. Computer simulations of reservoir flow performance are one of the essential ingredients in the analysis. On the basis of both field and laboratory data about the distributions of different rock types and the properties of each type, we at Mobil attempt to predict the average, or bulk, flow behavior of the fluids through the hydrocarbon-bearing rock of a reservoir. Many times our simula-

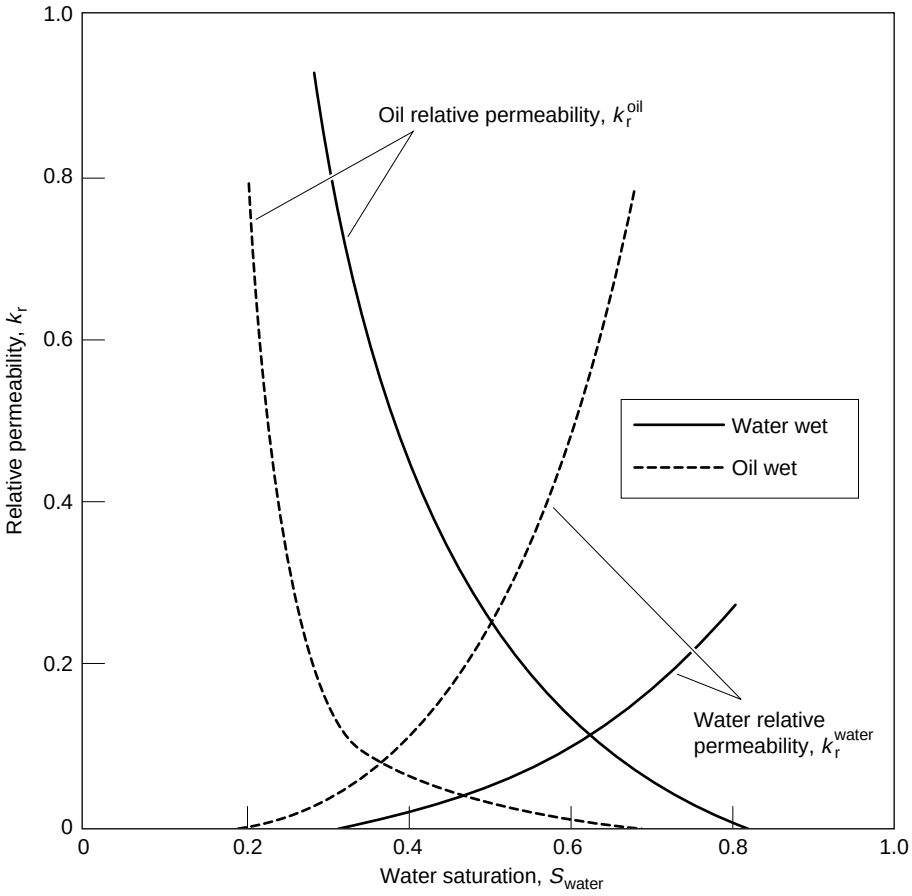


Figure 2. Typical Relative Permeability Curves for Oil and Water

Relative permeability versus water saturation (the fraction of the pore space occupied by water) is plotted for two rock types, one with a greater affinity for oil (oil-wet) and one with a greater affinity for water (water-wet). The curves were deduced from experiment. They show that oil can be recovered more easily from water-wet rock than from oil-wet rock. Note that if the rock is oil-wet (dashed lines), the relative permeability of oil falls precipitously as the fraction of the pore space occupied by oil goes below 80 percent (or equivalently, as the water saturation increases above 20 percent). For water-wet rock, the relative permeability of oil falls more gradually and not until the oil saturation goes below 70 percent.

tion-based predictions over- or underestimate reservoir performance because they do not properly model multiphase flow. Such errors can be the Achilles heel of the investment analysis, leading to very expensive errors in production strategy or even to a mistake in the decision of whether or not to invest.

The collaboration reported here between Mobil and Los Alamos National Laboratory is designed to improve reservoir-flow predictions by modeling fluid flow at the scale of individual pores, tens of microns across, and using those results to predict bulk-flow parameters. Ultimately our results will be incorporated into reservoir-scale computer simulations. Relative permeabilities are sensitive bulk parameters used in the simulations because they can change by factors of 2 or 3 depending on details of the fluid-fluid and rock-fluid interactions at the pore scale. Moreover such differences can translate into significant differences in the oil and water flow rates seen at the wellhead. An improved ability to predict relative permeabilities from easy-to-gather data is one of the major goals of our collaborative effort.

