Improving the Virtual Reservoir

Waterflood, gas flood or drill infill wells? Using a desktop laboratory, engineers can test reservoir-development scenarios, evaluating tens or even hundreds of possible well paths and iterating to a best solution before rig costs begin to mount.

Understanding a reservoir is much like unraveling the mysteries of the stars—both are far away and accessible only to remote-sensing technology. Astronomers ascend to their telescopes and arrays of antennae, and by careful study of captured optical, radio and X-ray frequencies, they characterize a small proportion of vast space, mostly major features like galaxies and nebulae, or stars within our own galaxy. The situation is not so different for geoscientists and engineers, who rely on remote sensing to understand major subsurface features such as formation boundaries and faults. Like our upward-looking colleagues who send rockets into space to obtain detailed data from a tiny fraction of the universe, in the oil industry, we obtain detailed information near wellbores sunk into the reservoir.

Whether from outer space or underground, the data provide a limited picture of remote environments. To understand the cosmos, scientists devise models, simulations of the way they think the universe behaves, and test those models against reality—represented by the captured data. In our industry, we do the same with, for example, basin, geomechanical and reservoir modeling. We test the models against seismic data, rock cuttings and cores, well logs, and ultimately hydrocarbon production.

In 1949, Morris Muskat indicated that he was working on a computer simulation to determine optimal well spacing.1 The first simple reservoir simulators appeared in the 1950s as solutions of differential equations for fluid flow in a homogeneous material with simple geometry. Later, computers were programmed to model flow through blocks of the earth.2 During the 1960s, improved algorithms solved equations faster and more accurately. The models became larger and more complex as computing speed, memory and algorithm sophistication improved. More physics was added, extending solutions from flowing a single phase to flowing three phases—gas, oil and water—then allowing the composition of the gas and oil to change with pressure and temperature. Methods for solving irregular geometries eliminated the need to model reservoir blocks using rectangular grids.

Until recently, simulators resolved the reservoir into blocks hundreds of meters across—significantly larger than the resolution of the seismic and well-log information used in geologic modeling. Today, reservoir simulators can handle more gridblocks and model more complicated geology, allowing closer adherence to geologic models. Incorporating complex geologic input makes a more realistic reservoir model, which can be used to match historical production data to confirm or improve the geologic model.

Simulation software also has changed as a result of improvements in drilling technology. Multilateral and extended-reach wells allow more options for draining reservoirs.3 A multilateral well...
splits deep in the subsurface to drain multiple horizons or provide several entries into the same formation to improve areal reach and recovery. Engineers must decide the optimal placement of these well branches. The ability to model these reservoirs prior to drilling becomes extremely important. Since hydrocarbons may come from different zones with vastly different fluid properties, models also must be able to account for these difficulties.

The ability to solve complex models now is largely the result of incredible improvements in computer processing speeds. A common maximum desired run time for a large reservoir simulation is “overnight,” so improvements in computer speed often translate into larger or increasingly complex models, or both—so long as the result is ready the next morning. Recent advances in parallel computing have increased simulator speed, but, as described later, doubling the number of processors generally does not halve the run time.

When computer simulation of reservoirs began, it was the province of specialists who both designed the computer programs and ran the models, and software development was mostly done within larger oil companies. The simulator often was reprogrammed for each new situation to account for differences in the reservoirs. Improvements in a model tended to parallel company asset-development strategy: for example, dual-porosity models were developed for large, fractured reservoirs. As the technology grew, so did the team of specialists, eventually distinguishing those who developed the program code from those who ran the models. The two disciplines typically maintained close ties, and often both were in a centralized technical support group.

Eventually, demand for reservoir simulation increased and companies began installing copies of the simulators outside the centralized facility. With programs and users remote from developers, software documentation—and ease of use—became much more important. Since reservoir-simulator developers in large oil companies often were not skilled in designing user interfaces, the era of vendor-supplied simulation software began. Although in-house reservoir modeling programs still exist, the trend is away from simulators owned and maintained by individual oil companies and toward third-party software suppliers. Today, the goal is to make the program simple to use, with automatic grid generation, easy import of geologic, fluid and formation data, and graphical output of the results end-users require.

Currently, the two dominant vendor simulators are the ECLIPSE model from Schlumberger GeoQuest and the VIP simulator from Landmark Graphics. Both packages include black oil and compositional models—without and with mixing of gas and oil—which are described in more detail later in this article. Other simulators are strong in niches—the Computer Modelling Group, Ltd., STARS model simulates thermal processes such as steamflooding.

This article shows how simulation software can build, manage and display results from a virtual reservoir. Unprecedented simulator technology allows more realistic wells in the model, each with multiple segments, such as branched or multilateral wells, complicated completions and inclusion of intelligent downhole controls within the simulation. Case studies illustrate advances in current reservoir engineering practice. One of the case studies has a complex computational scenario—a model using a fluid description with many components executed using parallel processing. Finally, a different kind of simulator is described that uses a front-tracking method instead of the usual finite-difference method.
The Virtual Reservoir Environment

Imagine drilling a well into a reservoir and producing from it for five years, then deciding you might have produced more by shifting the well to another location. You wind back the clock, drill the second option and produce again. And maybe a third trajectory looks promising.

The power of reservoir simulation is the ability to investigate all these options before a drill bit touches earth. Multiple scenarios can be examined inside the model’s virtual reservoir—changing well locations, reservoir geology, production limitations or any combination of inputs to the model. Just as cosmologists observe star formation to improve their models, leading to predictions of new phenomena, engineers develop reservoirs in stages—starting with exploration and ending with field abandonment—within models based on data from one stage influencing the next stage.

In the exploration phase, reservoir geology is uncertain. Multiple geostatistical realizations can be fed into a reservoir simulator. Given enough realizations, statistically meaningful high-, mean- and low-production cases can be examined to show economic variability.

More wells delineate the field during development drilling, adding information about the formation. Production results from early wells can be used to tune the reservoir model, further decreasing uncertainties about reservoir properties. Well trajectories result from informed decisions. The reservoir model provides estimates of hydrocarbons in place and recoverable hydrocarbons, which are needed for management decisions and for reporting to regulatory bodies. When contracts specify delivery requirements for supplying gas, models can include the cyclic nature of gas demand, including reinjection options.

