Simulation is one of the most powerful tools for guiding reservoir management decisions. From planning early production wells and designing surface facilities to diagnosing problems with enhanced recovery techniques, reservoir simulators allow engineers to predict and visualize fluid flow more efficiently than ever before.

Reservoir simulators were first built as diagnostic tools for understanding reservoirs that surprised engineers or misbehaved after years of production. The earliest simulators were physical models, such as sandboxes with clear glass sides for viewing fluid flow, and analog devices that modeled fluid flow with electrical current flow. These models, first documented in the 1930s, were constructed by researchers hoping to understand water coning and breakthrough in homogeneous reservoirs that were undergoing waterflood.

Some things haven’t changed since the 1930s. Today’s reservoir simulators generally solve the same equations studied 60 years ago—material balance and Darcy’s law. But other aspects of simulation have changed dramatically. With the advent of digital computers in the 1960s, reservoir modeling advanced from tanks filled with sand or electrolytes to numerical simulators. In numerical simulators, the reservoir is represented by a series of interconnected blocks, and the flow between blocks is solved numerically. In the early days, computers were small and had little memory, limiting the number of blocks that could be used. This required simplification of the reservoir model and allowed simulation to proceed with a relatively small amount of input data.

As computer power increased, engineers created bigger, more geologically realistic models requiring much greater data input. This demand has been met by the creation of increasingly complex and efficient simulation programs coupled with user-friendly data preparation and result-analysis packages. Today, desktop computers may have 5000 times the memory and run about 200 times faster than early supercomputers. However, the most significant gain has not been in absolute speed, but speed at a moderate price. Computational efficiency has reached a stage that allows powerful simulators to be run frequently.

Numerical simulation has become a reservoir management tool for all stages in the life of the reservoir. No longer just for comparing performance of reservoirs under different production schemes or trouble-shooting when recovery methods come under scrutiny, simulations are also run when planning field development or designing measurement campaigns. In the last 10 years, with the development of computer-aided geological and geostatistical modeling, reservoir simulators now help to test the validity of the reservoir models themselves. And simulation results are increasingly used to guide decisions on investing in the construction or overhaul of expensive surface facilities.

**Motivation for Simulation**

A numerical simulator containing the right information and in the hands of a skilled engineer can imitate the behavior of a reservoir. A simulator can predict production under current operating conditions, or the reaction of the reservoir to changes in conditions, such as increasing production rate; production from more or different wells; response to injection of water, steam, acid; or other fluids.
Creating models for input to reservoir simulators. The first-generation geomodel is created through the combined efforts of geologists, geophysicists, petrophysicists and reservoir engineers. Reservoir properties are then upscaled to produce the static reservoir model. Optimizing the grid and calibrating with dynamic data yield the simulation model. Finally, input from surface facilities analysis and risk calculations results in an execution model that can guide reservoir management decisions.

How a Simulator Works

The function of reservoir simulation is to help engineers understand the production-pressure behavior of a reservoir and consequently predict production rates as a function of time. The future production schedule, when expressed in terms of revenues and compared with costs and investments, helps managers determine both economically recoverable reserves and the limit of profitable production.

Once the goal of simulation is determined, the next step is to describe the reservoir in terms of the volume of oil or gas in place, the amount that is recoverable and the rate at which it will be recovered. To estimate recoverable reserves, a model of the reservoir framework, including faults and layers and their associated properties, must be constructed. This so-called static model is created through the combined efforts of geologists, geophysicists, petrophysicists and reservoir engineers (left). Much of the multi-billion-dollar business of oilfield services is centered on obtaining information that

Creating models for input to reservoir simulators. The first-generation geomodel is created through the combined efforts of geologists, geophysicists, petrophysicists and reservoir engineers. Reservoir properties are then upscaled to produce the static reservoir model. Optimizing the grid and calibrating with dynamic data yield the simulation model. Finally, input from surface facilities analysis and risk calculations results in an execution model that can guide reservoir management decisions.
eventually feeds reservoir simulators, leading to better reservoir development and management decisions.

The simulator itself computes fluid flow throughout the reservoir. The principles underlying simulation are simple. First, the fundamental fluid-flow equations are expressed in partial differential form for each fluid phase present. These partial differential equations are obtained from the conventional equations describing reservoir fluid behavior, such as the continuity equation, the equation of flow and the equation of state. The continuity equation expresses the conservation of mass. For most reservoirs, the equation of flow is Darcy’s law. For high rates of flow, such as in gas reservoirs, Darcy’s law equations are modified to include turbulence terms. The equation of state describes the pressure-volume or pressure-density relationship of the various fluids present. For each phase, the three equations are then combined into a single partial differential equation. Next, these partial differential equations are written in finite-difference form, in which the reservoir volume is treated as a numbered collection of blocks and the reservoir production period is divided into a number of time steps. Mathematically speaking, the problem is discretized in both space and time.