Parameters for porous-media flow. Permeabilities and relative permeabilities are defined by Darcy's law for flow through porous media. This empirical law says that the rate of flow through a porous rock is proportional to the pressure drop per unit length along the direction of flow. The constant of proportionality is called the permeability k. Specifically, the flow rate of a fluid, Q, along a direction x is proportional to the pressure gradient $\Delta p/\Delta x$ along that direction:

$$Q = \frac{kA}{\mu}\frac{\Delta p}{\Delta x},$$

where A is the cross-sectional area of

the porous rock perpendicular to the direction of flow and μ is the viscosity of the fluid. The permeability k describes the ease with which fluids flow through the porous network. Under a given pressure gradient, fluid will flow more slowly through a rock of low permeability than through one of high permeability. For the most part, the pore geometry of a rock (size and degree of connectedness of the pores) determines its permeability.

To describe the bulk flow in oil reservoirs, where pressure gradients cause oil, water, and gas to compete for space to flow, the concept of permeability is extended to include the sensitive parameters mentioned above, the relative permeabilities of each fluid present. Consider the case in which both oil and water occupy the pore space of a rock. Then the application of a pressure gradient will cause both oil and water to flow simultaneously. Darcy's law is modified to describe the flow rate of each fluid:

$$Q_{\text{total}} = Q_{\text{oil}} + Q_{\text{water}}$$

$$= (k_r^{\text{oil}} + k_r^{\text{water}})\frac{kA}{\mu}\frac{\Delta p}{\Delta x},$$

where Q_{oil} is the flow rate of oil, Q_{water} is the flow rate of water, k_r^{oil} is the relative permeability of oil, and k_r^{water} is the relative permeability of water. Relative permeabilities depend not only on the pore geometry, which is fixed, but also on variable quantities including the saturation of each fluid (fraction of the pore space occupied by each fluid), and the spatial distribution of each fluid within the pores. The sum of the two relative permeabilities is typically less than one because fluid-fluid interactions increase the resistance to flow.

Fluid distributions at the pore scale are governed, in turn, by fluid-fluid interactions and rock-fluid interactions. The latter determine an empirical quantity called wettability, the "preference" of a rock to be in contact with one fluid over another. In the jargon of the field, a rock is called water-wet and water is called the wetting fluid if, in the presence of water and oil, the rock surface interacts more strongly with water than with oil so that water wets (spreads out on) the rock surface and excludes direct contact with oil. A rock is called oil-wet and oil is called the wetting fluid if the rock "prefers" oil over water. At one time, experts thought all oil reservoirs were water-wet. Now most experts agree that reservoirs are predominantly of intermediate or mixed wettability. Intermediate wettability refers to the absence of any preferential interactions. Mixed wettability, on the other hand, implies that some regions are oil-wet and others water-wet on scales all the way down to individual pores.

Although it is well known that wettability influences the size and shape of pathways available for fluid flow and is therefore a controlling parameter for relative permeabilities, an explicit quantitative relationship between wettability and relative permeability has not yet been derived. Our current pore-scale studies, which include explicit modeling of fluid-fluid and fluid-rock interactions, should help to uncover that and other fundamental relationships among the empirical parameters used to describe multiphase flow through porous media.

Porous medium	k(experiment) [darcy]	k(simulation) [darcy]	Imaging resolution	Comments
Micromodel-1	23	21.5	~80 μm	Pore depth = 50 μm
Micromodel-2	37	32	~80 μm	Pore depth = 74 μm
Beadpack	1100	1000	50 μm	
Berea	1	1.2	10 μm	
Sandstone	7.4	8.6	20 μm	Flow in long direction
Sandstone	7.4	21.5	20 μm	Flow in short direction

Table 1. Permeabilities Deduced from Simulation and Experiment

Current data for reservoir-scale simulations. Obtaining relative permeability data is both difficult and expensive. Nevertheless, those data are crucial to large-scale simulations of reservoir flow performance. In the simulations the reservoir is treated as a set of tens of thousands of block-shaped regions, 100 to 1000 feet on a side, with each block assigned a permeability k and relative permeability curves for oil, water, and gas. These curves typically show relative permeabilities versus saturation of one of the fluids (see Figure 2). The saturation of a fluid is the fraction of the pore space occupied by that fluid.