Later in field life, reservoir engineers use models to study candidates for improved recovery in great detail. The virtual reservoir is a cost-effective way to examine multiple infill-drilling strategies, water- or gas-flooding scenarios and other, perhaps more exotic, recovery methods.

Managing the Virtual Reservoir

Reservoir modeling is not an exact science. Even with the best geologic interpretation and years of production data to provide guidance, many possible virtual scenarios might describe the reservoir. Until recently, reservoir engineers operating a model had to have special expertise, including designing grids and upscaling—converting from a fine-scale geologic model to a reservoir model with larger gridblocks—populating the gridblocks with appropriate data, adjusting parameters to match production history, scheduling drilling wells within the model and devising depletion schemes.

The need for specialized training restricted modeling to economically important reservoirs, leaving many smaller reservoirs to be managed with less sophisticated engineering methods. Within the past few years, new tools have been developed to put some of these expert capabilities into the hands of less experienced, even novice, users. New software tools expand the reservoir simulation user base to include geoscientists, completions engineers and drilling engineers.

The ECLIPSE Office software provides a single interface to tools that help the user design and execute a reservoir simulation. Buttons across the top of the Case Manager screen activate subprograms that help users set up a reservoir model (next page). Program modules, activated by the buttons on the left of the screen, guide users through the simulation process.

The Data Manager module in the ECLIPSE Office suite accesses a series of screens organized around logically consistent groups of data. FloGrid and GRID geologic modeling and simulation grid design software can input model geometry, or a user can create it interactively. FloGrid software has the additional power of generating an upscaled reservoir grid that retains the geologic model’s important features, such as faults, formation layers or channels.

One reservoir gridblock may comprise several geologic model gridblocks, which provide input data for reservoir parameters such as porosity and permeability. Although averaging values of porosity is a reasonable way to upscale, averaging permeability values may conceal geologic complexity, such as preferential flow direction. The FloGrid module can simulate flow through the geologic blocks composing a reservoir block to determine an upscaled permeability tensor.

Rock and fluid properties to populate gridblocks can be developed from laboratory data using SCAL special core analysis management software and PVT pressure-volume-temperature analysis software, respectively. Alternatively, correlations for rock and fluid properties can be obtained through panels in the Data Manager module.

Often the simulator has to match surface production data, not data at reservoir conditions. Converting from bottomhole pressure to tubing-head pressure depends on flow conditions in wells, which can vary. Gas lift, downhole pumps, gas compression and surface chokes affect flow, as do undulating and nonvertical wellbore sections. Some flow constraints come from surface facilities, so the simulator must know how wells connect to those facilities and honor the constraints. The VFP vertical-flow-performance program simulates the reservoir-to-tubing-head

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flow. The Schedule well-data transformation software can import and manipulate the flow and pressure history and define well groupings.

These tools in the ECLIPSE Office software work together to allow users to create data sets, without having to know the specifics of formatting and organizing data and keywords in input files. The Data Manager application can create graphical displays of data in relevant formats, such as grid-based contour maps or line plots.

If the field has already produced, the engineer can compare predictions to actual production to date and adjust parameters to optimize the model. This process—called history matching—improves confidence in future model predictions. The Run Manager routine allows the user to start and stop the simulator while monitoring selected data. For example, when simulating a waterflood pilot, the water cut of the producer might be monitored to ensure water breakthrough occurs at the correct time compared with the pilot history. If it occurs too early or too late, the user can abort the run and reset input parameters.

The Case Manager module provides visual bookkeeping of multiple runs or cases. The user could generate a hierarchy of cases to develop a reservoir with water injectors, gas injectors, or both working together. In a complex reservoir, the engineer may have hundreds of cases to track. The Case Manager software alters only the data files that differ among cases, to keep files from proliferating.

Another subprogram, the SimOPT model calibration software, can help in the history-matching process by determining which input parameters have a major impact on the results. It provides an interface for defining input variable ranges, runs multiple cases based on user-selected variables and displays the output. The program can automatically look for a best solution, or it can allow the user to control which variables to evaluate. Although it may not find the optimal solution, the SimOPT program helps the user determine whether a history match is possible within the range of values that the user considers credible.

Simulators generate predictions of pressure, saturation and other parameters for each gridblock, which the Result Viewer routine can display in two- or three-dimensional views. The user can query the values of any gridblock at any time through the graphical interface, and obtain presentation plots from run data. Some data are better displayed as x-y plots, such as gridblock saturation, or water, oil and gas production at a well as a function of time.

Simulation results must be documented. The Report Generator creates simplified summary reports and shows warnings and error messages in meaningful language, and users can define custom reports. Simulation results can be exported to the Peep economic analysis program, a standard asset management package in the petroleum industry.

The Calculator—another feature of ECLIPSE Office software—allows customized calculations using any parameters within the model. Users can define their own conditions, greatly expanding the possibilities for illustrating results. A button links the user to the Weltest 200 analysis software, which uses the simulation power of ECLIPSE software to numerically solve well tests, rather than relying on analytical models.

Better Well Modeling with Segments
Wells today are much more complicated than they were only a few years ago. Wellbores may have multiple branches, enabling a single well to drain a larger portion of the formation or to contact a number of isolated productive regions. Downhole sensors can monitor the conditions—temperature, pressure, density, flow rate and water and gas fractions—at selected locations within the well, while surface-activated flow-control devices can progressively reduce or shut off production from high water-cut or high gas/oil ratio (GOR) areas. The ECLIPSE family of reservoir simulators has added the multisegment well (MSW) option to help model conditions in these advanced wellbores.

Early reservoir simulators used simple well models, allowing fluid flow to and from the formation but using simplistic flow physics within the wellbore. The wellbore pressure gradient typically was based on a mixture density that did not allow for slip between phases—the tendency of individual fluids to flow with different velocities. Moreover, the model treated the fluid within a wellbore as completely mixed and uniform. With the advent of extended-reach and horizontal wells, some simulators included a refinement to account for friction, which can be a significant part of the
energy losses of fluids flowing in a horizontal section. This still did not allow the contents of the wellbore to vary with location, nor did it properly calculate the density of the flowing mixture.