Examples of simulators that solve this problem under a variety of conditions are found in the ECLIPSE family of simulators. These simulators fall into two main categories. In the first category are three-phase black-oil simulators, for reservoirs comprising water, gas and oil. The gas may move into or out of solution with the oil. The second category contains compositional and thermal simulators, for reservoirs requiring more detailed description of fluid composition. A compositional description could encompass the amounts and properties of hexanes, pentanes, butanes, benzenes, asphaltenes and other hydrocarbon components, and might be used when the fluid composition changes during the life of the reservoir. A thermal simulator would be advised if changes in temperature—either with location or with time—modified the fluid composition of the reservoir. Such a description could come into play in the case of steam injection, or water injection into a deep, hot reservoir.

Block-centered and corner-point geometries. Block-centered geometry features flat-topped rectangular blocks that match the mathematical models behind the simulator. Corner-point geometry modifies the rectilinear grid so that it conforms to important reservoir boundaries. Three-dimensional grids are constructed from a 2D grid by laying it on the top surface of the reservoir and projecting the grid vertically or along fault planes onto lower layers.

Local grid refinement (LGR). Local grid refinement allows engineers to describe selected regions of the reservoir in extra detail. Radial refined grids are often used around wellbores to examine coning or other phenomena resulting from rapid variation in properties away from the well. Refined grids are also one way to treat property variations near faults.
Engineers require more detail in many parts of the reservoir. However, this approach does not easily translate directly into the desired rock and fluid properties. How are these disparate data sets merged?

Two processes are required: extrapolating the well data into the interwell reservoir volume, then upsampling the fine-scale data to the scale of a simulation grid block. Traditionally log or core data were upscaled, or averaged, over lithological units at the wells. Then these data were interpolated and extrapolated through the reservoir and maps produced for each layer—formerly a handcrafting exercise by geologists. The maps would be passed to the reservoir engineer who would then generate grids, run preliminary simulations on a series of grid sizes, and attempt further upsampling based on the reservoir flow characteristics.

In recent years, the process has been reversed. The current trend is to use computer programs to build 3D geological models bounded by seismic data, and to populate the models using geostatistical or deterministic methods to distribute log and core data. Scaling core and log properties up to grid-block scales is still a challenging task. Some properties, such as porosity, are considered simple to upscale, following an arithmetic averaging law. Others, such as permeability, are more difficult to average. And relative permeabilities—different permeabilities for different fluid phases—remain the most difficult problem in upsampling. There is no universally accepted method for upsampling, and it is an area of active research.

After the model has been finalized, the simulator requires boundary conditions to establish the initial conditions for fluid behavior at the beginning of the simulation. Then, for a given time later, known as the time step, the simulator calculates new pressures and saturation distributions that indicate the flow rates for each of the mobile phases. This process is repeated for a number of time steps, and in this manner both flow rates and pressure histories are calculated for each point—especially the points corresponding to wells—in the system.

But even with the best possible model, uncertainty remains. One of the biggest jobs...
Visualizing the reservoir model in 3D. Visualization is a reliable means of checking reservoir models before input to a simulator. Inconsistencies in model parameters may be flagged and corrected. After simulation, results may also be viewed, allowing faster evaluation of comparative simulation runs and providing insight into recovery behavior. In this example reservoir pressure is color-coded to show regions of high and low pressure.

A simulation run itself can also help reduce uncertainty. Outside the oil industry, simulators are used to determine the reaction of a known environment to externally applied perturbations. An example is a flight simulator that tests varying visibility conditions. Although a reservoir environment is largely unknown, simulators can help improve the description. In a process known as history matching, reservoir production is simulated based on the existing, though uncertain, reservoir description. That description is adjusted iteratively until the simulator is able to reproduce the observed pressures and multiphase flow resulting from applied perturbations—that is, the known production and injection. If the production history can be matched, the engineer has greater confidence that the reservoir description will be a useful, predictive tool. The history-matching process is time-consuming and requires considerable skill and insight, but is a necessary prerequisite to the successful prediction of continued reservoir performance.