Relative permeabilities are derived from bench-top experiments on rock samples that are specially cut during the well-drilling process by a drill bit with a hollow core. The rock "cores" are typically 1 to 2 inches in diameter and 3 to 4 inches in length. The cores are carefully selected to represent larger sections of reservoir rock. Retrieval of such cored reservoir rock is expensive and has historically been limited to at most about a half-dozen samples per reservoir. The laboratory experiments attempt to simulate flow under subsurface conditions of the fluids found in reservoirs. Hydrocarbons and salty

water are pumped through the samples at the pressures of thousands of pounds per square inch and temperatures between 100 to 250 degrees Fahrenheit. Relative permeabilities, as defined by Darcy's law, are computed from the measured flow rates and applied pressure gradients. It is only through such experiments that the effects of wettability on multiphase flow are incorporated into the simulations. Unfortunately the laboratory experiments may not always reflect the conditions present in the subsurface. For example, the wettability of the samples may have been altered by the invasion of drilling lubricants during the sample-retrieval process. In fact, both the quality and quantity of data on permeability and relative permeability limit the accuracy of reservoir-scale simulations.

Lattice-Boltzmann simulations of pore-scale flow. The lattice-Boltzmann method was developed at the Laboratory. This method enables us to model explicitly, in the complex geometry of a porous network, the influence of fluid-fluid and fluid-rock interactions on bulk flow parameters. Details of the lattice-Boltzmann model for the flow of immiscible fluids are described in the companion article, "Lattice-Boltzmann Fluid Dynamics." The algorithm was designed to run most efficiently on large massively parallel computers such as the Laboratory's CM-5 Connection Machine. Here we present some comparisons between two- and three-dimensional lattice-Boltzmann simulations of single-fluid and two-fluid flow and corresponding laboratory experiments.

Pore geometry is a major factor determining flow in porous media, so we had to replicate realistic geometries in both the simulations and the experiments. To simulate two-dimensional flow in the laboratory, we took advantage of computerized etching techniques to create glass micromodels of thin sections of rock. The digitized pattern used to etch each glass micromodel was also used to create the two-dimensional pore geometry for the corresponding lattice-Boltzmann computer simulation. The three-dimensional experiments involve either beadpacks (beads of various sizes packed together to approximate the geometry of porous rock) or actual core samples from reservoirs. X-ray tomography performed at the National Synchrotron Light Source at Brookhaven National Laboratory is used to capture the three-dimensional pore structure of the rock samples in the digitized form needed for the simulations. The digital rendering of the x-ray image, which is used in the simulations, can have a resolution of one micron (much less than average pore diameters, which are typically tens of microns).

Table 1 lists the results of the single-fluid simulations, which yield values for the permeability k for different types of porous media. The simulations are in good agreement with experiment except for the case of flow across the shortest dimension of the sandstone sample. The discrepancy may be due to differences in the degree of homogeneity between the simulated region and the experimental sample. One of our present research goals is to determine the size and resolution of the simulated domain required to accurately predict permeabilities and other macroscopic flow properties from the details of pore structure, material texture, and rock-fluid interactions.

In the lattice-Boltzmann model for the flow of immiscible fluids, the viscosity of each fluid may be varied independently. Also, the surface tension at fluid-fluid interfaces and the contact angle of each fluid with the rock surface may be varied. (See Figure 6 in "Lattice-Boltzmann Fluid Dynamics"