The MSW option overcomes these limitations, allowing the reservoir modeler to divide a wellbore into segments and define the set of variables describing fluids in each one. In this one-dimensional grid of segments, wellbore contents and fluid-mixture properties can vary with location (see “Flowing Wells,” next page). A branching network of these segments defines multilateral well geometry.

Well segments representing perforated liners connect to the reservoir grid, allowing fluid passage. Other model elements can be defined with pressure-drop characteristics of flow-control devices such as valves, chokes and pumps.

The segmented structure follows the well trajectory independent of the reservoir grid. The well model can incorporate sections of unperforated tubing extending outside the grid and allows branches of multilateral wells to join outside the grid. This would not be possible with a conventional well model—without the MSW facility, the simulator defines the well path by the sequence of grid cells it intersects.

The M-15 well has two branches that drain a part of the Sherwood sandstone formation. The northern branch lies in a faulted area, so it was cased and perforated, whereas the southern lateral is an openhole completion. The potential problems were quite different. BP anticipated early water breakthrough in the northern, faulted area, and they felt drawdown had to be controlled to avoid borehole collapse in the southern, openhole completion.

While sharing a parent wellbore, the two laterals require different production strategies—high drawdown was desired in the northern branch, at least until water influx increased, but high drawdown was not possible in the southern. Downhole flow-control valves separately controlling production from the two laterals rectified the problem.

BP drilled and completed the well with three WRFC-H hydraulic, wireline-retrievable flow-control valves. Expected flow rates were higher in the northern lateral, so two valves were installed to allow more flow. The third valve controlled the southern lateral.

To determine optimal operating conditions for the control valves, the Completions Technology Group at the Schlumberger Reservoir Completions (SRC) Center developed a black-oil ECLIPSE100 reservoir model. They used the MSW option to model the parent well and the two laterals. Elements with inflow-control device characteristics modeled control valves.

Controlling a Dual-Lateral Well in Wytch Farm Field

Wytch Farm field has the world’s first downhole flow-control completion in an extended-reach multilateral well. The largest onshore oil field in Europe, Wytch Farm field lies in the south of England near Poole Harbor and extends into the English Channel (above). The operator, BP, developed the field using an ongoing program of extended-reach wells, some exceeding 10 km (6 miles).7

The abrupt slope change in oil production rate (shaded curves) from both conventional and advanced completion relates to choking back flow to control water production.

Model prediction of Wytch Farm production. Oil production from commingled zones of Well M-15 (green curve) was substantially improved by the addition of subsurface control valves (blue curve).
The ECLIPSE multisegment well (MSW) facility offers several options for modeling multiphase flow in the wellbore. The simplest option is a homogeneous flow model in which all phases flow with the same velocity.

A second option uses a simple "drift flux" model to represent slip between the phases. This type of model allows rapid calculation, and its results are continuous over a wide range of flowing conditions. It is valid with countercurrent flow, where the heavy and light phases flow in opposite directions. It also can be used to model phase separation within a wellbore, for example, when a well is shut in during a buildup test. Phase separation influences the wellbore-storage response, which must be understood to properly model test results.

A third option uses precalculated tables—similar to the vertical-flow performance tables widely used to model wellbore-pressure losses between the formation and the tubing head—to determine pressure drop across a segment. This option allows use of more complex and computationally expensive multiphase flow models, if their results are first translated into tabular form. Obtaining the pressure drop by interpolating the table is rapid and computationally efficient. Tables also provide an efficient way of representing pressure losses in certain flow-control devices such as chokes, because pressure-drop calculations for more accurate models of these devices require more computing time.

The ability to manipulate subsurface control devices is an important addition to the ECLIPSE MSW facility. The simulation engineer can change choke settings at any time during a simulator run by switching to a different table. Built-in models are available for certain devices such as subcritical valves, allowing "manual" changes to settings such as constriction area. Other device models are designed to operate automatically in response to a changing water cut or GOR, or to limit the flow rate of oil, water or gas to a specified maximum value.

Flowing wellbore conditions are represented in the black-oil simulator by four variables for each segment: pressure, total flow rate through the segment, and flowing fractions of water and gas. These variables allow computation of fluid-mixture properties and the pressure gradient. Four equations apply in each segment: the material conservation equations for oil, water and gas, and a relation for pressure drop along the segment. The compositional simulator uses additional variables for the molar density of each fluid component and additional material-conservation equations for each component (see "Composing Pseudofluids," page 44). These equations and those describing conditions in the reservoir grid are solved simultaneously—a computational technique known as implicit coupling. This ensures that the combined system of well plus reservoir remains stable over the timesteps chosen by the simulator. Computational stability is important since changes in flow conditions propagate through the well in a fraction of one timestep.

Conventional recovery—without subsurface control valves—allowed two options: produce first one lateral then the other, or produce both simultaneously. The ECLIPSE model showed that, of the two, producing simultaneously generated more oil over the five-year study period. To control high water cut in this scenario, production from the entire well was choked back.

Adding separate control valves for each branch provided significant additional production (previous page, bottom). The northern branch could be choked back without decreasing production from the other branch.

The well went on production in February 1999. The northern lateral produced alone for six months at over 10,000 B/D [1600 m³/d] of liquid. At the end of this period, only about 3000 B/D [477 m³/d] were oil. Then the operator shut in this lateral and opened the southern lateral. Oil production was the same as that provided by the northern lateral, but with significantly lower water production. After five months of production from this leg with increasing water cut, both laterals were produced simultaneously.

Reservoir engineers used the ECLIPSE model to history-match field production. A comparison of cases with and without downhole controls in the M-15 well indicates an expected incremental recovery of more than one million barrels [160,000 m³] of oil after five years.

Recently, a downhole pump failed and BP decided to replace it with a larger one to increase flow rate, so the downhole flow-control valves can no longer be adjusted. However, the results from this well encouraged BP to continue using multilateral wells with downhole control in Wytch Farm field. An electric, tubing-retrievable flow-control valve (TRFC-E) was installed in Well F-22 in September 2000.
Modeling Isolated Zones

Schlumberger studied a series of delta-plain channel sands braided with coal beds, targeting three isolated sand bodies. The gas-oil contact (GOC) intersected the upper sand, Zone 1, and the water-oil contact (WOC) probably fell within the lower sand, Zone 3, but the WOC location was uncertain. The ECLIPSE100 black-oil reservoir model assumed that the reservoirs were laterally extensive, but there was no flow communication between them. A segmented wellbore connected the three zones in the model to evaluate wellbore fluid interactions (right).