These new techniques and programs for loading data, computing simulations and viewing results are allowing engineers to use simulators to guide reservoir management decisions throughout the life of many fields. The following case studies highlight some of the uses of simulators in four different stages of reservoir maturity.
Because of overpressure conditions in the reservoir, the rock is expected to compact with depressurization. This means the rock is expected to decrease its porosity and effective permeability as production progresses. To quantify these effects, laboratory experiments were conducted on rock samples. The experiments showed that at the assumed well abandonment pressure of 4000 psi, permeability would be reduced by about 33% from the initial value, while porosity would be negligibly reduced.

Modeling flow in condensate reservoirs requires additional considerations. As pressure drops around the well, condensation, or dropout, occurs and liquid forms. The liquid saturation increases—in what is called condensate banking—until it is great enough to overcome capillary trapping forces and the liquid becomes mobile. But until the liquid becomes mobile, the presence of immobile liquid reduces the relative permeability to gas, resulting in a loss in productivity. The rapid change in fluid saturation away from the well requires a fine grid to accurately model reservoir properties. The ECLIPSE compositional simulator modeled the regions around the wells with a refined radial grid, and the remainder with a Cartesian grid.

In addition, condensate yields vary between the four different reservoirs, so each reservoir fluid was represented by its own equation of state. The local grid refinement and multiple equation of state capabilities were added to the ECLIPSE simulator for this project, and now form part of the commercial package.

The simulation was used to conduct uncertainty analysis for risk management. To maximize revenues, the tactic is to maximize gas rates without being penalized for coming up short. To understand the risks behind promising a given gas rate, it is desirable to understand the sensitivity of the simulation results to each important input parameter. In this case, repeated simulations indicated that the parameters with the

Developments in Gridding

Since the first grids were built, the variety, range and resolution of oilfield measurements have increased, and computer power and efficiency have grown. To take advantage of these developments, reservoir engineers require better and more comprehensive simulation software tools. Modern 3D seismic acquisition, processing and interpretation techniques have resulted in more reliable and higher-resolution definition of faults and erosional surfaces. The engineer wants to represent the full complexity of nonvertical faults, curving or listric faults, and faults that intersect or truncate against one another. Another development that requires more complex models is the increasing use of high-angle and horizontal wells and multilateral wells. These requirements stretch the traditional gridding programs based on corner-point geometry—such as the GeoQuest GRID program—to the limit.

This has led to the development of new gridding software techniques such as the FloGrid utility, which will produce grids that conform to the reservoir framework as defined by fault surfaces and lithological boundaries. Unstructured perpendicular bisector (PEBI) and tetrahedral grid systems are being developed and included in gridding and simulation programs (above right). “Blocks” in a PEBI grid may have a variety of shapes, and they may be arranged to fit any reservoir geometry. The smoother grid-block shape gives a more accurate simulation solution because there is less chance of choosing the wrong grid orientation.

Unstructured PEBI grids are of great benefit in these situations, allowing the radial components of flow into the wellbore to be combined with linear or planar features such as the trajectory of a horizontal well or a fault plane. Simulations run with PEBI grids tend to take longer than those run on structured grids, but the ability to capture the structural complexity of the reservoir’s flow units outweighs the need for speed. A compromise can be reached by building a structured grid in the geologically simple parts of the reservoir, and splicing in an unstructured grid when geologic complexity requires more flexibly shaped grid blocks.


Deliverability and cumulative production distributions were calculated from the sensitivity results using the parametric method developed for oilfield applications by P.J. Smith and coworkers at British Petroleum. A normalized average profile was combined with these distributions in a Monte Carlo simulator to give a probabilistic production profile.

The results of the risk analysis showed the effects of different production scenarios on the level of confidence in ability to deliver various possible contracted rates of gas over the initial plateau period. The required 90% confidence level for a three-year plateau period was achieved by modifying the production rate in the first year, adding a contingency well in the third year, and commingling production in one well between the main Erskine reservoir and the smaller but higher-permeability Kimmeridge reservoir.

As a result, Texaco has modified production plans, which now call for a lower production rate in the first year than in subse-
quent years. Risk analysis suggested an additional well in the third year, so platform construction has allowed a slot for a contingency well. In addition, production from the Erskine and Kimmeridge reservoirs will also be commingled.

Infill Drilling
Infill drilling is an expensive stage in the life of a reservoir. Simulation, in conjunction with other tools, can help guide the placement of wells and minimize their number. British Petroleum has harnessed simulation along with new reservoir description to optimize infill drilling in the Forties field in the North Sea (right).

The Forties field was discovered in 1970, and produced its first oil in 1975 (middle). Current production is from five platforms, with 78 producers and 25 peripheral injectors. Estimated recovery of the 4.2 billion stock tank barrels (STB) of original oil in place (OOIP) is 60%, or 90% of the movable oil.