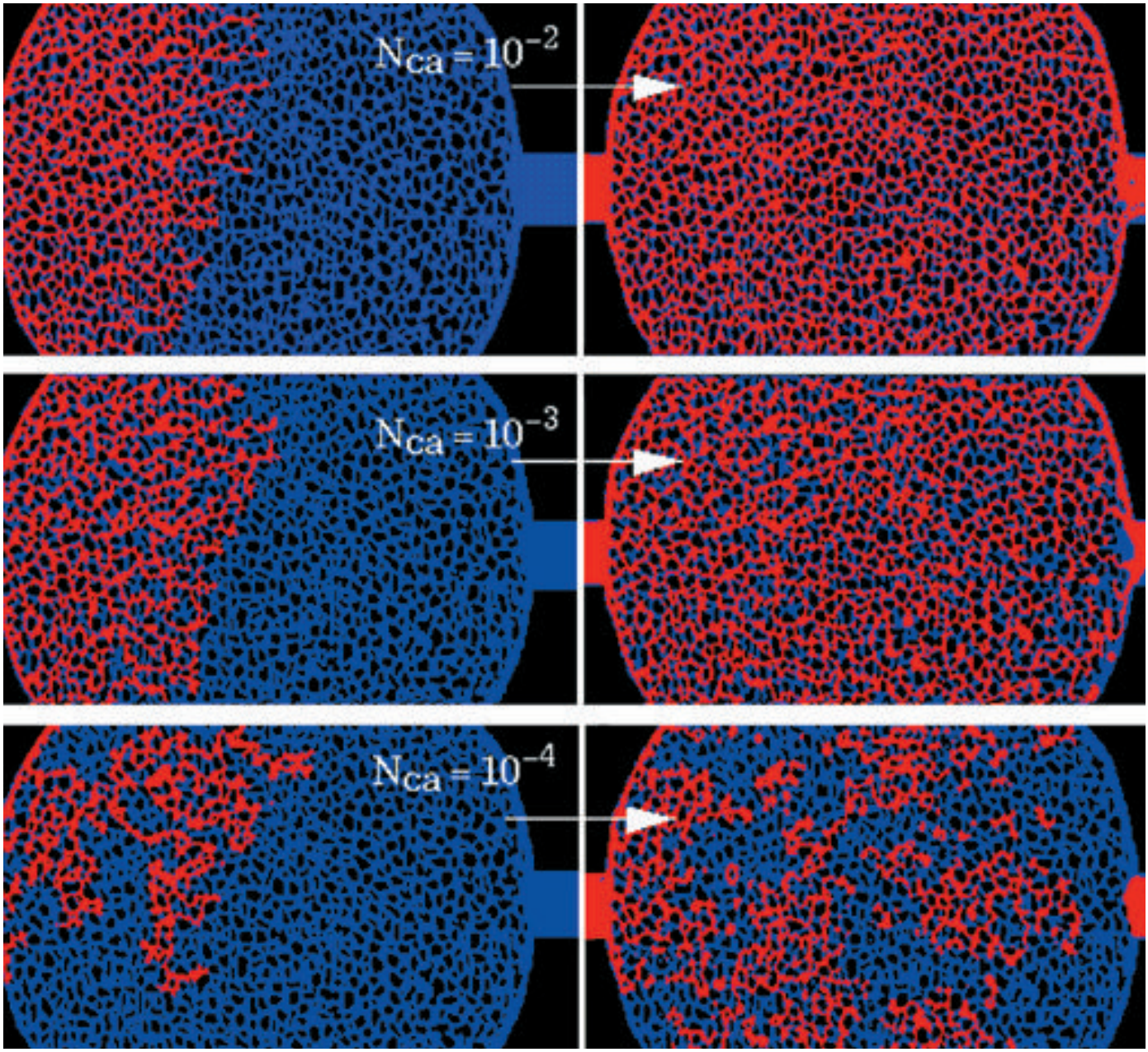


Figure 3. Water Displacing Oil at Different Capillary Numbers

These two-dimensional lattice-Boltzmann simulations show flow through a two-dimensional glass micromodel for three values of the capillary number, the ratio of viscous to interfacial (or capillary) forces. Here capillary number is defined as $N_{ca} = \mu U/\phi\sigma$, where μ is viscosity, U is displacement velocity, and ϕ and σ are porosity and interfacial tension, respectively. The pores are originally filled with the blue wetting fluid (oil). The red non-wetting fluid (water) is injected at left. Different displacement velocities were used to simulate the effect of different capillary numbers on the efficiency with which the pores are swept. Note that as the velocity decreases, or the capillary number decreases, the red non-wetting fluid (water) becomes less effective at displacing the blue wetting fluid (oil). At low capillary number, when interfacial forces dominate, the simulation produces an irregular displacement front. These results are realistic compared with published laboratory results.