The GOC in Zone 1 implies a potentially rapid increase in GOR from that zone. Uncertainty about the WOC in Zone 3 meant there was a possibility of substantial water production. With such diverse influx, the model had to account for complex fluid interactions within the wellbore. Downhole controls might be needed to choke back water or gas production.

^ Multisegment well (MSW) model of three sand bodies. Influx from each zone is controlled with a downhole flow-control valve. Three separated sets of gridblocks modeled behavior in the zones using the MSW option, which allows well segments outside reservoir gridblocks.

^ Production improvement with flow control. Production using flow-control valves (blue line) greatly exceeds serial production with no valves in the completion (green line). The shaded green flow-rate curve for the serial case shows rate decline for the lowest zone until it is shut off and middle zone production begins. The rapid changes in production rate (shaded blue) are a result of controlling gas influx with flow-control valves.
Without downhole flow-control devices, more oil is produced in the five-year model period by completing the well sequentially from the bottom sand up, rather than producing all three simultaneously. However, with downhole flow-control valves, the most productive case examined commingled production from all three zones. As GOR from Zone 1 increased, flow through the upper valve was restricted to limit gas rate. The lower valve controlled water influx. Another combination allowed the upper valve to be opened to provide gas for artificial lift, which might become necessary if water from Zone 3 could not be choked back without losing significant oil production. Compared with a conventional production approach, the advanced completion scheme not only extends the well life, but increases production rate throughout the five-year life of the study (previous page, bottom).

**Downhole Control in Dual-Drive Reservoirs**

Simple models can illuminate flow responses that may be hidden in more complex reservoirs. To understand simultaneous gas drive and water drive toward horizontal wellbores, engineers at SRC modeled a simple, homogeneous reservoir.9,10 The first case uses one well perforated throughout the straight, horizontal section from the bend leading to the vertical section, called the heel, to the wellbore termination, or toe (above). The fluid velocity inside the 6-in. liner increases from almost zero in the toe segment to about 10 feet per second [3 m/sec] at the heel.

At initial conditions and with only oil flowing into the wellbore, the greatest pressure drawdown occurs at the heel. For the geometry and properties of this model, the difference in drawdown between heel and toe is only 40 psi [275 kPa], but that causes almost 3000 B/D [477 m3/d] greater influx at the heel.

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Snapshots of fluid fronts. Without downhole flow-control valves, drawdown is greatest at the heel of the well, preferentially drawing water up and gas down in that region. Water breaks through first in this model, shown as two gridblocks touching the wellbore (top). Two years after water breakthrough, there is still poor recovery near the toe (bottom). Gridblocks retaining original oil saturation have been omitted from the illustrations.
The higher drawdown and flow rate at the heel will draw water up from the WOC and pull gas down from the GOC (previous page). Two years after breakthrough at the heel, there is still considerable unswept oil near the toe. If water breakthrough occurred first at the toe, watered-out zones could be shut off with a packer, but setting a packer at the heel would kill all production.

An intelligent completion lessens these problems by dividing the horizontal section into two parts with a packer and moving the maximum pressure drawdown point to the middle of each segment (top). Putting a surface-controllable valve in the heel section provides a capability to optimize the pressure profile and match the drawdown in the toe.

Creating a zoned reservoir by adding a valve will not prevent gas or water breakthrough, but can delay it and at the same time improve sweep efficiency along the length of a wellbore (above). The degree of postponement depends on a number of factors, such as wellbore friction, vertical location of the horizontal well within a reservoir and total flow rate. Greater wellbore friction—possibly due to undulations in the wellbore—steepens the slope of the pressure drawdown along the wellbore and exacerbates the sweep problem. This makes the completion with a valve more profitable, because as friction losses along the wellbore increase, incremental recovery from addition of a valve also increases.

Cumulative oil production provides a better assessment of well placement between the gas and water zones than breakthrough time. Optimal well placement within the oil zone depends on the liquid production rate—at higher flow rates, the well should be closer to the water layer. Of course, real reservoirs are not homogeneous, and relative sweep efficiencies for water and gas displacing oil will affect results.
Sometimes, reservoir geology or surface facility constraints dictate placing horizontal wells so close that they may interfere with one another’s production. To examine this situation, a second, parallel horizontal well was added to the simple reservoir model with gas cap and aquifer drive (above). Both wells can enter the reservoir from the same side, that is, heel-to-heel, or from opposite sides, heel-to-toe. The wells have a downhole control valve in the heel section that can be enabled or disabled. Six cases were examined: neither well instrumented, one well instrumented, or both wells instrumented, with each case in both heel-to-heel and heel-to-toe configurations.

The heel-to-heel, uninstrumented case has the least recovery, so it is considered the base case. Sweep efficiency is poor, particularly in the toe region of the model (right). Oil recovery after five years is 30.2 million barrels (4.8 million m³), representing 34.5% of the original oil in place. Switching the orientation of one well improves sweep between the wells by 172,000 barrels (27,400 m³), because in this configuration, the strong drawdown at the heel of one well complements the weaker drawdown at the toe of the other well.

Adding a control valve in one well improves recovery for both wells. The instrumented well in the heel-to-toe configuration has a greater improvement than in the heel-to-heel case, without significantly affecting recovery in the uninstrumented well. With a control valve in both wells, the recovery is even higher. The pressure drawdown also is more uniform, making the configuration—heel-to-heel or heel-to-toe—less important.

These two examples show the power of simple models to help engineers understand more complex reservoir cases and develop completion strategies.

^ Parallel well model similar to the single-well case, but made wider to accommodate a second well. Well 1 and Well 2 can either be heel-to-toe, as shown here, with flow along the horizontal sections in opposite directions, or heel-to-heel, with both wells flowing in the same direction.