The field is characterized by high permeability, high net-to-gross (NTG) pay thickness and a strong aquifer. A few years ago the Forties was considered to be essentially a homogeneous reservoir. But early water breakthrough and water fingering indicated a greater level of heterogeneity than expected, and suggested the need for more wells to be drilled to reach bypassed zones.

To understand the potential of infill drilling in the field, a simulation study was conducted, including careful reinterpretation of existing 3D seismic data and a new reservoir description. The required 90% confidence level (bottom line) was achieved by reducing the production rate in the first year, adding a well in the third year and commingling production from the Kimmeridge and Erskine reservoirs.

### Results of risk analysis ranking some of the simulated production scenarios. The required 90% confidence level (bottom line) was achieved by reducing the production rate in the first year, adding a well in the third year and commingling production from the Kimmeridge and Erskine reservoirs.
voir characterization to describe the heterogeneities encountered in the turbidite sandstone reservoir.

Simulation with a coarse full-field model allowed identification of regions that might benefit from infill wells, but the results were not refined enough for detailed well placement. Once a region was identified as containing possible infill well locations, other aspects were considered, such as: water cut and production of surrounding wells; interference tests confirming continuity or lack thereof with other layers; and reinterpretation of 3D seismic data for channel identification—prospective locations tend to be along submarine channel margins, where there is lower vertical permeability and so less efficient sweep.

Having passed these tests, the area was tapped for a new simulation study with local grid refinement spotlighting the volume of interest (below right). The refined grid block size was about 50 by 50 m [164 ft by 164 ft] in area by 8 m [26 ft] in depth. Reservoir properties were distributed in the LGR grid based on a geostatistical model. Then the flow in the LGR grid was simulated with the ECLIPSE black-oil simulator and checked against the production history from wells in the grid. The property distribution was modified and simulation rerun. This process was repeated until a history match was obtained, with only six iterations required.

The final simulation based on the refined grid predicted a fluid distribution at the Forties Alpha 31 sidetrack (FA31ST) location (above right). The predicted fluid distribution closely resembled that encountered and the predicted oil production matched the current rate. However, the predicted net-to-gross rock volume of the upper zone was optimistic relative to measured values. Lessons learned from this work have been fed back into subsequent studies with, for example, seismic attributes helping to characterize the NTG variation in the reservoir. Simulation played a similar role in assessing the potential for infill drilling around the other platforms.
Planning Enhanced Oil Recovery

In an example of simulation later in reservoir life, PanCanadian Petroleum Limited is relying on simulation to examine the feasibility of CO\textsubscript{2} injection in Unit 1 in the Weyburn field of Saskatchewan, Canada (right).\textsuperscript{12} This field was discovered in 1955 and put on waterflood in 1964. By 1994, recovery had reached 314 million STB, or 28\% of the unit’s original oil in place. Ultimate waterflood recovery is expected to be 348 million STB, or 31\%, leaving a large target for enhanced recovery methods. An opportunity to take advantage of one method, gravity segregation via CO\textsubscript{2} injection, is presented by the division of the reservoir into swept and unswept layers. Carbon dioxide injected into the lower, more permeable formation has the potential to contact large amounts of unswept oil in the tight upper formation since CO\textsubscript{2} is 30\% less dense than the reservoir fluids at the expected operating pressures (below right).

Evaluating the feasibility of CO\textsubscript{2} injection proceeded in stages. First, using the GeoQuest fluid PVT simulation software, a nine-component equation of state was developed that reproduced the behavior of the oil-CO\textsubscript{2} system. The equation of state also had to predict the development of dynamic miscibility in flow simulations while still representing the physical properties of the oil-CO\textsubscript{2} mixtures. The equation was validated by comparison of simulated and laboratory floods on cores.

Second, general performance parameters were established for the formations to be swept. These included CO\textsubscript{2} slug size, a water-alternating-gas injection strategy, CO\textsubscript{2} start-up pressure and post-CO\textsubscript{2} blow-down pressure.\textsuperscript{13} Then various orientations of injectors, producers and horizontal wells were tested with the ECLIPSE compositional


\textsuperscript{13} Blow-down pressure is the average field pressure maintained after CO\textsubscript{2} injection is stopped. Usually this is lower than during CO\textsubscript{2} injection to maximize oil recovery due to expansion of CO\textsubscript{2}. 

\begin{table}[h]
\centering
\begin{tabular}{|c|c|c|c|}
\hline
\textbf{Gamma Ray (API)} & \textbf{Density Porosity} & \textbf{Neutron Porosity} & \textbf{Porosity (\%)} \\
\hline
0 & 150 & 45 & -13 \\
\hline
\end{tabular}
\end{table}