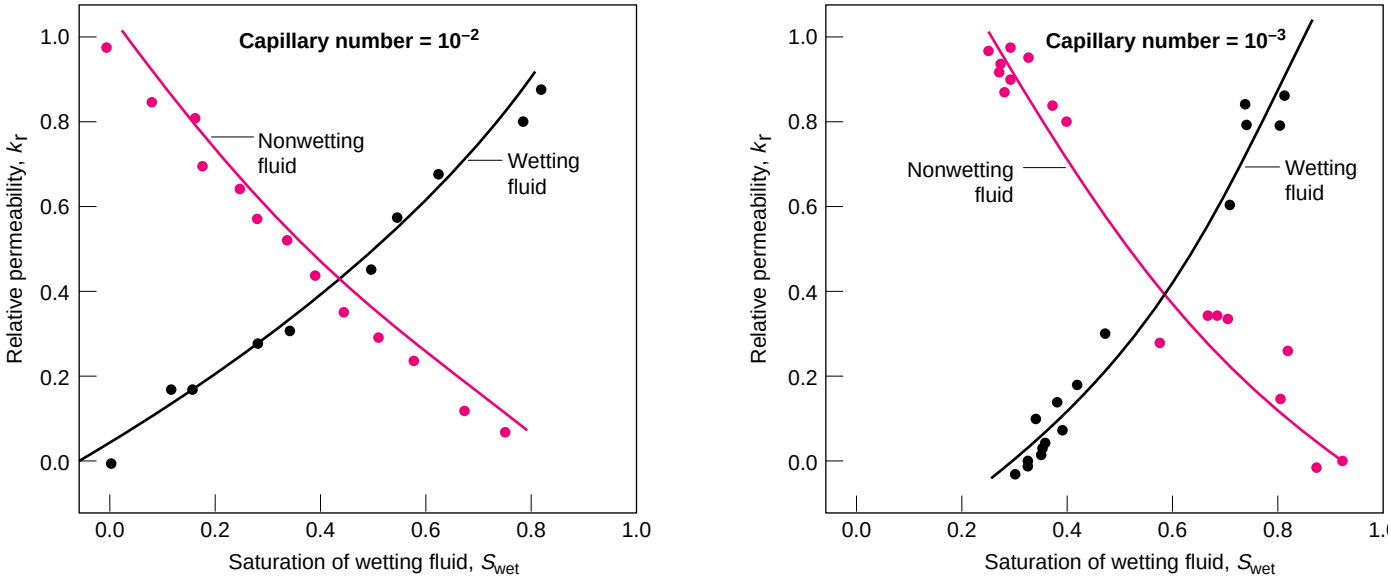


Figure 4. Relative Permeability Curves for Oil and Water Predicted by Lattice-Boltzmann Simulations

These two plots show relative permeabilities k_r for the wetting fluid (oil) and the nonwetting fluid (water) as a function of the wetting-fluid saturation for two values of the capillary number. Each data point was derived from lattice-Boltzmann simulations of flow through the network shown in Figure 3. The curves are similar to those obtained in the laboratory experiments. The relative permeability of the wetting fluid increases, that is, the fluid flows more easily, as its saturation (the fraction of pore space it occupies) increases. Similarly, the relative permeability of the nonwetting fluid decreases as its saturation (equal to $1 - S_{wet}$) decreases. Note how different values of the capillary number change the shape and position of the curves.

for the definition of contact angle.) The contact angle of a fluid is 0° if the fluid completely wets the rock and increases to 180° as the fluid changes from strongly wetting to strongly nonwetting. In lattice-Boltzmann simulations we vary the strength of rock-fluid interactions to control the contact angle and thus the wettability conditions.

One quantity used to characterize the flow is capillary number—the ratio of the viscous forces (the shear forces within each fluid) to the forces at the fluid-fluid interfaces. When the capillary number is low, interfacial forces are much stronger than viscous forces and tend to control the flow. For example, the interfacial forces will tend to draw the wetting fluid into the smallest pores and thereby block the invasion of the nonwetting fluid. We are using lattice-Boltzmann simulations to determine the quantitative effects of wettability and capillary number on relative permeabilities and displacement efficiency (the efficiency of displacing one fluid by injection of a second fluid).

Figure 3 shows the results of a two-dimensional simulation for three values of the capillary number. The pores are initially filled with the blue wetting fluid (oil) and are being invaded by the red nonwetting fluid (water). The simulation reproduces the correct qualitative relation between capillary number and oil recovery efficiency under oil-wet conditions—namely, the recovery becomes less efficient as the capillary number decreases. In part (a), where the capillary number is highest, viscous forces dominate and we see more uniform or piston-like displacement of the oil and higher displacement efficiency. In part (c), viscous forces are a hundred times smaller, so capillary forces dominate and the displacement front has many fingers. Also, the displacement efficiency is much lower than in (a). The blue (oil) and red (water) distributions in Figure 3 are similar to the oil and water distributions observed by nuclear-magnetic-resonance micro-imaging of flow through a mixture of glass and polystyrene beads.