^ Dual-well gas cusping. These snapshots, taken early in the simulation of a reservoir layer above the horizontal well, indicate interference of gas sweep (red) between the wells. The top row represents conventional, uninstrumented wells. In the middle, Well 1 is instrumented, and both wells are instrumented in the bottom row. The left-hand figures are heel-to-heel, and the right-hand ones are heel-to-toe. Sweep efficiency is improved when flow is controlled using downhole valves. Total recovery in the heel-to-heel, uninstrumented case is 30.16 million bbl (4.8 million m³) of oil. Incremental recovery beyond this is shown for other cases (beside each snapshot), with recovery improvement also shown for each well in each case (within the snapshot).
Many of today's reservoir models are huge—perhaps comprising millions of gridblocks—to capture as much relevant geologic data as possible. Models with so many more gridblocks than those of a decade ago require significantly more time to solve. Historical production data spanning several decades and hundreds of wells add even more simulation complexity and solution time.

One computer processor may not solve a mega-gridblock problem overnight, but by dividing the model into parts, several processors can work simultaneously. Versions of both the VIP simulator and the ECLIPSE simulator use parallel processing this way.

Ideally, doubling the number of processors working in parallel would halve the solution time. However, inefficient problem splitting and processor-to-processor communication curtail that level of speedup.

Parallel processors do not start a new step until they all complete the previous one. Proper division of the problem to equalize work among processors is necessary to optimize speedup.

Dividing the problem requires communication between processors. This includes transfer of flow and pressure information between adjacent gridblocks that are in different processors and between surface facilities and wells in separate processors. Dividing the problem along natural breaks helps control internal communication time—for example, a large fracture that conducts fluid should be completely within one processor.

Petróleos de Venezuela, S. A. (PDVSA) studied parallel-processing speedup to identify the best processor configurations and the balance between computer central processing unit (CPU) power and memory use. In 1998, initial PDVSA studies indicated four processors solved a variety of problems in about half the time of one processor. However, internal communications used a slow bus—computer communications link—on an older UNIX network. PDVSA engineers believed newer machines could achieve better speed. The study of efficient job distribution continued on new, more powerful IBM RS/6000 machines, using IBM's LoadLeveler load-management software.

LoadLeveler software makes parallel nodes behave as a single machine. It manages all jobs—serial or parallel—assigning each new request to the least-used processor or processors. When a particular job needs more nodes than are currently available, the management software puts it on hold until enough nodes are ready. Once a reservoir model begins running, CPU use will be uninterrupted, making comparisons between runs possible. These studies show significant speedups with parallel processors—a factor of six for eight machines and a factor of almost four for four machines (left).

PC processor speed has also improved since the 1998 study. Schlumberger evaluated a heavy-oil reservoir in the East Venezuela basin using a version of parallel ECLIPSE software on two PCs running the Windows NT operating system. The reservoir geology comprises prodeltaic shales and mouth bars, occasionally cut or overlain by fluvial channels. Part of the field was a major channel complex, probably feeding into the delta.

To capture geologic uncertainties, the reservoir model used a stochastic—or probabilistic—realization based on facies and stratigraphic features.

In this heavy-oil reservoir, water is about 50 times more mobile than oil, so water does not displace oil as a uniform front. Instead, it fingers, or creates narrow channels through the oil. Numerical cross-section and sector models indicated that a fine vertical resolution was needed to accurately model this displacement behavior. The simulation incorporated a fine grid, with a resolution in vertical direction of 1- to 3-ft [0.3- to 1-m] layers. The gridblocks were the same size as those in the stochastic model—50 m [164 ft] on a side—to maintain geologic heterogeneity. The numerical model had some 880,000 grid cells. A two-node PC system using the Windows NT operating system ran the simulation in 62 hours, compared with 119 hours on one PC. Doubling the number of processors sped simulation by 1.9 times.

### Speedups obtained for Venezuela reservoirs

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<th>Reservoir</th>
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<th>B</th>
<th>C</th>
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<td>4 times</td>
<td>1.9 times</td>
</tr>
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</table>

In Reservoir C, the heavy-oil reservoir, a speedup of 1.9 was achieved for the large stochastic model.
A second realization of this reservoir upscaled to a coarser grid—150 m [492 ft] on a side—had only 94,080 gridblocks (above). This smaller size allowed a global history match with reasonable computing efforts. On a single-processor PC with 1 gigabyte of RAM running at 900 MHz, simulation took about six hours. With parallel ECLIPSE simulation on two processors of the same specifications, run time decreased to about three hours—an almost ideal speedup factor close to two.

Simulating Complex Fluid Behavior

The ECLIPSE simulator was used to model a Middle East carbonate reservoir. It is a foreslope depositional environment, thickening and improving in reservoir quality to the south. Cyclic changes in sea level led to an alternating series of porous and dense limestones, which can be identified from wireline log response. The field is divided into a low-permeability northern area and a higher permeability southern area (next page). The northern part, termed the pattern area, had 1.7 billion barrels [270 million m³] original oil in place and the southern, or extension, area originally had 3.4 billion barrels [540 million m³].

The Abu Dhabi Company for Onshore Operations, ADCO, began production from the field shortly after discovery in 1962, but significant production did not start until 1986. The field has had peripheral water injection since 1974. Extension-area oil production peaked at about 13,000 B/D [2000 m³/d] in the late 1980s. The addition of twelve gas injectors in the poorer quality pattern area in 1996 led to a production peak at about that same rate in 1999 and 2000, while the extension area continued to contribute about 3000 B/D of oil.

ADCO initiated a study of two producing zones to determine future production scenarios. There were three concerns. First was uneven gas injection due to injection-well placement, which created a pressure differential between the pattern area and extension area and caused oil to migrate a great distance to the south. Alternating tight and permeable layers in the pattern area complicate fluid displacement.

The second concern was that pressure drawdown near producing wells was too great. This can cause gas to evolve from the liquid hydrocarbon near the well, reducing relative permeability for oil flow, thereby decreasing productivity. Finally, poor reservoir quality in the northern part of the pattern area caused low productivity and injectivity, which ADCO hoped to improve through a new reservoir-depletion plan.

The injected gas was expected to be miscible, that is, to go into solution with the oil upon contact. This change in oil composition alters its properties, including density and viscosity, so engineers used the ECLIPSE300 simulator, which can model compositional changes (see “Composing Pseudofluids,” page 44).