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{division_of_reservoir.png}
\caption{Division of the reservoir into swept and unswept layers, opening the opportunity for gravity segregation of injected CO\textsubscript{2}. Carbon dioxide (blue arrows) injected into the lower, more permeable formation will rise to displace the oil (green arrows) remaining in the tight, unswept upper formation.}
\end{figure}
Each original nine-spot pattern was found to require two symmetrically positioned horizontal wells in the upper zone to take advantage of the CO₂ segregation process. Results of the parametric pattern studies, using a 30% pore volume CO₂ slug, indicated ultimate recovery without any new horizontal wells to be an estimated 37% of OOIP. By adding two horizontal wells in each injection pattern, simulation predicted incremental recovery of 7.2%.

On the Surface
Once hydrocarbons have made it up the wellbore, most reservoir engineers consider their job done. But tracking fluid movement through a complex surface network with chokes, valves, pumps, pipelines, separators and compressors remains a daunting task. Optimizing flow through the surface network allows production managers to minimize capital investment in surface facilities and fine-tune field planning.

Reservoir simulators are not designed to solve for fluid flow all the way through the surface-gathering facility, but they can be integrated with network simulators built for this purpose. An example of such a network simulator is the Simulation Sciences PIPEPHASE system. The PIPEPHASE simula-
tor, based on a pressure-balance technique developed originally at Chevron in the 1980s, has been adapted to handle large, field-wide, multiphase flow networks, including wells, flowlines and associated surface facilities. Through a joint project between Geoquest Reservoir Technologies and Simulation Sciences, the PIPEPHASE simulator and the NETOPT production optimizer are being integrated with the Open-ECLIPSE system to provide a way to simulate fluid flow seamlessly from reservoir through surface network (previous page, top). Integration is achieved through an iterative algorithm that minimizes the differences between the well flow rates calculated by the two simulators from a given set of flowing well pressures.

The recent focus on integrated reservoir management teams is a major step in the direction of integrated reservoir and surface network simulation. But the emphasis has been on integration at the upstream end. The next step is to focus at the production and surface facilities end.

Traditionally, the integrated study has been approached along two independent paths. For a project involving pressure maintenance through water injection, for example, the impact on the reservoir has been studied in isolation. The reservoir simulation is carried out with a simplified well model: hydraulic behavior of injection or production wells is approximated through flow tables derived from single-well analysis. A second study is typically performed by the facilities engineering group to evaluate the impact of the injection water requirements on the surface facilities. The reservoir behavior at the well is incorporated through an injectivity index relating injection rate to pressure drop at the formation.

A limitation of this divided approach is that it ignores the true interaction between the elements of the surface network, the production and injection wells, and the reservoir. The results of a truly integrated study could be quite different.

The iterative approach to integrating the PIPEPHASE and ECLIPSE systems, while rigorous, may be limited by convergence issues in more complex applications. The truly integrated solution, with the surface and reservoir equations solved simultaneously, is expected to require a large effort, since significant restructuring will be needed in both simulators. One promising approach is to initially develop a simple single-phase application for a gas field. The experiences developed in this effort could then be extended to address the larger problem of multiphase fluids.

The Next Step
The future of reservoir simulators may parallel developments in other oilfield technologies that provide a view of fluid and rock behavior in the subsurface. For example, the seismic industry, operating on a similar physical scale and on equally staggering amounts of data, has turned to massively parallel processors (MPPs) for data processing and to high-performance graphics workstations for visualization of the results.

Simulation computer codes are being prepared for implementation on MPPs, but the switch cannot be made quickly. A simulator typically solves the fluid-flow equations one grid block at a time. The solution does not necessarily benefit by processing several steps in parallel.

For a typical simulation, doubling the number of processors cuts simulation time almost in half, and increasing to 16 processors reduces the time to one-tenth (above). Departure from ideal speed gains—16 times faster for 16 processors—is due to three factors. First, the parallel linear equation solution method is less efficient than the non-parallel solution. Second, it takes time to assemble and transfer data between processes. And third, load balancing between processors is uneven: some parts of the reservoir are easier to solve than others, but the simulation must wait for the slowest. Also, the high cost of MPPs targets them for hard-won data, simulation plays a key role in making sense of data acquired through different physical experiments, at different times, at different spatial scales. Simulation is one of the few tools available for understanding the changes a reservoir experiences throughout its life. Used together with other measurements, simulation reinforces conclusions based on other methods and leads to a higher degree of confidence in our understanding of the reservoir. —LS