Relative permeabilities of the pore network in Figure 3 under various conditions can be deduced from the results of lattice-Boltzmann simulations. In particular, Figure 4 shows the relative permeabilities of the wetting (blue/oil) and nonwetting (red/water) fluids versus the saturation of the wetting fluid for two of the three values of the capillary

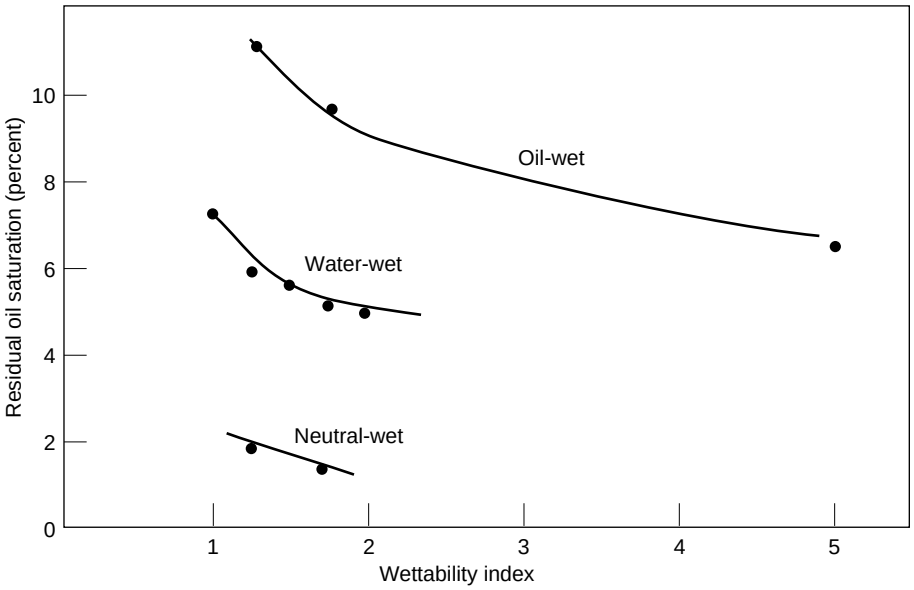


Figure 5. Residual Oil Saturation and Wettability

These data were obtained from lattice-gas simulations run on the system shown in Figure 2. The residual oil saturation is the percentage of pore space occupied by oil after the oil-filled pores have been flushed with water. The wettability conditions are varied by changing the collision rules at the fluid-rock boundaries. The rules implement slip or non-slip boundary conditions for all particles near a rock surface. Intermediate wettabilities are simulated by random fluctuations between the two types of boundary conditions. The wettability index is a dimensionless quantity that measures the relative affinity of a rock sample to draw in oil or water spontaneously.

number used in our simulations. Again, the curves are typical of those seen in the laboratory. The input to our simulations includes pore geometry, fluid viscosities, and interfacial tensions. The capability to predict relative permeability, an empirical quantity, from such a simulation is new and is still being validated against experimental flow data.

Although we are still validating the lattice-Boltzmann simulation technique, we have already begun a study of the effects of wettability on two-fluid flow in two- and three-dimensional simulations. Figure 5 shows the residual oil saturation (the percentage of the oil that remains after being flushed with water) versus wettability for oil-wet, water-wet, and neutral-wet conditions as obtained from some early two-dimensional simulations using lattice-gas rather than lattice-Boltzmann methods. As expected, the simulations show that the most efficient displacement of oil by water is obtained at neutral wettability, whereas it is most difficult to extract oil if the rock is oil-wet. A major input to such simulations are the rock-fluid interactions that define the wettability conditions. At Mobil we are developing techniques to map wettability on the basis of mineral distribution and fluid properties, so that we can incorporate realistic complex wettability distributions into our simulations. Figure 6 shows a typical three-dimensional lattice-Boltzmann simulation in which