The two zones needed 37 layers to account for vertical heterogeneity. A grid of 55 by 45 horizontal blocks, each 500 m [1640 ft] on a side, was sufficient to cover the field, but this would not allow an adequate number of gridblocks between wells in the center of the field. Separation by several gridblocks is necessary to define the saturation gradient between injectors and producers.
The solution was to use local grid refinement—making smaller gridblocks in a portion of the model. In this case, the central blocks, 15 in the north-south direction by 11 in the east-west direction, were divided into cells 100 m [328 ft] on a side, leaving larger blocks in the flanks. In conjunction with the local grid refinement in the center of the field, ADCO used a feature of the ECLIPSE300 simulator called adaptive implicit method, or AIM (see “Coupling Space and Time,” next page).

This model has about 238,000 cells. While not large for a Middle Eastern field study, a model with so many gridblocks will execute slowly, particularly when the fluid composition changes, as in this case. ADCO increased simulation speed by using 12 parallel processors.
Coupling Space and Time

The essential problem in simulation is advancing the state of a reservoir through time, affected by external changes such as oil production, or internal change, such as fluid phase transitions. Reservoir properties are stored in the computer as matrices, with a combination of properties defining each gridblock in a model. A change in one gridblock affects surrounding blocks, just as sucking on a straw drains a drink from the nearest crushed ice, causing fluid from ice farther away to flow toward the straw.

Variables in the reservoir model are gas, oil, and water saturation and pressure. The defining equations are based on a material balance—matter is neither created nor destroyed in the process—and force balance, which is essentially Newton’s second law, \( F = ma \), expressed in terms of pressure rather than force. The equations are partial differential equations that may take longer. The price is additional processing time to achieve a simultaneous solution for pressure and saturation. When the reservoir changes rapidly, a fully implicit method often can solve the model faster, even though each iteration may take longer.

The fully implicit procedure is more stable. Saturation and pressure are obtained simultaneously, so the disparity between one timestep and the next is less important. Timesteps can be larger than those in the IMPES method. The price is additional processing time to achieve a simultaneous solution for pressure and saturation. When the reservoir changes rapidly, a fully implicit method often can solve the model faster, even though each iteration may take longer.

The Landmark VIP simulator has a user option that compromises between these two methods. The grid can be divided into two parts, one using the IMPES method and the other a fully implicit solution.

The ECLIPSE 300 reservoir simulator has a feature called AIM, the adaptive implicit method, which takes a flexible approach. The program finds the parts of the model where properties change rapidly and the IMPES method may not converge easily, and the simulator sets them to solve implicitly. AIM seeks a timestep size that is optimal for both solution methods. The user can specify the maximum percentage of the model to be solved implicitly. If that proportion exceeds 10 to 20%, it is probably faster to solve the whole model using the implicit method.

Model parameters were adjusted to optimize the history match—correlating model output with production data recorded since the field was put on production. The primary data included the reservoir pressure at producing wells and tubinghead pressure at injectors (next page, left). A good history match allowed ADCO to evaluate future production scenarios with greater confidence.

The first recommendation from this reservoir study was to convert 24 vertical wells in the pattern area in the north of the field, including both injectors and producers, to horizontal completions by redrilling. This extended the production plateau and increased ultimate recovery compared with previous development plans (next page, top right). Surface facility constraints restricted liquid production from the pattern area to 30,000 B/D (4800 m³/d). The ECLIPSE simulator allows wells to be grouped, applying the limits to the whole group. Based on user-defined input, the simulator selects which wells to choke back to maintain production within field constraints. ADCO considers this ability to control groups a crucial feature of the simulator.

Converting the wells to a horizontal geometry also decreased long-distance oil migration to the extension area, since these wells allow more production from the pattern area. The flux, or migration rate, declines rapidly, whereas the model of the business plan showed continued flux out of the pattern area (next page, bottom right). The simulator handles the resulting hysteresis, or increase in saturation of a fluid phase when it had been decreasing, caused by the flow direction reversal in the pattern area.

The simulation study continued with a comparison of further field development with different injector-well patterns. In addition to evaluating gas injection, this study included evaluations of water injection, water-alternating-gas injection, and combined water and gas injection that are beyond the scope of this article.
Streamline Simulation
The ECLIPSE reservoir simulators, like most others, use finite-difference methodology. Saturation fronts are difficult to follow in a finite-difference model since the virtual reservoir is divided into blocks. As soon as the water saturation in a gridblock exceeds the minimum mobile saturation, flow into adjacent gridblocks will include some water. This effect—called numerical dispersion—occurs in the model even if water in the reservoir could not possibly have traveled from one side of the block to the other in the time since it entered. Modelers often resort to pseudofunctions—altered relative-permeability curves—to delay the transmission of water from one cell into another.

An alternative approach is to solve the problem using streamlines. The simplest visualization of a streamline is the path taken by a stream of dye carried along by flowing water. More complex patterns include the Gulf Stream, a flow of warm water from the tropics that passes along the east coast of the USA on its way to the North Atlantic Ocean, and the jet stream, a flow of high-speed air in the upper stratosphere or troposphere.

A flowing fluid moves within an energy field. The Gulf and jet streams are driven by a combination of forces, including rotation of the earth and convective heat transfer in either the air or the ocean. Gravity, density difference created by a temperature or composition difference, and pressure difference drive fluids in a reservoir. Lines of constant potential energy can be determined, like elevation contours on a topographic...
Streamlines are mathematical entities—an infinite number exist for a given force field. However, to make this concept practical for solving flow problems, a limited number of streamlines are considered, and the fluid surrounding a streamline is considered one stream. The situation can be extended to three dimensions, where streamlines become streamtubes, defining distinct volumes of fluid flowing together.

Since fluid does not pass from one streamline to another, flow within one stream can be considered independently of any other stream. This essentially uncouples the complex relationship of flow and material balance that finite-difference simulators must deal with. The problem can be solved as a series of independent, quasi-one-dimensional flow regimes. This avoids the problem of numerical dispersion and allows a clear definition of flood fronts or passage of a fluid slug through the reservoir. In addition, the source of fluid flowing to a producing well can be determined, whether it is from one of several injector wells, a bottom- or edge-drive aquifer or the oil column. Streamlines can also identify areas within a field that have been bypassed, or wells with inefficient injection, such as water or gas that is continuously sweeping the same part of a reservoir without moving additional oil.

Streamline simulators are not a replacement for standard reservoir simulators. When conditions change rapidly, a streamline simulator may give incorrect results or may not converge to a solution. The streamline simulator solves the pressure field, assuming negligible gravitational and thermal effects, as a first step toward solving the flow problem. This solution scheme assumes pressure changes are slow, so it is better suited to a pressure-maintenance situation than a rapid-depletion case. In addition, when the pressure field changes significantly because of addition of injectors or producers, streamline models may need to be history-matched again. Streamline simulators also neglect capillary forces.

On the other hand, streamline simulators can be very fast. The size of a timestep—the time period between solution steps in a model—is restricted in finite-difference simulators. The more grid cells and the smaller they are, the more CPU time is required in a step. Streamline simulators do not have the same timestep constraint, and can take large timesteps if necessary. As a consequence, the simulator is capable of handling large models with many wells or large geologic models, which might be difficult or impossible for a finite-difference simulator to solve in a reasonable time.

The FrontSim streamline simulator can use the same gridding and property assignment, such as porosity and permeability, as an ECLIPSE reservoir model. Changes to the underlying geologic model made in one simulator can be carried immediately into the other.

In most cases, the geologic model developed for a field is considerably more detailed than the reservoir model. These high-density models are usually upscaled to decrease the number of cells before reservoir modeling is done. With streamline simulation, upscaling is not necessary—the large number of cells in a geologic model can be evaluated for production potential.


Streamlines flow from Injector I2 to Producer P3. For a horizontal reservoir at constant temperature, pressure drives flow. Lines of constant pressure decrease from high pressure (yellow) to low pressure (orange) around the producer. The injector-producer pair influences an existing pressure field, gradually decreasing from left to right. Streamlines are perpendicular to the pressure field, with color designating the decreasing proportion of water flowing out from the injector (blue, shading to green then yellow), with oil flow in most of the model (purple). The underlying gridblocks (light gray) contain reservoir property definitions.
The speed of streamline simulators makes them useful for ranking multiple geostatistical realizations of a reservoir. After many cases are run, those with—for example—a high, a mean and a low recovery factor can be further evaluated. This can improve the economic evaluation of prospective reservoirs.

Schlumberger used the FrontSim streamline reservoir model on a structurally complex, three-dimensional, faulted geologic model of a Gulf of Mexico sandstone field. The cell properties were assigned using a geostatistical approach based on a related seismic attribute. Permeability was assigned based on a relationship to porosity. FloGrid software was used to create a FrontSim model with the same dimensions as the geologic model, with twelve production and two injection wells. The million-cell FrontSim model executed in about six hours, much faster than a finite-difference model would have run.

The model was upscaled to obtain a finite-difference case of about 120,000 cells, using harmonically averaged permeability and arithmetically averaged porosity. This smaller version was run using a finite-difference model. After nine years of simulated production, the pressure difference between the streamline and finite-difference models was about one psi out of almost 5200 psi [35.8 MPa]. The field water cut differed by only about 0.1% of liquid production. The excellent agreement validated the upscaling method.

Flow Streams in Prudhoe Bay Field
Some reservoirs are difficult to simulate with a finite-difference model. Large reservoirs may need millions of gridblocks to define faults or other complex geology. Water and gas flooding add dynamic movement of flood fronts, which may need to be tracked closely. There may be many wells, each with a production or injection history to match. The time required to solve such a model can be beyond the budget of a company and the patience of a reservoir engineer.

Prudhoe Bay field, on the north slope of Alaska, USA, provided just such a problem for the operator, BP. This large field—26 billion barrels [4 billion m³] of oil in place—now has more than 23 years of production history, including water and water-alternating-gas injection in the water-flood areas. Simulating over 1000 wells penetrating the reservoir is difficult.

In the Northwest Fault Block (NWFB) area of Prudhoe Bay field, a finite-difference simulator with over 200,000 gridblocks was abandoned after 10 months because it was unable to achieve a detailed history match of the more than 200 wells included. The operator evaluated alternatives to a finite-difference model and decided to use the FrontSim streamline model. The geologic complexity could be maintained, as could the large number of wells, and sufficient gridblocks could be included to adequately cover the reservoir. One engineer using the FrontSim model matched the complex production history of the NWFB in only six months.
The simplest reservoir model would use a single fluid. Although a single-component model is useful for describing aquifers, it is not adequate for hydrocarbon production, which can have three flowing phases—gas, oil, and water. Three-component models, called black-oil models, are actually simple compositional models with water and two hydrocarbon phases, because gas can go in and out of solution with the oil. The gas and oil components have defined properties, such as density and viscosity, and the gas-oil phase behavior is treated as a two-component system. This means that any gas evolved from the oil or present as a free-gas cap will have a set composition. The only variable is how much of the gas is still dissolved in the oil.

However, gas in a reservoir is not a single component, but a combination of many components such as methane, ethane, propane, butane and so forth. The amount of each component in the gas phase is given by the pressure-volume-temperature, or PVT, relationship of the mixture. It is important to note the difference between a component, such as pentane, and a phase, such as gas.

Water at atmospheric pressure has a simple phase relationship. It is a single phase that goes from solid to liquid to gas—ice to water to water vapor. Chill water to the freezing point and it begins to convert to ice. Two phases coexist at that temperature, and we can speak of the percentage of each phase that is present at any time, but both the solid and liquid phases are still H2O.

In a two-component system, such as propane [C3H8] and hexadecane [C16H34], the picture gets more complicated. At reservoir temperature and pressure conditions, the two-component system can be all gas, all liquid, or gas and liquid together. But now, not only do the percentages of the gas and liquid phases depend on conditions, so does the amount of propane or hexadecane in each phase. Starting in the gas phase and decreasing pressure, there comes a point when drops of liquid begin to appear. At this “dewpoint,” the first drops of liquid are richer in hexadecane, the heavier component. With decreasing pressure, more of both components move from gas to liquid. The last bubble of gas to transform to liquid is richer in propane, the lighter phase. The final state is all liquid, with the same mixture of the two components as the original gas.