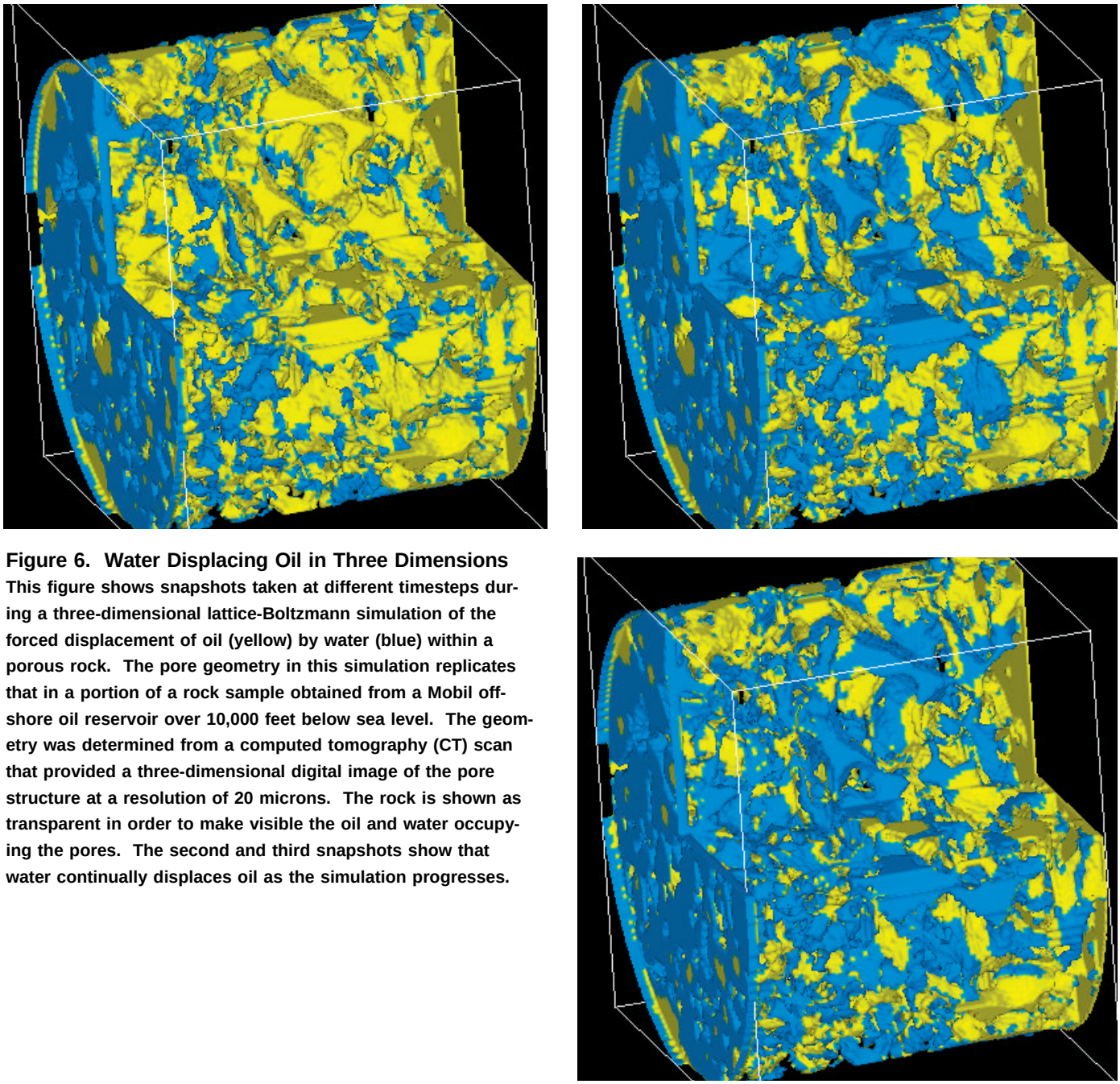
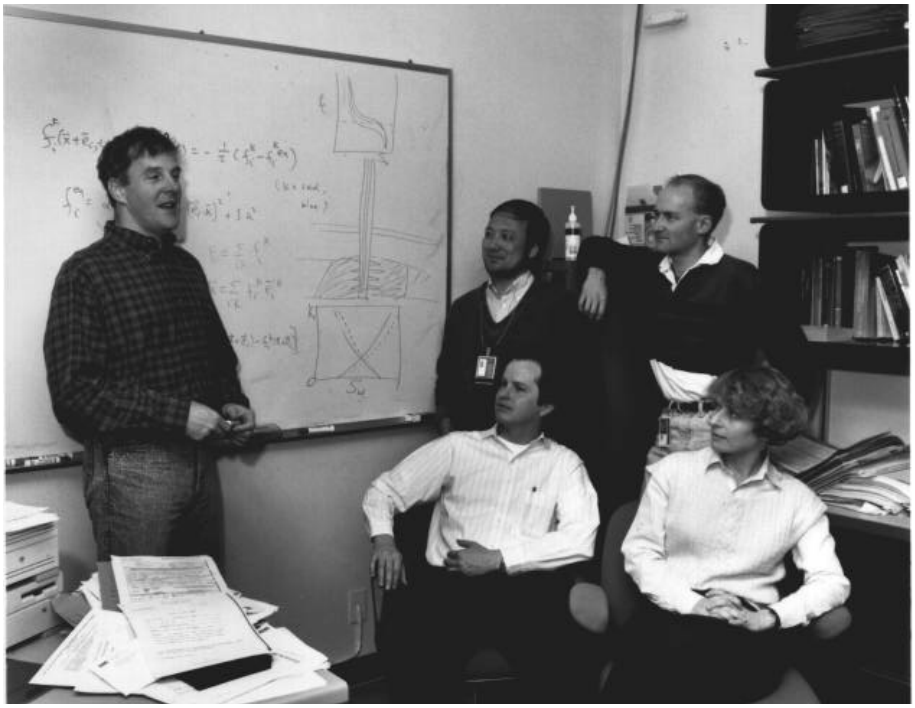