Hydrocarbon phase envelope. The phase envelope is bounded by the bubblepoint and dewpoint curves, which meet at the critical point. Under pressure and temperature conditions at Point A, the fluid is all liquid. Depletion decreases the pressure, and at Point B, bubbles of gas begin forming. Continued depletion increases the proportion of free gas in the system, crossing lines of constant composition. At a higher temperature, such as Point C, depletion intersects the dewpoint curve at Point D, where liquid begins to drop out of the gas. Lines of constant gas-to-liquid ratio meet at the critical point. By following a path from B to A to C to D, first increasing pressure, then increasing temperature and finally decreasing pressure, a fluid can be taken from liquid to gas without going through a phase transition.
A reservoir hydrocarbon is a more complex mixture of components, ranging from those with one carbon atom to compounds with perhaps more than 40. The phase diagram is similar to a two-phase case, but now there is a broader distribution of components that can be in either phase. The phase diagram of reservoir oil from a field in the Middle East indicates some of the important characteristics of phase behavior (previous page). The phase diagram shows the fluid behavior as pressure and temperature change at constant volume, going from a single phase outside the diagram to two phases inside. The fluid is a liquid above the bubblepoint curve, where bubbles first form as pressure decreases, and a gas above the dewpoint curve, where liquid droplets first form as pressure decreases. The point where the bubblepoint and dewpoint curves meet is the critical point. Lines of constant composition inside the diagram all meet at the critical point. At the critical point, intensive properties, such as density, are identical for both gas and liquid phases. Near the critical point, small changes in pressure or temperature yield large changes in phase composition.

Fluid composition defines phase-envelope shape, position of the critical point on the envelope and location of the constant-composition curves. Since hydrocarbon fluids may have 40 or more components, modeling behavior would be an enormous problem if each component were included. To simplify the problem, the concept of lumping or creating pseudocomponents was developed. One common grouping puts all components heavier than hexane into a C7+ pseudocomponent. The lighter components may also be lumped into two or more groups. Tools such as the PVTi software help in defining pseudocomponents.

So long as the specific composition of the gas phase is not crucial to the reservoir situation, the black-oil model can work well. The engineer must determine how important the effect of changing composition is on fluid properties, and ultimately on the revenue stream from a field. A compositional model may be required in the following situations:

- gas injection, due to gas stripping
- miscible flooding, as the injection gas goes into solution with oil
- carbon dioxide flooding with the gas soluble in both oil and water
- thick reservoirs with a compositional gradient due to gravity
- reservoirs with areal variations in fluid composition
- reservoirs near the critical point
- high-pressure, high-temperature reservoirs.

Equation-of-state modeling. Parameters describing pseudocomponents are tuned by comparing laboratory measurements (blocks) to pseudocomponent model output (lines). Hydrocarbon liquid density (green) and saturation pressure (purple) are shown as functions of gas composition.
The operator sought to understand in detail the relationship between injectors and producers to allocate water injection and manage the waterfloods. A well-by-well examination using the NWFB model can identify problems with water influx, illustrating whether water comes from the aquifer or a nearby injection well (above). Based on such an analysis, BP altered the injection program, including redrilling wells and adjusting injection allocation. After these changes, flow patterns were more localized, and water injection was reduced by 40% (next page).

BP maintains FrontSim reservoir models for all Prudhoe Bay waterflood areas, considering them an important tool for day-to-day reservoir management. These models run in one or two hours, making them useful in assessing new well locations for waterflooding and in predicting enhanced oil recovery.

Managing Reservoirs from Cradle to Grave
Radical ups and downs in oil prices drive the industry toward two extremes of reservoir management. Some operators in mature areas want to produce as much oil and gas as possible with minimal expenditure of capital and engineering resources. They seek simple engineering solutions. Although reservoir simulation may never be possible “on the back of an envelope,” these users drive the need for an intuitive user interface. Therefore, to succeed, future computer programs must have intelligent defaults so novice users can obtain reasonable solutions quickly.

At the other end of the spectrum are large fields, both under production or still in delineation and exploration phases, where huge capital investments must be protected with the best engineering available. Developers will improve algorithms and internal design of simulators to satisfy the voracious need for more gridblocks, more complexity and more speed to solve large problems.

Parallel processing has been an option in reservoir simulators for several years, but in the future, it will become the default method, particularly for models with multimillion gridblocks. This requires improvements in the way processors communicate with one another and better tools that divide simulation models into sections that are logically consistent and easy for the program to handle.

The modeler faces two major tasks that need improved automation. First, the user must design the grid, which can be made easier through automated links with geologic models and improved importation of gridblock data from geologic to reservoir models. Closer linking of these two types of models will help geologists use reservoir models when assessing prospects.

Second, the modeler must match the production history of the field. Complete automation of history matching is probably far in the future, but in the near term, optimization routines will help
users focus their efforts on identifying variables with the greatest influence on solutions. Engineering judgment will continue to play a key role. However, improved history-matching routines could revolutionize simulator algorithms.

Most of the preceding discussion relates to user interfaces or the way models will change internally. With improvements, other disciplines will find reservoir simulators more useful. Already available, the Weltest 200 module provides engineers with a numerical tool for evaluating well tests. In addition, the MSW option of ECLIPSE software provides new possibilities for completion engineers to analyze multilateral wells and some intelligent downhole control devices.

Efforts are under way to improve models in the near-well region. Greater flexibility in well placement within models will help optimize future well locations, not just to the level of one gridblock versus another, but to define well location within a few meters. Engineers and geoscientists will be able to evaluate the influence of faults and natural fractures, sand or shale lenses, and zone pinchouts, to cite a few geologic examples, as well as interaction of existing wellbores and flood fronts.

Today, reservoir simulators include simple relations to earth stresses. Modeling of stress changes is done using rock mechanical models. The future will see simulators capable of solving flow and earth-stress models simultaneously. Reservoirs with significant compaction and subsidence need these integrated solutions to ensure reservoir energies are assessed correctly. Permeability increase or decrease due to compaction must be related to stress changes. More production practices will be included in reservoir models as modules are added to numerically handle fracturing and sand production and control. Further in the future, drilling-bit interaction with formations may become a standard part of models, accounting for formation damage and drilling-fluid invasion as well as breakouts and cave-ins.

Until a few years ago, astronomers and astrophysicists didn’t have the ability to detect planets around other stars, but they improved detection techniques and planetary-system models. Now it seems every few months more new planetary objects are found. In our industry, the idea of a single program providing discovery-to-abandonment modeling for a reservoir is a dream for the distant future, but the elements exist to make it happen sooner rather than later. —MAA