Figure 6. Water Displacing Oil in Three Dimensions
This figure shows snapshots taken at different timesteps during a three-dimensional lattice-Boltzmann simulation of the forced displacement of oil (yellow) by water (blue) within a porous rock. The pore geometry in this simulation replicates that in a portion of a rock sample obtained from a Mobil offshore oil reservoir over 10,000 feet below sea level. The geometry was determined from a computed tomography (CT) scan that provided a three-dimensional digital image of the pore structure at a resolution of 20 microns. The rock is shown as transparent in order to make visible the oil and water occupying the pores. The second and third snapshots show that water continually displaces oil as the simulation progresses.

water is displacing oil in a water-wet system. During this simulated displacement, we recover bulk flow properties, such as mass fluxes, local velocities, and pressure profiles, from which we can compute relative permeabilities. Such computer experiments provide far more insight into and control over the displacement process than wet-lab experiments.

The state-of-the-art technology resources required for such a project are beyond what private companies—even large ones—can afford. The Laboratory and Mobil Corporation have combined their expertise and their resources to apply Laboratory-developed lattice-Boltzmann technology to tough research problems in the oil industry. We expect the results of this work to have major implications as U.S. reservoirs mature and require more complex and risky recovery schemes. ■



Standing (left to right): John J. Buckles, Shiyi Chen, and Daryl W. Grunau; seated: Randy D. Hazlett and Mary E. Coles

Further Reading

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John J. Buckles earned his B.S. in chemical engineering from Purdue University in 1976 and his Ph.D. in chemical engineering from the University of Illinois in 1983. For the past eleven years he has been employed at Mobil Research and Development Corporation. Buckles's research interests include enhanced oil recovery and pore-scale flow modeling.

Daryl W. Grunau was a graduate research assistant at the Laboratory in 1990 and again from 1991 to 1993. His work included the development of theory and computer code for research in computational fluid dynamics using the lattice-gas and lattice-Boltzmann methods. He is currently an applications engineer at Thinking Machines Corporation. Grunau received his B.A. in mathematics and computer science from Tabor College in Kansas in 1987 and his M.S. and Ph.D. in applied mathematics from Colorado State University in 1989 and 1993.

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Wendy E. Soll has been a staff member of the Geoanalysis Group in the Earth and Environmental Sciences Division since 1993. She was a postdoctoral fellow at the Laboratory from 1992 to 1993. Her research includes the study of multiphase flow and transport in porous media utilizing lattice-Boltzmann pore-scale modeling. She received her B.S.E. in mechanical engineering from Princeton University in 1984. At the Massachusetts Institute of Technology she earned her M.S. in mechanical engineering in 1987 and her Sc.D. in civil engineering in 1991. Soll is a member of the American Geophysical Union, the Society of Petroleum Engineers, and the American Society of Mechanical Engineers.

The biographies of co-authors Shiyi Chen and Kenneth G. Eggert appear on page 109.